EB-2022-0200

EGI PANEL 1

COMPENDIUM OF MATERIALS

SCHOOL ENERGY COALITION

[Blank page inserted intentionally]

Allocation of Rate Base Costs to Rate Classes

Category	Total	Rate 1	Rate 6	Rate M1	Rate M2	Rate 01	Rate 10	Total	Percentage
Rate Base	16,281,096	5,973,078	2,600,252	3,507,836	622,116	1,075,879	151,755	13,930,916	85.6%
Return on Rate Base	955,722	350,628	152,638	205,915	36,519	63,156	8,908	817,764	85.6%
Depreciation	892,000	343,164	138,342	203,629	31,563	62,194	7,580	786,472	88.2%
Income Tax	121,754	44,668	19,445	26,232	4,652	8,046	1,135	104,178	85.6%
Property Tax	127,183	46,104	20,850	26,337	4,691	8,156	1,179	107,317	84.4%
Total Rev. Req. (capital)	2,096,659	784,564	331,275	462,113	77,425	141,552	18,802	1,815,731	86.6%
Total Revenue Requirement	6,312,905	2,322,283	1,211,058	1,408,048	281,908	422,217	68,643	5,714,157	90.5%
Less: Cost of Gas	3,251,888	1,152,070	739,698	717,615	173,233	218,234	42,354	3,043,204	93.6%
Net Dx Revenue Requirement	3,061,017	1,170,213	471,360	690,433	108,675	203,983	26,289	2,670,953	87.3%
Percent Capital	68.5%	67.0%	70.3%	66.9%	71.2%	69.4%	71.5%	68.0%	

Source Exhibit 7/2/1/2

2024 Cost Allocation Study - Current Rate Classes
Revenue Requirement Summary by Rate Class

/u

Line No.	Particulars ($000s)	Revenue Requirement	EGD Rate Zone Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Return on Rate Base												
1	Rate Base	16,281,096	5,973,078	2,600,252	6,927	189,674	26,129	67,097	3,237	1,838	4,429	31,702	-
2	Rate of Return on Rate Base	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%
3	Total Return on Rate Base	955,722	350,628	152,638	407	11,134	1,534	3,939	190	108	260	1,861	-
4	Depreciation Expense	892,000	343,164	138,342	347	9,048	1,226	3,468	313	93	197	1,182	-
	Taxes												
5	Income Tax	121,754	44,668	19,445	52	1,418	195	502	24	14	33	237	-
6	Property Tax	127,183	46,104	20,850	55	1,563	213	672	5	3	16	231	-
7	Total Taxes	248,936	90,772	40,295	107	2,982	409	1,173	30	17	49	469	-
	Operating & Maintenance Expenses												
8	Cost of Gas	3,251,888	1,152,070	739,698	3,562	38,932	5,167	787	1,538	307	4,953	32,758	-
9	Storage	30,285	8,494	7,272	22	583	55	1	0	4	18	186	-
10	Transmission	12,038	2,143	1,912	7	219	46	-	1	-	-	51	-
11	Distribution	101,331	42,060	15,519	34	868	100	508	40	15	24	63	-
12	General Operating & Engineering	197,654	77,583	30,497	81	2,166	255	960	57	22	42	272	-
13	Sales Promotion & Merchandise	186,670	71,347	30,408	297	3,380	1,057	177	1,043	318	380	43	-
14	Distribution Customer Accounting	125,998	64,842	7,436	79	2,049	105	19	197	24	56	127	-
	Administrative & General Expense												
15	Employee Benefits	176,362	70,148	25,379	140	3,169	387	596	315	68	113	222	-
16	Administrative & General	219,654	89,272	30,717	152	3,437	416	689	317	70	119	297	-
17	Total Operating & Maintenance Expenses	4,301,880	1,577,958	888,839	4,374	54,804	7,587	3,738	3,508	828	5,705	34,020	-
18	Total Revenue Requirement	6,398,539	2,362,522	1,220,115	5,235	77,967	10,755	12,317	4,040	1,046	6,211	37,531	-
19	Other Revenue	85,633	40,239	9,057	25	719	163	31	36	15	128	176	-
20	Total Revenue Requirement Less Other Revenue	6,312,905	2,322,283	1,211,058	5,209	77,248	10,592	12,286	4,004	1,030	6,083	37,355	-

2024 Cost Allocation Study - Current Rate Classes
Revenue Requirement Summary by Rate Class (Continued)

/u

Line		Union North Rate Zone					Union South Rate Zone									
No.	Particulars ($000s)	Rate 01	Rate 10	Rate 20	Rate 25	Rate 100	Rate M1	Rate M2	Rate M4 (F)	Rate M4 (I)	Rate M5 (F)	Rate M5 (I)	Rate M7 (F)	Rate M7 (I)	Rate M9
		(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)
	Return on Rate Base														
1	Rate Base	1,075,879	151,755	76,027	15,946	26,234	3,507,836	622,116	151,250	38	1,731	2,116	191,432	3,099	11,718
2	Rate of Return on Rate Base	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%
3	Total Return on Rate Base	63,156	8,908	4,463	936	1,540	205,915	36,519	8,879	2	102	124	11,237	182	688
4	Depreciation Expense	62,194	7,580	3,896	827	1,428	203,629	31,563	7,496	1	102	192	8,967	123	503
	Taxes														
5	Income Tax	8,046	1,135	569	119	196	26,232	4,652	1,131	0	13	16	1,432	23	88
6	Property Tax	8,156	1,179	695	167	249	26,337	4,691	1,311	0	13	3	1,603	6	94
7	Total Taxes	16,201	2,314	1,263	286	445	52,570	9,343	2,442	0	26	19	3,035	29	182
	Operating & Maintenance Expenses														
8	Cost of Gas	218,234	42,354	9,348	1,380	1,316	717,615	173,233	24,014	3	160	1,039	23,039	1,358	4,825
9	Storage	1,575	432	145	0	2	4,994	1,709	489	0	4	0	771	13	54
10	Transmission	395	116	40	-	-	1,262	468	166	-	1	-	246	-	20
11	Distribution	7,659	877	483	118	206	25,204	3,739	719	0	12	27	809	17	35
12	General Operating & Engineering	13,911	1,762	994	231	376	45,461	7,292	1,739	0	23	40	2,020	27	110
13	Sales Promotion & Merchandise	7,141	1,583	1,418	86	896	45,155	6,749	5,862	2	47	434	3,764	395	27
14	Distribution Customer Accounting	11,169	205	306	24	57	36,425	826	1,112	-	33	143	298	21	33
	Administrative & General Expense														
15	Employee Benefits	12,140	1,373	1,004	156	340	41,060	5,772	2,674	1	43	170	2,117	88	95
16	Administrative & General	15,540	1,649	1,115	179	375	52,120	6,908	2,880	1	45	172	2,403	92	116
17	Total Operating & Maintenance Expenses	287,764	50,352	14,853	2,174	3,568	969,296	206,696	39,655	6	368	2,026	35,467	2,011	5,315
18	Total Revenue Requirement	429,316	69,154	24,475	4,223	6,982	1,431,409	284,121	58,472	10	598	2,361	58,706	2,345	6,687
19	Other Revenue	7,098	510	215	10	17	23,361	2,213	472	0	6	32	675	38	61
20	Total Revenue Requirement Less Other Revenue	422,217	68,643	24,260	4,214	6,965	1,408,048	281,908	57,999	10	592	2,329	58,031	2,307	6,626

2024 Cost Allocation Study - Current Rate Classes
Revenue Requirement Summary by Rate Class (Continued)

/u

Line		Union South Rate Zone					Ex-Franchise									
No.	Particulars ($000s)	Rate T1 (F)	Rate T1 (I)	Rate T2 (F)	Rate T2 (I)	Rate T3	Rate 331	Rate 332	Rate 401	Rate C1 (F)	Rate C1 (I)	Rate M12	Rate M13	Rate M16	Rate M17
		(aa)	(ab)	(ac)	(ad)	(ae)	(af)	(ag)	(ah)	(ai)	(aj)	(ak)	(al)	(am)	(an)
	Return on Rate Base														
1	Rate Base	66,715	118	563,547	3,282	60,637	60	205,295	-	10,917	226	625,724	24	54	2,957
2	Rate of Return on Rate Base	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%	5.870%
3	Total Return on Rate Base	3,916	7	33,081	193	3,559	4	12,051	-	641	13	36,731	1	3	174
4	Depreciation Expense	3,163	7	23,804	169	2,536	1	5,148	-	480	2	30,664	0	0	147
	Taxes														
5	Income Tax	499	1	4,214	25	453	0	1,535	-	82	2	4,679	0	0	22
6	Property Tax	550	1	4,509	35	470	0	633	-	103	0	6,630	0	0	35
7	Total Taxes	1,049	2	8,723	59	923	0	2,168	-	184	2	11,310	0	0	57
	Operating & Maintenance Expenses														
8	Cost of Gas	1,300	67	14,550	75	1,408	-	-	-	7,712	3,070	25,358	123	450	85
9	Storage	207	-	1,569	-	344	1	4	-	32	2	1,297	0	0	4
10	Transmission	83	-	1,054	-	105	-	51	-	51	-	3,592	-	-	7
11	Distribution	298	1	1,704	24	157	-	-	-	-	-	-	-	-	11
12	General Operating & Engineering	736	2	5,286	47	561	0	1,241	-	61	0	3,767	0	0	31
13	Sales Promotion & Merchandise	962	80	3,458	28	109	-	-	-	-	-	21	-	-	-
14	Distribution Customer Accounting	217	-	193	-	5	-	-	-	-	-	-	-	-	-
	Administrative & General Expense														
15	Employee Benefits	757	11	3,992	30	434	0	508	-	49	1	2,988	0	0	20
16	Administrative & General	849	11	4,697	34	528	0	586	-	63	1	3,783	0	0	23
17	Total Operating & Maintenance Expenses	5,410	172	36,503	239	3,651	1	2,390	-	7,968	3,074	40,806	123	451	181
18	Total Revenue Requirement	13,538	188	102,111	660	10,670	6	21,757	-	9,272	3,091	119,510	125	455	558
19	Other Revenue	40	0	271	1	22	-	-	-	-	-	-	-	-	-
20	Total Revenue Requirement Less Other Revenue	13,498	188	101,839	659	10,648	6	21,757	-	9,272	3,091	119,510	125	455	558

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-10-5, p.23

Question(s):

Please provide a detailed analysis of the risk responsibilities of customers, shareholders, and any others for the costs associated with the natural gas system if the transition does not move from natural gas to hydrogen/RNG, as Enbridge proposes.

Response:

As noted in paragraph 71 of Exhibit 1, Tab 10, Schedule 5, the diversified pathway described in the P2NZ Study is only one version of a diversified energy transition pathway that may unfold. Enbridge Gas looks forward to working with the electricity sector, its customers and its stakeholders to ensure customers have access to reliable, resilient, affordable and lower emissions energy based on the government's energy transition policies.

Enbridge Gas has invested shareholder capital to serve its customers under a regulatory compact that allows the Company to earn a fair rate of return and for the recovery of prudently invested capital through the rates charged to its customers. Enbridge Gas expects its underground storage, transmission and distribution assets to be used or useful for the foreseeable future due to their current capacity to deliver vast amounts of energy annually, and on a peak basis, inherent resiliency and reliability and the low cost of connecting to the gas system.

The Company notes that the current cost of staying connected to the system for its low volume customers provides unparalleled resiliency relative to the electricity system at under $50/month for the average customer. In particular, Table 1 shows that the unit capital cost of delivering annual and peak hour energy in the form of natural gas is approximately a quarter of the unit cost of delivering annual and peak hour electricity in Ontario. These unit costs do not include the much higher cost of building out the electric system in today's dollars, nor do they reflect the much higher cost of burying electrical infrastructure underground to provide equivalent resiliency. Hydro Ottawa, for instance, states on its website that burying its electrical wires will cost $10 billion and take 90 years and that burying electrical infrastructure costs 11 times more than overhead infrastructure at $2-$4 million per kilometre.[1] It is Enbridge Gas's view that the 150,000 kilometres of buried gas transmission, storage and distribution infrastructure, with a net book value of $16.7 billion in 2021, is an extremely valuable asset for Ontario that must be factored into energy transition policies. Please also see response at Exhibit I.1.10-SEC 13.

Table 1

Unit Cost to build out today's energy systems		
	Gas System	Electricity System
Net Property, plant and equipment ($)(1)	16,661,687,725	25,550,529,231
Annual Energy (kWh)(2)	272,242,600,000	117,804,064,413
Peak Energy(3)	82,262,906	24,341,946
Annual $/kWh (4)	0.06	0.22
Peak $/kW (5)	202.54	1,050

Notes:

(1) Net property plant and equipment from the 2021 OEB Yearbooks for gas and electricity systems
(2) Annual energy from 2021 OEB Yearbook, cubic metres of gas expressed in KWh by adjusting for calorific value of 39.12 divided by 3.6

(3) Highest peak hour flow measured on Feb 16, 8 a.m converted to kW

(4) Net property, plant and equipment divided by annual energy

(5) Net property, plant and equipment divided by peak energy

References:
2021 OEB Year book for Gas Distributors:
https://www.oeb.ca/oeb/_Documents/RRR/2021_Yearbook_of_Natural_Gas_Distributors.pdf
2021 OEB Year book for Electricity Distributors, Pivot Table Tab :
https://www.oeb.ca/sites/default/files/yearbook-Unitized-Statistics-and-Other-2021.xlsx

Enbridge Gas expects to fully recover from its customers the cost of prudently invested long-lived capital and operating and maintenance costs of providing safe, reliable and affordable energy to them. Increasing the fixed charges to connect to the system as proposed in this application will provide cost recovery even if the amount of natural gas consumed is gradually displaced by non-emitting electricity. Should the government institute a policy mandating disconnection from the gas system, the Company expects that it will accelerate recovery of its invested capital through regulatory measures such as higher depreciation rates and other tools including cost allocation changes to reflect a changing customer mix over time.

[1] Hydro Ottawa (2022) Between the lines: Overhead vs. underground. Available at https://hydroottawa.com/en/blog/between-lines-overhead-vs-underground#:~:text=For%20a%20full%20scope%20look,about%2090%20years%20to%20complete.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-2-1, p.12

Question(s):

Please confirm that at no time during the stakeholdering of this Application did Enbridge, or its consultants, tell customers that they would be responsible for paying the cost of any new or existing assets stranded due to the energy transition.

Response:

Confirmed.

government and stakeholders work to determine how best to achieve net-zero, Enbridge Gas believes that if energy transition is to be implemented in an orderly manner, that delaying all action is not an option. Despite the uncertainty that exists, there are safe bet actions that can and need to be taken now.

36. Enbridge Gas considers an action to be a safe bet if it:
    a) Supports Ontario's near term GHG reductions, including achievement of the 2030 target; and/or
    a) Is required, regardless of whether a diversified or an electrification pathway unfolds in Ontario; and/or
    b) Maintains consumer choice, a safe and reliable gas system in a manner that considers pathway uncertainty, and/or pathway optionality until greater certainty around how best to transition is obtained.

37. The safe bet actions that have shaped Enbridge Gas's ETP are:
    a) Maximizing energy efficiency;
    b) Increasing the amount of RNG in the gas supply;
    c) Reducing GHG emissions from the industrial and transportation sectors via fuel switching and CCUS;
    d) Integrating gas and electric system planning; and
    e) Supporting consumer choice and the energy transition journey.

38. With the ETP based upon these identified safe bets and objectives, Enbridge Gas believes the ETP, and its associated rebasing application proposals, are prudent as they support continued progress towards a net-zero future despite current policy uncertainty, but they don't overinvest in a particular pathway prior to the Ontario government defining its future energy transition plans in more detail.

39. Enbridge Gas's ETP includes actions ranging from those which Enbridge Gas has been undertaking for some time, such as Demand Side Management (DSM), to actions that the Company is in the early stages of exploring, such as CCUS. Enbridge Gas notes that not all actions discussed within its ETP have associated proposals within the rebasing application. In some cases, where noted, the safe bet action requires additional provincial government policies, investments, and/or OEB support to move forward. A discussion of all actions Enbridge Gas is exploring, or pursuing has been included to provide the OEB with a full picture of the role Enbridge Gas can play in supporting Ontario's energy transition, both during the rebasing term and over the longer term. Enbridge Gas may bring forward applications in the future to implement additional actions contemplated in its ETP or in future iterations.

40. Table 1 identifies, for each safe bet, the ETP rebasing proposal, where applicable. Following Table 1 is a more detailed overview of each safe bet and the associated actions that Enbridge Gas is proposing, pursuing, or exploring.

Table 1
Summary of Energy Transition Related Rebasing Proposals

Safe Bet	Enbridge Initiative	Rebasing Proposal	Proposal Related Evidence
Maximizing Energy Efficiency	DSM	• No proposal. • The DSM Plan for 2023-2027 is currently pending OEB approval through a separate application[31]	Not applicable

[31] EB-2021-0002

Investing in Renewable Natural Gas (RNG)	Voluntary RNG Program	Proposal: • Discontinue the current pilot Voluntary RNG (VRNG) program and establish a Low-Carbon Voluntary Program (LCVP) for large volume sales service customers. • Procure up to 1% of the planned gas supply commodity purchases as low-carbon energy beginning in 2025 and increasing by 1% annually up to 4% in 2028. • Include any costs not recovered through the LCVP in the cost of gas supply commodity purchases.	Exhibit 4, Tab 2, Schedule 7
	RNG upgrading	• No proposal. • Note: Enbridge Gas's Asset Management Plan (AMP) includes strategies to support investments for RNG injection stations.	Exhibit 2, Tab 6, Schedule 2
Decarbonizing the Industrial and Transportation Sectors	Industrial fuel switching	• No proposal. • Note: Enbridge Gas's AMP includes strategies to support investments for RNG injection stations.	Exhibit 2, Tab 6, Schedule 2
	Carbon Capture and Sequestration (CCS)	• No proposal.	Not applicable

	Natural Gas Vehicle (NGV) Program	Proposal: • Expand the NGV program in the EGD rate zone to all Enbridge Gas franchise areas, continued operation of the NGV Program as part of the utility business activities. • Modify the current regulatory treatment to remove the need for revenue imputation, such that the NGV Program is funded solely by the monthly service rates charged to participating customers over the life of the program. • Note: Enbridge Gas's AMP includes strategies to support investments for NGV stations.	Exhibit 1, Tab 14, Schedule 2 Exhibit 2, Tab 6, Schedule 2
Integrating Gas and Electric System Planning	Optimizing energy system planning	• No proposal.	Not applicable
Supporting Consumer Choice and the Energy Transition Journey	Hydrogen Blending Grid Study (HBGS)	Proposal: • Conduct a full evaluation of the hydrogen-readiness of the natural gas grid in Ontario. Costs are estimated at $12 million.	Exhibit 4, Tab 2, Schedule 6
	Low Carbon Energy Project (LCEP) Phase 2	• No proposal in the Rebasing application. • Enbridge Gas intends to pursue approval for and implementation of Phase 2 of the LCEP through	Exhibit 4, Tab 2, Schedule 7

		an upcoming Leave-to-Construct application. An estimate of the cost of Phase 2 of LCEP is currently projected at $7.0 million.	
	Energy Transition Technology Fund (ETTF)	Proposal: • Approval of an Energy Transition Technology Fund in the amount of $5 million per year, totaling $25 million over the 2024 to 2028 period. Enbridge Gas is proposing to fund the ETTF through a rate rider.	Exhibit 1, Tab 10, Schedule 7
	Maintaining the Gas System – via Integrated Resource Planning (IRP) and Scope 1 & 2 emissions reductions focus	• No proposal in the Rebasing application • Note: Enbridge Gas's AMP (Appendix B) provides information on IRP alternatives. • Note: Enbridge Gas's AMP includes projects to support scope 1 and 2 GHG emission reductions.	IRP: Exhibit 2, Tab 6, Schedule 2, Appendix B Scope 1 & 2: Exhibit 2, Tab 6, Schedule 2

41. The following sub-sections describe each safe bet and the associated actions within each that Enbridge Gas is proposing, pursuing, or exploring.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 209

To take under advisement as when by additional years.

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

The impacts presented below do not include 2024 PREP forecast in-service additions, consistent with the Capital Update, and related rate base impacts in future years. /u

This request asked Enbridge Gas to expand the response provided at Exhibit I.1.2-SEC-6 to provide an estimate of Enbridge Gas's total rate base each year until 2033.

Total rate base forecast for years 2024 to 2028 is provided in Table 1.

Table 1
2024 to 2028 Rate Base

($ millions)	2024	2025	2026	2027	2028	
Rate base	16,212.3	16,275.4	17,366.8	17,820.6	18,136.5	/u

Enbridge Gas is not providing a rate base forecast for the 2029 to 2032 period. This information does not relate to the relief requested in this Application. Any rate base amounts post 2028 would be subject to the rate setting mechanism(s) in place at that time, not yet proposed or known by the Company. Directionally, and based on the information and requests contained in the immediate Application, Enbridge Gas would expect rate base to increase from 2029 to 2032, however the average annual growth rate in rate base over that period would be less than the average annual growth rate from 2024 to 2028.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Issue 1

Reference:

Ex. B/1/1, p. 8

Question(s):

Please provide details of the Applicant's "longer term natural gas savings reduction target" including, without limiting the generality of the foregoing:

a) The Applicant's current twenty year forecast of natural gas throughput, by year and by rate class, before the impact of any DSM programs,
b) The economic growth, carbon price, and other key assumptions used in that forecast,
c) The impact of DSM programs, by year and by rate class, on total natural gas throughout, and
d) The net twenty year forecast of natural gas throughput, by year and by rate class, after the impact of any DSM programs.

Please provide all reports, memoranda, presentations or other documents in the possession of the Applicant relating to its current or immediately preceding "longer term natural gas savings reduction targets".

Response:

a) The Company does not have a twenty-year forecast of natural gas volumes. Below, please find the current forecast for 2022-2031 by year, and rate class, before the forecasted impact of DSM program activity from 2022-2031.

Enbridge Gas Inc.
EGI Volumes by Rate Classes (10^3 m^3)
Before DSM

General Service/Rate Zone	Rate Class	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EGD	Rate 1	5,109,043	5,145,845	5,190,599	5,233,660	5,278,180	5,321,402	5,362,525	5,401,399	5,438,456	5,473,321
EGD	Rate 6	4,734,934	4,802,659	4,848,973	4,899,333	4,954,533	5,009,561	5,063,948	5,117,790	5,171,370	5,224,904
Union South	M1	3,139,151	3,159,248	3,194,936	3,199,477	3,218,945	3,237,490	3,270,502	3,271,656	3,287,502	3,302,501
Union South	M2	1,293,515	1,300,581	1,313,513	1,315,442	1,322,573	1,329,335	1,341,151	1,341,769	1,347,483	1,352,840
Union North	R01	1,026,564	1,032,064	1,043,883	1,045,373	1,052,202	1,058,603	1,069,783	1,070,534	1,076,991	1,078,939
Union North	R10	368,185	369,127	371,707	371,192	372,210	373,104	375,441	374,499	376,662	373,871
Total		15,671,392	15,809,526	15,963,611	16,064,478	16,198,643	16,329,495	16,483,351	16,577,647	16,698,464	16,806,377

Contract Market / Rate Zone	Rate Class	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EGD	Rate 100	31,607	31,607	31,607	31,607	31,607	31,607	31,607	31,607	31,607	31,607
EGD	Rate 110	1,089,746	1,147,246	1,147,246	1,147,246	1,147,246	1,147,246	1,147,246	1,147,246	1,147,246	1,147,246
EGD	Rate 115	365,312	375,312	375,312	375,312	375,312	375,312	375,312	375,312	375,312	375,312
EGD	Rate 125	558,826	558,826	558,826	558,826	558,826	558,826	558,826	558,826	558,826	558,826
EGD	Rate 135	55,937	59,362	59,362	59,362	59,362	59,362	59,362	59,362	59,362	59,362
EGD	Rate 145	17,614	25,939	25,939	25,939	25,939	25,939	25,939	25,939	25,939	25,939
EGD	Rate 170	245,795	253,710	253,710	253,710	253,710	253,710	253,710	253,710	253,710	253,710
EGD	Rate 200	188,317	188,317	188,317	188,317	188,317	188,317	188,317	188,317	188,317	188,317
EGD	Rate 300	123	123	123	123	123	123	123	123	123	123
EGD	Rate 315	-	-	-	-	-	-	-	-	-	-
Union North	Rate_20	795,311	802,954	803,282	803,282	803,282	816,970	816,970	816,970	830,657	830,657
Union North	Rate_25	91,136	91,137	89,182	89,183	89,184	89,185	89,186	89,187	89,188	89,189
Union North	Rate_100	1,030,213	1,097,713	1,112,841	1,112,841	1,112,841	1,112,841	1,112,841	1,112,841	1,112,841	1,112,841
Union South	Rate_M4	593,926	629,947	642,678	655,428	668,178	680,928	693,678	706,428	719,178	731,928
Union South	Rate_M5	62,606	62,606	62,606	62,606	62,606	62,606	62,606	62,606	62,606	62,606
Union South	Rate_M7	685,612	721,860	756,922	791,985	827,047	862,110	897,172	932,235	967,297	1,002,360
Union South	Rate_M9	88,845	88,845	88,845	88,845	88,845	88,845	88,845	88,845	88,845	88,845
Union South	Rate_M10	360	360	360	360	360	360	360	360	360	360
Union South	Rate_T1	415,616	422,616	422,616	422,616	422,616	422,616	422,616	422,616	422,616	422,616
Union South	Rate_T2	4,230,819	4,244,414	4,260,351	4,276,289	4,369,058	4,384,996	4,477,765	4,493,703	4,586,472	4,602,410
Union South	Rate_T3	264,209	264,209	264,209	264,209	264,209	264,209	264,209	264,209	264,209	264,209
Total		10,811,930	11,067,102	11,144,334	11,208,085	11,348,668	11,426,107	11,566,690	11,630,441	11,784,711	11,848,462
Total EGI Volumes (Before DSM)		26,483,322	26,876,628	27,107,945	27,272,563	27,547,311	27,755,602	28,050,041	28,208,087	28,483,175	28,654,839

b) The economic growth, carbon price, and other key assumptions used in that forecast are attached as Attachment 1.

c) Below, please find the forecasted impact of DSM program activity from 2022-2031[1], by year and by rate class, used in Enbridge Gas's forecast of natural gas throughput

[1] These values are based on historical DSM savings by rate class and do not correspond with the forecasted DSM savings underpinning this application. These values were inputs into Enbridge Gas's 2022-2031 Long Range Planning process, which was completed prior to finalization of this application.

Enbridge Gas Inc.
EGI DSM Volumes by Rate Classes (10^3 m^3)

General Service/Rate Zone	Rate Class	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EGD	Rate 1	4,771	16,515	28,258	40,002	51,746	63,489	75,233	86,977	98,721	110,464
EGD	Rate 6	10,755	37,230	63,705	90,180	116,654	143,129	169,604	196,079	222,553	249,028
Union South	M1	4,380	15,163	25,945	36,728	47,510	58,292	69,075	79,857	90,640	101,422
Union South	M2	2,658	9,202	15,746	22,289	28,833	35,376	41,920	48,463	55,007	61,551
Union North	R01	834	2,887	4,940	6,993	9,045	11,098	13,151	15,204	17,257	19,310
Union North	R10	328	1,136	1,944	2,752	3,561	4,369	5,177	5,985	6,793	7,601
Total		23,727	82,133	140,538	198,943	257,349	315,754	374,160	432,565	490,970	549,376

Contract Market / Rate Zone	Rate Class	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EGD	Rate 100	369	1,277	2,185	3,093	4,001	4,909	5,817	6,725	7,633	8,541
EGD	Rate 110	1,464	5,066	8,669	12,272	15,874	19,477	23,080	26,682	30,285	33,888
EGD	Rate 115	1,833	6,345	10,857	15,369	19,881	24,394	28,906	33,418	37,930	42,442
EGD	Rate 125	-	-	-	-	-	-	-	-	-	-
EGD	Rate 135	383	1,326	2,269	3,212	4,154	5,097	6,040	6,983	7,926	8,869
EGD	Rate 145	-	-	-	-	-	-	-	-	-	-
EGD	Rate 170	172	596	1,019	1,443	1,867	2,290	2,714	3,137	3,561	3,985
EGD	Rate 200	-	-	-	-	-	-	-	-	-	-
EGD	Rate 300	-	-	-	-	-	-	-	-	-	-
EGD	Rate 315	-	-	-	-	-	-	-	-	-	-
Union North	Rate_20	855	2,958	5,062	7,166	9,269	11,373	13,477	15,580	17,684	19,788
Union North	Rate_25	-	1	2	3	4	5	6	7	8	9
Union North	Rate_100	444	1,536	2,629	3,722	4,814	5,907	6,999	8,092	9,184	10,277
Union South	Rate_M4	5,840	20,215	34,590	48,965	63,340	77,715	92,091	106,466	120,841	135,216
Union South	Rate_M5	290	1,005	1,719	2,433	3,148	3,862	4,577	5,291	6,005	6,720
Union South	Rate_M7	5,430	18,797	32,163	45,529	58,896	72,262	85,629	98,995	112,362	125,728
Union South	Rate_M9	-	-	-	-	-	-	-	-	-	-
Union South	Rate_M10	-	-	-	-	-	-	-	-	-	-
Union South	Rate_T1	289	999	1,710	2,421	3,131	3,842	4,553	5,263	5,974	6,684
Union South	Rate_T2	2,916	10,093	17,271	24,448	31,626	38,803	45,981	53,158	60,336	67,513
Union South	Rate_T3	-	-	-	-	-	-	-	-	-	-
Total		20,284	70,214	120,145	170,075	220,006	269,936	319,867	369,798	419,728	469,659
Total DSM Volumes		44,011	152,347	260,683	369,019	477,355	585,691	694,027	802,362	910,698	1,019,034

d) Below, please find the current forecast for 2022-2031 by year, and rate class, after the forecasted impact of DSM program activity from 2022-2031 (see part c, footnote 1).

Enbridge Gas Inc.
EGI Volumes by Rate Classes (10^3 m^3)
Net forecast-after DSM

General Service/Rate Zone	Rate Class	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EGD	Rate 1	5,104,272	5,129,331	5,162,340	5,193,658	5,226,434	5,257,913	5,287,292	5,314,422	5,339,735	5,362,857
EGD	Rate 6	4,724,179	4,765,429	4,785,268	4,809,154	4,837,878	4,866,432	4,894,345	4,921,712	4,948,816	4,975,876
Union South	M1	3,134,770	3,144,086	3,168,991	3,162,749	3,171,434	3,179,198	3,201,427	3,191,798	3,196,862	3,201,079
Union South	M2	1,290,856	1,291,379	1,297,768	1,293,153	1,293,741	1,293,958	1,299,232	1,293,306	1,292,476	1,291,289
Union North	R01	1,025,730	1,029,177	1,038,943	1,038,381	1,043,157	1,047,504	1,056,632	1,055,330	1,059,735	1,059,630
Union North	R10	367,857	367,990	369,762	368,440	368,649	368,735	370,264	368,514	369,869	366,270
Total		15,647,665	15,727,393	15,823,073	15,865,534	15,941,294	16,013,741	16,109,191	16,145,082	16,207,494	16,257,001

Contract Market / Rate Zone	Rate Class	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EGD	Rate 100	31,239	30,331	29,423	28,515	27,607	26,699	25,791	24,883	23,975	23,067
EGD	Rate 110	1,088,282	1,142,179	1,138,577	1,134,974	1,131,371	1,127,769	1,124,166	1,120,563	1,116,961	1,113,358
EGD	Rate 115	363,479	368,967	364,455	359,943	355,431	350,919	346,407	341,895	337,382	332,870
EGD	Rate 125	558,826	558,826	558,826	558,826	558,826	558,826	558,826	558,826	558,826	558,826
EGD	Rate 135	55,553	58,036	57,093	56,150	55,207	54,264	53,321	52,379	51,436	50,493
EGD	Rate 145	17,614	25,939	25,939	25,939	25,939	25,939	25,939	25,939	25,939	25,939
EGD	Rate 170	245,623	253,114	252,691	252,267	251,843	251,420	250,996	250,573	250,149	249,725
EGD	Rate 200	188,317	188,317	188,317	188,317	188,317	188,317	188,317	188,317	188,317	188,317
EGD	Rate 300	123	123	123	123	123	123	123	123	123	123
EGD	Rate 315	-	-	-	-	-	-	-	-	-	-
Union North	Rate_20	794,457	799,996	798,220	796,117	794,013	805,597	803,493	801,390	812,973	810,870
Union North	Rate_25	91,136	91,136	89,180	89,180	89,180	89,180	89,180	89,180	89,180	89,180
Union North	Rate_100	1,029,770	1,096,177	1,110,212	1,109,120	1,108,027	1,106,935	1,105,842	1,104,750	1,103,657	1,102,564
Union South	Rate_M4	588,086	609,732	608,088	606,463	604,838	603,212	601,587	599,962	598,337	596,712
Union South	Rate_M5	62,316	61,601	60,887	60,172	59,458	58,744	58,029	57,315	56,601	55,886
Union South	Rate_M7	680,182	703,063	724,759	746,455	768,151	789,848	811,544	833,240	854,936	876,632
Union South	Rate_M9	88,845	88,845	88,845	88,845	88,845	88,845	88,845	88,845	88,845	88,845
Union South	Rate_M10	360	360	360	360	360	360	360	360	360	360
Union South	Rate_T1	415,327	421,617	420,906	420,195	419,485	418,774	418,063	417,353	416,642	415,931
Union South	Rate_T2	4,227,903	4,234,321	4,243,081	4,251,841	4,337,432	4,346,193	4,431,784	4,440,544	4,526,136	4,534,896
Union South	Rate_T3	264,209	264,209	264,209	264,209	264,209	264,209	264,209	264,209	264,209	264,209
Total		10,791,646	10,996,888	11,024,189	11,038,010	11,128,662	11,156,170	11,246,823	11,260,643	11,364,983	11,378,804
Total EGI Volumes (after DSM)		26,439,311	26,724,281	26,847,262	26,903,544	27,069,956	27,169,911	27,356,014	27,405,725	27,572,477	27,635,805

Table: Key Economic assumptions used in the Enbridge's Average use per Customer / Volume forecast

	Employment; 15 years and over; Seasonally adjusted (x 1,000); Persons	Unemployment rate (%)	GDP: Gross domestic product at market prices (x 1,000,000); Dollars	Consumer Price Index (CPI), 2005 basket; All-items; 2002=100	Enbridge Gas Natural Gas prices (¢/m^3)*						Commodity prices (cents/m^3)			Federal Carbon Charges**		Vacancy Rates	
Level	Ontario	Ontario	Ontario	Ontario	Rate 1	Rate 6	Rate M1	Rate M2	Rate 01	Rate 10	Enbridge	Henry Hub	Dawn	($/tCO2e)	(¢/m3)	GTA Commercial	GTA Industrial
2015	6,845	6.8	724,946	127.4	36.50	29.22	32.57	22.49	41.43	27.83	12.72	12.47	13.90			7.75	4.35
2016	6,922	6.6	740,164	129.7	34.36	26.64	28.12	18.75	37.80	23.93	10.13	12.16	12.53			7.75	3.43
2017	7,053	6.1	761,025	131.9	39.17	31.36	35.56	29.62	47.11	33.71	11.18	14.43	14.54			7.20	2.73
2018	7,173	5.7	782,115	135.0	37.46	29.24	32.31	23.55	45.10	31.30	9.76	14.58	14.99			6.48	1.88
2019	7,375	5.6	798,213	137.5	35.98	27.54	32.44	23.09	42.61	29.62	10.62	12.56	11.86	20.00	3.91	5.60	1.38
2020	7,026	9.6	753,889	138.4	39.31	30.49	34.70	24.35	43.30	29.85	8.85	10.48	9.24	30.00	5.87	6.70	1.70
2021	7,337	8.1	796,129	141.5	44.31	35.54	37.92	26.38	46.19	32.00	11.69	13.52	13.52	40.00	7.83	6.70	1.70
2022	7,579	6.3	829,506	144.4	46.73	37.93	39.34	28.95	49.34	35.07	11.99	13.87	13.58	50.00	9.79	6.70	1.70
2023	7,663	6.1	843,921	147.3	47.32	38.49	40.87	30.08	50.91	36.26	12.22	14.14	13.70	51.00	9.99	6.70	1.70
2024	7,747	5.9	860,870	150.2	47.86	39.00	41.67	30.65	51.74	36.87	12.39	14.34	13.99	52.02	10.19	6.70	1.70
2025	7,832	5.7	881,138	153.2	48.41	39.52	42.58	31.25	52.68	37.50	12.57	14.54	14.27	53.06	10.40	6.70	1.70
2026	7,918	5.5	901,884	156.3	48.97	40.05	43.46	31.84	53.58	38.13	12.76	14.76	14.56	54.12	10.61	6.70	1.70
2027	8,006	5.4	923,118	159.4	49.55	40.60	44.34	32.45	54.50	38.77	12.95	14.99	14.86	55.20	10.82	6.70	1.70
2028	8,094	5.3	944,852	162.6	50.14	41.15	45.18	33.05	55.37	39.41	13.15	15.21	15.15	56.31	11.04	6.70	1.70
2029	8,183	5.2	967,098	165.8	50.73	41.72	46.18	33.70	56.38	40.09	13.34	15.44	15.47	57.43	11.26	6.70	1.70
2030	8,273	5.1	989,867	169.2	51.34	42.29	47.11	34.33	57.33	40.76	13.55	15.67	15.77	58.58	11.49	6.70	1.70
2031	8,364	5.1	1,013,173	172.5	51.96	42.88	48.08	34.99	58.31	41.45	13.75	15.91	16.10	59.75	11.72	6.70	1.70

*Burner tip gas prices that excludes Rate Riders and HST

**Greenhouse Gas Pollution Pricing Act, Schedule 2 and 4

Figure 2: Annual Volumetric Gas Demand by Scenario (m3)

Year	Steady Progress	Reference Case	Electricity Centric	Diversified Portfolio
2019	25,162,554,893	25,162,553,580	25,162,554,699	25,162,554,774
2020	25,115,879,327	25,360,221,687	25,257,208,162	25,257,136,202
2021	25,182,659,402	25,570,675,761	25,349,529,231	25,348,981,389
2022	25,259,393,250	25,780,886,392	25,450,388,613	25,471,602,632
2023	25,011,983,148	25,824,098,754	25,473,541,920	25,457,064,561
2024	24,803,531,044	25,869,114,505	25,320,780,989	25,381,342,109
2025	24,622,383,275	25,972,479,976	24,919,303,737	25,220,634,343
2026	24,405,856,221	25,932,543,902	23,864,048,374	24,863,378,083
2027	24,194,714,941	25,982,975,696	22,916,820,018	24,640,173,150
2028	24,049,220,277	26,005,604,048	21,915,603,498	24,365,697,688
2029	23,759,714,605	26,026,425,887	20,768,422,130	23,884,083,152
2030	23,763,857,757	26,259,383,371	19,678,077,493	24,167,638,404
2031	23,542,398,233	26,310,851,594	18,470,132,000	24,210,005,455
2032	23,469,060,953	26,368,140,367	17,441,750,581	24,270,464,347
2033	23,232,737,162	26,428,573,641	16,409,951,355	24,817,168,435
2034	22,948,928,085	26,491,522,802	15,422,665,691	25,153,232,324
2035	22,729,542,173	26,555,283,897	14,435,406,326	25,255,385,800
2036	22,496,117,450	26,618,871,983	13,676,532,249	26,146,504,223
2037	22,134,353,076	26,680,676,993	12,961,539,180	26,974,717,238
2038	21,848,810,518	26,739,843,947	12,248,785,986	27,842,707,794

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 69

To file the 2022 and 2023 scorecards.

Response:

The 2022 GDS Scorecard results are provided at Attachment 1. The 2023 GDS Scorecard is provided at Attachment 2.

▲ Above target (> 1.25 multiplier)
O On target (1.00 - 1.25 multiplier)
▼ Below target (< 1.00 multiplier)

GDS 2022 year-end results

Key performance indicator	Weight	Year-end target: Doesn't meet	Year-end target: Meets	Year-end target: Exceeds	Year-end
Ensure safe, reliable operations	**35%**	**0x**	**1x**	**2x**	
People not getting hurt Total recordable injury frequency (TRIF) per 200,000 employee and contractor hours worked	15%	1.00	0.76	0.68	▲
Environmental incident frequency (EIF) Number of environmental incidents (non-compliances) per 200,000 employee and contractor exposure hours	5%	0.26	0.18	0.15	▲
Pipeline system safety (PSS) Leak and release frequency (LRF) defined as: (Tier 1 Count x 10 + Tier 2 Count) x 1,000 kms/kms of pipelines	5%	0.21	0.10	0.08	▲
Total damages per 1,000 locates First, second and third party line breaks per 1,000 locate requests	5%	2.28	2.07	1.86	▼
Cybersecurity: predictive susceptibility to a real phishing attack Percent clicked on compliance phishing test	5%	6.9%	4.9%	2.9%	▲
Maintain financial strength and flexibility	**35%**				
Adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA)	35%	$1,784	$1,839	$1,894	▲
Progress toward our ESG goals	**10%**				
DE&I	5%				
Composite Net increase on overall diverse representation as a percentage of our workforce	3%	1.2%	1.5%	2.5%	▼
Composite Employee/leader training completion percentage of completion of Indigenous awareness training	2%	90%	95%	100%	▲
Emissions	5%				
GHG emissions reduction	5%	-8%	-4%	2%	▲
Execute and extend growth	**20%**				
EBITDA generated by growth capital (millions) Includes organic growth projects and M&A	20%	$17	$30	$58	O
Total	100%			2022 multiplier 1.40x	▲

ENBRIDGE
Life Takes Energy

GDS 2023 scorecard

		Year-end target		
Key performance indicator	**Weight**	**Doesn't meet**	**Meets**	**Exceeds**
Ensure safe, reliable operations	**35%**	**0x**	**1x**	**2x**
People not getting hurt Total recordable injury frequency (TRIF) per 200,000 employee and contractor hours worked	15%	0.81	0.72	0.68
Environmental incident frequency (EIF) Number of environmental incidents (non-compliances) per 200,000 employee and contractor exposure hours	5%	0.26	0.16	0.13
Process safety performance metric Leak and release frequency (LRF) defined as: (Tier 1 Count x 10 + Tier 2 Count) x 1,000 kms/kms of pipelines	5%	0.14	0.07	0.01
Total damages per 1,000 locates First, second and third party line breaks per 1,000 locate requests	5%	2.34	2.13	1.92
Cybersecurity: predictive susceptibility to a real phishing attack Percent clicked on compliance phishing test	5%	6.6%	4.6%	2.6%
Maintain financial strength and flexibility	**35%**			
Adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA)	35%	3% under budget	Meets budget	3% over budget
Progress toward our ESG goals	**10%**			
DE&I				
Representation Enterprise net increase in percentage of all diverse talent	5%	1.5%	2.0%	2.5%
Emissions				
GHG emissions Reducing methane: Optimize blowdown mitigation/recovery	5 %	0.0%	33.0%	36.5%
Execute and extend growth	**20%**			
EBITDA generated by growth capital (millions) Includes organic growth projects and M&A	20%	$17	$30	$58
Total	100%			

4 Critical Drivers

4.1 Defining Critical Drivers

Critical Drivers (CDs) are the key variables identified by Enbridge Gas and PG as most likely to impact Enbridge Gas' system over the next 20 years. PG and Enbridge Gas worked together to develop an initial list of CDs. Although there are countless variables that can or could impact Enbridge Gas' system, the project needed a finite list of variables to analyze.

The criteria for a variable to be included as a CD for the project were:

A) It was thought the variable would have a material impact on Enbridge Gas annual volume, peak hour and day, and/or GHG emissions in the next 20 years.
B) There was sufficient data available to predict what the variable could be in the next 20 years.

Enbridge Gas provided feedback on the long list of CDs and then a series of virtual meetings, called "Discovery Sessions", were hosted to discuss potential CDs with Enbridge Gas subject-matter expects and PG. The long list was adjusted based on the feedback and Discovery Sessions until a short-list of CDs was created for analysis in the ETSA project.

4.2 Input Assumptions for Critical Uncertainties

Once the list of CDs was established, PG and Enbridge Gas worked together to develop input assumptions for each CD. The input assumptions are meant to reflect the range of possible trajectories each CD are thought to plausibly take over the next 20 years. For each CD, a theoretical but plausible maximum and minimum bound were established to form the range of uncertainty for how each CD may evolve under various policy and economic conditions. For some CDs, the maximum setting would cause natural gas demand to decrease (e.g., higher carbon price, lower natural gas demand) and for some CDs, the maximum setting would cause natural gas demand to increase (e.g., customer accounts increase, gas demand increases). Exhibit 14 provides a description of each CD, how the CD impacts the model outputs, the maximum and minimum setting which reflects the range of input assumptions, and the data source used to develop the input assumptions.

Exhibit 14 – Critical Driver Input Assumptions

Critical Driver	Description	Impact on the model output	Maximum Setting	Minimum Setting	Data Source(s)
Carbon price	• The federal carbon charge applied to natural gas in Ontario (30% of the federal backstop carbon price was applied to Industrial customers to	• Gas demand: price increases, demand decreases and vice-versa	• The maximum value, \$282/tonne by 2030, is the price that the Parliamentary Budget Officer estimated would be required to meet Canada's	• The minimum value, \$50/tonne, is the price currently legislated for 2022 in the Greenhouse Gas	• GGPPA, and the Parliamentary Budget Office

Critical Driver	Description	Impact on the model output	Maximum Setting	Minimum Setting	Data Source(s)
	reflect the Output Based Pricing System[9])		2030 climate targets[10]	Pollution Pricing Act (GGPPA) • Post-2022, the carbon price is escalated by inflation	
Natural Gas Price	• Cost of natural gas including commodity price, and transportation, customer & distribution charges. Only the commodity price varied, while other bill charges were held constant[11]	• Price increases, gas demand decreases and vice-versa	• 400% higher than current natural gas commodity prices	• 50% of current natural gas commodity prices	• EGI
Climate Change	• Proxy for climate change is average temperature	• Gas demand for space heating: Warmer winters due to climate change are expected to reduce space heating demand;	• Average annual temperature increases by 3.3-5.9C in 2100 according to IPCC RCP 8.5 (Intergovernmental Panel on Climate Change worst-case climate scenario)[12] [13]	• No change (cooler average annual temperature not expected)	• IPCC & PG analysis

[9] Direction on the application of carbon price to Industrial customers was provided by Enbridge Gas to PG in an email titled "OBPS & EPS Stringency Factors" on November 10, 2020.
[10] Office of the Parliamentary Budget Officer, "Carbon pricing for the Paris target: Closing the gap with output-based pricing", 2020. [Online]. Available: https://www.pbo-dpb.gc.ca/en/blog/news/RP-2021-019-S--carbon-pricing-paris-target-closing-gap-with-output-based-pricing--tarification-carbone-accord-paris-combler-ecart-avec-tarification-fondee-rendement
[11] More details on cost of natural gas Critical Driver are provided in Appendix E.
[12] Intergovernmental Panel on Climate Change, "AR5 Synthesis Report: Climate Change", 2014.
[13] York University – Laboratory of Mathematical Parallel Systems, "Ontario Climate Data Portal", 2018. [Online]. Available: https://lamps.math.yorku.ca/OntarioClimate/index_v18.htm

Critical Driver	Description	Impact on the model output	Maximum Setting	Minimum Setting	Data Source(s)
		estimated using Enbridge Gas' weather-elasticities of demand			
Codes and standards: Retrofit	• Energy-related building codes and equipment standards for existing buildings that would apply to retrofits	• Gas demand for space and water heating declines as more stringent codes for equipment and building envelope take effect	• Mandatory retrofitting of the worst-performing 5% of buildings ever year post-2030 • Implementation of the Toronto Green Standard and similar codes in other municipalities, beginning in 2022[14]	• No change from current code	• Building Knowledge Canada, and research & analysis conducted by PG (details in Appendix C)
Codes and standards: New Construction	• Energy-related building codes and equipment standards applicable to new construction	• Gas demand for space and water heating declines as more stringent codes for equipment and building envelope take effect	• Energy performance targets from the National Energy Code of Canada for Buildings tiers 3, 4, and 5 are implemented for new buildings in 2025, 2030, and 2035 respectively[15] [16] • Implementation of the Toronto Green Standard and similar codes in other municipalities, beginning in 2022	• No change from current code	• Building Knowledge Canada, and research & analysis conducted by PG (details in Appendix C)
Enbridge Gas Customer	• Variation in Enbridge Gas'	• Gas demand increases or	• Annual account growth of about	• Annual account	• EGI

[14] Toronto Green Standard, "TGS Version 3", 2019. [Online]. Available: https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/toronto-green-standard/
[15] NECB 2020 Tiered Code (Part 3)
[16] NBC 2020 Tiered Code (Part 9)

POSTERITY GROUP

Critical Driver	Description	Impact on the model output	Maximum Setting	Minimum Setting	Data Source(s)
Account Growth Due to Population and Economic Growth	account forecast to account for uncertainty in population growth and economic conditions	decreases with the number of new buildings that do or do not connect to the gas grid	0.5% above Enbridge Gas' forecast growth of 0-1% growth from industrial, commercial, and residential accounts	growth of about 0.5% below Enbridge Gas' forecast growth of 0-1% growth from industrial, commercial, and residential accounts	
Non-Price Driven fuel-switching (gas to electricity)	• Regulatory requirements or customer policies that restrict the use of gas-fired space and water heating equipment	• Gas demand decreases and customers switch to electric equipment	• Beginning in 2025, no new gas connections, and space and water heating equipment at existing accounts is replaced with electric alternatives at the equipment's natural end of life	• No fuel-switching away from natural gas	• Enbridge Gas & PG analysis (details in Appendix C)
DSM Program Spending	• Annual Enbridge Gas DSM spending, as a percentage of the proposed 2022-2026 annual spending	• Higher spending decrease gas demand, and vise versa • Energy savings are estimated using PG's library of DSM measures, prepared for Enbridge Gas' DSM group	• Starting in 2022, a 3% year-over-year real increase in DSM spending. Starting in 2028, a 10% annual increase	• Starting in 2022, a 3% year-over-year real increase in DSM spending	• EGI
Natural Gas Transportation	• Transportation sector demand for natural gas	• Increased demand from transportation increases gas demand	• The Canada Energy Regulator's	• No change from 2019 levels	• Enbridge Gas & Canada's Energy Regulator

POSTERITY GROUP

Critical Driver	Description	Impact on the model output	Maximum Setting	Minimum Setting	Data Source(s)
			forecast of Ontario NGT demand[17]		
Renewable Natural Gas (RNG)	• The amount of RNG blended into Enbridge Gas' gas supply	• GHG Emissions: Increased supply of RNG decreases GHG emissions	• Mandated use of RNG requires about three billion cubic meters per year by 2038, which is 11% of reference case demand in 2038	• 0.005% of total sales volumes by 2030, the amount currently forecasted due to Enbridge Gas' existing voluntary RNG program	• EGI
Hydrogen (H2)	• The amount of low-carbon hydrogen blended into the Ontario gas supply	• GHG Emissions and volume: increase supply of H2 results in lower GHG emissions & increased volume of gas delivered because of hydrogen's energy density	• Hydrogen blending begins in the late 2025, consumption reaches 12 billion cubic meters per year in 2038, or about 14% of reference case demand in 2038, based on mandated hydrogen targets	• 0.003% of total sales volumes by 2030, the amount currently forecasted due to Enbridge Gas' approved Low Carbon Energy Project	• EGI
Carbon Capture and Storage (CCS) adoption	• The fraction of applicable industrial accounts that adopt CCS technology	• GHG emissions: CCS adoption increases, GHG emissions decrease	• Carbon capture is used for all process heating and power generation in refineries, chemicals, non-metallic minerals, primary metals, and utilities in the Union-South region, phased-in between 2028 and 2037	• No carbon capture and storage	• EGI

[17] Canada Energy Regulator, "Canada's Energy Future", 2019.

Treatment of Costs for RNG, Hydrogen and CCS

The costs of RNG, hydrogen, and CCS were not treated as CDs. Rather, these costs we used as an assumption to develop supply forecasts for RNG, hydrogen and CCS.

Critical Drivers Discussed but Excluded

The following items were discussed as possible CDs but ultimately were not selected as drivers because it was too difficult to obtain data to support modelling and/or the topic was included in another CD captured in the list above. The rationale for excluding these items as CDs is provided briefly below.

- DSM savings potential: This was not a CD, but a DSM budget was specified in the scenarios and the associated energy savings potential was included in the scenario results.
- Changing customer behaviours: Non-price driven fuel switching is a CD and designed to capture non-price reasons why customers may switch away from gas. Also, account defection was modelled in the Diversified Scenario to reflect customers leaving the gas system.
- Delivery charges: It was too difficult to forecast delivery charges and develop ranges of a forecast.
- Gas quality: It was too difficult to integrate gas quality considerations into the analysis.
- Clean Fuel Regulation: The CFR was not an explicit CD; however, the impacts of the CFR were included in terms of how it may influence the supply forecast for RNG, H2 and CCS from impacts on costs for these fuels.

5 Parametric Analysis & Boundary Establishment

This section provides an overview of the parametric analysis process and how the results of the parametric analysis define the boundaries (upper and lower limits) for the scenario analysis.

Parametric analysis is the process of determining the effect of varying one independent variable along a range of values on the dependent variable. For the ETSA project, the parametric analysis was conducted in the following steps:

- Establish the maximum and minimum bounds for the input assumptions for each CD.
- Estimate the impact from each CD over their range of input assumptions on system volume, peak consumption and GHG emissions while holding all other CDs constant.
- Establish the boundaries – the upper and lower bounds – for energy demand based on the combination of max/min settings for the CDs. This provides the boundaries of the scenario analysis.

The parametric analysis is a precursor to the scenario analysis which varies all the Critical Uncertainties to establish a combination of settings that vary from the Reference Case to estimate load under the combined effect of the Critical Uncertainties with specific settings.

5.1 Parametric Analysis Results

The parametric analysis provides insight into what CDs cause the largest impact on annual volumes, peak, and GHG emissions. It also provides the upper and lower bounds for the scenario analysis by setting all the CDs to their maximum and minimum settings to cause the largest increase and decrease in annual volumes. This section presents these results.

5.1.1 Sensitivity to Critical Drivers

How much change is caused to annual volumes of gaseous fuels, system peak, and GHG emissions for gaseous fuels relative to the Reference Case is established by setting each CD to the maximum or minimum setting, whichever is further from the Reference Case setting. The results below reflect the extreme of the values possible developed for this project so the results would vary if different bounds were developed. Note that the scenarios used settings for each Critical Driver that were not the maximum or minimum setting (input settings for each Critical Driver used to generate the scenarios is provided in 6.4.)

Using this approach, the input assumptions for the CDs (provided in Exhibit 14), and the key assumptions used for the modelling method (provided in Section 3), the CDs that had the largest estimated impacts are:

- *Non-price driven fuel switching:* Set to its maximum setting, there is an estimated 42% decline in annual volume by 2038, a 50% decline in hourly peak, a 55% decline in daily peak, and a 42% decline in GHG emissions, relative to the Reference Case caused by the non-price driven fuel switching CD.
- *Natural Gas Price:* Set to its maximum setting, there is an estimated 30% decline in annual volume by 2038, a 6% decline in hourly and daily peak, and a 30% decline in GHG emissions, relative to the Reference Case caused by increase in natural gas price.

- *Hydrogen:* Set to its maximum setting, there is an estimated 30% increase in annual volume and daily/hourly peak by 2038, and a 14% decline in GHG emissions, relative to the Reference Case caused by blending hydrogen into the gas system.

The CDs that had the smallest estimated impact are:

- *Natural gas transportation:* at the maximum setting, there is about a 1% increase in annual volume, daily/hourly peak and GHG emissions from natural gas demand compared to 2019 levels.
- *RNG and CCS:* RNG and CCS do not impact annual volume or peak, however both CDs do impact GHG emissions. At their maximum settings, RNG and CCS each cause an estimated 10% decline in GHG emissions.

Exhibit 15 provides a summary of the sensitivity for each CD in terms of the difference in annual volumes, peak and GHG emissions relative to the Reference Case forecast. Impacts have been rounded in this table. For further details, including changes in terms of m^3 and tonnes of CO2e, and to visualize these impacts, please see the “ESTA Critical Drivers Sensitivity Visualizer” dashboard in PowerBI.

Exhibit 15 – Sensitivity of Annual Volumes, Peak and GHG Emissions by Critical Driver

Critical Driver	Setting that deviates the most from the Reference Case assumption	Impact on Annual Volume by 2038	Impact on Peak	Impact on GHG Emissions by 2038
Carbon price	Max: $282/tonne.	22% decline	22% decline in hourly and daily peak	22% decline
Natural Gas Price	Max: 400% higher than current natural gas prices.	30% decline	~27% decline in hourly and daily peak	30% decline
Climate Change	Max: 3.4 degrees Celsius increase in average annual temperature by 2050.	4% decline	~6% decline in hourly and daily peak	4% decline
Codes and standards: Retrofit	Max: Mandatory retrofitting of the worst-performing 5% of buildings every year post-2030.	5% decline	~7% decline in hourly and daily peak	5% decline
Codes and standards: New Construction	Max: Energy performance targets from the National Energy Code of Canada for Buildings tiers 3, 4, and 5 are implemented for new buildings in 2025, 2030, and 2035 respectively; Implementation of the Toronto Green Standard and similar codes in other	9% decline	12% decline in hourly peak; 13% decline in daily peak	9% decline

Critical Driver	Setting that deviates the most from the Reference Case assumption	Impact on Annual Volume by 2038	Impact on Peak	Impact on GHG Emissions by 2038
	municipalities with community energy plans, beginning in 2022.			
Enbridge Gas Customer Account Growth Due to Population and Economic Growth	The Reference Case account growth is based on Enbridge Gas' 10-year customer account forecast. The maximum and minimum setting deviate equally from this forecast. Max: Annual account growth of .5% *above* Enbridge Gas' forecast growth of 0-1% growth from industrial, commercial, and residential accounts. Min: Annual account growth of 0.5% *below* Enbridge Gas' forecast growth of 0-1% growth from industrial, commercial, and residential accounts.	Max setting (increase in accounts): 8% increase Min setting (decrease in accounts): 8% decrease	Max setting (increase in accounts): 10% increase in hourly and daily peak Min setting (decrease in accounts): ~7% decrease in daily and hourly peak	Max setting (increase in accounts): 8% increase Min setting (decrease in accounts): 8% decrease
Non-Price Driven fuel-switching (gas to electricity)	Max: Beginning in 2025, no new gas connections, and space and water heating equipment at existing accounts must be replaced with electric alternatives at the equipment's natural end of life.	42% decline	Hourly peak: 50% decline Daily peak: 55% decline	42% decline
DSM Program Spending	Max: Starting in 2022, a 3% year-over-year real increase in DSM spending. Starting in 2028, a 10% annual increase.	12% decline	~14% decline in hourly and daily peak	12% decline
Natural Gas Transportation	Min: no change from 2019 volume. Max: Canada Energy Regulator's forecast of Ontario NGT demand.	1% increase	~1% increase in hourly and daily peak	1% increase
Renewable Natural Gas (RNG)	Max: Mandated use of RNG requires about three billion cubic meters per year by 2038, which is 11% of Reference Case demand in 2038.	No impact	No impact	10% decline
Hydrogen (H2)	Max: Hydrogen blending begins in 2025, consumption reaches 12 billion cubic meters per year in 2038, or about 14% of Reference Case demand in 2038, based on mandated hydrogen targets.	30% increase	30% increase in hourly and daily peak	14% decline

Critical Driver	Setting that deviates the most from the Reference Case assumption	Impact on Annual Volume by 2038	Impact on Peak	Impact on GHG Emissions by 2038
Carbon Capture and Storage (CCS) adoption	Max: Carbon capture is used for all process heating and power generation in refineries, chemicals, non-metallic minerals, primary metals, and utilities in the Union-South region, phased-in between 2028 and 2037.	No impact	No impact	10% decline

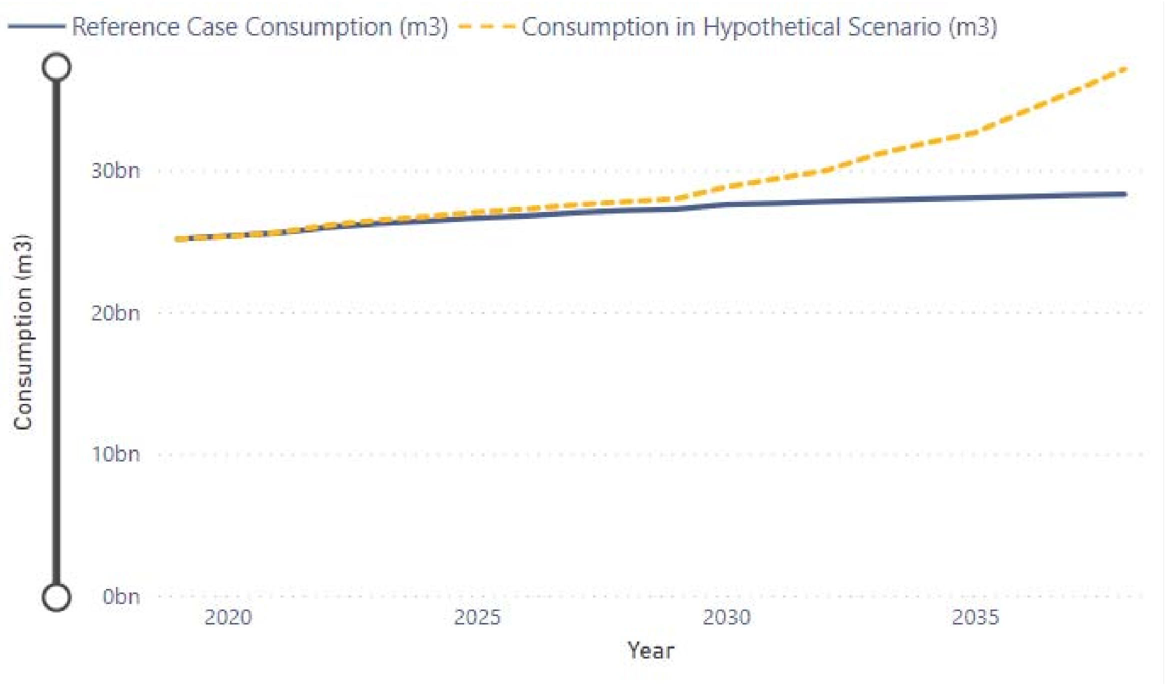
5.1.2 Upper and Lower Bounds

Setting all the CDs to their maximum/minimum setting such that the largest increase/decrease in annual volumes is created provides the upper and lower bounds. These bounds provide the “jaws” for which the scenarios should fall between. The bounds help set the most extreme expected change in annual volume based on the CDs.

Upper Bound

To create the upper bound (highest theoretical annual volume), all CDs are set to their minimum setting except for natural gas transportation, hydrogen, RNG, and customer account CDs, which are set to their maximum setting to increase annual volume as much as possible. Using these settings, the Upper Bound represents a 31% increase in total volume by 2038 relative to the Reference Case, as illustrated in Exhibit 16 (the ‘hypothetical scenario' is the upper bound).

Exhibit 16 – Upper Bound Annual Volume (m3)



below were taken to be representative of single-family houses in their gas regions. Note that this does not affect forecasted consumption, which was still calibrated to Enbridge Gas' forecasts, but does affect the applicability of DSM measures and codes and standards. For example, some DSM measures differ if they are applicable to attached or detached houses.

Exhibit 77 - Residential Housing Starts in 2020

	Attached/Row House Share of SF Accounts	Representative Region in CMHC Data	Attached/Row House Share of 2020 Housing Starts
EGD-GTA	33%	Toronto CMA	45%
EGD-Niagara	22%	St. Catherines-Niagara CMA	38%
EGD-Ottawa	41%	Ottawa CMA (Excluding Gatineau)	54%
Union - North	5%	Sudbury and Thunder Bay CMAs	31%
Union - South	16%	London and Windsor CMAs	33%
Total	26%	Ontario	44%

- Annual changes to UECs were calculated based on Enbridge Gas' forecasted consumption and account growth in that segment and region. For multi-family and low-income segments, the annual change in UEC was the growth rate of consumption divided by the growth rate of accounts. For the single-family segment, this was further adjusted so that the ratio of annual consumption in attached and detached houses remains constant in order to ensure the sum of the two segments equals Enbridge Gas' forecast.
- Added RNG and hydrogen based on expected volumes under Enbridge Gas' planned programs. Enbridge Gas provided RNG and hydrogen volume scenarios for the study. The lower bound of that forecast (planned programs only) was included in the Reference Case. This volume, about 0.01% of total demand in 2030, was added to the Reference Case, with fuel shares for conventional natural gas reduced accordingly so that overall energy demand remain the same.

Commercial Sector

The first year of the study period, the "base year" for the ETSA project is 2019.

The commercial sector was extracted from the "Com Ind" base year data files provided by EGI. The multi-family residential sector was removed (included in residential), and a subset of the "Com Ind" sectors were used to match with the APS segments in the commercial sector.

Commercial Base Year

Accounts

- Enbridge Gas' account data has a "Sector" field which was used to sort accounts into the APS segments. The mapping is presented in Exhibit 83 below.

7 Summary of Scenario Results

This section summarizes the key results for the Reference Case, Steady Progress, Diversified Portfolio, and Electricity Centric scenarios. Results are discussed in terms of annual volume, hourly and daily peak, and greenhouse gas (GHG) emissions. Results in 2030 and 2038 are compared to 2019 (the base year) as 2030 is a milestone year for many GHG targets and 2038 is the end of the forecast period. Results are presented for gaseous fuels only, which include fossil-based natural gas ('natural gas' for short), renewable natural gas (RNG), hydrogen, and natural gas with carbon capture and storage (CCS). The section concludes with a brief comparison between the four scenarios. Further details of the results are available in an online data visualization dashboard.[21]

7.1 Reference Case Scenario

This section summarizes results for the Reference Case scenario for annual volume, hourly and daily peaks, and GHG emissions from gaseous fuels. Recall that the Reference Case represents 'business as usual' trends continuing based on what was in-market and enshrined in law as of 2019. The Reference Case was calibrated to Enbridge Gas' latest 10-year (2020 to 2030) customer account and annual volume forecast and PG extrapolated the trends from 2030 to 2038. (Please see Appendix A for details on how the reference case scenario was developed.) These forecasts have embedded assumptions about economic and population growth. Energy savings potential from demand side management (DSM) programming is included based on the 2021 DSM budget which is held constant over the forecast period.

7.1.1 Annual Volume

In the Reference Case scenario, annual volume increases by 4% by 2030 and by 6% by 2038, relative to 2019. The increase in volume is mainly driven by account growth (due to an increasing population and economic growth).

In the Reference Case, the DSM program budget is fixed at $132 million. At this spending level, there is an estimated 6% of energy savings by 2038 compared to the Reference Case absent DSM. The commercial sector saves about 4%, and the industrial and residential sectors save about 6% each by 2038 relative to the Reference Case without DSM.

In 2038, natural gas comprises nearly 100% of annual volume. Volumes of RNG and hydrogen are almost nil (0.01%) as the Reference Case reflects expected RNG and hydrogen volumes under Enbridge Gas' currently planned programs (Voluntary RNG Program and Low Carbon Energy Project). The Reference Case does not include natural gas with carbon capture and storage (CCS). The increase in total volume by 2038 is about the same as the increase in natural gas volume, both overall (6%) and across the sectors (9%, 4%, and 6% in the residential, industrial, and commercial sectors, respectively) because total volume is nearly all natural gas. The forecasted increase in volume is greater than the energy savings from the DSM programming.

Exhibit 28 illustrates total volume by fuel. RNG and hydrogen do not appear on the graph as they account for 0.01% of total volume by 2030.

[21] Please contact the Enbridge Gas Energy Transition Planning Department for login information to the data visualization dashboard in PowerBI.

Exhibit 28 - Reference Case Scenario: Annual volume by fuel

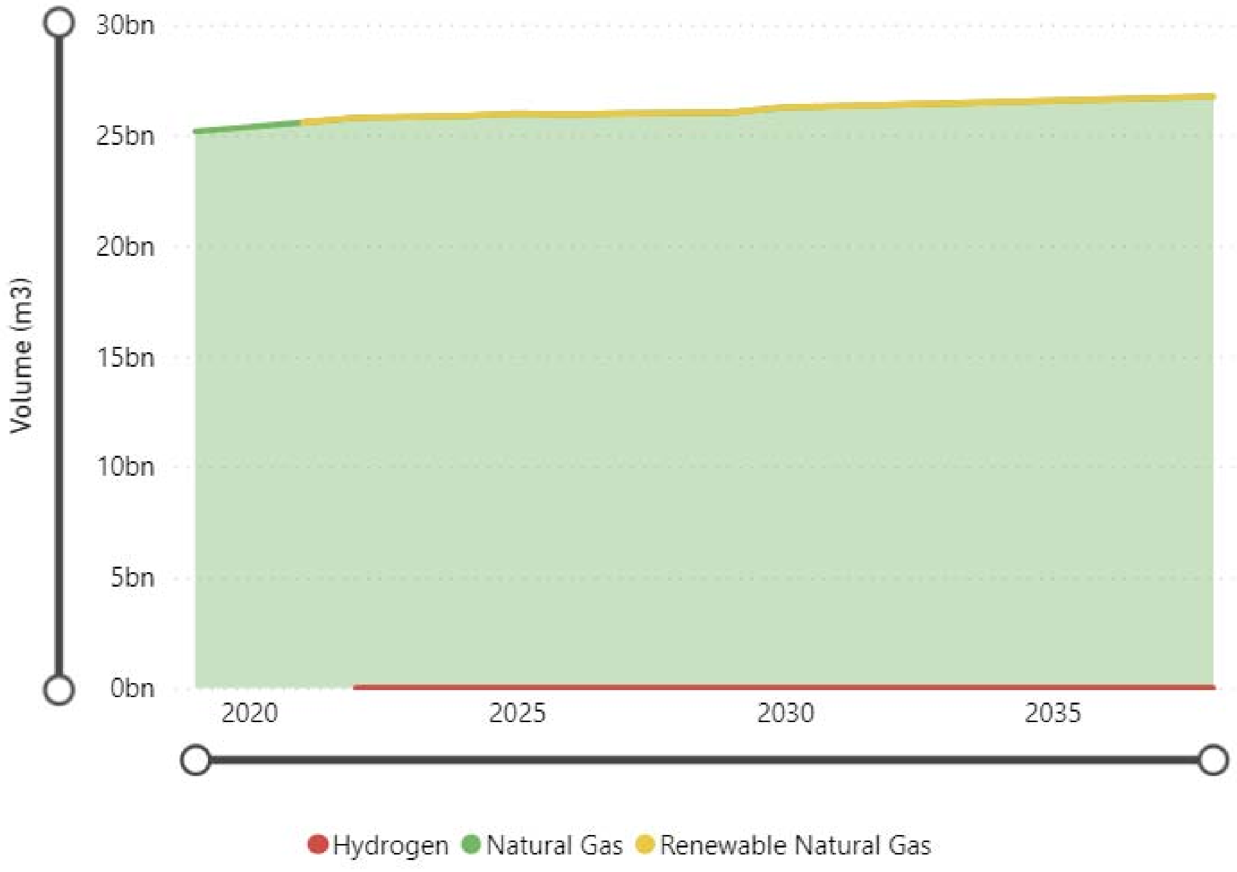


Exhibit 29 and Exhibit 30 provide annual volume composition by fuel in 2019, 2030, and 2038.

Exhibit 29 - Reference Case Scenario: Annual Volume Composition by Fuel (m^3) in 2019, 2030, and 2038

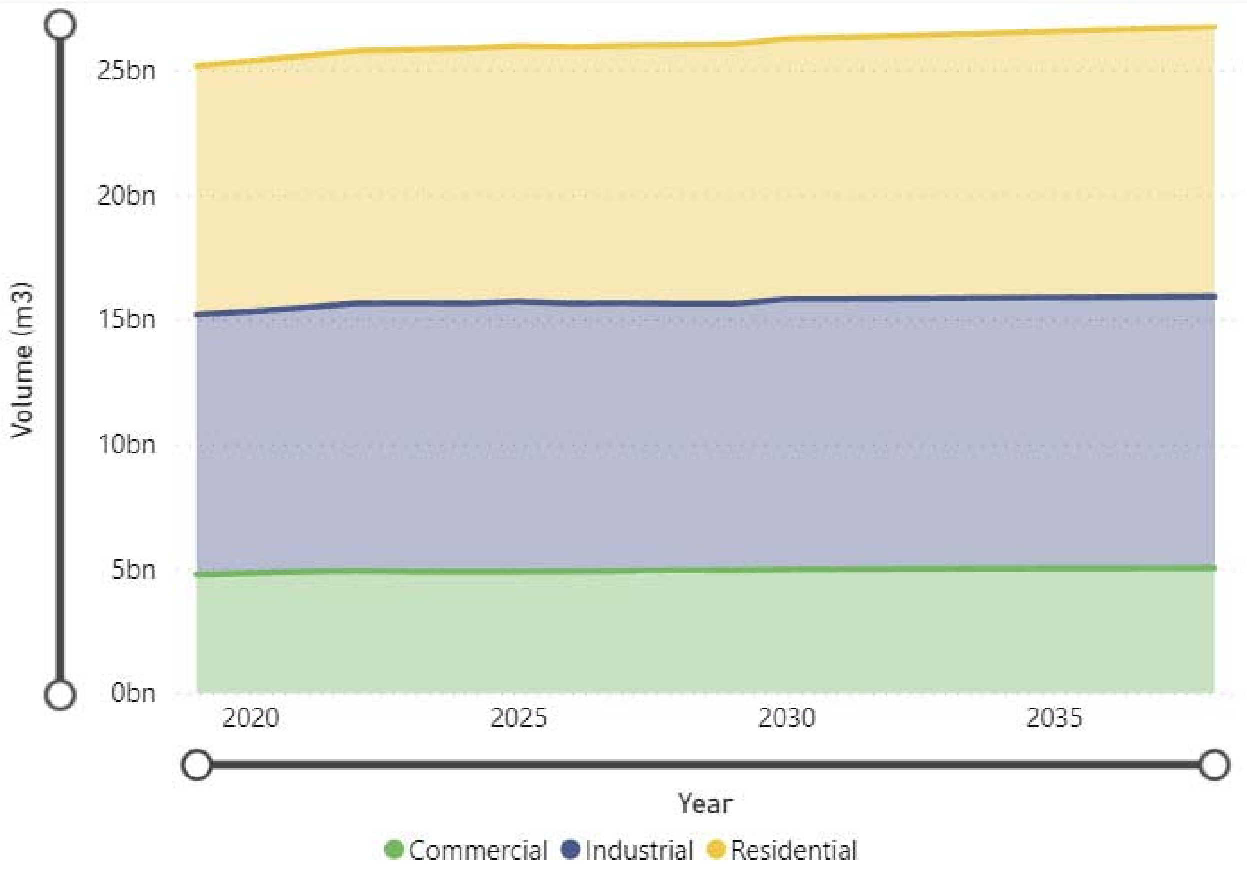
Year	Hydrogen	Natural Gas	Renewable Natural Gas	**Total**
2019		25,162,554K		**25,162,554K**
2030	746K	26,248,404K	1,347K	**26,250,497K**
2038	1,007K	26,737,703K	1,861K	**26,740,570K**

Exhibit 30 - Reference Case Scenario: Annual Volume Composition by Fuel (%) in 2019, 2030, and 2038

Year	% H2 Volume	% Natural Gas Volume	% RNG Volume	% CCS Volume
2019	0%	100%	0%	0%
2030	<0.01%	99.99%	0.01%	0%
2038	<0.01%	99.99%	0.01%	0%

Exhibit 31 illustrates annual volume by sector. The industrial and residential sectors each account for about 40% of volume, while the commercial sector accounts for the remaining 20%.

Exhibit 31 - Reference Case: Annual volume by sector

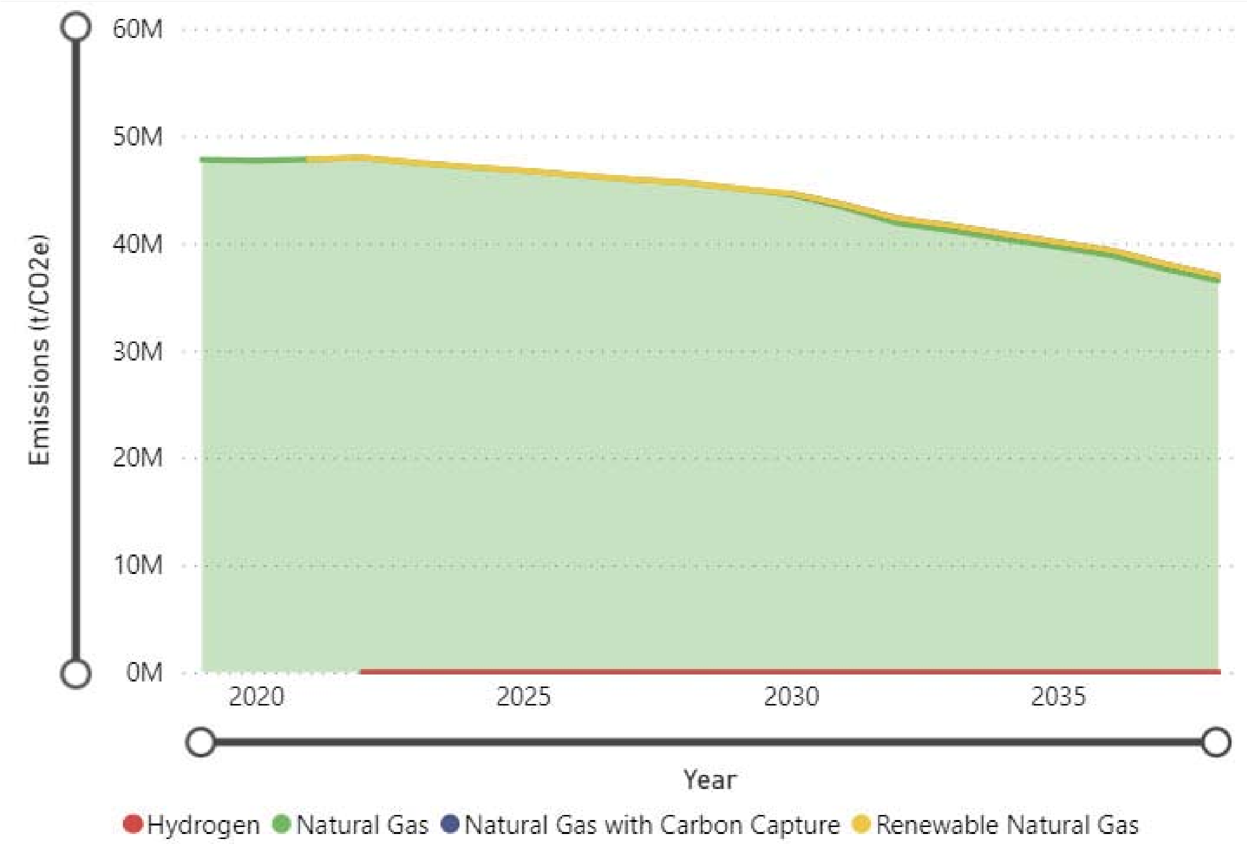


7.1.2 Peak

In the Reference Case scenario, hourly peak increases by 6% by 2030 and 8% by 2038, relative to 2019. Daily peak increases by 5% by 2030 and by 7% by 2038, relative to 2019. These increases are mainly driven by the same factors that increase annual volume.

Peak hour increases by 7%, 8%, and 11% in residential, commercial, and industrial sectors, respectively. Industrial segments with higher HVAC end-use shares (e.g., Agriculture) are projected to grow faster than

Exhibit 47 - Steady Progress Scenario: Annual GHG emissions by fuel



7.3 Diversified Portfolio Scenario

This section summarizes results for the Diversified Portfolio scenario for annual volume, hourly and daily peaks, and GHG emissions. The Diversified Portfolio scenario reflects a future where GHG reductions are mainly achieved by decarbonizing the gas grid with some electrification in specific segments and end-uses. This scenario builds on the Steady Progress scenario with additional low carbon gas mandates, greater hydrogen and carbon capture development, earlier adoption of, and more stringent, codes and standards, and some electrification.

7.3.1 Annual Volume

In the Diversified Portfolio scenario, annual volume decreases 4% by 2030 and then increases 11% by 2038 relative to 2019. The increase in volume by 2038 is from hydrogen replacing natural gas in pursuit of lowering emissions from the gas system. There is also uptake of RNG and CCS, as these fuels lower GHG emissions without changing energy demand. Exhibit 48 and Exhibit 49 provide annual volume composition by fuel in 2019, 2030, and 2038.

Exhibit 48 - Diversified Portfolio Scenario: Annual Volume Composition by Fuel (m3) in 2019, 2030, and 2038

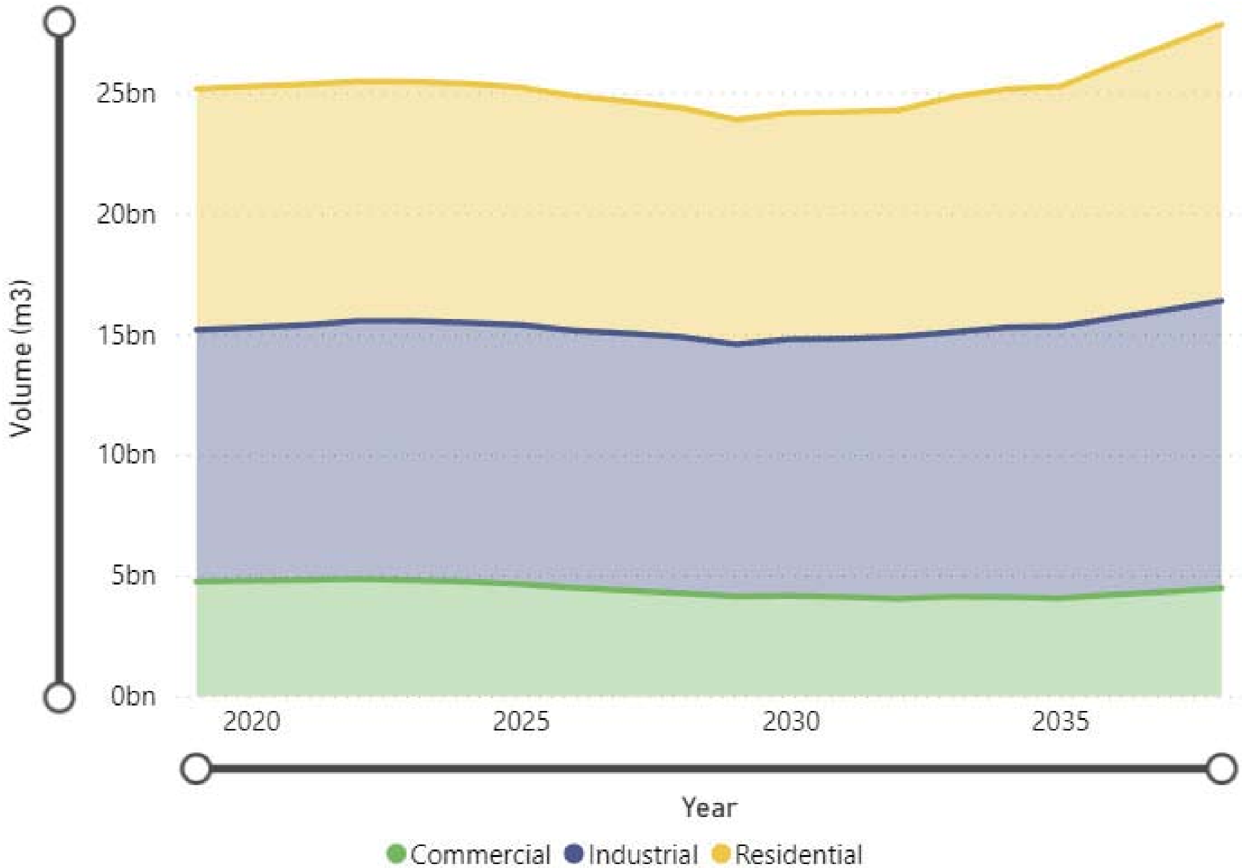
Year	Hydrogen	Natural Gas	Natural Gas with Carbon Capture	Renewable Natural Gas	**Total**
2019		25,162,555K			**25,162,555K**
2030	766,464K	20,800,872K	1,351,849K	1,248,453K	**24,167,638K**
2038	10,762,947K	11,128,731K	3,228,904K	2,722,126K	**27,842,708K**

Exhibit 49 - Diversified Portfolio Scenario: Annual Volume Composition by Fuel (%) in 2019, 2030, and 2038

Year	% H2 Volume	% Natural Gas Volume	% RNG Volume	% CCS Volume
2019	0%	100%	0%	0%
2030	3%	86%	5%	6%
2038	39%	40%	10%	11 %

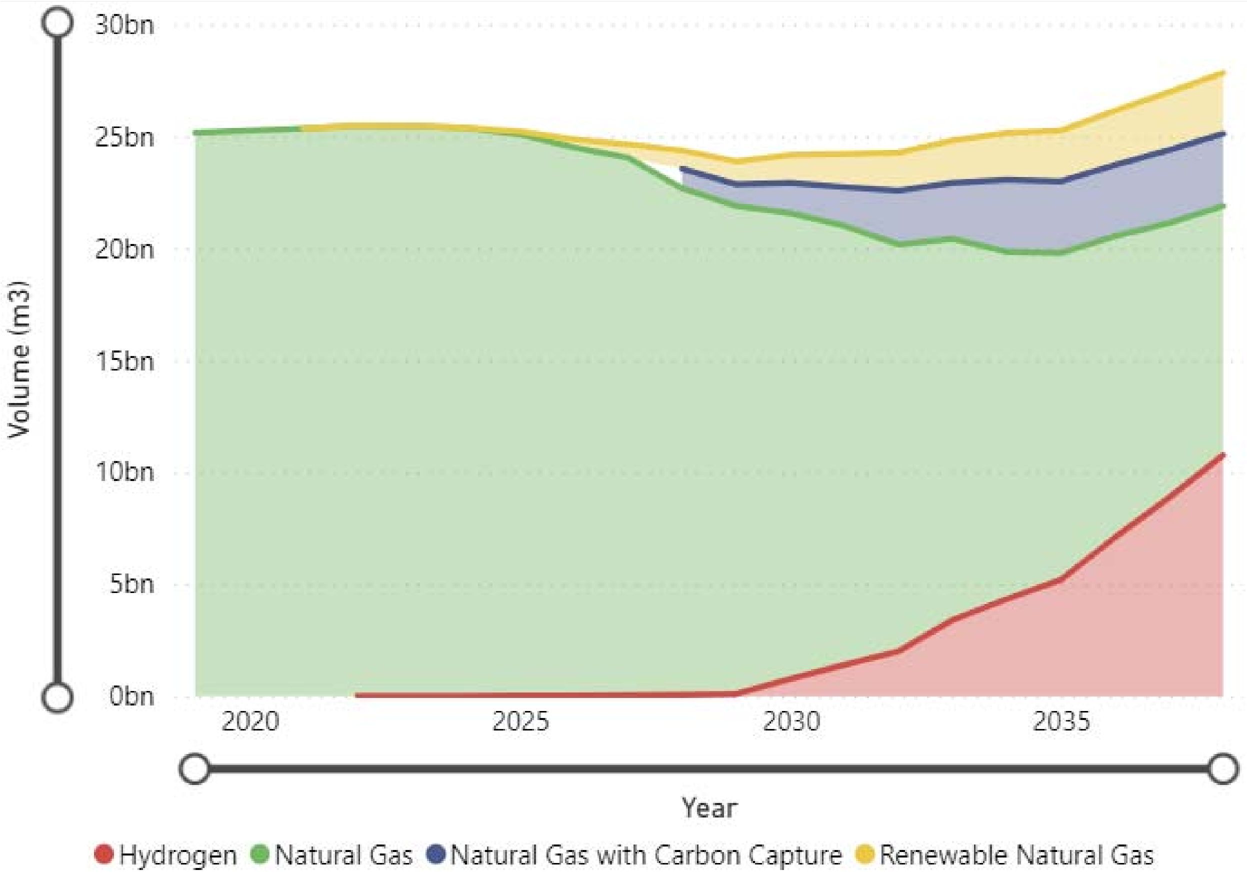
By sector, industrial and residential volume increase by about 15% by 2038, while the commercial sector decreases by 6%. Hydrogen supply is contributing to volume increases in the residential and industrial sector. Commercial sector customers are also receiving hydrogen, but there is a small overall decrease in volume resulting from codes and standards driver assumptions. While the commercial and residential sectors follow similar timeline trajectories for codes and standards changes, the impact of these changes are different. The National Energy Code for Buildings ('NECB', applicable to the commercial sector) and National Building Code ('NBC', application to the residential sector) have different savings assumptions, where improvements to commercial facilities are expected to be higher (as a percentage compared to current code) than residential improvements over the forecast period. For example, under the high stringency performance targets, the first round of upgrades for building codes occurs in 2025, where the required savings over code are 14% higher for commercial buildings compared to residential buildings. The next round of code changes in 2030 are even more significant. (Please see Appendix C for details on the assumptions for the codes and standards Critical Driver.) Exhibit 50 presents annual volume by sector.

Exhibit 50 - Diversified Portfolio Scenario: Annual volume by sector



Natural gas volume decreases by 56% by 2038 due to a combination of CDs which lower gas demand: higher carbon price and policy-driven fuel switching, high stringency codes and standards, and DSM programming. In 2038, annual volume is 40% natural gas, 39% hydrogen, 10% RNG, and 12% natural gas with carbon capture. The Diversified Portfolio scenario emphasizes “sharing the load” between fuels and working with the existing gas system to reach net zero emissions by 2050. Hydrogen, RNG, and natural gas with carbon capture all help replace natural gas in the system, largely driven by low carbon mandates. Exhibit 51 presents annual volume by fuel.

Exhibit 51 - Diversified Portfolio Scenario: Annual volume by fuel



7.3.2 Peak

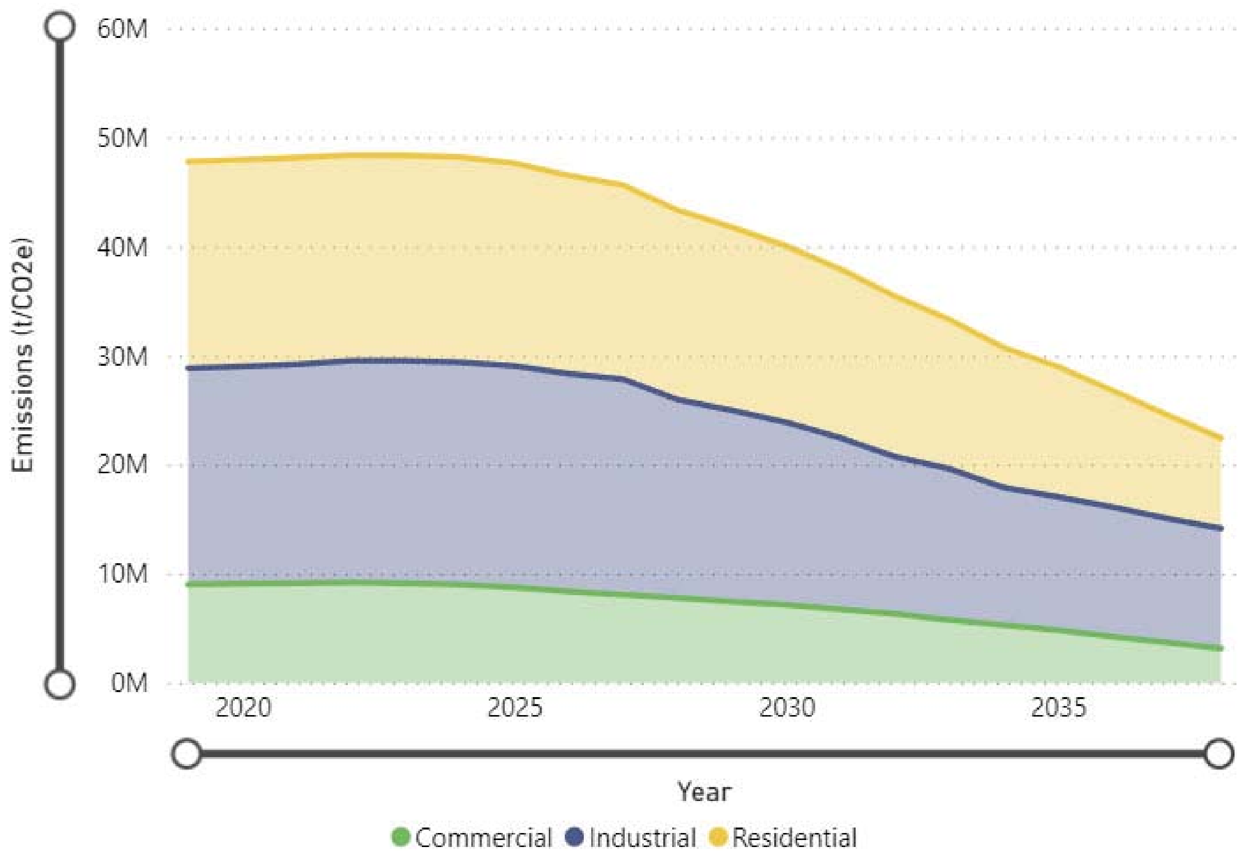
In the Diversified Portfolio Scenario, the peak hour increases by about 5% by 2038 relative to 2019, mainly caused by the uptake in hydrogen after 2030. The hourly peak increases by 12% in the industrial and residential sectors, while it decreases by 12% in the commercial sector. This is due to the increasingly stringent building codes which caused volume in the commercial sector to decrease by 2038. Exhibit 52 presents hourly peak by sector.

Exhibit 56 - Diversified Portfolio Scenario: GHG emissions by fuel (%) in 2019, 2030, and 2038

Year	% H2 Emissions	% Natural Gas Emissions	% RNG Emissions	% CCS Emissions
2019	0%	100%	0%	0%
2030	0%	98.6%	0.04%	1%
2038	0%	94.3%	0.1%	5.6%

Each sector sees GHG emission decline by 2038. The commercial sector has a 65% emissions reduction, the industrial sector a 44% reduction, and the residential sector has 56% reduction. Exhibit 57 presents GHG emissions by sector.

Exhibit 57 – Diversified Portfolio Scenario: Annual GHG emissions by sector



7.4 Electricity Centric Scenario

This section summarizes results for the Electricity Centric scenario for annual volume, hourly and daily peak, and GHG emissions. The Electricity Centric scenario illustrates a pathway where GHG reductions are sought primarily from electrification. The policies assumed to achieve this pathway include the 2020

Federal Climate Action Plan, the Clean Fuel Regulation, more stringent building codes including for new construction and retrofits, as well as mandated electrification of space and water heating for new construction and existing buildings. The energy savings potential achieved through DSM programming is based on Enbridge Gas' 2021 DSM budget increasing by 3% annually from 2021 to 2027 and then by 10% annually from 2028 to 2038.

7.4.1 Annual Volume

In the Electricity Centric scenario, annual volume decreases by 22% by 2030 and by 52% by 2038 relative to 2019. Increased electrification of space and water heating, high stringency codes and standards, high carbon pricing, and high DSM spending all lower volumes of gaseous fuels.

In 2038, the annual volume is 80% natural gas, 11% RNG, and 9% natural gas with carbon capture. The amount of hydrogen is negligible. This scenario focuses on decarbonizing by investing in the electric grid rather than leveraging existing gas infrastructure. Consequently, development of hydrogen, RNG, and natural gas with carbon capture is minimal, and the annual volume is still mostly natural gas by 2038. However, the natural gas volume decreases by 62% by 2038 because of electrification. Exhibit 58 presents annual volume by fuel.

Exhibit 58 – Electricity Centric Scenario: Annual volume by fuel

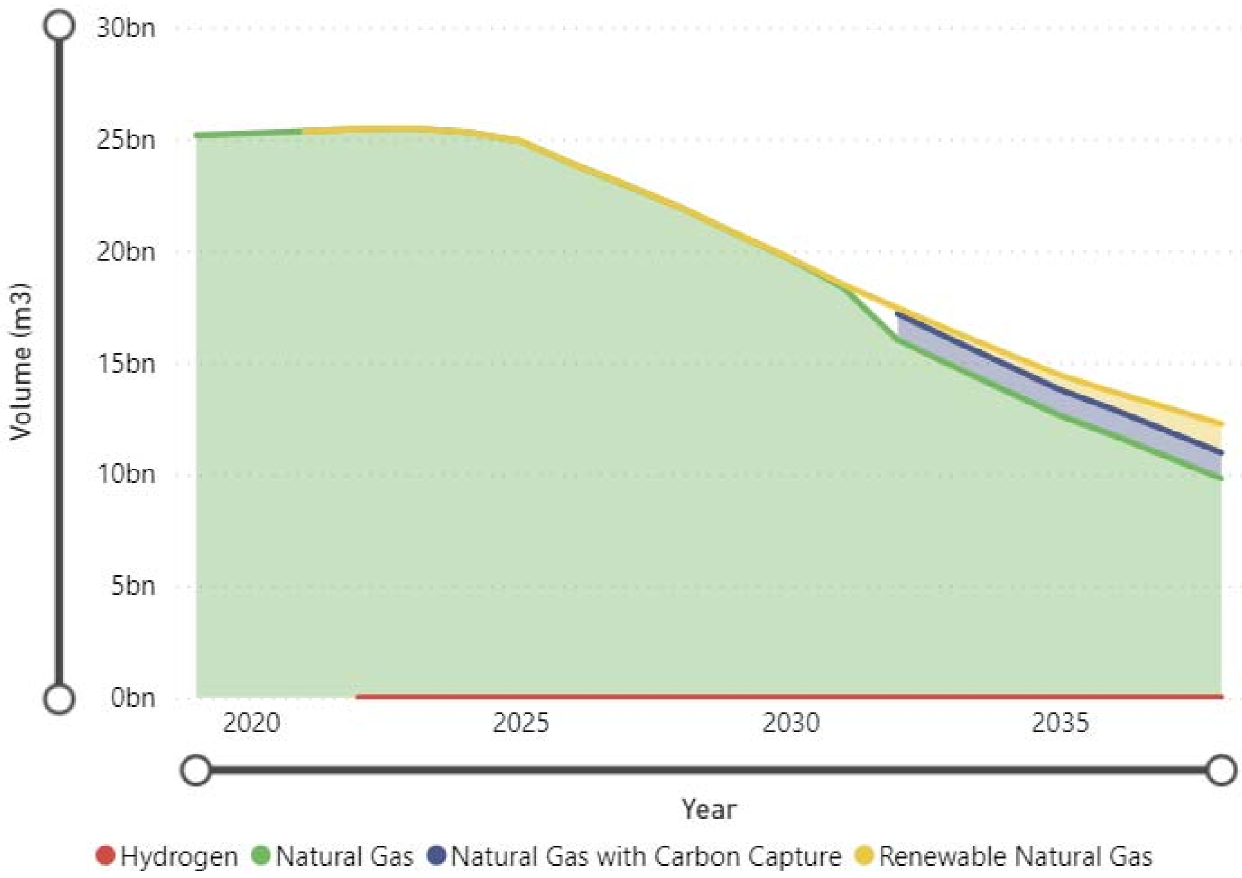


Exhibit 59 and Exhibit 60 show annual volume composition by fuel in 2019, 2030, and 2038.

Exhibit 59 - Electricity Centric Scenario: Annual Volume Composition (m^3) in 2019, 2030, and 2038

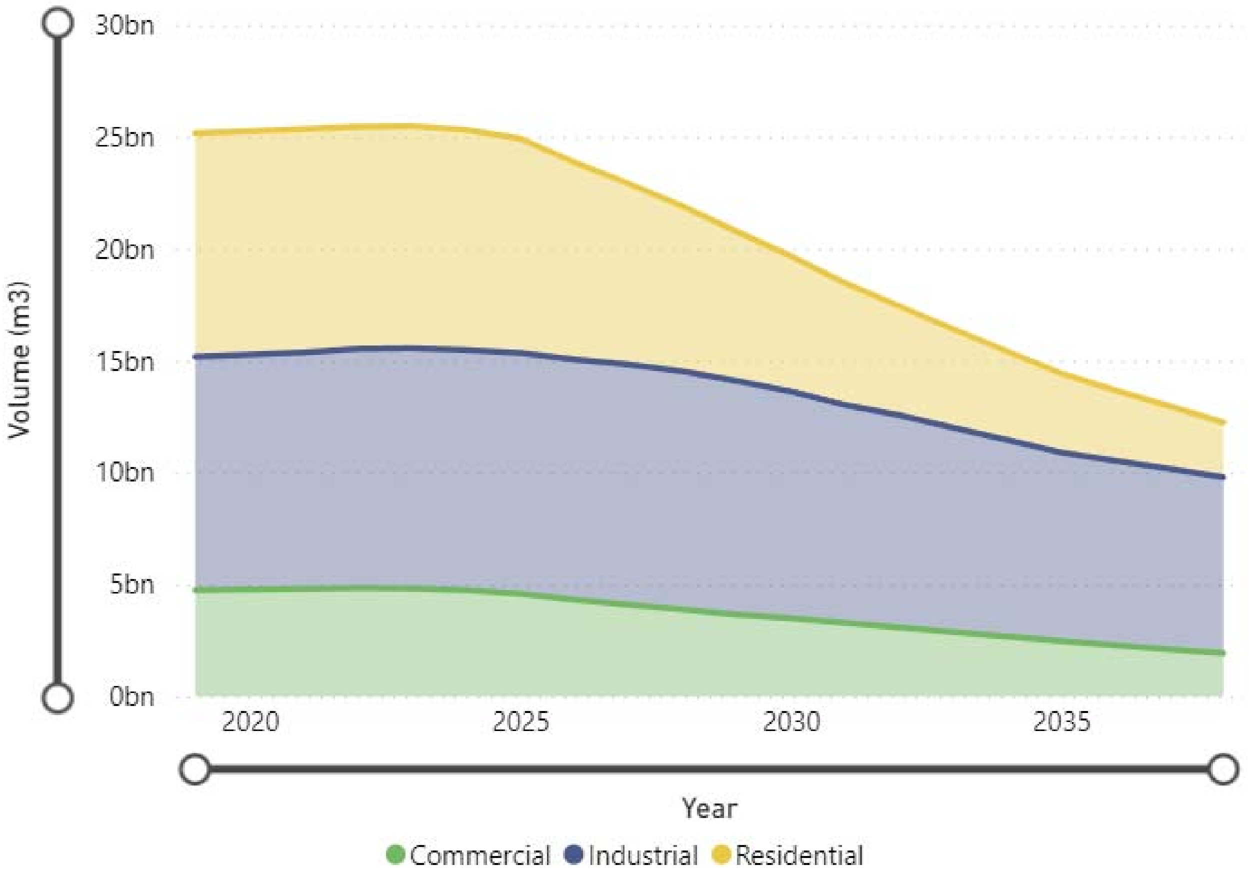
Year	Hydrogen	Natural Gas	Natural Gas with Carbon Capture	Renewable Natural Gas	**Total**
2019		25,162,554K			**25,162,554K**
2030	750K	19,564,013K		25,842K	**19,590,606K**
2038	5,362K	9,674,265K	1,146,483K	1,280,873K	**12,106,983K**

Exhibit 60 - Electricity Centric Scenario: Annual Volume Composition (%) in 2019, 2030, and 2038

Year	% H2 Volume	% Natural Gas Volume	% RNG Volume	% CCS Volume
2019	0.00%	100.00%	0.00%	0.00%
2030	<0.01%	99.86%	0.13%	0.00%
2038	0.04%	80.00%	10.59%	9.36%

By 2038, the residential sector annual volume decreases by 75% relative to 2019. The commercial and industrial sectors decrease 60% and 26%, respectively. In this scenario, new residential and commercial construction do not connect to the gas grid and existing space and water heating end-uses in these sectors are mandated to electrify as end-of-life equipment is replaced. In the Industrial sector, some end-uses switch to electricity when replaced. Exhibit 61 presents annual volume by sector.

Exhibit 61 - Electricity Centric Scenario: Annual volume by sector



7.4.2 Peak

In the Electricity Centric scenario, hourly peak decreases by 25% by 2030 and by 60% by 2038 relative to 2019. The daily peak decreases by 28% by 2030 and by 62% by 2038 relative to 2019. Widespread electrification and a reduction of new customers connecting to the gas grid decreases peak across the sectors like the annual volume decrease.

The industrial hourly peak decreases by 35% by 2038. The commercial and residential hourly peaks decrease by 62% and 76%, respectively, by 2038. Exhibit 62 presents hourly peak by sector.

OUR BUILT ENVIRONMENT

Canada's built environment includes over 16 million dwellings and 482,000 commercial and public buildings.[i] The sector is responsible for 13% of Canada's direct greenhouse gas (GHG) emissions, or 88 Mt.[ii] When accounting for off-site generation of electricity for use in buildings, it brings the total to around 18%, and even more emissions are embedded in the materials and supply chains associated with the buildings and construction sector. **These emissions are trending upward.**[1]

At the same time, the built environment is facing **increasing pressure from extreme weather and climate change** and building stock climate resilience is a concern. It is estimated that 14% of Canadian homes are located in areas at risk of flooding.[iii] However; the overall rate of return on investments in adaptation is high, with benefit-cost ratios ranging from 2:1 to 10:1, and in some cases even higher.[iv] We must take the opportunity to increase buildings' resilience, alongside retrofits to reduce emissions.

The majority of buildings standing today will still be in use in 30 years, which means that in addition to building better new buildings, **to achieve net-zero and climate resilience**, **we need to retrofit a large majority of the standing buildings in this country**.

Retrofits that are being undertaken today are often not going far enough in terms of emissions reduction and increased efficiency. **We need to transform programs and investment toward deep decarbonization**.

Over 78% of operational building emissions come from space and water heating, the majority of which is due to equipment that runs on fossil fuels, such as natural gas furnaces.[v] **Electrification of space and water heating will be an essential component of decarbonizing the buildings sector**, with other clean fuels also playing a role where access to electricity is a barrier.

Canada's green building industry currently employs 462,000[vi] workers, ranging from disciplines in architecture, interior and product design, engineering, data science, building material and equipment manufacturing and supply, logistics, marketing, and construction trades – **most of which are already facing labour and supply chain shortages**.

WHY DO WE NEED A STRATEGY?

Canada has legislated a commitment to reach **net-zero emissions by 2050**. In the interim, the 2030 Emissions Reduction Plan sets out a potential buildings sector contribution that would **reduce direct residential, commercial and institutional building emissions to 53 Mt by 2030** (37% reduction from 2005 levels).

These are ambitious objectives. The challenge of decarbonizing buildings is significant – as is the opportunity. Creating net-zero emissions, climate resilient buildings supports the economy on multiple fronts, increasing economic activity, increasing jobs, and increasing money in Canadians' pockets. It will improve energy affordability for Canadians, reduce impacts of energy price fluctuations and extreme weather

---

[1] Emissions decreased by 3 Mt between 2019 and 2020; however, this is not expected to reflect a downward trend and the extent of influence of changes in building use due to the COVID-19 pandemic is unknown.

3) **Transform space and water heating:** The overwhelming majority of building emissions come from space and water heating equipment, largely due to fossil fuel equipment, such as natural gas- and oil-fired furnaces. Electrification of space and water heating (allowing for flexibilities such as hybrids where full electrification is not feasible) – and ensuring that building envelopes are well insulated – will be essential components of decarbonizing the buildings sector. *Phased timelines for transition off of fossil fuel heating systems are needed (e.g. when installation of oil or natural gas heating systems would no longer be permitted).*

Looking toward 2030 and 2050, the Canada Green Buildings Strategy will align with an economy-wide approach to achieve net-zero emissions by 2050, in particular through supporting increased use of low-carbon construction materials in buildings; increasing the energy efficiency of buildings to free up electricity for other needs (e.g. electric vehicles); and making sure electricity supply is taken into consideration for operationalizing the strategy.

WHAT OTHER FEDERAL STRATEGIES WILL INFLUENCE THE BUILDINGS STRATEGY?

The Strategy will be developed within the wider ecosystem of the Emissions Reduction Plan and other federally led strategies that also help position Canada to achieve net-zero emissions in the buildings sector by 2050. It also builds on previous actions under the Pan-Canadian Framework on Clean Grown and Climate Change and Strengthened Climate Plan, summarized in Annex B.

It will reflect, and in some cases directly help advance, complementary initiatives – such as those outlined below – to ensure the guiding principles, objectives and actions of the Strategy work collaboratively to deliver on Canada's vision for a buildings sector composed of net-zero emission, climate-resilient buildings.

Strategy	Objective
National Adaptation Strategy	To unite actors across Canada through shared priorities, cohesive action, and an integrated whole-of-Canada approach to reducing climate change risks
Urban, Rural and Northern Indigenous Housing Strategy	To ensure more Indigenous People have access to safe and affordable housing (this is a stand-alone companion to the National Housing Strategy). This strategy will be co-developed with Indigenous governments and peoples - its link to the Canada Green Buildings Strategy will need to be determined through the co-creation process.
National Housing Strategy	To build stronger communities and help Canadians across the country access a safe, affordable home.
National Supply Chain Strategy	To help build more resilient and efficient supply chains to meet the needs of the Canadian economy and withstand disruptions caused by climate change and global events
Innovation Superclusters	To support further growth and development of Canada's innovation ecosystems, including joint missions between the private sector, academia and government

AREAS REQUIRING CHANGE

ACCELERATE THE CREATION, ADOPTION AND ENFORCEMENT OF HIGH PERFORMANCE, CLIMATE-RESILIENT AND ZERO-CARBON BUILDING CODES, STANDARDS, AND SPECIFICATIONS

Efforts to harmonize code adoption and reduce or eliminate variations across Canada are underway. Provinces and territories have committed to adopting new codes, such as the recently published 2020 model codes, within two years of publication, and subsequent iterations within 18 months. This commitment addresses the adoption of the model codes, but does not address performance pathways set out in the codes (e.g. energy performance tiers in the 2020 model building codes).

As innovation in low-carbon materials and technologies progresses, codes and standards must adjust to fairly assess new products and not restrict their application, where appropriate. Performance-based codes are the best regulatory practice internationally to enable innovative construction projects and to allow the buildings sector to improve and measure its performance. A performance-based national building code would enable greater uptake of a full range of low-carbon building materials such as mass timber, low-carbon concrete or steel. In addition, model building codes could be developed for measuring, reporting and reducing the embodied carbon of building materials.

With respect to resiliency, Canada's buildings are guided by codes and standards that were developed based on historical data, such that some buildings are not designed to withstand the future impacts of climate change. The Federal Advisory Committee on Climate Resilience and Infrastructure is working on linkages with federal objectives and priorities for codes and standards development, including flood risk management, wildfires, climate-resilient building envelopes, and building material durability. There is significant work that remains to be done to address the growing risk of extreme weather events, and the associated hazards to Canadians' well-being, which creates an urgency to adapt and build resilience.

MODERNIZE LEGISLATIVE TOOLS

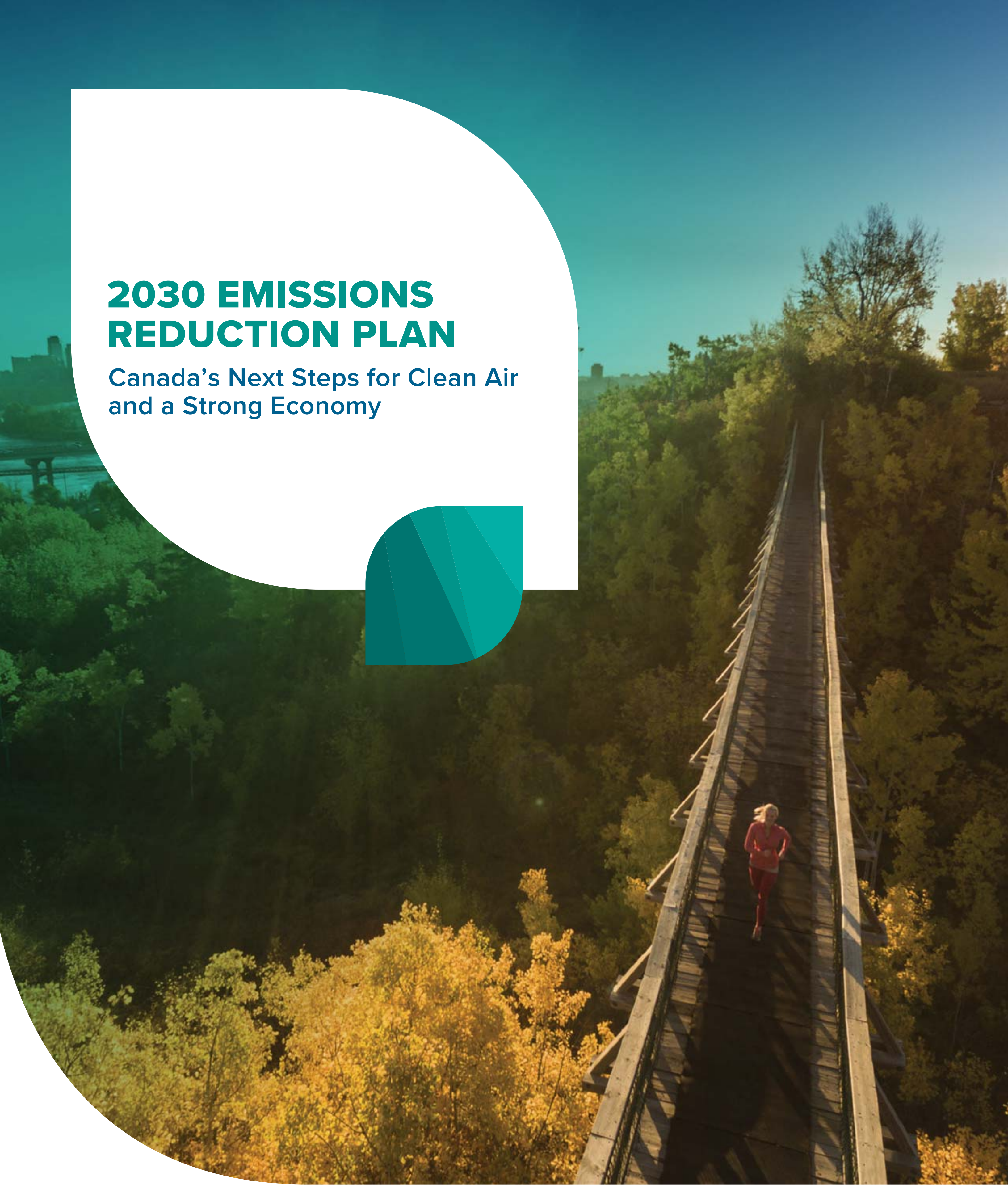
Current federal, provincial, and territorial legislative tools need to reflect our climate priorities, digitalized world, integrated systems, advanced technologies, how we think about energy efficiency, embodied carbon (or low-carbon materials), re-use of building materials at end of life, and building resiliency. These tools need to be designed with a net-zero carbon and climate-resilient future in mind. This means taking an ambitious approach that is capable of driving the required change (e.g. enable better data sharing and gathering, mandate carbon disclosure in buildings, introduce modern regulations).

REGULATE AND INCENTIVIZE THE TRANSFORMATION OF SPACE AND WATER HEATING

Space and water heating accounts for **78% of all emissions** from energy used in buildings.[xii] The majority of Canada's buildings (60% of homes and over 80% of commercial and institutional buildings) heat with fossil fuels. Transitioning the majority of these buildings off fossil fuel heating systems by 2050 is core to decarbonizing the sector. In most buildings across Canada, electric heat pumps are the right solution. Not only is electricity cleaner than fossil fuels in most jurisdictions (and will continue to get cleaner via the Clean Electricity Standard), the technology to use them more efficiently than fossil fuels to heat our buildings is available. Full electrification may not be feasible for some homes, such as in northern, remote and Indigenous communities, and consideration can be given to alternative solutions such as heat-pump/cleaner-fuel hybrid systems. Remote buildings that are off the electricity grid will also require unique solutions to decarbonize.

ACTIONS

Current and potential federal actions (below) will advance change, but bolder actions are required - from the federal government and partners.



2030 EMISSIONS REDUCTION PLAN

Canada's Next Steps for Clean Air and a Strong Economy

Environment and Climate Change Canada
Environnement et Changement climatique Canada

Canada

businesses, and individuals, will transform every sector of the economy and create new job opportunities. In recognition of the significant efforts that will be required, Canada recently launched the Sustainable Finance Action Council to capitalize on opportunities on the road to net-zero.

While Canada will strive to reduce its emissions as much as possible, some areas of the economy will not be able to completely decarbonize, so remaining emissions will need to be offset.

Key Elements of Net-Zero by 2050 and Linkage to the 2030 ERP

Using less energy and supporting energy efficiency	The IEA's *Canada 2022 Energy Policy Report* notes Canada's energy intensity is still one of the highest in the OECD, and that energy efficiency will play a key role in Canada achieving net-zero emissions. Energy efficiency means reducing the consumption of energy and saving money. The 2030 ERP includes a number of commitments to strengthen energy efficiency standards across the economy. See chapters 2.2 (buildings) and 2.6 (transportation).
Increased electrification and use of clean fuels	Replacing fossil fuel-based technologies with ones that use electricity will be essential. A number of key reports have estimated that the resulting demand for electricity in 2050 will be one and a half to three times current levels. Investments in existing, commercially available renewable energy and grid interties, as well as developing new sources of electricity, such as geothermal and SMRs, will be key to both replacing the current emitting sources of electricity generation and to meeting increased demand. With this in mind, it is also important to continue to support Indigenous Peoples and rural and remote communities in their transition from diesel-generated electricity to non-emitting sources. Reaching net-zero also requires non-emitting space and water heating systems. Supporting the development and use of clean electricity and clean fuels is recognized as a priority in this 2030 ERP. See chapters 2.1 (economy-wide), 2.3 (electricity), 2.4 (heavy industry), and 2.6 (transportation).
Cleaner industrial processes	Electrification opportunities in heavy industry sector are currently limited, but are expanding. New uses for hydrogen, such as steel making, are expected to enable many industrial processes to move towards net-zero emissions. For processes that are not able to eliminate all emissions, emerging CCUS technologies will play an important role. The sector that will likely undergo the greatest transformation by 2050 will be oil and gas. In their *Net-Zero by 2050* report, the IEA estimates that global oil demand will fall by approximately 75% from current levels by 2050. CCUS and hydrogen will help decarbonize ongoing oil and gas production, while the sector will also invest in a transition to producing clean fuel and non-emitting products To support the development of new clean industrial processes, the ERP reflects strategies and investments in technologies that can transform Canada's economy. See chapter 2.4 (heavy industry) and 2.5 (oil and gas)
Transforming the way people and	Reaching net-zero emissions will require modal shifts such as public and active transportation, more low-carbon intensity fuels in the short-to-medium term,

94% and 82% were likely to replace their equipment with natural gas space and water heating equipment, respectively, which is similar to 2020 penetration rates (96% for space heating and 85% for water heating).[4]

19. Table 2 provides a summary of the energy transition assumptions that were used to adjust the general service forecast number of customer additions (new construction and replacements) and average number of customers (existing customers). Future customer forecasts will continue to consider government policy and market trends on an annual basis to develop adjustments specific to energy transition.

Table 2
Summary of Energy Transition Assumptions Affecting Customer Forecast – General Service

Line No.	Forecast Type	Energy Transition Assumption	Forecast Item Reference
1	Customer Addition – New Construction	A small segment of builders (<1%) voluntarily do not connect to natural gas network starting in 2023, increasing to an estimated 12.5% by 2032.	- Exhibit 3, Tab 2, Schedule 6, Attachment 1, - Asset Management Plan 2023-2032, Figures 5.1.4-1, and 5.1.4-2
2	Customer Addition – Replacement Conversions	Starting in 2030, 10% fewer existing homes (not previously heated with natural gas) convert to natural gas	- Exhibit 3, Tab 2, Schedule 6, Attachment 1 - Asset Management Plan 2023-2032, Figures 5.1.4-1, and 5.1.4-2
3	Average Number of Customers – Existing Customers	Equipment lifespan is estimated at 20 years, resulting in a 5% annual turnover rate. 10% of customers have only one gas appliance.[5] Starting in 2026, it is assumed that 10% of general service customers voluntarily replace with non-gas equipment at the end of equipment life, those with one appliance are assumed to disconnect from the natural gas network.	- Exhibit 3, Tab 2, Schedule 6, Attachment 2

[4] 2020 Residential: Single Family Natural Gas End Use Study.
[5] Based on 2019 and 2020 Residential Natural Gas End Use Survey.

65. While some assume that the only pathway to achieve net-zero is the complete electrification of the energy demand that is currently served by natural gas, it is critical to understand that this would eliminate the resiliency and reliability that is provided by the gas distribution, storage, and transmission system in the province, as provided at Exhibit 1, Tab 10, Schedule 2, Section 2. In addition, an electrification pathway to net-zero will require massive investment in new electrical generation, transmission, storage and distribution systems, and end user equipment. This investment is so large because the value of the natural gas system is not leveraged.

66. Conversely, a diversified pathway, which uses both gas and electric systems working together, will be the most cost-effective, reliable, resilient, and seamless pathway for Ontario’s energy system to achieve net-zero, while providing consumer choice and ensuring Ontario’s businesses remain competitive.

67. A diversified pathway includes using energy more efficiently in the short term, as well as beginning to invest in a longer-term shift to an increasing amount of renewable or low-carbon energy sources, including solutions such as wind and solar electricity generation, RNG and hydrogen, as well as use of technologies to capture carbon emissions from remaining natural gas use.

68. Within the buildings sector, energy demand reductions would be driven via continued energy efficiency and increased building code stringency. Most of the remaining building heat load would decarbonize via the transition from natural gas to hydrogen and renewable natural gas (RNG) and the balance of heating load would electrify. The transportation sector would see light and medium duty vehicles electrify, and hydrogen and RNG would fuel most heavy transport. Finally, the

depreciation rates are supported by a depreciation study conducted by Concentric Energy Advisors, Inc. (Concentric), which is provided at Exhibit 4, Tab 5, Schedule 1, Attachment 1.

51. In developing the proposed depreciation rates, Enbridge Gas and Concentric considered the introduction of an 'Economic Planning Horizon' (EPH) or truncation date to reflect the potential impact that energy transition could have on the economic life of Enbridge Gas's system.

52. There is potential that climate change legislation, such as municipal or provincial plans to phase out the use of natural gas, could have a life-shortening effect on Enbridge Gas's system. However, there is also the possibility that service lives could be lengthened or maintained if low-carbon fuels, such as hydrogen and RNG, are determined to be viable sustainable alternatives to natural gas. Also, as demonstrated in the P2NZ Study provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, and Exhibit 1, Tab 10, Schedule 5, Section 3, Enbridge Gas's system will be a key contributor to achieving net-zero in the province.

53. Enbridge Gas and Concentric concluded that introducing an EPH is not appropriate at this time. There remains uncertainty around the impacts that energy transition could potentially have on Enbridge Gas's system as discussed above. However, future depreciation studies may warrant the introduction of regional or system wide EPHs, as the energy transition unfolds and more information on the future utilization of Enbridge Gas's assets becomes available.

54. 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. For illustrative purposes, if a system-wide 2050 EPH were to be implemented starting

2024, the 2024 Test Year depreciation expense would increase by $282 million[15], from $921 million to $1.2 billion. The depreciation study used to calculate this is provided at Exhibit 4, Tab 5, Schedule 1 Attachment 1.

3.3. Equity Thickness

55. The uncertainty around energy transition has significantly increased Enbridge Gas's business risk and is a major factor underpinning the Company's proposal to increase the equity thickness component of its deemed capital structure from 36% to 42%. The equity thickness proposal is provided at Exhibit 5, Tab 3, Schedule 1.

56. Enbridge Gas retained Concentric to perform an independent assessment of the reasonableness of the capital structure currently authorized by the OEB. The resulting report is provided at Exhibit 5, Tab 3, Schedule 1, Attachment 1, Enbridge Gas Inc. Common Equity Ratio Study (the Equity Ratio Study).

57. Enbridge Gas and Concentric concur that the Company's risk profile has increased significantly since 2012, the last time the OEB reviewed equity thickness for EGD[16] and Union[17]. In early 2013, the OEB concluded that new environmental policies at the time had not increased EGD's risks in comparison to 2007.

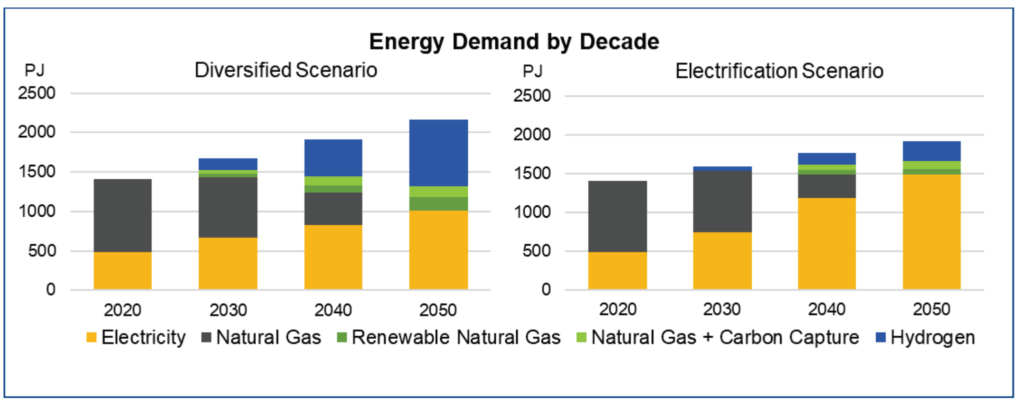
58. Since then, energy transition has become the most significant factor contributing to increased business risk for Enbridge Gas, as evidenced by findings in the Equity Ratio Study:

---

[15] Calculated using the depreciation rates from Enbridge Gas Depreciation Study (Exhibit 4, Tab 5, Schedule 1, Attachment 1).
[16] EB-2011-0354.
[17] EB-2011-0210.

43. By 2050, gaseous energy in both scenarios is provided by RNG, hydrogen and natural gas with CCUS, as shown in Figure 4, which is also provided at Attachment 2, page 5. RNG can replace natural gas in pipelines today, achieving emissions reductions across all sectors in the near-term. Hydrogen can also reduce emissions across all sectors and provides a critical pathway for the decarbonization of hard to electrify sectors like industry and heavy transportation in both scenarios. CCUS is needed to produce blue hydrogen, and for high temperature processes in industry that may not have another means to reach net-zero. This demonstrates that investments in RNG, hydrogen and CCUS must begin today to meet the demand seen in 2030 onwards.

Figure 4: Energy Demand by Decade /u



44. In the Diversified scenario, hydrogen plays a large role in building heat. Since hydrogen is less energy dense on a volumetric basis than natural gas, the volumetric peak demand in the Diversified scenario increases, as shown in Figure 5, which is also provided at Attachment 2, page 31. In the Electrification scenario, the volumetric peak demand decreases to approximately 58% of 2020 levels. /u
Enbridge Gas's pipeline network can be repurposed for the distribution of hydrogen and will play an important role in achieving net-zero in either scenario, as provided

GDS DRAFT
2023 Budget & LRP Review

October 28th 2022

ENBRIDGE

Key Assumptions / Executive Summary

Executive Summary

- GDS EBITDA average growth of 7.03%, achieving EBITDA in all years mainly due to Price Cap Index and recovery of deficiency in 2024
- GDS achieving DCF target in all years due to strong EBITDA overcoming Maintenance Capital pressures

Assumptions

- 2023 Budget Assumptions include:
  - PCI 3.6% (PCI = 2021 Actual GDP IPI FDD (3.9%) – Productivity (0%) - Stretch (0.3%))
  - Achieved ROE of 9.7%, Board Approved ROE 8.66%. ESM Gap at $35M.
- 2024 is a rebasing year and assumed to be Cost of Service, with all CTA recovered and earning Board Approved ROE
- 2025 and 2026 assumes earning Board Approved ROE

GDS Plan Review

ENBRIDGE

(CAD millions[1], except for percentages)	2021A	2022F (2+10F)	2023B	2024 LRP	2025 LRP	3 Year CAGR (2022-2025)	Comments
Revenue	**2,943**	**3,024**	**3,112**	**3,395**	**3,546**	**5.44%**	Growth due to PCI, Customer Growth, rebasing rate increase in 2024 carrying through LRP as we earn Board Approved ROE with increased equity thickness and depreciation proposal
YoY%		3%	3%	9%	4%		
Operating Expenses *	**1,089**	**1,154**	**1,178**	**1,224**	**1,252**	**2.77%**	Central function decrease in 2023 due to insurance premium reduction, pension & benefits. CF increasing throughout rest of plan. Merit & inflation and DSM (offset by increasing revenue) increasing throughout rest of plan
YoY%		6%	2%	4%	2%		
EBITDA	**1,853**	**1,870**	**1,934**	**2,171**	**2,293**	**7.03%**	Increasing EBITDA due to drivers above
YoY%		1%	3%	12%	6%		
BU DCF	**1,580**	**1,491**	**1,602**	**1,724**	**1,868**	**7.80%**	DCF growth driven by increasing EBITDA at faster rate than Maintenance Capital throughout plan
YoY%		-6%	7%	8%	8%		
Growth Capital	**963**	**1,143**	**1,425**	**1,183**	**1,181**	**1.11%**	System reinforcement, Dawn C compression, Dawn to Parkway Expansion throughout plan adding to strong rate base growth
YoY%		19%	25%	-17%	0%		
Maint. Capital	**273**	**380**	**333**	**448**	**425**	**3.81%**	Higher REWS, Compression stations, meter purchases throughout plan adding to strong rate base growth
YoY%		39%	-12%	35%	-5%		
CTA Capital	**88**	**42**	**44**	**-**	**-**		Integration projects leading to high CTA capital during deferred rebasing term, ending in 2023
YoY%		-52%	5%	-	-		
Free Cash Flow (EBITDA less all Capital)	**530**	**306**	**133**	**540**	**687**	**30.91%**	Strong EBITDA growth due to rebasing rate increase in 2024 carrying through LRP, relative to Growth Capital and no CTA in 2024 and 2025 leading to strong free cash flow in 2025
YoY%		-42%	-57%	307%	27%		

Note: Operating Expenses includes Central Functions

EBITDA/DCF Bridge (2023 Budget vs 2022 2+10F)

ENBRIDGE

Segment	2023 Budget	2022 2+10F	Total Variance *(A)*	Variance due to CF *(B)*	Business Drivers *(A-B)*	Variance Explanation (Quantified if possible)
Distribution Margin	2,471	2,361	110	-	110	PCI +80M, Customer Growth +20M, ICM - Lakeshore KOL and St Laurent P3 +22M, Acc CCA - CTA projects reversing +10M, DSM +9M, Gas Supply Margin/Fuels due to lower UFG and UAF true up +5M, CM +3M, CPT +1M, Comm. Exp. +2M, APCDA due to higher capitalization rates and depreciation change -17M, Weather -27M
S&T Revenue	437	448	(11)	-	(11)	LT Transport due to Turnback -6M, LT Storage optimization due to higher mitigation costs in 2023 -12M, LT Storage price -2M, partially offset by PCI +5M, FX +4M
O&M	1,168	1,133	(35)	-	(35)	Merit & Inflation -18M, Self Insurance -13M, Property Tax due to higher inflation assumption -5M, Bad Debt -5M, DSM -10M, Ops – Locates/Lakeside/Crossbore -7M, Donations -3M, Rebasing consultant -2M, Finance & Other BU support costs -3M; partially offset by 1% Budget savings commitment +8M, higher Capitalization +24M (BU+9M, CF +15M)
Other	139	148	(9)	(4)	(5)	Discontinuing open bill -5M
EGI EBITDA	**1,879**	**1,824**	**55**	**(4)**	**59**	
Other GD EBITDA	55	46	9	1	8	Niagara RNG +3M, Lakeside +4M, Combined Heat and Power Plant sales +1M, Project Trafalgar +1M, partially offset by Gazifere -1M
GDS EBITDA	**1,934**	**1,870**	**64**	**(3)**	**67**	
Maintenance Capital	333	380	**47**	-	47	REWS +45M, +8M lower Compression Stations due to Crowland Station Renewal ending in 2022; higher Meter purchases -7M
Equity Dividends in excess of Equity Earnings	1	1	-	-	-	
Total DCF	**1,602**	**1,491**	**111**	**(3)**	**114**	
EBITDA (from above)	1,934	1,870	64	(3)	67	
Depreciation	784	772	**(12)**	-	**(12)**	Panhandle Regional Expansion Project, Dawn to Corruna, addition of TIS assets, increased overheads, lower ACDA amortization
GDS EBIT	**1,150**	**1,098**	**52**	**(3)**	**55**	

EBITDA/DCF Bridge (2023 Budget vs 2023 PY LRP)

ENBRIDGE

Segment	2023 Budget	2023 LRP	Total Variance (A)	Var. due to CF (B)	Business Drivers (A-B)	Variance Explanation (Quantified if possible)
Distribution Margin	2,471	2,412	59	-	59	PCI +49M, return on carrying costs of gas inventory +10M, ICM +10M, Gas Supply Margin/Fuels +7M; APCDA -9M, Acc CCA -9M
S&T Revenue	437	424	13	-	13	Storage price +6M, higher LT Transport +4M, ST transport +4M, PCI +3M; Storage optimization due to higher mitigation costs -7M
O&M	1,169	1,110	(59)	(36)	(23)	Inflation -22M, Self Insurance -13M, Integrity -9M, Ops – Locates/Lakeside/Crossbore -7M, Bad Debt -6M, additional Merit -2M; 1% Budget savings commitment +8M, higher Capitalization +31M (BU+17M, CF +14M)
Other	140	124	16	13	3	
EGI EBITDA	**1,879**	**1,850**	**29**	**(23)**	**52**	
Other GD EBITDA	55	53	2	1	1	
GDS EBITDA	**1,934**	**1,903**	**31**	**(22)**	**53**	
Maintenance Capital	333	312	**(21)**	-	(21)	TIS -24M, higher meter purchases -3M, accumulation of Other small projects -13M; REWS +10M, lower Compression Stations +4M
Equity Dividends in excess of Equity Earnings	1	1	-	-	-	
Total DCF	**1,602**	**1,592**	**10**	**(22)**	**32**	
EBITDA (from above)	1,934	1,903	31	(22)	53	
Depreciation	784	809	**25**	-	**25**	Lower software depreciation due to higher retirements in 2021 reflected in 2023 Budget, removal of GDS Oracle Cloud Project (included in PY LRP), lower ACDA amortization
GDS EBIT	**1,150**	**1,094**	**56**	**(22)**	**78**	

- Other includes Other Revenue, Other Income/Expense, and L25104 EBITDA

Capital Bridge (2023 Budget vs 2023 PY LRP)

2023 PY Capital LRP	Category	1,518	Variance Explanations (+ increase, - decrease)
Maintenance Capital	MC	20	+24M TIS, +3M higher meter purchases, +7M accumulation of Other small projects; -10M REWS, -4M lower Compression Stations
Growth	Growth	269	+23M Increase in Dawn to Corunna, +71M Panhandle Expansion, +35M higher Distribution Pipe, +44M higher Distribution Stations, +15M higher Transmission Pipe and Underground Storage, +70M higher Unregulated Storage and RNG projects, +3M BioRefinx RNG, +4M Other
Integration Capital (CTA)	MC	(7)	Cancellation of Building System Management Solution, removal of GDS Oracle Cloud costs, Site 2 & 3 (East & West), and AWS costs for phase 3 not being identified in last year's LRP.
2023 CY Capital Budget		**1,800**	

Key Message: MC pressures due to TIS and REWS. Increasing Growth Capital significantly due to Panhandle Expansion, Crowland Storage Transfer and Lisgar station, higher RNG.

EBITDA/DCF Bridge (2024 CY LRP vs 2024 PY LRP)

Segment	2024 CY LRP	2024 PY LRP	Total Variance (A)	Var. due to CF (B)	Business Drivers (A-B)	Variance Explanation (Quantified if possible)
Distribution Margin	2,880	2,524	356	-	356	Gas Supply Margin/Fuels primarily due to removal of LEGD LT Transport contract leading to cost savings (offset in reduction to S&T rev) +145M, Deficiency rate adj. +179M (242M CY plan vs 63M PY), PCI +49M (from 2023), return on carrying costs of gas inventory +10M, Comm. Exp. +2M, higher fuels due to new UFG methodology and reduction of CSF from LEGD contracts -25M, PDCI costs -4M, ICM -1M
S&T Revenue	311	440	(129)	-	(129)	Lower LT Transport primarily due to LEGD Contracts going away -142M, Storage optimization -4M; Storage price +4M, RNG injection station (PY budget in Other Revenue) +4M, PCI +3M, ST transport +3M
O&M	1,213	1,124	(89)	(70)	(19)	Inflation -16M, Integrity -11M, Ops – Locates/Lakeside/Crossbore -10M and Self Insurance Reserve -10M, Bad Debt -7M, additional Merit -6M; higher Capitalization +32M (BU+11M, CF +21M), 1% Budget savings commitment +12M
Other	133	127	6	17	(11)	Discontinue Open bill program -22M (partially offset by 12M O&M savings), RNG injection station (CY LRP in S&T) -5M; increase in LPP +7M, increase from various services revenues +4M
EGI EBITDA	**2,111**	**1,967**	**144**	**(53)**	**197**	
Other GD EBITDA	60	55	5	1	4	
GDS EBITDA	**2,171**	**2,022**	**149**	**(52)**	**201**	
Maintenance Capital	448	352	**(96)**	-	(96)	Higher OH Allocation -24M, higher Transmission Pipe and Storage -23M, higher REWS -22M, higher TIS -21M, higher Meter purchases -21M, higher Fleet & Equipment -9M, Rockcliffe Project Increase -7M; lower Compression Stations +29M
Equity Dividends in excess of Equity Earnings	1	1	-	-	-	
Total DCF	**1,724**	**1,671**	**53**	**(52)**	**105**	
EBITDA (from above)	2,171	2,022	149	(52)	201	
Depreciation	985	851	**(134)**	-	**(134)**	Impacts of new depreciation study for rebasing, higher overall capital plan; partially offset by GDS Oracle Cloud included in PY LRP but removed in CY
GDS EBIT	**1,186**	**1,171**	**15**	**(52)**	**67**	

Proposed Deficiency Drivers

In $ millions

Net sustainable synergies and productivity	(67)
Changes in accounting policy and methodologies	(26)
Impact related to ICM and Capital Pass Through projects	42
Deferred Rebasing Impact	**(51)**
Cost pressures	69
Depreciation	198
Equity thickness	26
Cost of Service Impacts	**293**
Total Delivery Revenue Deficiency	**242**
Gas Supply Deficiency	**23**
Total Deficiency	**265**
Total Revenue Requirement	6,279
Deficiency as a % of Revenue Requirement	4%

Capital Bridge (2024 CY LRP vs 2024 PY LRP)

ENBRIDGE

2024 PY Capital LRP	Category	1,520	Variance Explanations (+ increase, - decrease)
Maintenance Capital	MC	95	+21M higher TIS, +22M higher REWS,+21M higher Meter purchases and Regulator Refit replacements, +23M higher Transmission Pipe and Storage, +24M higher OH Allocation, +9M higher Fleet & Equipment, +7M Rockcliffe Project Increase; -29M lower Compression Stations -3M Other.
Growth	Growth	15	+38M higher Transmission Pipe & Underground Storage due to Panhandle expansion project and Dawn parkway Expansion project, +16M higher Customer Connections, +5M higher System Reinforcement; -31M lower Distribution Pipe, -7M lower Distribution Station, -6M lower Meter purchases
Integration Capital (CTA)	MC	-	No integration capital starting in 2024
2024 CY Capital LRP		**1,630**	

Key Message: MC DCF pressures due to higher TIS, higher REWS, higher overheads, and higher meter purchases. Growth consistent with PY LRP.

EBITDA/DCF Bridge (2025 CY LRP vs 2025 PY LRP)

ENBRIDGE

Segment	2025 CY LRP	2025 PY LRP	Total Variance (A)	Var. due to CF (B)	Business Drivers (A-B)	Variance Explanation (Quantified if possible)
Distribution Margin	3,024	2,555	469	-	469	Gas Supply Margin/Fuels primarily due to removal of LEGD LT Transport contract leading to cost savings (offset in reduction to S&T rev) +145M, PCI +131M*, deficiency rate adj. +182M**, return on carrying costs of gas inventory +10M, CM +5M, PDO/CPT rate var. +3M, storage allocation rate var.+3M, Comm. Exp. +2M, higher fuels due to reduction of CSF from LEGD contracts -11M, PDCI costs -4M
S&T Revenue	311	440	(129)	-	(129)	Lower LT Transport primarily due to LEGD Contracts going away -142M, Storage optimization -4M; RNG injection station (PY budget in Other Revenue) +5M, PCI +4M, ST transport +3M, Storage price +1M
O&M	1,242	1,132	(110)	(82)	(28)	Integrity -11M, inflation -10M, Ops – Locates/Lakeside/Crossbore -10M and Self Insurance Reserve -10M, Bad Debt -7M, addit. Merit -6M, higher Property Tax due to higher inflation assumption. -4M, Travel -1M; higher Capitalization +31M (BU+8M, CF +23M)
Other	137	132	5	21	(16)	Discontinue Open bill program -23M (partially offset by 12M O&M savings), Construction Heat Meter Activation -1M; increase in LPP +7M, increase from various services revenues +3M
EGI EBITDA	**2,230**	**1,995**	**235**	**(61)**	**296**	
Other GD EBITDA	63	57	6	1	5	
GDS EBITDA	**2,293**	**2,052**	**241**	**(60)**	**301**	
Maintenance Capital	425	332	**(93)**	**-**	(93)	Higher OH Allocation -44M, higher Meter purchases -27M, higher REWS -21M, higher TIS-17M, higher Fleet and Equipment -9M; lower Unregulated Storage Enhancement projects +13M, lower Compression Stations +8M
Equity Dividends in excess of Equity Earnings	-	1	**(1)**	**-**	(1)	
Total DCF	**1,868**	**1,721**	**147**	**(60)**	**207**	
EBITDA (from above)	2,293	2,052	241	(60)	301	
Depreciation	1,028	849	**(179)**	**-**	**(179)**	Impacts of new depreciation study for rebasing, increase in TIS assets PvP
GDS EBIT	**1,265**	**1,203**	**62**	**(60)**	**122**	

*PCI +131M due to higher PCI from 2023 and PCI of 3.04% in 2025 vs none in PY LRP
**Deficiency rate adjustment = (242M 2024 Distribution deficiency – 7M DSM) * 3.04% PCI + 14M Equity Thickness – 6M Productivity Update =249M – 67M deficiency in PY LRP = +182M

Capital Bridge (2025 CY LRP vs 2025 PY LRP)

ENBRIDGE

2025 PY Capital LRP	Category	1,831	Variance Explanations (+ increase, - decrease)
Maintenance Capital	MC	94	+44M higher OH Allocation, +27M higher Meter purchases and Regulators refit, +21M higher REWS, +17M higher TIS, +9M higher Fleet and Equipment; -13M lower Unregulated Storage Enhancement projects, -8M lower Compression Stations, -3M Other.
Growth	Growth	(317)	-93M lower Distribution Pipe, -64M lower System Reinforcement, -131M lower Transmission Pipe & Underground Storage, -53M lower Compression Stations, -8M lower Meter purchases; partially offset by +17M higher Customer Connections, +8M higher Distribution Station, +4M Gazifere, and +3M Other.
Integration Capital (CTA)	MC	-	
2025 CY Capital LRP		**1,607**	

Key Message: MC pressures due to higher OH's, TIS, REWS, and higher meter purchases. Growth Capital decrease due to removal of Vintage Steel Replacement, reduction to Owen Sound Transmission, Marten River Compression, and Rideau Reinforcement, reduced D-P expansion and lower Dawn C spend

Key Sensitivities

ENBRIDGE

Segment	Asset	Description	DCF Impact – '23 Budget	DCF Impact – CY '24 LRP	DCF Impact – CY '25 LRP
EGI	All	2024 Rebasing	-	?	?
EGI	All	Energy Transition	?	?	?
EGI	Utility	ROE: 10 basis point change in ROE (based off 36% equity thickness)	+/- 7	+/- 7	+/- 7
EGI	Utility	Equity Thickness +1% change	-	+/-14	+/-14
EGI	Revenue	10 basis point change in PCI	+/- 2	+/- 2	+/- 2
EGI	Dist. Margin	Weather 5% change in HDD's	+/-38	+/-38	+/-38
EGI	Dist. Margin	Contract Market: 10% change in throughput (Fixed Revenue 80% for EGI)	+/- 5	+/- 5	+/- 5
EGI	Dist. Margin	10% Change in Ref. Price Impact on Return on Carrying Cost GIS (based off April QRAM)	+/- 3	+/- 3	+/- 3
EGI	Dist. Margin	+/- 3,000 Change in Customers	+/- 2	+/- 2	+/- 2
EGI	S&T	Storage Revenue: $0.1 US/mmbtu change in Storage price	+/- 1	+/- 8	+/- 15
EGI	O&M	Additional 1% of inflation/CPI than currently in Plan	+/- 5	+/- 5	+/- 5
EGI	O&M	Inflation/Market Conditions impact on Customer Care/ Bad Debt	?	?	?
Total Tailwinds/Headwinds Impact			**~+/-63**	**~+/-84**	**~+/-91**

Assumptions

Assumptions	Proposal			
Year	**2023**	**2024**	**2025**	**2026**
Board Approved ROE	8.66%	8.66%	8.66%	8.66%
FX Rate	1.25	1.25	1.25	1.25
Debt/Equity	64/36	62/38	61/39	60/40
Merit	4%	5%	3%	3%
Inflation *	2.4%	2.2%	2%	2%
GDP IPI FDD	3.9%	N/A	2%	2%
Productivity	0%	N/A	-1.04%	-1.04%
Stretch	0.30%	N/A	0%	0%
PCI (GDP IPI FDD less Productivity less Stretch)	3.6%	N/A	3.04%	3.04%
Customer Growth	39,377	37,624	37,624	37,624

* Only applicable to small portion of O&M. Majority is based off bottoms up approach where known costs are used and not an assumption. Effective inflation rate inherent in O&M budget 5.4% for 2023, 2.4% for 2024

ENBRIDGE GAS INC.

Answer to Undertaking from
Green Energy Coalition (GEC)

Undertaking

Tr: 85

To review 1.3-SEC-7, Attachment 1.3, page 7 of 14, under the diversified and electric pathways that Guidehouse has considered, included, or not included within its study.

Response:

The following response was provided by Guidehouse Canada Ltd.:

The interveners asked Guidehouse to evaluate which items from Exhibit I.1.3-SEC-7, Attachment 3, page 7 of 14 that were considered, included, or not included within the study. In Table 1, the referenced table is reproduced exactly, to align with the previous filing. In Table 2, Guidehouse provides a response to the considerations for the Diversified pathway. In Table 3, Guidehouse provides a response to the considerations for the Electrification pathway.

Table 1
Table from 1.3-SEC-7, Attachment 3, page 7 of 14

	Steady Progress	Diversified Pathway	Electric Pathway
Achieves net-zero by 2050	• Not likely	• Targeting	• Targeting
Carbon price by 2038	• $200/tCO2 ($170/tCO2 by 2030, escalated by inflation)	• $200/tCO2 ($170/tCO2 by 2030, escalated by inflation)	• $338/tCO2
Codes & Standards	• Net-zero energy ready by 2038 • Retrofit code implemented by 2035	• Net-zero energy ready by 2035 • Retrofit code implemented by 2030	• Net-zero energy ready by 2035 • Retrofit code implemented by 2030
Fuel switching policy	• None	• Some communities ban gas for new construction • Incentives encourage existing homes to fuel switch	• Province-wide mandate to switch to electric heating starting in 2025 for new construction and existing homes • Some industrial electrification

	Steady Progress	Diversified Pathway	Electric Pathway
RNG	• Modest, <10% of gas supply	• Maximized, 15-25% of gas supply	• Modest, 10% of gas supply
Hydrogen	• Modest, <5% of gas supply	• 100% H2 networks introduced in 2030 • Blending 10% H2 in natural gas system	• Minimal, <1% of gas supply
CCS	• Minimal, capture mainly at refineries, H2 generation	• Maximized, capture at most large emitting industries	• Minimal, capture mainly at refineries, H2 generation

Table 2
Guidehouse Response to Table from 1.3-SEC-7, Attachment 3, page 7 of 14, Diversified Pathway

	Diversified Pathway	Guidehouse Response
Achieves net-zero by 2050	• Targeting	**Included.** For the diversified pathway, the P2NZ study models a transition in which energy consuming sectors (buildings, transportation, industry, power) shift to an energy mix that achieves net-zero by 2050.
Carbon price by 2038	• \$200/tCO2 (\$170/tCO2 by 2030, escalated by inflation)	**Included.** The P2NZ modeling studied four model years (2020, 2030, 2040, and 2050), and the escalating price of carbon in these years is consistent with a \$200/tCO2 nominal price in 2038.
Codes & Standards	• Net-zero energy ready by 2035 • Retrofit code implemented by 2030	**Considered.** The P2NZ study assumed a high rate of improvement in space conditioning efficiency for buildings, on the assumption that retrofit and net-zero codes are adopted. However, the P2NZ study did not conduct premise-level modeling.
Fuel switching policy	• Some communities ban gas for new construction • Incentives encourage existing homes to fuel switch	**Considered.** The P2NZ study assumed a high rate of fuel switching in the diversified scenario, with buildings switching from natural gas to electricity, RNG, and hydrogen. This assumption was based on the hypothesis that fuel switching will be motivated by incentive programs and, in some cases, will be forced by gas bans. However, the P2NZ study did not conduct community- or premise-level modeling.
RNG	• Maximized, 15-25% of gas supply	**Not Included.** The diversified scenario assumed that in 2038, about 10% of pipeline natural gas supply will be displaced by RNG.
Hydrogen	• 100% H2 networks introduced in 2030 • Blending 10% H2 in natural gas system	**Included.** The P2NZ diversified scenario assumes that 100% H2 networks are introduced in 2030 and that H2 blending in pipeline networks is about 10% by volume in 2038. The scenario assumes H2 use ramps up from 2039 through 2050 to achieve a net-zero emissions target.
CCS	• Maximized, capture at most large emitting industries	**Included.** The diversified scenario utilizes CCS for hydrogen production and for industrial natural gas consumption.

Table 3
Guidehouse Response to Table from 1.3-SEC-7, Attachment 3, page 7 of 14, Electric Pathway (named the "Electrification Pathway" in the P2NZ report)

	Electric Pathway	Guidehouse Response
Achieves net-zero by 2050	• Targeting	**Included.** For the electrification pathway, the P2NZ study models a transition in which energy consuming sectors (buildings, transportation, industry, power) shift to an energy mix that achieves net-zero by 2050.
Carbon price by 2038	• $338/tCO2	**Included.** The P2NZ modeling studied four model years (2020, 2030, 2040, and 2050), and the escalating price of carbon in these years is consistent with a $338/tCO2 nominal price in 2038.
Codes & Standards	• Net-zero energy ready by 2035 • Retrofit code implemented by 2030	**Considered.** The P2NZ study assumed a high rate of improvement in space conditioning efficiency for buildings, on the assumption that retrofit and net-zero codes are adopted. The P2NZ study did not conduct premise-level modeling.
Fuel switching policy	• Province-wide mandate to switch to electric heating starting in 2025 for new construction and existing homes • Some industrial electrification	**Not Included.** The P2NZ study assumed a high rate of building and industry electrification in the electrification scenario. However, the electrification scenario projected that a small portion of existing homes would still use gaseous fuels for heating in 2030, 2040, and 2050. The electrification scenario assumed a moderate amount of electrification in the industrial sector.
RNG	• Modest, 10% of gas supply	**Included.** The electrification scenario assumed that in 2038, about 10% of pipeline natural gas supply is displaced by RNG.
Hydrogen	• Minimal, <1% of gas supply	**Included.** The P2NZ assumes for the electrification scenario hydrogen blending is very low 2038, but that hydrogen use ramps up from 2039-2050 to achieve a net-zero emissions target.
CCS	• Minimal, capture mainly at refineries, H2 generation	**Included.** The electrification scenario utilizes CCS for hydrogen production and for a limited amount of industrial natural gas consumption.

b) The cost of developing interregional hydrogen-only transmission pipelines and repurposing existing interregional gas pipelines to carry hydrogen is provided in response at Exhibit I.1.10-GEC-20. Guidehouse declines to provide costs for distribution pipelines in Ontario. Costs for upgrading methane distribution pipelines to accept hydrogen blending and for the hydrogen distribution system within Ontario are outside the scope of the P2NZ analysis and not included. This is because a more detailed regional analysis is needed to understand how new hydrogen networks would develop depending on where demand centers develop geographically and potential opportunities for collocated supply. /u

Hydrogen derived from fossil gas (i.e. blue)					
Hydrogen derived from electrolysis (i.e. green)					

Response:

a) The following response was provided by Guidehouse Canada Ltd.:

Guidehouse declines to provide the requested table because the *Pathways to Net Zero Emissions for Ontario* Study modelled gaseous fuel consumption on a decade basis and not for the individual years specified in the requested table.

b) The following response was provided by Guidehouse Canada Ltd.:

Please see tables below.

Table 1
Consumption of Gaseous Fuels by Scenario and Decade (PJ/yr)

	2020	2030	2040	2050
Diversified scenario				
Fossil gas	922	789	390	0
Renewable natural gas	0	46	112	172
Fossil gas with CCS	0	48	116	133
Hydrogen derived from fossil gas (i.e. blue)	0	145	252	252
Hydrogen derived from electrolysis (i.e. green)	0	0	211	592
Electrification scenario				
Fossil gas	922	783	317	0
Renewable natural gas	0	15	60	79
Fossil gas with CCS	0	0	65	103
Hydrogen derived from fossil gas (i.e. blue)	0	55	99	98
Hydrogen derived from electrolysis (i.e. green)	0	0	53	164

Table 2
Consumption of Gaseous Fuels by Scenario and Decade (million m3/yr)

	2020	2030	2040	2050
Diversified scenario				
Fossil gas	24,073	20,601	10,183	0
Renewable natural gas	0	1,201	2,924	4,491
Fossil gas with CCS	0	1,253	3,029	3,473
Hydrogen derived from fossil gas (i.e. blue)	0	3,786	6,569	6,568
Hydrogen derived from electrolysis (i.e. green)	0	0	5,520	15,468
Electrification scenario				
Fossil gas	24,073	20,444	8,277	0
Renewable natural gas	0	392	1,567	2,063
Fossil gas with CCS	0	0	1,697	2,689
Hydrogen derived from fossil gas (i.e. blue)	0	1,436	2,575	2,571
Hydrogen derived from electrolysis (i.e. green)	0	0	1,393	4,270

c) Enbridge Gas declines to provide forecasted amount for RNG. This issue will be addressed in Phase 2 of the proceeding in accordance with the OEB's Decision on Issues List dated January 27, 2023.

Enbridge Gas declines to provide forecasts for demand associated with natural gas with CCS and blue hydrogen as forecasts for these low carbon alternatives cannot be reliably estimated at this time, pending the development of further government regulations required to permit these activities within Ontario.

Please see Tables 3 and 4 below for the forecasted amount of gas demand for the 2024 to 2028 period, presented in millions m3/yr and PJ/year respectively. The forecasted volumes for natural gas in line 1 of the tables below represent the general service annual volume forecast as provided in the response to Exhibit I.1.10-STAFF-31 Attachment 1, Table 1 and the throughput volume forecast for the distribution contract market sales and T-service, as provided in the response to Exhibit I.1.10-STAFF-30, Attachment 1. The forecast for hydrogen in line 2 of the tables below reflects the maximum blend percentage of 2 percent by volume for the current area served by the Low Carbon Energy Project Phase (LCEP) Phase 1. The forecast builds on the year 1 actual hydrogen consumption in LCEP Phase 1, but may not fully represent future volumes. The forecast is subject to variability in gas flow in the system where blending is occurring at a rate between 0 to 2 percent and from variability in the hydrogen plant operations. Enbridge Gas is unable to estimate the impacts to the forecast due to LCEP Phase 2 as the blending rate has yet to be established for LCEP Phase 2.

Table 3 Forecast Consumption of Gaseous Fuels per Enbridge Application (millions m3/yr)						
Line No.		2024	2025	2026	2027	2028
1	Combined General Service and Contract Volume forecast	27,922.9	28,140.7	28,963.0	28,963.3	28,942.6
2	Hydrogen derived from electrolysis (i.e. green)	0.18	0.18	0.18	0.18	0.18

Table 4 Forecast Consumption of Gaseous Fuels per Enbridge Application (PJ/yr)						
Line No.		2024	2025	2026	2027	2028
1	Combined General Service and Contract Volume forecast	1091.2	1099.7	1131.9	1131.9	1131.1
2	Hydrogen derived from electrolysis (i.e. green)	0.0023	0.0023	0.0023	0.0023	0.0023

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2022-0200**	**Enbridge Gas Inc.**
VOLUME:	**1**	
DATE:	**July 13, 2023**	
BEFORE:	**Patrick Moran**	**Presiding Commissioner**
	Allison Duff	**Commissioner**
	Emad Elsayed	**Commissioner**

transition plan presentation.

EXHIBIT K1.3: OVERVIEW PRESENTATION OF ENBRIDGE GAS'S ENERGY TRANSITION PLAN

MR. MILLAR: K1.4?

MR. STEVENS: Enbridge's feedback on the electrification and energy transition panel's consultation, dated June 30, 2023.

EXHIBIT K1.4: ENBRIDGE FEEDBACK ON ELECTRIFICATION AND ENERGY TRANSITION PANEL'S CONSULTATION, DATED JUNE 30, 2023

MR. MILLAR: And finally, K1.5.

MR. STEVENS: Ontario government report titled, "Powering Ontario's Growth."

EXHIBIT K1.5: ONTARIO GOVERNMENT REPORT TITLED, "POWERING ONTARIO'S GROWTH."

MR. MILLAR: Thank you.

MR. STEVENS: And, with that, I believe that the Guidehouse witnesses are ready to commence their presentation. So perhaps, if you could, Angela, if you could pull up exhibit K1.2.

PRESENTATION BY MS. ROSZELL:

MS. ROSZELL: Thank you. And let's move to the next slide, please.

So just starting off by giving an overview of what the study objective was. The study objective in this case was to look at net zero economy and to find plausible pathways to get there that looked at all sectors. Looking at one sector alone wouldn't provide the macro picture to ensure tag of capacity expansion required to supply the projected future energy demand. Scenarios are defined by the modeler and scenario parameters, such as the precent electrification, are used to develop energy demand projections that are unique to each scenario.

The model estimates the cost of installing and operating new infrastructure required to produce, transmit, and store energy sufficient to meet projected demand in each scenario. Next slide, please.

Both pathways in this case achieve net zero. Both result in higher peak demand; however, the electrification pathway leads to significant higher peak, approximately double that of the diversified scenario. This requires more significant scale-up of electric generation, transmission, and distribution assets. Our analysis founds that a diversified approach that leverages existing gas delivery infrastructure to deliver low-carbon fuels and offer cost savings compared to an electrification-focused approach that would underutilize existing infrastructure, resulting in a lower -- the diversified scenario then results in a lower cost and more resilient energy system.

The analysis also demonstrates the role that gas delivery infrastructure has in both approaches, delivering low-carbon fuels across sectors in the diversified approach and, for hard-to-abate sectors like industry and heavy transport, an electrification approach. This is consistent with the findings of similar analysis that Guidehouse has conducted regarding utilities' role in energy transition electrification scenario, which was $722 billion, or 6 percent lower. The reduced costs are due to less spending on electricity generation capacity and infrastructure, end-user heating systems, and building energy retrofits.

Both scenarios do face implementation challenges. The diversified scenario relies on customer conversion to hydrogen-consuming equipment, including industrial use and gas heat pumps, as well as more rapid adoption of electrolyser and CCS technologies. The electrification pathways leads to more rapid growth in electric peak demand, which will require more rapid growth in electric generation capacity to avoid system failures, especially during extreme weather events.

The electricity and gas system will become increasingly integrated in the future. Gas power generation is going to play a critical role in Ontario's electricity system and electricity generation will shift from natural gas to hydrogen sources. Energy system resilience will be a key consideration as peak electric demand grows in both scenarios. The diversified pathway provides resilience and reliability benefits and provides solutions for hard-to-electrify sectors, such as industrial customers and heavy transport vehicles.

We also completed a number of sensitivity analyses, and the key findings of those sensitivity analyses were that lower-cost distributed energy resources could drive increased deployment, which would lead to cost savings in include the value of resilience that the gas system can provide and costs to decommission gas lines or stranded gas assets.

On May 26, 2023, Guidehouse also provided an addendum to the updated Pathways to Net Zero report as a response to intervenor requests by way of undertaking JT 9.16. This addendum discusses the sensitivity of modeling results to different assumptions related to the emission and production of blue hydrogen. This addendum showed that the cost differential between compared scenarios is not sensitive to blue hydrogen assumptions, as the main effect of increasing assumed emission rates is to reduce the amount of blue hydrogen that is selected to meet demand.

The cost differential between the diversified and electrification scenarios narrows slightly for the two sensitivity cases, to 34 billion in sensitivity 5A and 29 billion in sensitivity 5B. While the cost differential has changed overall, the results of these changes and additional analyses do not substantially change any of the conclusions of the Pathways to Net Zero report.

The Pathways to Net Zero report continues to illustrate the value of a diversified approach to achieving Ontario's net zero goal. Maintaining and repurposing gas infrastructure as part of a holistic decarbonization strategy as opposed to an electrified-only pathway continues to be the best approach to achieving net zero for Ontario. This is true because the maintenance and repurposing of gas infrastructure provides greater resilience in the face of extreme weather events, limits the stranded costs of existing infrastructure, and results in a lower cost pathway.

Guidehouse does not anticipate any further changes to the report, because we do not believe that further revisions would provide additional value to stakeholders. Other studies that are complete or underway include the Ministry of Energy Ontario pathways study, the CER study which was recently released, and the IESO's pathways study. Next slide, please.

Finally, after completion or responding to the additional undertakings, as mentioned earlier, we continue to maintain the recommendations as they stand in chapter 6 of the original report. For example, gas generation will continue to play a critical role in Ontario's electricity system, and low- and zero-carbon gases like renewable natural gas and hydrogen will play a role in the GHG emission reductions of most sectors. While electrification remains a powerful tool for reducing GHG emissions, electrification is not practical for all sectors. The findings also remain consistent with other similar studies and policies across the world, for example recommendations to develop integrated electricity and gas planning; to develop regulatory structures that value energy system resilience; to establish an RNG production binding target; to assess future hydrogen network needs; and to develop pilot CCUS projects to demonstrate the feasibility of CO2 collection, transport, and sequestration. Thank you.

mentioned, Enbridge Gas has proposed an increase to the company's deemed equity ratio from 36 percent to 42 percent. And in the context of potential future stranded assets, the proposed equal life group approach ensures a better starting point than an average life group, as it ensures that the consumption of the capital aligns with the benefit of the capital. In addition, Enbridge Gas has determined that an economic planning horizon is not appropriate at this time.

Next slide, please. While some assume the only pathway to achieve net zero is the complete electrification of the [audio dropout] demand that is currently served by natural gas, Enbridge Gas's vision is one of a diversified approach. At a high level, Enbridge Gas defines a diversified pathway as one where energy choices are not mandated by government policy, rather policies enable customers to meet emission reductions targets by making energy choices that meet their affordability, reliability and resiliency requirements. Energy system utilization and build-out would respond to these 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, low- and zero-carbon fuels and low-carbon electricity. Depending on customers' preferences, gaseous fuels could be used to meet year-round requirements, peak season demands, backup for resiliency, or not at all.

Enbridge Gas understands that the pathway and the associated policies reside with the Ontario government, and that not all aspects have yet been defined to align with the company's vision, but acknowledge this.

The company developed an energy transition plan with the following objectives: support an orderly energy transition in Ontario; maintain alignment with Ontario's energy plans and policies and objectives, and with provincial and federal climate change targets.

As these plans and policies continue to be defined, Enbridge Gas will refine its energy transition plan. Enbridge notes that in previously mentioned "Powering Ontario's Growth", just released this week, the government has highlighted that natural gas will continue to play a critical role in providing Ontarians with a reliable and cost-effective fuel supply for space heating, industrial growth and economic prosperity.

And they also note that with developments in energy efficiency and low-carbon fuels such as renewable natural gas and low-carbon hydrogen, the natural gas distribution system will [audio dropout] the province's transition from higher carbon fuels in a cost-effective way.

In addition, the Canadian energy regulator's analysis that was just recently released demonstrates that emerging technologies such as carbon capture paired with natural gas and low-carbon fuels can have a key role to play in achieving net zero.

Adhering to these objectives, Enbridge Gas then included within its energy transition plan associated actions and proposals that are considered to be safe bets.

Next page, please. Enbridge Gas believes that taking no action is not an option. And so it has proposed a set of actions that it considers to be safe bets. Enbridge defines a safe bet as an action that can and should be taken now, as it is required regardless of whether or not a diversified or an electrification pathway unfolds in Ontario. It supports Ontario's near term greenhouse gas reductions, including the achievement of the 2030 target, and it maintains pathway optionality without over-investing in a particular pathway prior to the Ontario government further defining its policies, which all supports government's focus on consumer choice. And finally, it considers a safe bet if it maintains a safe and reliable system.

Enbridge Gas's safe bets include actions ranging from those with which Enbridge Gas has been undertaking for some time, to actions that the company is in the early stages of exploring. The company notes that not all safe bets discussed within its plan have associated proposals within the rebasing application. In some cases, where noted, the safe-bet action requires additional provincial government policies, investments and/or OEB support to move forward.

These safe bet actions include maximizing energy efficiency, increasing the amount of renewable natural gas supply, as this will provide consumer choice and an immediate opportunity to reduce greenhouse gas emissions, and develop an Ontario-based market.

The third safe bet is reducing emissions in the industrial and transportation sector. This includes supporting customers in their evaluation and take-up of low-carbon fuel gases, to switch away from the consumption of higher carbon-intensity fuels or feedstocks. This could include customers attaching to the gas distribution system and, if so, these actions must be taken with a province-wide, not-gas-system-only lens, as they support both the customer's own carbon targets and the achievement of Ontario's goals.

The next is coordinated gas and electric system planning. Enbridge believes that coordinated planning enables optimized pathway modelling by region and that, without it, planning decisions could be made on a shorter term siloed view, and not on the long-term implications of the province.

The importance of coordinated planning has been recognized in the Ontario government's "Powering Ontario Growth" plan. It highlights that implementing an integrated energy planning process is important in making the most cost-effective decisions necessary to prepare for a clean energy future. And they note that they are exploring topics such as roles and responsibilities for the province, energy agencies and options to optimize energy demand and decarbonize future energy supply.

The last is supporting consumer customer choice in energy transition journey. That last safe bet is based on

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2022-0200**	**Enbridge Gas Inc.**

VOLUME:	**2**	
DATE:	**July 14, 2023**	
BEFORE:	**Patrick Moran**	**Presiding Commissioner**
	Allison Duff	**Commissioner**
	Emad Elsayed	**Commissioner**

diversified, is it not reasonable to assume that in a system where you have got your distribution costs largely in a fixed charge, that many of those customers will want to avoid that charge and leave the system?

MS. ROSZELL: Andrea Roszell with Guidehouse. I think, as Malini just stated, we don't think the value of the system is going to be only related to energy, and so we can't make that assessment, but your original question, Mr. Poch, I think was about -- related to cooking and whether or not we believe that consumers are going to stay connected just for gas cooking appliances. We didn't model consumer choice specifically. But I don't think that we would be able to opine on that. And I know that that is more of an opinion-based statement that you made, I think, than a fact. I don't think we would be positioned to be able to respond to that.

MR. POCH: All right. You didn't model that.

MS. ROSZELL: We did not model specifically what a consumer would choose, in terms of gas appliances. We modelled the specific percentage of gas cooking appliances in future years.

MR. POCH: All right --

MS. GIRIDHAR: Mr. Poch, it is Malini Giridhar from Enbridge. I'd just like to respond to the presumption that customers would not want to pay higher fixed charges than they do today for the resilience of the gas system. So in SEC-28 --

MR. POCH: I am sorry to interrupt, but that is not my

That is the history. Fair?

MS. ROSZELL: Andrea Roszell with Guidehouse. I would say that, just to clarify, we are doing scenario analysis here. I think we can all agree based on the opening remarks which everyone made that we are tackling what is one of the most complex issues that humanity has ever faced. There isn't any certainty in terms of what 2050 is going to look like. And so, as we have gone through the process, we have refined the analysis to reflect a lot of the feedback that we have got from the intervenors and to reflect a lot of the dialogue that is happening in the Ontario sector.

The changes are happening on a daily basis. As we have seen, the Ontario government has just released the Powering Ontario report, so we could remodel a number of different scenarios based on that report now and find different findings which would probably be more favourable than the reduction that we have seen from that original $181 to the $41 billion that we now have.

So I just want to make sure that it's clear that it is a scenario, it isn't a forecast, and we could continue to refine it, but there isn't any value in doing that, given the number of studies that are still happening in the sector.

MR. POCH: Let me just clarify. The changes that I spoke of, from $181 billion difference to $41 billion, they weren't because of new findings from outside. They were where you made corrections in your analysis. Fair?

MS. WADE: Mr. Poch, I would just note, the intent of having a carbon charge is to drive the behaviour of the electrification, as we have noted earlier, which we think would be required in order to reach such deep electrification in that pathway. It is not done for the rebate. So it really is intended to drive the electrification behaviour.

MR. POCH: I totally understand you assuming a policy driver would be there to underlie your scenario to the attainability of your scenario. But you have included it in the cost, even though that cost gets refunded to Ontario. So I am wondering why that cost persists in your study, when you say this is a cheaper scenario diversified than electrified, when that 57 billion is going to get refunded to Ontario.

MS. WADE: I would also note that the study extends out to 2050. The rebate exists today. We did not include an assumption that the policy regarding a refund would extend all the way to 2050. And I think I just want to reiterate Mr. Ringo's point that it is different in the sense that it is tied to the operation of the equipment that is being used within the facility, unlike the incentive that would be given on investment in a certain technology or energy supply.

MR. POCH: Okay.

MR. RINGO: This is Decker Ringo at Guidehouse. May I offer another point here. Mr. Poch, you portrayed this as the only policy lever included in our study, but several

MR. POCH: Would you need to do any inspection in advance to make sure that homes are hydrogen ready?

MS. MARTIN: Yes. We would have to inspect the appliances to ensure that they were appropriate to receive any fuel-mixture change.

MR. POCH: Right. And so you would have to check the service pipes too, I assume. The service pipes would have to be hydrogen ready?

MS. MARTIN: If they are following the building code, which I am assuming they are, then they should -- it should be appropriate for hydrogen.

MR. POCH: Okay. In your materials, you talked about a portion of your pipes are polyethylene and a portion of them are metal, and that at least the metal ones, you would have to inspect and possibly coat or otherwise treat, in both at the distribution level and the transmission level, to be hydrogen ready. Have I got that right?

MS. MARTIN: No. Actually, we don't really know that yet. The system-wide blending engineering assessment is intended to study all of the components in our system to understand what if any modifications need to be made at what percentages of hydrogen blend, up to and including 100 percent.

MR. POCH: Okay. And what about meters? Are they hydrogen ready?

MS. MARTIN: They are hydrogen ready up to a certain blend. They may need to be modified beyond that, but Measurement Canada hasn't yet approved a 100 percent takes into account all of the components in your system. There is a risk assessment. Operational readiness. There is a lot of elements that go into an engineering assessment.

MR. ELSON: So I have another question that I was confused about from your testimony earlier today. You seemed to say that all of the pipes in all of our homes are 100 percent hydrogen-ready. Is that really what you said? Because it appears to me to be different from the evidence in the interrogatory responses and at the technical conference.

MS. MARTIN: That is what I said. And actually, maybe at this time I might be able to correct something. We don't have iron pipes in homes. The literature that I have seen, because it is inches delivery water column, there is no risk with 100 percent hydrogen.

MR. ELSON: I am sorry, I didn't understand that answer. Can you repeat it again?

MS. MARTIN: Well, at the pressures that are entering into the homes, the latest literature suggests that there no increased risk between natural gas and 100 percent hydrogen.

MR. ELSON: And so are you saying on the record today that all pipes in homes are 100 percent hydrogen-ready and we don't need to change any or swap out the couplings or anything like that?

MS. MARTIN: That is what the latest literature suggests, yes.

that correct?

MR. RINGO: This is Decker from Guidehouse: Yes.

MR. ELSON: Your model is a scenario comparison tool. Right?

MR. RINGO: Yes.

MR. ELSON: It doesn't for example determine the optimal amount of fuel switching from gas furnaces to cold-climate heat pumps.

MR. RINGO: That is correct. That amount of switching is specified in the definition of the scenarios.

MR. ELSON: Thank you, Mr. Ringo. That is helpful. And it doesn't show us whether a pathway that involves increasing investment in pipelines is cheaper overall than a pathway involving more electricity instead, because it just compares two defined scenarios as opposed to all available potential pathways. Is that fair to say?

MR. RINGO: I am not sure I understand the question. I think you are saying does it do a cost analysis of two scenarios? It does --

MR. ELSON: Yes. Well, that is what it does. It says the model compares two defined scenarios. Right?

MR. RINGO: That is right.

MR. ELSON: What it doesn't do is say that the cheapest pathway overall is going to be one with increasing investment in pipelines versus a pathway involving more electricity. It is just comparing two defined scenarios, not --

MR. RINGO: Not the entire universe of potential

The Diversified Portfolio scenario also implicitly assumes:

a) Innovations in electric storage (or some other supply side electric technology or resource) will occur, and this technology would be available to facilitate additional load on the electricity grid resulting from fuel switching.

b) Hydrogen-ready equipment will be available and is installed (when equipment reaches its effective useful life) for industrial end-uses that switch to hydrogen.

c) Some residential and commercial customers install hydrogen-ready equipment (when equipment reaches its effective useful life).

d) CCS technology will be available and will be retrofitted on existing equipment for some industrial end-uses.

e) Low-carbon fuels, and the technology required to upgrade and inject these fuels in the grid, will be available.

iv) Please provide rationale for assuming widespread adoption of CCS by 2037 given current level of technical feasibility.

The maximum setting for carbon capture and storage technology adoption was defined as a possible upper bound for industrial segments and end-uses served by Enbridge Gas's system. The pace and scale of CCS technology development and availability is assumed as a response to demand creation. This upper bound was provided by Enbridge Gas.

More detailed assumptions on the industrial sector CCS input settings for the Diversified Portfolio Scenario (the scenario with the highest input assumptions for CCS) are presented in Appendix F of the report. Please see Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 114.

v) For RNG, hydrogen, and CCS assumptions in all scenarios, please explain how uncertainty related to technical feasibility has been accounted for in comparison to decarbonization options that are currently technically feasible (e.g. electric heat pumps, energy efficiency).

Uncertainty related to technical feasibility was accounted for by developing multiple scenarios. Please see Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 39 for details on the process used to develop the scenario narratives and inputs assumptions for the study. As indicated on this page, the process is founded on the idea that "Scenarios are not about predicting the future, rather they are about perceiving futures in the present. A good scenario asks people to suspend disbelief

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.

Theme Five: Facilitating Economic Growth

Consumer choice and policy decisions will shape the nature and pace of energy transition investments and economic growth in Ontario. The pace of adoption of new technologies (e.g., EVs / heat pumps) and new generation sources (e.g., central generation, DERs) will be a function of consumer preferences, cost, innovation, global supply chains, and policy choices made at all levels of government, in turn driving the required investments in Ontario's industries and the energy systems that support them.

While transitioning to a clean energy future is the right thing to do, factoring long-term competitiveness into climate policy decision-making is essential. The energy transition approach directly impacts businesses and industry in Ontario – cost, reliability, choice, and competitiveness. Continued access to and maintenance of gas infrastructure is critical to industry, Ontario's economic future, and ensuring that Ontario's energy systems remain robust, reliable, affordable, and sustainable. **Ontario industry is afforded low gas rates today due to the benefit of sharing infrastructure costs with 3.9 million households**, an advantage that will diminish as that demand declines. A diversified "pipes and wires" approach to energy transition can achieve net zero emissions while maintaining this critical benefit for the industry in Ontario.

Companies with energy-intensive manufacturing processes that cannot be practically electrified, like steel and cement, depend on natural gas as an affordable and reliable energy supply, and as discussed in the section on Emerging Technologies, the gas system can be decarbonized via hydrogen, RNG, and CCUS. As far as CCUS is concerned, the government should work with the federal government to ensure that companies with energy-intensive manufacturing processes in Ontario are eligible for the federal Incentive Tax Credits and funding opportunities announced in the federal Budget 2023.

Reaching net zero emissions in Ontario means diversifying the provincial energy mix, including assessing the province's reliance on imports. Roughly 75% of Ontario's energy is imported.[13] In-province RNG and hydrogen production present an excellent opportunity to minimize Ontario's reliance on energy imports, promote energy independence, and create jobs in the energy sector while supporting Ontario's economic competitiveness with other jurisdictions.

Reducing regulatory barriers can serve as a low-cost approach to accelerate job creation and private-sector investment in energy infrastructure projects. **We recommend ensuring that any changes suggested by the EETP that add regulatory efficiency and transparency to the OEB and the IESO do not inadvertently add new red tape or uncertainty to the planning process and focus on the planning process at the IESO, as opposed to operations and procurements.** To optimize investment, it is important to shift the risk perspective away from a fear of overbuilding to prudently building enabling infrastructure while leveraging existing systems.

Conclusion

Enbridge reiterates the utmost significance of embracing a comprehensive and inclusive approach to Ontario's energy transition to achieve net-zero emissions while fostering economic prosperity. We strongly advocate for integrating crucial recommendations in the EETP report, including coordinated energy planning, enhanced governance, defined targets for low-carbon fuels, expanded regulatory oversight, community perspectives, affordability, and leveraging Ontario's gas system to drive economic growth. Enbridge earnestly requests the thoughtful consideration of these recommendations and welcomes the opportunity to meet with you to discuss the consultation and recommendations in further

[13] Government of Canada. (2022, July 28). Provincial and Territorial Energy Profiles – Ontario. Canada Energy Regulator. https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincialterritorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html