EB-2022-0200

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Enbridge Gas Inc., pursuant to section 36(1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2024

COMPENDIUM OF CANADIAN MANUFACTURERS AND EXPORTERS
Panel 7 - EGI Equity Thickness

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EB-2011-0354

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

BEFORE: Cynthia Chaplin
Presiding Member and Vice Chair

Paula Conboy
Member

Ellen Fry
Member

DECISION ON EQUITY RATIO AND ORDER

February 7, 2013

Background

Enbridge Gas Distribution Inc. ("Enbridge") filed an application on January 31, 2012 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B (the "Act") for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

The Board issued a Notice of Application dated March 2, 2012. Details on the various procedural steps which followed are available on the Board's website.

Enbridge submitted that

> It is important that changes in Enbridge's business and financial risk be viewed over the long term. Enbridge's equity ratio should be commensurate with its long-term business risk, which can only be assessed through a long-term view. That is why Enbridge has presented business risk evidence showing changes over the past 20 years. While it is true that Enbridge's equity ratio was considered in a 2006 proceeding, the fact is that there is now additional information available that was not considered at that time. This additional information adds to the conclusion that Enbridge's business and financial risks have increased, over both the long term and the more immediate term. To confine the examination of changes in Enbridge's business risks to consider only changes since 2006 would result in an incomplete examination and evaluation.[7]

The intervenors that made submissions on the past point of reference took the position that the Board should only consider changes in risk since EB-2006-0034. Concerning future risks, CCC submitted that

> ...the change in business and/or financial risk must be within some proximate timeframe. If evidence of a change in business and/or financial risk is of circumstances that may or may not occur at some indeterminate time in the future, then the evidence doesn't satisfy the Board's test. In the case of [Enbridge], the Board must be satisfied not only that there is evidence of a significant change in business and/or financial risk, but that the change will affect [Enbridge] in 2013 or in the near term beyond that.[8]

Board Findings

In 2007 the Board made a decision in EB-2006-0034 concerning the appropriate level for Enbridge's equity ratio. In that proceeding, Enbridge had a full opportunity to present evidence and argument in support of its position.

In arguing that the Board should now consider evidence for a period starting in 1993, as indicated in the extracts of its argument reproduced above, Enbridge is in effect arguing

[7] Enbridge Argument in Chief, p. 5
[8] CCC Argument, p. 3

that the Board should reconsider the basis for its decision in EB-2006-0034. Enbridge had the right to seek a review of that decision, but did not do so. Parties and ratepayers are entitled to rely on the results of Board proceedings, subject to the established legal review mechanisms.

In EB-2006-0034, the Board performed an assessment of the change in Enbridge's risk and determined the appropriate equity ratio for Enbridge at that time. In this proceeding, the Board's task in assessing the change in risk is to examine how risk has changed from the time the issue was previously decided in EB-2006-0034. To extend the analysis to a date before the Board's last consideration of the issue would inappropriately revisit the basis for the Board's risk assessment in EB-2006-0034, which was embodied in the approved equity ratio at that time. If there is now information available which was not known when the equity ratio was previously set, this will inform the analysis of change in risk only to the extent it is relevant to the change in risk since the equity ratio was last set.

Accordingly, the Board will determine whether there has been a significant change in Enbridge's risk since the Board rendered its decision in EB-2006-0034 in 2007.

Regarding the risk of future events, the Board agrees with CCC that the relevant future risks are those that are likely to affect Enbridge in the near term. Any risks that may materialize over the longer term can be taken into account in subsequent proceedings. In considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize.

Assessment of Change in Risk

Although Enbridge has presented evidence and argument concerning changes in its risk since 1993, its position is also that it has experienced a significant increase in its business and financial risk since 2007. Intervenors take the position that this is not the case. Although the intervenors' expert witness, Dr. Booth, expressed the view that risk has decreased since 2007, the intervenors do not focus on arguing this position. No party argued that the risk had declined sufficiently to warrant a decrease in the common equity ratio. The Board has therefore focused only on the question of whether the risk has increased significantly.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 16 of 164

Question(s):

At page 16, Concentric quoted from the Board's EB-2011-0354 decision. As part of that decision, the Board determined "[t]he evidence does not demonstrate a tangible risk that new environmental policy and laws in relation to gas distribution will be implemented over the near term, or if implemented, will be likely to have a detrimental effect on Enbridge in terms of volume over the near term."

a) How does Concentric understand the phrase "near term" in relation to EGI and the horizon for risks.

Response:

The following response was provided by Concentric Energy Advisors, Inc.:

a) To Concentric's knowledge, the OEB did not define the precise meaning of "near term" in its EB-2011-0354 decision. From a risk horizon perspective, Concentric understands that the OEB has considered risk both retrospectively and prospectively. As the Board made clear in its EB-2011-0354 decision, the retrospective period the Board found relevant was that between its last decision and the current period:

> In EB-2006-0034, the Board performed an assessment of the change in Enbridge's risk and determined the appropriate equity ratio for Enbridge at that time. In this proceeding, the Board's task in assessing the change in risk is to examine how risk has changed from the time the issue was previously decided in EB-2006-0034.

And prospectively, the OEB indicated:

> Regarding the risk of future events, the Board agrees with CCC that the relevant future risks are those that are likely to affect Enbridge in the near term. Any risks that may materialize over the longer term can be taken

> into account in subsequent proceedings. In considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize."[1]

Concentric's risk analysis considered both a retrospective view, from the time of the OEB's last decisions on this matter in 2012 for EGD and Union prior to amalgamation, and a prospective view of business and financial risk. Even though investors consider both longer term and near term risks, Concentric considers near term risks as those likely to impact Enbridge Gas over the five-year rate period from 2024 to 2028.

[1] EB-2011-0354, Ontario Energy Board Decision on Equity Ratio and Order, February 7, 2013, at 7.

Throughput Volumes - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service

Line No.	Particulars (10^3m^3)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
	General Service								
1	Rate 1	EGD	4,637,500	4,785,600	5,380,900	4,997,000	4,506,700	4,739,200	5,296,300
2	Rate 6	EGD	4,645,700	4,739,900	5,321,900	5,006,600	4,488,600	4,700,600	5,283,900
3	Rate 9	EGD	2,000	700	600	300	200	0	0
4	Total - EGD Rate Zone		9,285,200	9,526,200	10,703,400	10,003,900	8,995,500	9,439,800	10,580,200
5	Rate M1	Union	2,939,543	3,030,675	3,328,692	3,020,628	2,779,165	2,921,299	3,192,398
6	Rate M2	Union	975,571	1,176,964	1,284,428	1,226,506	1,174,963	1,216,844	1,293,975
7	Rate 01	Union	884,421	979,534	1,053,067	962,033	908,447	963,968	1,030,116
8	Rate 10	Union	322,887	362,073	379,430	351,747	342,884	357,062	364,734
9	Total - Union Rate Zone		5,122,423	5,549,246	6,045,617	5,560,914	5,205,459	5,459,173	5,881,223
10	Total General Service		14,407,623	15,075,446	16,749,017	15,564,814	14,200,959	14,898,973	16,461,423
	Contract								
11	Rate 100	EGD	0	3,200	4,400	3,700	3,200	1,200	2,100
12	Rate 110	EGD	487,600	522,300	528,400	667,900	827,600	798,200	845,900
13	Rate 115	EGD	539,400	568,600	539,400	512,200	497,600	508,600	499,400
14	Rate 125	EGD	0	830,883	738,469	726,900	617,490	227,478	507,609
15	Rate 135	EGD	55,200	55,400	62,700	68,600	64,600	66,000	62,600
16	Rate 145	EGD	152,800	166,500	141,700	77,500	45,700	46,100	43,300
17	Rate 170	EGD	516,400	496,800	454,900	394,800	302,200	312,700	328,100
18	Rate 200	EGD	163,100	184,300	183,200	176,400	169,600	173,900	184,400
19	Rate 300	EGD	31,000	1,014	403	493	544	461	418
20	Rate 315	EGD	0	0	0	0	0	0	0
21	Total - EGD Rate Zone		1,945,500	2,828,998	2,653,571	2,628,493	2,528,534	2,134,639	2,473,827

Throughput Volumes - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service (Continued)

Line No.	Particulars (10^3m^3)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
22	Rate M4	Union	404,678	474,815	484,404	457,328	471,413	549,760	656,761
23	Rate M7	Union	147,143	172,283	392,256	427,707	474,216	507,692	513,836
24	Rate M9	Union	60,750	63,240	67,138	66,583	72,124	69,174	78,946
25	Rate M10	Union	189	284	312	300	248	274	410
26	Rate 20	Union	629,802	650,968	535,626	540,839	564,912	501,499	478,104
27	Rate 100	Union	1,895,488	1,926,579	1,710,928	1,398,114	1,365,738	1,029,145	1,038,045
28	Rate T1	Union	548,986	452,838	470,811	442,947	447,127	458,243	466,596
29	Rate T2	Union	4,880,297	4,241,475	4,305,103	4,368,501	4,212,740	3,762,498	4,101,435
30	Rate T3	Union	272,712	273,597	288,979	263,235	250,167	257,343	279,794
31	Rate M5	Union	535,132	524,481	259,358	208,631	194,162	140,648	74,007
32	Rate 25	Union	159,555	215,467	186,550	144,313	116,847	106,997	156,126
33	Rate 30	Union	0	0	0	0	0	0	0
34	Total - Union Rate Zone		9,534,732	8,996,027	8,701,465	8,318,498	8,169,694	7,383,273	7,844,060
35	Total Contract		11,480,232	11,825,025	11,355,036	10,946,991	10,698,228	9,517,912	10,317,887
36	Total Volumes		25,887,855	26,900,471	28,104,053	26,511,805	24,899,187	24,416,885	26,779,310

Throughput Volumes - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service

Line No.	Particulars (10^3m^3)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)
	General Service							
1	Rate 1	EGI	5,358,589	4,894,404	4,748,722	5,211,648	5,045,468	5,001,027
2	Rate 6	EGI	5,300,022	4,650,326	4,438,432	4,910,686	4,887,113	4,795,694
3	Rate 9	EGI	0	127	3	0	0	0
4	Total - EGD Rate Zone		10,658,611	9,544,857	9,187,158	10,122,335	9,932,581	9,796,721
5	Rate M1	EGI	3,301,399	3,003,878	2,897,087	3,145,665	3,063,170	3,255,132
6	Rate M2	EGI	1,348,932	1,204,341	1,113,864	1,292,501	1,253,164	1,319,376
7	Rate 01	EGI	1,071,407	982,736	929,941	1,024,908	1,012,937	989,005
8	Rate 10	EGI	380,692	342,656	311,794	341,593	358,834	327,974
9	Total - Union Rate Zone		6,102,429	5,533,611	5,252,686	5,804,667	5,688,104	5,891,487
10	Total General Service		16,761,040	15,078,468	14,439,844	15,927,002	15,620,686	15,688,208
	Contract							
11	Rate 100	EGI	15,377	20,111	33,994	26,965	28,090	27,429
12	Rate 110	EGI	875,396	981,141	1,101,890	1,111,051	1,074,372	1,068,281
13	Rate 115	EGI	441,616	378,039	387,697	367,381	386,039	381,873
14	Rate 125	EGI	591,623	523,436	707,660	690,079	824,971	824,971
15	Rate 135	EGI	63,020	65,287	63,112	55,771	55,486	52,646
16	Rate 145	EGI	30,440	23,396	24,785	19,073	15,331	15,714
17	Rate 170	EGI	286,358	247,430	255,701	277,330	322,426	323,254
18	Rate 200	EGI	196,879	189,473	192,010	201,047	186,602	188,852
19	Rate 300	EGI	349	262	269	139	0	0
20	Rate 315	EGI	0	0	0	0	0	0
21	Total - EGD Rate Zone		2,501,058	2,428,575	2,767,118	2,748,835	2,893,316	2,883,020

Throughput Volumes - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service (Continued)

Line No.	Particulars (10^3m^3)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)
22	Rate M4	EGI	674,011	621,380	610,808	596,466	598,163	593,900
23	Rate M7	EGI	541,343	618,372	686,353	718,754	749,542	789,737
24	Rate M9	EGI	103,989	88,765	90,096	89,547	90,073	90,073
25	Rate M10	EGI	391	360	320	341	329	0
26	Rate 20	EGI	522,900	778,476	637,600	811,568	839,751	929,101
27	Rate 100	EGI	1,020,510	996,605	958,587	1,006,653	1,036,696	1,076,378
28	Rate T1	EGI	437,372	430,312	453,007	423,268	434,564	431,289
29	Rate T2	EGI	4,136,389	4,017,975	4,700,474	4,359,326	4,962,964	5,005,643
30	Rate T3	EGI	283,374	264,209	241,187	277,095	249,200	249,200
31	Rate M5	EGI	73,965	61,817	63,511	61,664	60,802	59,493
32	Rate 25	EGI	119,200	92,838	143,898	97,099	111,374	126,831
33	Rate 30	EGI	0	0	0	0	0	0
34	Total - Union Rate Zone		7,913,444	7,971,109	8,585,841	8,441,782	9,133,458	9,351,645
35	Total Contract		10,414,502	10,399,684	11,352,959	11,190,617	12,026,774	12,234,665
36	Total Volume		27,175,542	25,478,152	25,792,803	27,117,619	27,647,460	27,922,873

Throughput Volumes - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service (Continued)

Line No.	Particulars (10^3m^3)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)
	General Service - Sector							
37	Residential	EGI	8,669,670	7,928,784	7,681,525	8,383,291	8,136,829	8,179,258
38	Commercial	EGI	7,553,939	6,685,696	5,815,079	6,498,338	6,472,519	6,448,091
39	Industrial	EGI	537,431	463,988	943,240	1,045,372	1,011,337	1,060,859
40	Total		16,761,040	15,078,468	14,439,844	15,927,002	15,620,686	15,688,208
	Contract - Sector							
41	Automotive	EGI	186,181	186,802	179,967	189,115	200,474	214,930
42	Buildings	EGI	526,141	542,150	591,355	640,572	643,146	642,128
43	Chemical	EGI	1,644,708	1,608,227	1,689,380	1,695,446	2,015,061	2,013,902
44	Food & Beverage	EGI	751,934	762,623	779,697	766,720	776,224	774,166
45	Greenhouse - Agricultural	EGI	586,862	632,603	689,721	725,449	756,500	816,729
46	Manufacturing	EGI	733,716	706,036	758,462	720,196	752,042	749,817
47	Mining	EGI	347,841	334,362	313,157	339,823	343,877	406,498
48	Other	EGI	649,352	628,324	624,800	578,305	470,953	421,610
49	Power	EGI	1,552,060	1,564,142	1,975,099	1,928,645	2,298,498	2,427,690
50	Pulp & Paper	EGI	526,282	552,620	560,152	609,426	623,810	623,250
51	Refining	EGI	1,383,051	1,467,050	1,457,273	1,435,427	1,450,521	1,454,573
52	Steel	EGI	1,526,373	1,414,744	1,733,896	1,561,491	1,695,668	1,689,373
53	Total		10,414,502	10,399,684	11,352,959	11,190,617	12,026,774	12,234,665
54	Total Volume		27,175,542	25,478,152	25,792,803	27,117,619	27,647,460	27,922,873

Revenue - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
	General Service								
1	Rate 1 (1)	EGD	1,410.5	1,573.4	1,729.9	1,760.5	1,541.3	1,811.1	1,932.8
2	Rate 6	EGD	822.5	889.3	1,045.8	1,042.6	876.6	1,084.6	1,151.8
3	Rate 9	EGD	0.5	0.2	0.2	0.1	0.1	0.0	0.0
4	Total - EGD Rate Zone		2,233.5	2,462.9	2,775.9	2,803.2	2,418.0	2,895.7	3,084.6
5	Rate M1	Union	777.6	834.6	936.0	866.6	762.3	835.3	842.8
6	Rate M2	Union	116.5	162.0	179.3	157.5	140.2	159.0	158.8
7	Rate 01	Union	337.2	372.9	393.2	382.0	346.4	387.3	394.7
8	Rate 10	Union	70.1	77.2	77.8	74.2	67.7	74.2	72.4
9	Total - Union Rate Zone		1,301.4	1,446.7	1,586.3	1,480.3	1,316.6	1,455.8	1,468.7
10	Total General Service		3,534.9	3,909.6	4,362.2	4,283.5	3,734.6	4,351.5	4,553.3
	Contract								
11	Rate 100	EGD	0.0	0.6	0.9	0.9	0.5	0.6	0.6
12	Rate 110	EGD	24.9	32.6	33.4	38.1	44.6	59.9	51.9
13	Rate 115	EGD	7.4	7.7	7.3	9.6	7.9	14.5	12.7
14	Rate 125	EGD	10.9	11.2	11.0	9.9	11.0	11.1	11.1
15	Rate 135	EGD	1.7	2.5	3.1	4.0	3.5	6.0	3.2
16	Rate 145	EGD	7.5	8.7	8.2	5.3	3.4	4.6	4.0
17	Rate 170	EGD	7.5	14.4	15.8	16.3	12.7	14.5	11.3
18	Rate 200	EGD	23.7	29.8	31.2	33.9	28.3	29.8	30.2
19	Rate 300	EGD	0.2	0.2	0.1	0.1	0.1	0.1	0.1
20	Rate 315	EGD	0.0	0.4	0.4	0.5	0.4	0.2	0.0
21	Total - EGD Rate Zone		83.8	108.1	111.4	118.6	112.4	141.3	125.1

Revenue - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service (Continued)

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
22	Rate M4	Union	15.2	19.5	21.7	20.0	22.7	28.5	35.6
23	Rate M7	Union	4.1	6.3	16.0	15.8	14.0	15.6	17.0
24	Rate M9	Union	0.7	0.7	0.8	0.8	1.8	4.8	5.0
25	Rate M10	Union	0.0	0.1	0.1	0.1	0.1	0.1	0.1
26	Rate 20	Union	25.3	22.3	21.4	25.2	25.2	22.4	27.5
27	Rate 100	Union	15.6	15.8	15.8	12.5	12.9	10.9	10.4
28	Rate T1	Union	10.6	10.0	10.2	10.1	10.6	11.3	12.8
29	Rate T2	Union	42.2	46.6	49.3	51.1	57.5	59.5	69.0
30	Rate T3	Union	4.4	4.5	4.7	4.8	5.1	6.7	6.9
31	Rate M5	Union	15.7	17.4	10.0	7.5	7.8	6.4	3.6
32	Rate 25	Union	13.4	24.0	24.4	21.3	11.0	9.9	15.1
33	Rate 30	Union	0.0	0.1	0.1	0.0	0.0	0.0	0.0
34	Total - Union Rate Zone		147.4	167.2	174.5	169.1	168.7	176.1	203.0
35	Total Contract		231.2	275.3	285.9	287.7	281.1	317.4	328.1
36	Subtotal		3,766.1	4,184.9	4,648.1	4,571.2	4,015.7	4,668.9	4,881.4

Revenue - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service (Continued)

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Accounting Adjustments								
37	US GAAP adjustment elimination for deferral & variance clearance recognition	EGD	0.0	(107.3)	(197.5)	(444.2)	(139.5)	(5.7)	(43.7)
38	Removal of Cap and Trade Revenues	EGD	0.0	0.0	0.0	0.0	0.0	(353.3)	(224.1)
39	Eliminate earnings sharing in the financial statements	EGD	0.0	0.0	0.0	0.0	0.0	0.0	27.2
40	Elimination of 2013 OHCVA write-off as per the EB 2014-0195 Decision	EGD	0.0	0.0	0.4	0.0	0.0	0.0	0.0
41	Calendarization Impact	EGD	0.0	(13.7)	169.3	412.6	191.4	91.1	(121.8)
42	Average Use/ Normalized Average Consumption	Union	0.0	(11.5)	(2.6)	10.2	23.3	(2.9)	(20.3)
43	Parkway Obligation Rate Variance	Union	0.0	0.0	3.6	(0.0)	2.9	(0.2)	0.0
44	Capital Pass-through	Union	0.0	0.0	0.0	0.6	2.5	0.2	(0.4)
45	LRAM	Union	0.0	2.8	0.8	(0.9)	0.5	0.6	0.4
46	Cap and Trade Revenue	Union	0.0	0.0	0.0	0.0	0.0	227.3	144.2
47	Federal Carbon Program	Union	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Parkway West Capital Pass Through	Union	0.0	0.0	(1.1)	0.0	0.0	0.0	0.0
49	Community Expansion	Union	0.0	0.0	0.0	0.0	0.0	0.0	0.1
50	Bill C-97 (Accelerated CCA) Ratepayer Revenue Adjustment (1)	Union	0.0	0.0	0.0	0.0	0.0	0.0	(1.3)
51	Bill C-97 (Accelerated CCA) 50% Shareholder Revenue Adjustment	Union	0.0	0.0	0.0	0.0	0.0	0.0	(0.9)
52	Tax Variance (HST) 50% Shareholder Revenue Adjustment	Union	0.0	0.0	0.0	0.0	0.0	0.0	(0.4)
53	Total		0.0	(129.6)	(27.1)	(21.7)	81.1	(42.9)	(241.0)

Revenue - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service (Continued)

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
54	Total Utility Revenue		3,766.1	4,055.3	4,621.0	4,549.5	4,096.8	4,626.1	4,640.4

Note:

(1) Includes revenue reduction related to 50% ratepayer portion of Bill C-97 in the Tax Variance Account and 100% of Bill C-97 CPT impact.

Revenue - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)
	General Service							
1	Rate 1	EGI	1,824.8	1,646.6	1,768.3	1,972.9	2,212.3	2,206.4
2	Rate 6	EGI	1,009.2	850.9	920.1	1,056.4	1,206.6	1,190.7
3	Rate 9	EGI	0.0	0.0	0.0	0.0	0.0	0.0
4	Total - EGD Rate Zone		2,834.0	2,497.6	2,688.3	3,029.3	3,418.9	3,397.1
5	Rate M1	EGI	884.9	792.4	871.4	955.9	1,130.0	1,242.2
6	Rate M2	EGI	166.5	134.8	144.2	174.9	218.6	248.3
7	Rate 01	EGI	401.6	354.8	377.1	415.8	481.5	484.2
8	Rate 10	EGI	72.5	58.9	60.9	69.6	89.8	82.4
9	Total - Union Rate Zone		1,525.5	1,341.0	1,453.5	1,616.1	1,919.9	2,057.1
10	Total General Service		4,359.5	3,838.5	4,141.9	4,645.4	5,338.8	5,454.2
	Contract							
11	Rate 100	EGI	3.1	3.0	4.7	4.2	5.7	5.6
12	Rate 110	EGI	42.2	45.9	57.0	55.8	68.3	68.1
13	Rate 115	EGI	9.1	7.8	8.3	8.9	9.6	9.5
14	Rate 125	EGI	11.3	11.4	11.9	12.0	12.5	12.5
15	Rate 135	EGI	2.2	2.0	2.2	2.0	2.5	2.3
16	Rate 145	EGI	1.8	1.6	1.9	1.9	1.8	1.8
17	Rate 170	EGI	7.8	1.4	2.3	2.8	2.3	2.3
18	Rate 200	EGI	30.3	25.5	30.2	36.1	38.1	38.6
19	Rate 300	EGI	0.1	0.1	0.1	0.0	0.0	0.0
20	Rate 315	EGI	0.0	0.0	0.0	0.0	0.0	0.0
21	Total - EGD Rate Zone		107.8	98.7	118.6	123.6	140.7	140.6

Revenue - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service (Continued)

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)	2023 Bridge Year (e)	2024 Test Year (f)
22	Rate M4	EGI	37.8	38.0	40.8	42.6	47.8	49.6
23	Rate M7	EGI	18.6	21.8	27.9	31.4	36.1	37.8
24	Rate M9	EGI	5.4	3.4	4.0	4.5	5.2	5.4
25	Rate M10	EGI	0.1	0.1	0.1	0.1	0.1	0.0
26	Rate 20	EGI	30.9	33.1	33.5	34.5	39.6	40.7
27	Rate 100	EGI	10.7	11.3	11.5	11.8	11.4	11.8
28	Rate T1	EGI	12.7	13.6	13.9	14.0	14.4	14.4
29	Rate T2	EGI	71.6	74.1	76.1	78.7	79.3	79.8
30	Rate T3	EGI	6.9	7.2	7.2	7.5	7.8	7.8
31	Rate M5	EGI	3.5	2.5	3.1	3.3	3.2	3.3
32	Rate 25	EGI	11.0	7.8	18.8	6.6	6.0	6.2
33	Rate 30	EGI	0.0	0.0	0.0	0.0	0.0	0.0
34	Total - Union Rate Zone		208.9	212.9	236.8	234.9	250.9	256.8
35	Total Contract		316.7	311.6	355.4	358.5	391.5	397.4
36	Subtotal		4,676.2	4,150.1	4,497.3	5,004.0	5,730.3	5,851.6

Revenue - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service (Continued)

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)	2023 Bridge Year (e)	2024 Test Year (f)
	Accounting Adjustments							
37	Tax Variance	EGI	(24.1)	(13.4)	(18.0)	(34.1)	(27.5)	0.0
38	Elimination of Prior Year Tax Variance	EGI	4.5	0.0	0.0	0.0	0.0	0.0
39	Accounting Policy Change	EGI	1.1	(14.0)	(16.2)	(15.5)	(33.4)	0.0
40	Average Use/ Normalized Average Consumption	EGD (1)	(8.6)	(4.6)	15.4	4.1	0.0	0.0
41	Dawn Access Cost	EGD	2.2	2.1	2.0	1.2	0.0	0.0
42	Incremental Capital Module	EGD	0.0	(0.3)	0.2	(9.4)	6.9	0.0
43	Prior Year Earnings Sharing Adjustment	EGD	(1.7)	0.0	0.0	0.0	0.0	0.0
44	Elimination of Prior Year Earnings Sharing Adjustment	EGD	1.7	0.0	0.0	0.0	0.0	0.0
45	Transactional Services Revenue	EGD	12.0	12.0	12.0	12.0	12.0	0.0
46	LRAM	EGD	0.0	0.0	0.0	0.0	0.0	0.0
47	Federal Carbon Program	EGD	0.1	0.6	0.7	0.0	0.0	0.0
48	Greenhouse Gas Emissions Administration	EGD	0.2	0.2	0.1	0.0	0.0	0.0
49	Reverse 2019 Gas Supply Plan Cost Consequences	EGD	(3.9)	(3.9)	0.0	0.0	0.0	0.0
50	Elimination of 2019 Gas Supply Plan Cost Consequences Reversal	EGD	0.0	3.9	0.0	0.0	0.0	0.0
51	Average Use/ Normalized Average Consumption	Union (2)	(4.7)	7.2	19.0	9.4	(6.1)	0.0
52	Parkway Obligation Rate Variance	Union	0.3	0.0	0.0	0.0	0.0	0.0
53	Incremental Capital Module	Union	(7.0)	(5.6)	(14.0)	(4.4)	1.2	0.0
54	Capital Pass-through	Union	(1.0)	(1.1)	(4.4)	(3.6)	(2.9)	0.0
55	LRAM	Union	0.4	1.4	0.7	0.4	0.4	0.0
56	Federal Carbon Program	Union	0.4	1.2	1.5	0.0	0.0	0.0

Revenue - Unnormalized - General Service Sales & T-Service, Contract Sales & T-Service (Continued)

Line No	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)	2023 Bridge Year (e)	2024 Test Year (f)
57	Elimination of the Union rate zones unregulated storage cost from EGD rate zone revenues	Union	(17.4)	(17.7)	(17.2)	(16.7)	(16.4)	0.0
58	Miscellaneous	EGI	0.5	0.7	1.4	0.0	0.0	0.0
59	Total		(44.8)	(31.3)	(16.7)	(56.7)	(65.8)	0.0
60	Total Utility Revenue		4,631.5	4,118.8	4,480.6	4,947.2	5,664.5	5,851.6

Notes:

(1) EGD rate zone.

(2) Union rate zones.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2022-0200**	**Enbridge Gas Inc.**
VOLUME:	**3**	
DATE:	**July 17, 2023**	
BEFORE:	**Patrick Moran**	**Presiding Commissioner**
	Allison Duff	**Commissioner**
	Emad Elsayed	**Commissioner**

MR. SHEPHERD: Well --

MS. GIRIDHAR: The government has to figure out what it wants to spend on energy system resiliency, versus health care, versus education, et cetera. So let's wait for the government to tell us how they want to make those allocative decisions.

I don't think it's fruitful to be here and say we that want to disconnect everybody from the gas system because we love heat pumps.

MR. SHEPHERD: I am not suggesting that anybody in this room wants to disconnect people. We are predicting the future. You are forecasting, and you are forecasting no disconnections. Right?

MS. GIRIDHAR: I don't believe we are forecasting no disconnections. We believe in customer choice.

MR. SHEPHERD: How many energy transition disconnections are you forecasting over the next five years? You haven't done that work, so you don't know. That is the answer, isn't it.

MS. WADE: We have done the work. I think roughly in the next -- I think, from a customer additions forecast, you are correct; over the next five years, it is not a substantial number. And that is because, over the next five years, we don't see this coming to fruition, or the changes that are going to happen in the energy transition happening in a major way over the next five years.

MR. SHEPHERD: It is hundreds. Right?

MS. WADE: Roughly -- just less than 400.

Adam Stiers
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Enbridge Gas Inc.
P.O. Box 2001
50 Keil Drive N.
Chatham, Ontario, N7M 5M1
Canada

October 22, 2020

BY RESS, EMAIL AND COURIER

Ms. Christine Long
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: Enbridge Gas Inc.
Ontario Energy Board File No.: EB-2019-0159
2021 Dawn Parkway Expansion Project – Project Status Report

<u>Background</u>

On May 4, 2020, Enbridge Gas Inc. ("Enbridge Gas" or the "Company") filed a letter with the Ontario Energy Board ("OEB" or "Board") requesting that the OEB temporarily adjourn the 2021 Dawn Parkway Expansion Project (the "Project") proceeding in order for Enbridge Gas to gain clarity as to any impacts of the ongoing and unprecedented COVID-19 pandemic (the "Pandemic") on the Project. As a condition of the adjournment, Enbridge Gas proposed to report to the OEB as soon as reasonably possible and within six (6) months of the date of the adjournment as to whether the Company had gained sufficient clarity to proceed with the application as originally filed, including responses to the interrogatories already asked and any further interrogatories arising from any updated evidence. Enbridge Gas also acknowledged that the Board might find it appropriate to award certain interim costs to eligible intervenors as part of the adjournment.

On May 7, 2020, the OEB issued Procedural Order No. 6, recognizing the uncertainties arising from the Pandemic and their potential impact on the Project. The OEB went on to state that it was the OEB's intention to grant the adjournment. Prior to doing so, the OEB requested submissions on the conditions of the adjournment, including regarding the completion of interrogatory responses by Enbridge Gas.

On May 19, 2020, following submissions from intervenors[1] (on or before May 11, 2020) and Enbridge Gas's responding submission (dated May 13, 2020), the OEB issued its Procedural Order No. 7 and Decision on Adjournment ("PO No. 7"). In PO No. 7, the OEB: (i) decided to allow the requested temporary adjournment upon the terms that Enbridge Gas suggested in its letter of May 4; (ii) directed that Enbridge Gas report to the OEB no later than November 19, 2020 (six months from the date of PO No. 7) on

[1] Importantly, none of the parties who made submissions opposed granting the adjournment request.

the prospects of continuing with the Project application; (iii) determined that it would not be helpful or efficient to have the responses to interrogatories filed at that time; and (iv) made provision for cost eligible intervenors to file interim cost claims.

On July 15, 2020, the OEB issued its Decision and Order on Interim Cost Awards, ordering the Company to pay awarded interim costs subject to certain conditions and understandings.

Project Status and Notice of Withdrawal

At this time, and with the ongoing Pandemic persisting for the foreseeable future, Enbridge Gas has determined that there is no longer a need for the Project in the time frame as originally proposed. Therefore, in accordance with section 20 of the Board's *Rules of Practice and Procedure*, the Company hereby provides notice that it is withdrawing its application for leave to construct[2] the Project and for approval of the form of Pipeline Easement and Temporary Land Use agreements[3] previously filed with the Board.

Enbridge Gas will reassess customer demand for Dawn Parkway System capacity and the need for the Project in 2021 and expects that as sufficient need can be confirmed in the future, it will bring forward a new application for OEB approval.

Enbridge Gas will await any further directions from the Board regarding this notice of withdrawal as it may see fit.

Sincerely,

Adam Stiers
Technical Manager, Regulatory Applications

c.c.: C. Keizer (Torys)
Z. Crnojacki (OEB Staff)
M. Millar (OEB Counsel)
EB-2019-0159 (Intervenors)

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[2] Pursuant to Section 90 (1) of the *Ontario Energy Board Act, 1998, c. 15, Schedule B.*
[3] Pursuant to Section 97 of the *Ontario Energy Board Act, 1998.*

Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2020-0293

ENBRIDGE GAS INC.

St. Laurent Ottawa North Replacement Project

BEFORE: **Anthony Zlahtic**
Presiding Commissioner

Emad Elsayed
Commissioner

May 3, 2022

The estimated cost associated with such an event in the Enbridge Gas franchise area in the 47 Degree Day scenario is $54M (Enbridge Gas estimated the cost of repair in the Gazifere franchise area to be $37M). Under the 1 Degree Day scenario, Enbridge Gas estimated the cost of an event to be $22M in its franchise area. Most of the cost estimates provided by Enbridge Gas for the two scenarios would be attributable to projected customer claims due to loss of service.[11]

Positions of Parties

The City of Ottawa submitted that the evidence on the integrity of the existing pipeline is contradictory. The City of Ottawa recommended that "…provided that integrity issues are not an immediate significant concern" the OEB should consider not approving the Project. The City of Ottawa noted that its Energy Evolution Plan, which would contribute to lowering demand for natural gas, should be considered and that not approving the Project would have benefits such as reducing the impact on local businesses, allowing the transition to a lower natural gas demand, continuing to monitor the integrity of the St. Laurent Ottawa North Pipeline, and allowing for natural gas infrastructure planning integrated with the Energy Evolution Plan.

FRPO's view was that Enbridge Gas's evidence was lacking sufficient technical information (i.e. disclosure of the potential for robotic inspection) to demonstrate that the pipeline is in poor condition and that the replacement is urgently needed. FRPO stated that risk and consequences of failure and outage to the customers were exaggerated. FRPO urged the OEB to deny the application and "…order EGI to perform enhanced in-line inspection and maintenance and report findings as part of its rebasing application".[12]

IGUA submitted that the OEB should carefully consider whether Enbridge Gas has established that the integrity of the existing pipeline is "compromised and full replacement is required at this time".[13] IGUA highlighted the inelasticity of natural gas demand of large industrial customers (compared to residential and commercial), and barriers to their conversion from natural gas indicating that increasing access to natural gas may be part of decarbonization transition for the industrial customers. IGUA is concerned with "…exposure to stranded 'small pipe' assets" such as the potentially under-utilized St. Laurent Ottawa North Pipeline should the trends of reduced demand continue as part of wider decarbonization programs. IGUA noted a risk of higher natural

[11] Enbridge Gas Inc. in response to I.FRPO.25
[12] FRPO Written Submission, March 21, 2022, page 1
[13] IGUA Written Submission, March 24,2022

gas costs to its members who are, in IGUA's words, captive customers, because of the inelasticity of their demand for industrial processes and manufacturing.

Pollution Probe recommended that the OEB reject the Project, stating that the need for a replacement has not been supported by Enbridge Gas's evidence on declining integrity and safety risks.

SEC submitted that the OEB should deny the approval of the Project. SEC's position was that the need for replacement at this time was not supported by Enbridge Gas's evidence.

OEB Staff was not convinced that an immediate pipeline replacement was required. OEB staff noted that, based solely on the predicted likelihood of leaks, the urgency to address the integrity decline concerns did not appear high.

Findings

The OEB finds that Enbridge Gas has not demonstrated that the risk associated with the subject pipelines warrants complete replacement at this time. The issue of associated risk is addressed in this section. The issue of Project alternatives is addressed in the next section.

The risk of a catastrophic failure of the subject pipelines is a function of the probability of failure and the consequences of such failure. While Enbridge Gas may have demonstrated that a catastrophic failure of the pipelines could have severe consequences for its customers by virtue of their location in a densely populated urban area, the OEB finds that Enbridge Gas has not demonstrated that the likelihood of such failure warrants a replacement of these pipelines at this time.

This finding is based on Enbridge Gas's probabilistic analysis which predicted a small number of future leaks over the next 20 to 30 years and a very low likelihood of those leaks requiring pipeline isolation leading to customer disconnection. Enbridge Gas's predicted AHI shows that the subject pipelines would remain in the top (best health) category for at least 20 more years.

In its reply argument, Enbridge Gas downplayed the significance of its AHI statistical analysis stating that "the AHI analysis (and the resulting corrosion-related leak forecast) is derived not from known issues related to the St. Laurent Pipeline, but it is instead derived from a statistical analysis of a number of pipelines across Enbridge Gas's service territory and based upon a specific set of generalizing assumptions."[14] Enbridge Gas introduced and relied on the AHI analysis during the proceeding and did

[14] Enbridge Gas Reply Submission, page 21, para 41.

not describe these limitations in the original application. Given that Enbridge Gas only emphasized these limitations in its reply argument, the parties in this proceeding did not have an opportunity to challenge Enbridge Gas's claims about the AHI limitations and the weight that should be placed on the AHI results. The OEB also notes that the low actual historical incidence of corrosion-related leaks specific to the St. Laurent system (one such leak in the last 10 years) does not demonstrate that pipeline replacement is warranted at this time.

Enbridge Gas did indicate that the AHI information should be considered along with other information obtained from integrity digs and repairs on the St. Laurent Pipeline. Enbridge Gas stated that these other sources of information were excluded from the AHI as they could not be reliably translated into meaningful qualifiers at the time of assessments.

Enbridge Gas also indicated that the risk can be mitigated by increased leak survey frequency and regular monitoring of the pipelines.

The OEB suggests that Enbridge Gas take a proactive approach to inspecting and maintaining the subject pipeline until it can be demonstrated that pipeline replacement is necessary. This may include development and implementation of an in-line inspection and maintenance program using available modern technology as discussed in the next section. The evidence in this proceeding revealed that Enbridge Gas does not currently have the necessary infrastructure to carry out such in-line inspections in the St. Laurent Pipeline.

3.2 Alternatives to the Project

Enbridge Gas presented comparative assessments of alternatives to the Project including:

- Options to manage integrity decline risk: Retrofit Option and Repair Option
- Integrated Resource Planning Alternatives (IRPAs)
- Downsizing the pipeline in response to potential natural gas demand reduction in the future

Enbridge Gas did not accept the Retrofit Option or Repair Option as preferred alternatives to the Project because, in Enbridge Gas's view, these alternative options do not resolve the integrity issues and cause additional costs (the potential cost of ongoing repairs, and, for the Retrofit Option, the upfront cost of retrofit). Enbridge Gas

Retrofit Option would allow the pipeline life to be extended by several decades, and the retrofit would also likely be more economical than a full replacement at this time, due to, among other things, the time value of delaying the high capital cost of the replacement. OEB staff noted that this would also provide flexibility for a possible pipeline size reduction if a replacement would be required should demand reductions associated with Energy Evolution or through IRPA initiated by Enbridge Gas be realized. OEB staff suggested that a Retrofit Option may be the most appropriate alternative to address the declining conditions of the St. Laurent Ottawa North Pipeline.

OEB staff submitted that the IRP alternatives pursued by Enbridge Gas, including targeted DSM, in the near term would not feasibly reduce the peak demand served by the St. Laurent system on a scale sufficient to reduce the sizing of the proposed Project.

OEB staff supported the energy planning approach described by the City of Ottawa, and closer collaboration between Enbridge Gas and the City of Ottawa to proactively plan a course of action.

Findings

The OEB finds that Enbridge Gas has not provided sufficient evidence to demonstrate that the proposed Project (pipeline replacement) is the best available alternative. As an example, Enbridge Gas's comparison of the total cost and Net Present Value of the Project (pipeline replacement) versus the pipeline Retrofit Option which would allow for ongoing in-line inspection and repair, showed that the Retrofit Option is a less costly alternative even though Enbridge Gas presented a number of qualitative factors to demonstrate that the replacement option is preferrable.

Several parties argued the Retrofit Option, in addition to having a lower initial capital cost, would also have the potential advantage of providing flexibility for a possible pipeline size reduction should demand reductions be realized. In its reply argument, Enbridge Gas only provided a qualitative description of some of the disadvantages of the Retrofit Option.

The OEB urges Enbridge Gas to thoroughly examine other alternatives such as the development and implementation of an in-line inspection and maintenance program using available modern technology, and propose appropriate action based on its findings, as part of its next rebasing application.

The OEB suggests that Enbridge Gas should work collaboratively with the City of Ottawa and other stakeholders to proactively plan a course of action if and when pipeline replacement is required, including the pursuit of Integrated Resource Planning (IRP) alternatives. Enbridge Gas has not carried out a detailed assessment of the IRP alternative citing that the pipeline integrity concerns must be addressed in less than three years which is the OEB threshold for carrying out an IRP assessment. As discussed earlier, Enbridge Gas has not provided strong evidence to support the claim that the integrity threat to the pipelines is imminent and that replacement in less than three years is necessary.

In more general terms and to the extent applicable for future leave to construct applications, the OEB encourages Enbridge Gas to undertake in-depth quantitative and qualitative analyses of alternatives that specifically include the impacts of IRP, DSM programs and de-carbonization efforts.

3.3 Project Cost and Economics

Enbridge Gas estimated the Project costs as shown in the table below to be approximately $33.9 M for the IP PE pipeline segments and $89.8 M for XHP ST pipelines, totalling approximately $123.7 M.

The abandonment costs are not included in the cost estimates for the Project.

Table 9: Estimated Project Costs

Item No.	Description	IP PE Costs	XHP ST Costs	Total Costs
1.0	Material Costs	$358,484	$1,268,313	$1,626,797
2.0	Labour Costs	$20,369,317	$48,953,572	$69,422,889
3.0	External Permitting & Land	$6,303	787,387	$793,690
4.0	Outside Services	$2,849,096	$4,523,814	$7,372,910
5.0	Direct Overheads	$531,062	$751,515	$1,282,577
6.0	Contingency Costs	$3,318,390	$16,405,401	$19,723,791
7.0	**Project Cost**	**$27,432,652**	**$72,690,002**	**$100,122,654**
8.0	Indirect Overheads	$6,203,171	$16,340,923	$22,544,094
9.0	Interest During Construction	$230,655	$782,119	$1,012,774
10.0	**Total Project Costs****	**$33,866,478**	**$89,813,044**	**$123,679,522**

*XHP ST costs are a Class 5 cost estimate
**Abandonment costs are not included in the cost estimates. Abandonment costs for IP PE are estimated to be $2,817,235 and XHP ST abandonment costs are estimated to be $7,518,548

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DECISION AND ORDER

EB-2021-0205

ENBRIDGE GAS INC.

Application for Leave to Construct Natural Gas Pipeline and Associated Facilities in the Municipality of Greenstone

BEFORE: Robert Dodds
Presiding Commissioner

David Sword
Commissioner

March 17, 2022

1 OVERVIEW

On September 10, 2021, Enbridge Gas Inc. (Enbridge Gas) applied to the Ontario Energy Board (OEB) under section 90 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B) (OEB Act), for an order granting leave to construct a natural gas pipeline and associated facilities in the Municipality of Greenstone (Project). The Project is needed to provide service to the Greenstone Gold Mine near the community of Geraldton, which is located within the Municipality of Greenstone, approximately 270 km northeast of Thunder Bay. The Greenstone Gold Mine is an open pit mine that will be owned and operated by Greenstone Gold Mine LP.

The Project involves:

- 13 km of 6-inch diameter extra high-pressure steel pipeline
- a new metering station
- a rebuild of the existing TransCanada PipeLines Limited/Enbridge Gas custody transfer station

The Project would start at the Enbridge Gas Custody Station located adjacent to the TransCanada pipeline, 3.5 km north of the community of Geraldton and terminate south of TransCanada Highway 11 at the Greenstone Gold Mine site. The general location of the Project is shown on a diagram in Schedule A to this decision and order.

The OEB grants leave to construct a natural gas pipeline and associated facilities as described in the Application, subject to the Conditions of Approval (see Schedule B), based on the following findings:

- there is a need for natural gas service to meet the energy demand of the Greenstone Gold Mine.
- the proposed route for a dedicated pipeline and station facilities to the Project is the preferred route.
- the Project meets the economic test.
- the environmental impacts of the Project are being adequately addressed.
- the OEB approves the forms of landowner agreements related to the construction of the Project.

- Enbridge Gas has satisfied the requirement of the Indigenous Consultation in accordance with OEB's Environmental Guidelines.
- the OEB accepts the Standard Conditions of Approval with modification of condition 2(a)(i) to reduce the construction start notice requirement to 5 days from the current 10 days.

Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2022-0086

ENBRIDGE GAS INC.

Application for leave to construct natural gas pipeline and ancillary facilities in the Township of Dawn-Euphemia and St. Clair Township

BEFORE: **Patrick Moran**
Presiding Commissioner

Robert Dodds
Commissioner

David Sword
Commissioner

November 3, 2022

1 OVERVIEW

Enbridge Gas Inc. (Enbridge Gas) has applied for leave to construct:

- Approximately 20 kilometres of 36-inch diameter natural gas pipeline from its Dawn Operations Centre in the Township of Dawn-Euphemia to its Corunna Compressor Station in St. Clair Township, and
- Station work to tie in the new pipeline at the Dawn Operations Centre and the Corunna Compressor Station,

to replace the equivalent capacity of seven compressors at the Corunna Compressor Station that Enbridge Gas proposes to retire and abandon (the Project).

Enbridge Gas also applied for approval of the forms of easement agreement and temporary land use agreements to be offered to landowners for the routing and construction of the proposed pipeline.

The OEB finds that the Project is in the public interest pursuant to section 96(1) of the OEB Act and grants Enbridge Gas leave to construct the Project subject to the Conditions of Approval set out in this decision. The OEB also finds that Enbridge Gas did not seek to establish that the Project is for the benefit of ratepayers in the context of its integrated storage system and that the ability to include the proposed assets in rate base is a matter that Enbridge Gas may pursue in its 2024 rebasing proceeding.

The OEB finds that the Crown’s duty to consult has been adequately discharged.

The OEB also approves the forms of landowner agreements as updated in a letter to the OEB dated October 20, 2022.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 41-44 of 164

Question(s):

At page 41, Concentric outlined EGI's recent experience regarding leave to construct applications. In some cases, it cited the number of interrogatories received or the number of intervenors to conclude that EGI's experience with regulatory opposition is consistent with the industry wide trend of increasing opposition and increased operational risk.

a) Please provide a list of all leave to construct applications submitted by either EGD or Union since 2012. For each one, please provide:

   i. The number of intervenors;
   ii. The number of interrogatories received; and
   iii. The outcome of the application.

Response:

a) Due to the volume of Leave to Construct applications filed between 2012-2023, for ease of review Enbridge Gas has summarized the number of approved intervenors and interrogatories received for Pipeline Projects by year in Table 1. Similarly, Enbridge Gas has summarized the number of approved intervenors and interrogatories received for Storage Project Applications by year in Table 2.

Table 1
Average Number of Intervenors & Interrogatories received for LTC Applications < $100 Million in Capital Cost

Year	Average # Intervenors and OEB Staff	Average # Interrogatories
2012	1	16
2013	1	0
2014	1	12
2015	2	16
2016	2	36
2017	2	36
2018	2	35
2019	4	96
2020	8	258
2021	4	95
2022	7	204

Please note, in Table 1 Enbridge Gas has only included Pipeline Projects where Leave to Construct was sought with capital costs less than $100 million. Large Projects with capital cost estimates over $100 million, regardless of the general state of regulatory opposition, have historically drawn widespread attention and resulting interest during the discovery phases of the OEB proceedings. Enbridge Gas also did not include proceedings that sought approval (under Section 36) for Union's proposed volumetric-based System Expansion Surcharge (SES) for Community Expansion Projects, as the number of interrogatories and intervenors largely reflects intervenor participation related to Union's proposal for the SES.

Table 2
Average Number of Intervenors & Interrogatories received for Storage Project Applications

Year	Average # Intervenors and OEB Staff	Average # Interrogatories
2012	2	8
2013	1	0
2014	2	4
2015	2	6
2016	4	21
2017	2	10
2019	1	0
2020	2	56
2021	3	54

A list of all pipeline and storage projects for which Leave to Construct was sought between 2012 to 2022 can be found at Attachment 1 to this response. The outcome of each project application is accessible via the hyperlinks to OEB Decision and Order provided. Please note that the information contained in Attachment 1 was compiled on a best-efforts basis directly from the OEB's website (listing of archived applications available via regulatory document search).

Table 1: Pipeline Projects < $100 Million

Year	Average # Intervenors	Average # Interrogatories
2012	1	16
2013	1	0
2014	1	12
2015	2	16
2016	2	36
2017	2	36
2018	2	35
2019	4	96
2020	8	258
2021	4	95
2022	7	204

Table 2: Storage Projects

Year	Average # Intervenors	Average # Interrogatories
2012	2	8
2013	1	0
2014	2	4
2015	2	6
2016	4	21
2017	2	10
2019	1	0
2020	2	56
2021	3	54

Table 1 Data										
Project	Docket	Applicant	# Intervenors Approved and OEB Staff	# Interrogatories	Decision and Order	Technical Conference perscribed (y/n)	# Undertakings from Technical Conference	Oral Hearing (y/n)	# Undertakings from Oral Hearing	Capital Cost from OEB Application
Projects included in Table 1										
Angus Reinforcement Project	EB-2012-0013	Enbridge Gas Distribution	1	1	https://www.rds.oeb.ca/CMWebDrawer/Record/350247/File/document	n	n/a	n	n/a	4,134,963.00
Ottawa Reinforcement Project	EB-2012-0099	Enbridge Gas Distribution	1	27	https://www.rds.oeb.ca/CMWebDrawer/Record/375231/File/document	n	n/a	n	n/a	51,236,000.00
Thunder Bay Pipeline Project	EB-2012-0226/EB-2012-0227	Union Gas	2	36	https://www.rds.oeb.ca/CMWebDrawer/Record/393556/File/document	n	n/a	n	n/a	26,726,000.00
Durham York Energy Centre Pipeline	EB-2012-0382	Enbridge Gas Distribution	1	8	https://www.rds.oeb.ca/CMWebDrawer/Record/388540/File/document	n	n/a	n	n/a	3,900,000.00
Owen Sound Replacement Project	EB-2012-0430	Union Gas	2	44	https://www.rds.oeb.ca/CMWebDrawer/Record/387336/File/document	n	n/a	n	n/a	23,907,000.00
Leamington Expansion Pipeline Project (Pipeline)	EB-2012-0431	Union Gas	1	11	https://www.rds.oeb.ca/CMWebDrawer/Record/388384/File/document	n	n/a	n	n/a	6,392,000.00
Leamington Expansion Pipeline Project (Stations)						n	n/a	n	n/a	1,778,000.00
2013 Panhandle Replacement	EB-2012-0432	Union Gas	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/381598/File/document	n	n/a	n	n/a	2,368,000.00
Ashtonbee Station (Request to Vary from GTA Project)	EB-2012-0451/EB-2016-0034	Enbridge Gas Distribution	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/517304/File/document	n	n/a	n	n/a	14,378,598.00
Dawn Parkway NPS 26 Strathroy-Caradoc Project	EB-2013-0191	Union Gas	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/399548/File/document	n	n/a	n	n/a	1,520,000.00
Dawn Parkway NPS 48 Replacement	EB-2013-0284	Union Gas	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/408032/File/document	n	n/a	n	n/a	3,915,000.00
Panhandle NPS16 Replacement (Highway 40- Chatham Kent)	EB-2013-0407	Union Gas	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/424723/File/document	n	n/a	n	n/a	NA
Panhandle NPS16 Replacement Project	EB-2013-0420	Union Gas	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/431364/File/document	n	n/a	n	n/a	29,597,000.00
Sarnia Expansion Pipeline Project	EB-2014-0333	Union Gas	2	7	https://www.rds.oeb.ca/CMWebDrawer/Record/467288/File/document	n	n/a	n	n/a	24,318,000.00
Bay of Quinte Replacement Pipeline Project	EB-2014-0350	Union Gas	1	16	https://www.rds.oeb.ca/CMWebDrawer/Record/470722/File/document	n	n/a	n	n/a	8,900,000.00
Ottawa Innes Road Pipeline Replacement Project	EB-2012-0438/EB-2014-0017/EB-2015-0037	Enbridge Gas Distribution	1	14	https://www.rds.oeb.ca/CMWebDrawer/Record/391074/File/document	n	n/a	n	n/a	7,254,286.00
Panhandle 2015 Replacement Project	EB-2015-0041	Union Gas	1	8	https://www.rds.oeb.ca/CMWebDrawer/Record/481645/File/document	n	n/a	n	n/a	9,737,000.00
Sudbury NPS 10 Replacement	EB-2015-0042	Union Gas	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/475446/File/document	n	n/a	n	n/a	NA
Sudbury Expansion Project	EB-2015-0120	Union Gas	3	50	https://www.rds.oeb.ca/CMWebDrawer/Record/486066/File/document	n	n/a	n	n/a	10,825,000.00
Canadian Nuclear Laboratories	EB-2015-0194	Enbridge Gas Distribution	2	7	https://www.rds.oeb.ca/CMWebDrawer/Record/502586/File/document	n	n/a	n	n/a	15,503,141.00
Panhandle Relocation Project	EB-2015-0366	Union Gas	1	14	https://www.rds.oeb.ca/CMWebDrawer/Record/526414/File/document	n	n/a	n	n/a	NA
Leamington Pipeline Expansion Project	EB-2016-0013	Union Gas	5	80	https://www.rds.oeb.ca/CMWebDrawer/Record/533347/File/document	n	n/a	Y	7	12,344,000.00
Seaton Land Development Project	EB-2016-0054	Enbridge Gas Distribution	1	9	https://www.rds.oeb.ca/CMWebDrawer/Record/532738/File/document	n	n/a	n	n/a	4,050,672.00
Sudbury Replacement Project	EB-2016-0122	Union Gas	2	27	https://www.rds.oeb.ca/CMWebDrawer/Record/534155/File/document	n	n/a	n	n/a	2,188,144.00
Sudbury Maley Replacement Project	EB-2016-0222	Union Gas	1	29	https://www.rds.oeb.ca/CMWebDrawer/Record/550392/File/document	n	n/a	n	n/a	6,303,741.00
2017 Panhandle Replacement Project (Jefferson)	EB-2017-0118	Union Gas	1	10	https://www.rds.oeb.ca/CMWebDrawer/Record/575871/File/document	n	n/a	n	n/a	1,518,500.00
Fenelon Falls Community Expansion Project	EB-2017-0147	Enbridge Gas Distribution	6	76	https://www.rds.oeb.ca/CMWebDrawer/Record/600928/File/document	n	n/a	n	n/a	23,055,488.00
2018 Sudbury Replacement Project	EB-2017-0180	Union Gas	1	33	https://www.rds.oeb.ca/CMWebDrawer/Record/585519/File/document	n	n/a	n	n/a	74,057,000.00
Scugog Island Community Expansion Project	EB-2017-0261	Enbridge Gas Distribution	1	26	https://www.rds.oeb.ca/CMWebDrawer/Record/610116/File/document	n	n/a	n	n/a	3,448,946.00
2018 Oxford Reinforcement Project	EB-2018-0003	Union Gas	1	18	https://www.rds.oeb.ca/CMWebDrawer/Record/608836/File/document	n	n/a	n	n/a	7,396,000.00
Liberty Village Project	EB-2018-0096	Enbridge Gas Distribution	1	11	https://www.rds.oeb.ca/CMWebDrawer/Record/621216/File/document	n	n/a	n	n/a	3,623,263.00
Bathurst Reinforcement Project	EB-2018-0097	Enbridge Gas Distribution	2	47	https://www.rds.oeb.ca/CMWebDrawer/Record/630326/File/document	n	n/a	n	n/a	9,147,651.00
Don River 30" Pipeline Project	EB-2018-0108	Enbridge Gas Distribution	1	28	https://www.rds.oeb.ca/CMWebDrawer/Record/627559/File/document	n	n/a	n	n/a	25,318,141.00
2019 Community Expansion Project	EB-2018-0142	Enbridge Gas Distribution	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/648498/File/document	n	n/a	n	n/a	NA
Chatham-Kent Rural Project	EB-2018-0188	Enbridge Gas Distribution	3	76	https://www.rds.oeb.ca/CMWebDrawer/Record/659415/File/document	n	n/a	n	n/a	19,100,000.00
Georgian Sands Pipeline Project	EB-2018-0226	Enbridge Gas Inc	2	56	https://www.rds.oeb.ca/CMWebDrawer/Record/648124/File/document	n	n/a	n	n/a	2,827,537.00
Stratford Reinforcement Project	EB-2018-0306	Enbridge Gas Distribution	3	46	https://www.rds.oeb.ca/CMWebDrawer/Record/638162/File/document	n	n/a	n	n/a	28,540,000.00
St Laurent Pipeline Project	EB-2019-0006	Enbridge Gas Inc	1	29	https://www.rds.oeb.ca/CMWebDrawer/Record/653713/File/document	n	n/a	n	n/a	5,510,519.00
Chippewas of the Thames First Nation Community Expansion	EB-2019-0139	Enbridge Gas Inc	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/648674/File/document	n	n/a	n	n/a	NA
Owen Sound Reinforcement Project	EB-2019-0183	Enbridge Gas Inc	9	171	https://www.rds.oeb.ca/CMWebDrawer/Record/673999/File/document	n	n/a	n	n/a	68,965,000.00
Saugeen First Nation Community Expansion	EB-2019-0187	Enbridge Gas Inc	2	37	https://www.rds.oeb.ca/CMWebDrawer/Record/667099/File/document	n	n/a	n	n/a	2,537,360.00
North Bay Community Expansion Project	EB-2019-0188	Enbridge Gas Inc	3	129	https://www.rds.oeb.ca/CMWebDrawer/Record/676707/File/document	n	n/a	n	n/a	10,095,250.00
Sarnia Reinforcement Project	EB-2019-0218	Enbridge Gas Inc	2	59	https://www.rds.oeb.ca/CMWebDrawer/Record/670180/File/document	n	n/a	n	n/a	NA
Low Carbon Energy Project	EB-2019-0294	Enbridge Gas Inc	9	247	https://www.rds.oeb.ca/CMWebDrawer/Record/691859/File/document	n	n/a	n	n/a	NA
Cherry to Bathurst	EB-2020-0136	Enbridge Gas Inc	7	269	https://www.rds.oeb.ca/CMWebDrawer/Record/697732/File/document	n	n/a	n	n/a	NA
London Lines Replacement Project	EB-2020-0192	Enbridge Gas Inc	9	210	https://www.rds.oeb.ca/CMWebDrawer/Record/701326/File/document	n	n/a	n	n/a	NA
St Laurent Ottawa North Pipeline Project	EB-2020-0293	Enbridge Gas Inc	8	296	https://www.rds.oeb.ca/CMWebDrawer/Record/746476/File/document	y	37	n	n/a	NA
Greenstone Pipeline Project	EB-2021-0205	Enbridge Gas Inc	4	95	https://www.rds.oeb.ca/CMWebDrawer/Record/743222/File/document	n	n/a	n	n/a	NA
Waterfront Toronto Relocation Project	EB-2022-0003	Enbridge Gas Inc	7	99	https://www.rds.oeb.ca/CMWebDrawer/Record/750562/File/document	n	n/a	n	n/a	NA
Dawn to Corunna	EB-2022-0086	Enbridge Gas Inc	11	459	https://www.rds.oeb.ca/CMWebDrawer/Record/760243/File/document	Y	52	n	n/a	NA
Haldimand Shores Community Expansion Project	EB-2022-0088	Enbridge Gas Inc	2	42	https://www.rds.oeb.ca/CMWebDrawer/Record/753826/File/document	n	n/a	n	n/a	NA
Crowland Test Well Drilling Project	EB-2022-0155	Enbridge Gas Inc	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/755862/File/document	n	n/a	n	n/a	NA
Panhandle Regional Expansion Project	EB-2022-0157	Enbridge Gas Inc	12	419	NA	Y	49	n	n/a	NA
Projects excluded from Table 1										
Section 36 Approval Applications										
Kettle Point & Lambton Shores Community Expansion	EB-2015-0179	Union Gas	22	582	https://www.rds.oeb.ca/CMWebDrawer/Record/580124/File/document	Y	18	N	n/a	2,095,346.00
Milverton, Rostock, Wartburg Community Expansion	EB-2015-0179	Union Gas								5,976,291.00
Moraviantown Island Community Expansion	EB-2015-0179	Union Gas								563,873.00
Prince Township Community Expansion	EB-2015-0179	Union Gas								2,720,959.00
Projects > $100 M										
Parkway West Project	EB-2012-0433	Union Gas	40	527	https://www.rds.oeb.ca/CMWebDrawer/Record/424176/File/document	y	52	y	45	219,400,000.00
GTA Reinforcement Project (without Stations)	EB-2012-0451	Enbridge Gas Distribution	40	942						667,400,000.00
Brantford-Kirkwall Project	EB-2013-0074	Union Gas								96,056,000.00
Union's Dawn Parkway 2016 Expansion Project	EB-2014-0261	Union Gas	16	188	https://www.rds.oeb.ca/CMWebDrawer/Record/476933/File/document	n	n/a	y	0	231,037,000.00
Panhandle Reinforcement Project	EB-2016-0186	Union Gas	15	389	https://www.rds.oeb.ca/CMWebDrawer/Record/562743/File/document	Y	24	Y	11	264,468,000.00
Kingsville Transmission Reinforcement Project	EB-2018-0013	Union Gas	4	28	https://www.rds.oeb.ca/CMWebDrawer/Record/620564/File/document	n	n/a	n	n/a	105,716,000.00
Windsor Line Replacement Project	EB-2019-0172	Enbridge Gas Inc	3	69	https://www.rds.oeb.ca/CMWebDrawer/Record/673434/File/document	y	22	n	n/a	106,805,000.00
2019 Dawn Parkway Expansion	EB-2019-0159	Enbridge Gas Inc	18	714	https://www.rds.oeb.ca/CMWebDrawer/Record/694289/File/document	n	n/a	n	n/a	203,526,396.00

Table 2 Data										
Project	Docket	Applicant	# Intervenors Approved	# Interrogatories	Decision and Order	Technical Conference perscribed (y/n)	# Undertakings from Technical Conference	Oral Hearing (y/n)	# Undertakings from Oral Hearing	Capital Cost from OEB Application
Jacob Pool Storage Development	EB-2011-0013	Union Gas	4	55	https://www.rds.oeb.ca/CMWebDrawer/Record/286183/File/document	Y	1	n	n/a	NA
Jacob Pool Storage Development	EB-2011-0014	Union Gas								NA
Jacob Pool Storage Development	EB-2011-0015	Union Gas								NA
Application to Drill Wells in the Kimball-Colinville DSA	EB-2012-0060	Enbridge Gas Distribution	3	15	https://www.rds.oeb.ca/CMWebDrawer/Record/351362/File/document	n	n/a	n	n/a	NA
Bentpath Rosedale Pool - Well Drilling Project	EB-2012-0391	Union Gas	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/377765/File/document	n	n/a	n	n/a	NA
Licence to drill within the Kimball-Colinville DSA	EB-2013-0289	Enbridge Gas Distribution	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/416033/File/document	n	n/a	n	n/a	NA
Chatham D Designated Storage Area Amendment	EB-2014-0288	Enbridge Gas Distribution	2	6	https://www.rds.oeb.ca/CMWebDrawer/Record/479071/File/document	n	n/a	n	n/a	NA
2015 Storage Enhancement Project	EB-2014-0306	Union Gas	2	1	https://www.rds.oeb.ca/CMWebDrawer/Record/465854/File/document	n	n/a	n	n/a	NA
Application to Drill Well in the Wilksport DSA	EB-2014-0378	Enbridge Gas Distribution	1	5	https://www.rds.oeb.ca/CMWebDrawer/Record/481605/File/document	n	n/a	n	n/a	NA
Wilkesport Gathering Line	EB-2015-0033	Enbridge Gas Distribution	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/477010/File/document	n	n/a	n	n/a	NA
2016 Storage Enhancement Project	EB-2015-0250	Union Gas	2	5	https://www.rds.oeb.ca/CMWebDrawer/Record/509241/File/document	n	n/a	n	n/a	NA
Application to Drill Wells in the Corunna DSA	EB-2015-0303	Enbridge Gas Distribution	2	14	https://www.rds.oeb.ca/CMWebDrawer/Record/520200/File/document	n	n/a	n	n/a	NA
2017 Storage Enhancement Project	EB-2016-0322	Union Gas	4	28	https://www.rds.oeb.ca/CMWebDrawer/Record/568339/File/document	n	n/a	n	n/a	NA
Application to Drill a Well in the Corunna DSA	EB-2016-0378	Enbridge Gas Distribution	3	13	https://www.rds.oeb.ca/CMWebDrawer/Record/570186/File/document	n	n/a	n	n/a	NA
Terminus Well Replacement Project	EB-2017-0162	Union Gas	3	16	https://www.rds.oeb.ca/CMWebDrawer/Record/582251/File/document	n	n/a	n	n/a	1,797,000.00
Dow Moore Storage Pool Drilling	EB-2017-0354	Enbridge Gas Distribution	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/635014/File/document	n	n/a	n	n/a	8,877,796.00
Sarnia Airport Storage Pool LP	EB-2017-0362	Union Gas	2	17	https://www.rds.oeb.ca/CMWebDrawer/Record/606551/File/document	n	n/a	n	n/a	NA
2018 Storage Enhancement Project	EB-2017-0363	Union Gas	3	6	https://www.rds.oeb.ca/CMWebDrawer/Record/603105/File/document	n	n/a	n	n/a	NA
Application to Drill a Well in the Ladysmith Storage Pool	EB-2019-0012	Enbridge Gas Inc	1	0	https://www.rds.oeb.ca/CMWebDrawer/Record/648102/File/document	n	n/a	n	n/a	NA
2020 Storage Enhancement Project	EB-2020-0074	Enbridge Gas Inc	2	34	https://www.rds.oeb.ca/CMWebDrawer/Record/680644/File/document	n	n/a	n	n/a	NA
Application to Drill Storage Wells in Kimball-Colinville & Payne	EB-2020-0105	Enbridge Gas Inc	3	50	https://www.rds.oeb.ca/CMWebDrawer/Record/686335/File/document	n	n/a	n	n/a	NA
2021/2022 Storage Enhancement Project	EB-2020-0256	Enbridge Gas Inc	2	85	https://www.rds.oeb.ca/CMWebDrawer/Record/713151/File/document	n	n/a	n	n/a	NA
2022 Storage Enhancement Project	EB-2021-0078	Enbridge Gas Inc	3	40	https://www.rds.oeb.ca/CMWebDrawer/Record/745071/File/document	n	n/a	n	n/a	NA
Corunna and Ladysmith Well Drilling Project	EB-2021-0079	Enbridge Gas Inc	3	31	https://www.rds.oeb.ca/CMWebDrawer/Record/732594/File/document	n	n/a	n	n/a	NA
Coveny and Kimball-Colinville Well Drilling Project	EB-2021-0248	Enbridge Gas Inc	3	92	https://www.rds.oeb.ca/CMWebDrawer/Record/746200/File/document	n	n/a	n	n/a	NA

ENBRIDGE GAS INC.

Answer to Undertaking from
Canadian Manufacturers & Exporters (CME)

Undertaking

Tr: 17

To advise with the exception of EB-2002-0293 whether any of the projects listed has resulted in a denial of relief by the OEB in its Decision.

Response:

Aside from the OEB's Decision related to Enbridge Gas's application seeking an order of the OEB for leave to construct (LTC) the St. Laurent Ottawa North Replacement Project[1], none of the remaining projects listed were denied the LTC relief sought.

[1] EB-2022-0293

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL AND WEB POSTING

March 29, 2021

To: All Regulated Entities
All Other Interested Parties

Re: **Updates to Performance Standards and Other Process Improvements**

In keeping with its commitment to modernize, promote accountability and provide greater predictability for regulated entities and other interested stakeholders, the Ontario Energy Board (OEB) has updated its performance standards for certain types of applications. Effective April 1, 2021, updated performance standards will apply to the processing of Leave to Construct applications and Motions to Review.

Also, to enhance the effectiveness of Leave to Construct applications, the OEB will be introducing a standard issues list for each type of Leave to Construct application (electricity and natural gas respectively). While the OEB will begin applying these issues lists for applications filed with the OEB starting April 1, 2021, the OEB will consider whether amendments are warranted based on experience with the issues lists over time.

The changes described in this letter are responsive to stakeholders' expressed desire for greater predictability in terms of application processing timelines, and contribute to the OEB's efforts to embody the characteristics of a top-quartile regulator in its operations.

Updated Performance Standards for Leave to Construct Applications & Motions to Review

Performance standards outline the typical procedural steps associated with processing a particular type of application and the typical number of calendar days for each step.

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The current performance standards for Leave to Construct applications and Motions to Review were established in 2009. Since that time, the OEB's regulatory practices and requirements have evolved, as have the type and complexity of the applications that come before it.

In developing its updated performance standards, the OEB was informed by a review of historical application processing timelines and performance standards used by other regulators, such as the Alberta Utilities Commission and the Canadian Energy Regulator.

Performance Standards and Performance Measures for Leave to Construct Applications

The OEB's current total cycle time for Leave to Construct applications is determined by hearing type (i.e., oral or written). Through an analysis of past Leave to Construct applications, it was identified that application complexity influences the time required for review and processing, and this is not necessarily related to the type of hearing. Accordingly, the OEB is establishing one performance standard for more complex applications and one performance standard for more straightforward applications. This is consistent with the OEB's approach for rate applications.

Along with the performance standards, the OEB developed criteria for assessing which performance standard will apply to Leave to Construct applications. This is included in Appendix A and posted on the OEB's website. These criteria are intended as a guide. The actual performance standard that will apply will depend on the exact nature of the application and its content, including any requests that may not be reflected in Appendix A.

Total cycle time for both of these performance standards is the number of days from the issuance of a completeness letter[1] to the issuance of the final decision. The OEB will report two measures for application processing performance for Leave to Construct applications:

1. Time elapsed from the close of the record to the issuance of the final decision (Decision Writing Period)
2. Total cycle time – from issuance of a completeness letter to final decision

[1] The OEB conducts a preliminary review of each Leave to Construct application to ensure the information presented is complete and consistent with the filing requirements, as applicable. The OEB will not commence a proceeding until the OEB is satisfied that any deficiencies have been addressed. The OEB will strive to communicate the results of the preliminary review in 14 calendar days.

The table below details each of these performance measures:

<table>
<tr><td colspan="2" rowspan="2"></td><td colspan="2">Elapsed Calendar Days</td></tr>
<tr><td>Decision Writing Period</td><td>Total Cycle Time</td></tr>
<tr><td rowspan="2">Leave to Construct</td><td>Complex Electricity & Natural Gas</td><td>60</td><td>210</td></tr>
<tr><td>Short-form Electricity & Natural Gas</td><td>30</td><td>135</td></tr>
</table>

The updated performance standards are included in the schedules set out in Appendix B and posted on the OEB's website. The actual procedural steps and timelines for individual proceedings may vary, and may be affected by statutory holidays. Applicants intending to file leave to construct applications are encouraged to contact OEB staff in advance of their filing.

Performance Standards for Motions to Review

Currently, the total cycle time for Motions to Review is determined by hearing type (i.e., oral or written). An analysis of past Motions to Review revealed that the type of motion influences the time required for review and processing. Specifically, the time to hear a Motion to Review is influenced by whether new evidence is filed that requires time for discovery. Accordingly, the updated performance standards reflect the type of motion rather than the hearing type.

Total cycle time for these performance standards is the number of days from receipt of the motion to the issuance of the final decision. The OEB will report two measures for application processing performance for Motions to Review:

1. Time elapsed from the close of the record to the issuance of the final decision (Decision Writing Period)
2. Total cycle time – from receipt of the motion to the final decision

The table below details each of these performance measures for Motions to Review:

<table>
<tr><td colspan="2" rowspan="2"></td><td colspan="2">Elapsed Calendar Days</td></tr>
<tr><td>Decision Writing Period</td><td>Total Cycle Time</td></tr>
<tr><td rowspan="2">Motion to Review</td><td>New Evidence / Facts or Change in Circumstances</td><td>60</td><td>165</td></tr>
<tr><td>Error (no discovery)</td><td>60</td><td>135</td></tr>
</table>

Adjudicative reporting dashboard

The OEB monitors and evaluates the timeliness of its adjudicative proceedings on an ongoing basis, using performance standards and key performance indicators established for all application types.

The Adjudicative Reporting Dashboard provides stakeholders and industry with a comprehensive, online report of the OEB's overall adjudicative performance, updated mid-way through and at the end of each fiscal year.

On this page

Current Report

Fiscal 2022-2023: Results (April 1, 2022 to March 31, 2023)

1. The OEB has issued more than 260 decisions in Fiscal 2022-2023 – 98% of which were issued in accordance with performance standards (the OEB target is 90%).
2. Of all decisions issued, more than 80% were issued more than 14 days in advance of the decision metric date.
3. The OEB met all of its decision writing timelines including the approval of 12 complete settlement agreements for rate applications.
4. March 2023 was the month in which the most decisions (47 or 18% of all decisions) were issued by the OEB.

Click here for a print version (pdf) of the dashboard or scroll down for more detailed information on each component of the dashboard.

262
Total Decisions

258
Within Target

4
Outside Target

49
Decisions Issued by Panels of Commissioners

213
Decisions Issued by Delegated Authority

98%
Total Decisions Issued within Standard (Target = 90%)

83%
Total Decisions Issued More than 14 Days Early

100%
Decision Writing Time within Standard (for Decisions Issued by Panels of Commissioners)

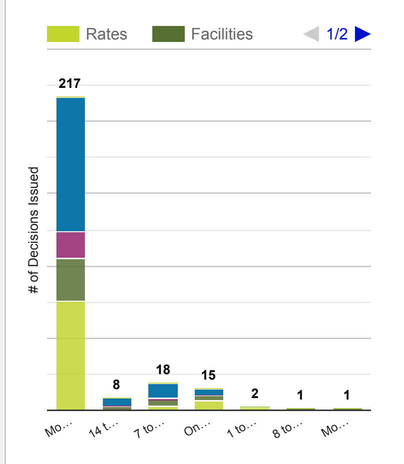
Total Decisions Issued

The majority of decisions (81%) issued by the OEB were heard by Delegated Authority. This is consistent with Fiscal 2021-2022 where 79% of the decisions issued by the OEB were heard by Delegated Authority.

75% of the decisions issued in Fiscal 2022-2023 were for applications related to electricity.

43% of all the decisions issued were for Licence applications; Rates comprised 33% of decisions, followed by Facilities (16%) and MAADs (8%).

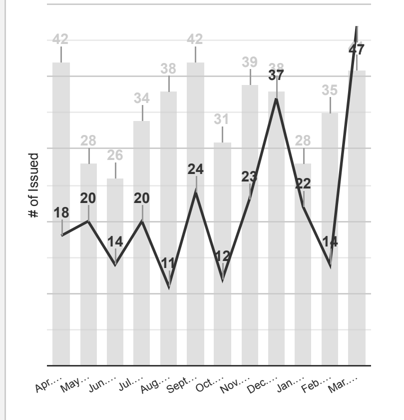
Decision Issuance Spectrum



In addition to monitoring whether a decision is issued on time or late, the OEB also monitors the degree to which decisions were issued early or late relative to the decision metric date established by the applicable performance standard. This Decision Issuance Spectrum highlights the fact that more than 80% of decisions issued this reporting period were issued more than two weeks in advance of the metric date.

Two panel decisions for QRAM applications (EB-2022-0173 and EB-2022-0174) were each issued four days late. On the day that the OEB was planning to issue these decisions, the applicant requested an additional change on its rate schedule. To address this, the OEB needed more time to finalize and issue the two decisions. Two other panel decisions for Franchise applications (EB-2022-0201 and EB-2022-0207) were also issued late. This was due to the fact that the OEB allowed evidence to be filed by the municipality in each application, a step which is not contemplated in the performance standards.

Key Documents Issued

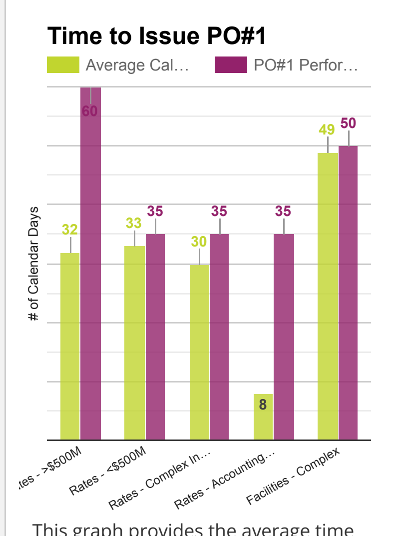


The OEB issues many documents aside from decisions each month. Key Documents refers to all other documents that are issued by the OEB, but are not a final Decision and Order (e.g., Notice, Procedural Order, Letter to Industry, etc.). The OEB issued 35 Key Documents on average each month in Fiscal 2022-2023.

Average Time for Procedural Order No. 1 (PO#1), Decision Writing and Total Cycle

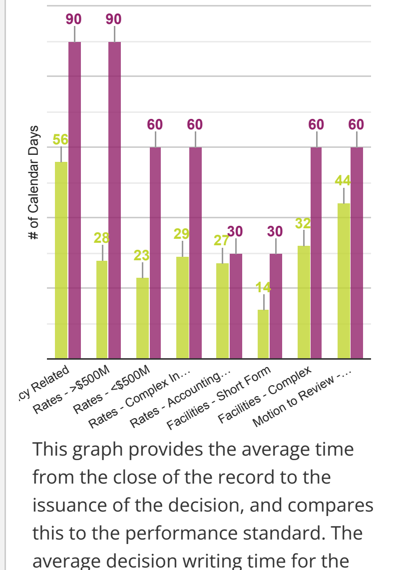
The OEB has committed to report on the performance of key application milestones for applications heard by panels of Commissioners for major application types. The three graphs illustrate the performance for various application types relative to the performance standard for:

Time to Issue PO#1



This graph provides the average time from receipt of a complete application to the issuance of PO#1, and compares this to the performance standard.

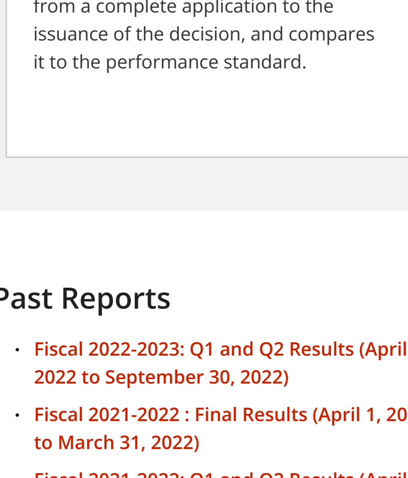
Decision Writing Time



This graph provides the average time from the close of the record to the issuance of the decision, and compares this to the performance standard. The average decision writing time for the Rates >$500M and Rates <$500M performance standards are much lower than the respective metrics of 90 and 60 calendar days because twelve applications heard under these performance standards all had full settlement proposals that were accepted by the panels of Commissioners. Full settlements generally reduce the amount of time required for decision writing relative to the performance standard.

A relatively small number of matters adjudicated by the OEB can involve significant policy matters, such as proceedings that develop a 'policy framework' to be employed in subsequent proceedings or generic proceedings applicable across a sector. There were two such proceedings in which the OEB issued decisions (EB-2021-0002 and EB-2021-0243). These proceedings do not have performance standards for total cycle time given their more unique nature. They have a performance measure of 90 calendar days assigned for the decision writing period.

Total Cycle Time



This graph provides the average time from a complete application to the issuance of the decision, and compares it to the performance standard.

Past Reports

- Fiscal 2022-2023: Q1 and Q2 Results (April 1, 2022 to September 30, 2022)
- Fiscal 2021-2022 : Final Results (April 1, 2021 to March 31, 2022)
- Fiscal 2021-2022: Q1 and Q2 Results (April 1, 2021 to September 30, 2021)

Related Documents

- Chief Commissioner Letter to Industry (April 20, 2023) (pdf)

EGI Financial Metrics

Source (Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 65-67, figures 18, 20.

Metric	2012 Result	2024 Forecast (No Change to Equity Thickness)	2012/2024 % Change
Debt/EBITDA	4.70	5.24	11% (deteriorating)
FFO/Debt	14.24%	13.76%	3.4% (deteriorating)
FFO/Interest Coverage	3.35	4.25	26% (improving)
EBIT/Interest Coverage	2.13	2.40	12% (improving)
Debt Capitalization	64%	64%	0 (stable)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 4, Tab 4, Schedule 3, Attachment 4, p. 20 of 48; Exhibit 4, Tab 4, Schedule 3, Attachment 3, page 32 and 38 of 59.

Question(s):

At page 20, Schedule 1, the agreement lists the services provided pursuant to the Intercorporate Services Agreement. For Technology and Information Systems, the agreement lists, inter alia, the following services being provided: core infrastructure and operations; enterprise business applications; enterprise architecture and data; cyber security and governance, and the office of the Chief Information Officer.

At page 32 of 59 of Attachment 3, TIS costs were normalized for comparison with the peer group based on “total operating cost”.

At page 38, Guidehouse determined that EGI’s normalized TIS cost per $M in total operating cost was $61,319. Guidehouse determined that the minimum was approximately $26K, average was approximately $44K and the maximum was approximately $73K

a) Please list (on an anonymized basis) all of the comparators normalized TIS costs;

b) Please provide an explanation for why, on a normalized basis, EGI was significantly higher than the average TIS costs.

Response:

The following response was provided by Guidehouse:

a) The table below summarizes normalized TIS costs, based on $M of total operating cost for the relevant and anonymized utility comparators in CAD 2022 real dollars and CAD 2024 real dollars respectively.

Comparator Utility	Normalized TIS Cost (2022)	Normalized TIS Cost (2024)
1	Not available	Not available
2	$41,453	$41,453
3	$47,233	$47,233
4	Not available	Not available
5	Not available	Not available
6	$28,605	$36,446
7	$32,783	$31,240
8	$29,815	$29,815
9	$73,643	$69,610
10	$58,654	$65,577

b) Guidehouse did not specifically compare discrete components of Enbridge Gas TIS costs relative to comparator utilities to rationalize where Enbridge Gas falls within the band.

Guidehouse understood from Enbridge Gas that allocated TIS costs were, in general, increasing because of significant investment this period in improvements to system reliability, enhancing business systems and to ensure system security as cyber security threats continue to grow. These increases are following a relatively consistent period from 2018 to 2021 resulting from inflation at that time combined with reductions from synergies and restructuring due to merger integration. It was also noted that industry shifts towards TIS ‘as-a-service' models have also resulted in shifting costs, particularly shifts from capital intensive to OM&A in nature. These factors may be different in need or in timing relative to other utilities.

Given Enbridge Gas TIS costs fall within the range on a normalized basis relative to comparator utilities and were not assessed as the highest cost, Guidehouse did not determine it necessary to further test the incurrence of TIS costs. TIS costs are by nature lumpy and can vary from one period to another based on the investments being made to increase reliability, security, safety and overall efficiency of operations over the long term.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

4-4-2, p. 53

Question(s):

Central Functions costs have increased by $135M since amalgamation in 2019. One of the explanations Enbridge has provided for the increase is the move to an 'as a service' model' in the Technology Information Systems area:

a) Please describe in further detail the ‘as a service’ model which Enbridge has moved to and explain the reasons for the resulting increases in costs in each year between 2021 and 2024.

b) Provide the business case for moving to this model, including the change in costs and the benefits.

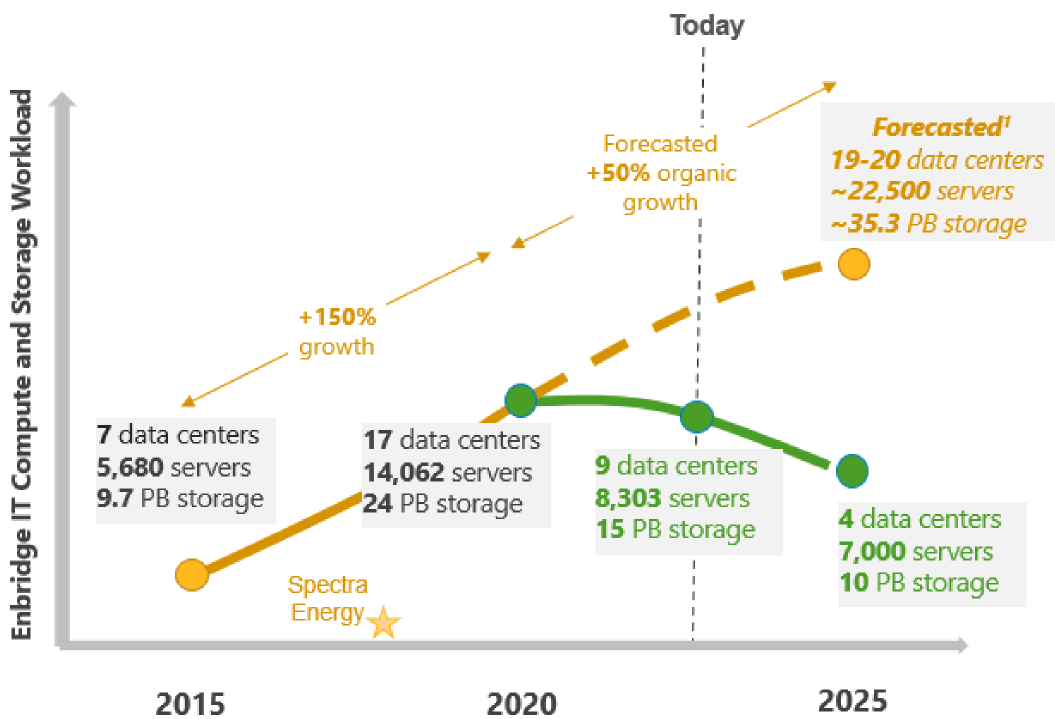
c) Provide details of the resulting reduction in capital and depreciation related to this move to an ‘as a service’ model.

Response:

a) Please see response at Exhibit I.4.4-STAFF-142 part a).

b) In early 2019, Technology Information Services’ (TIS’) core infrastructure was becoming a complex, multi-platform landscape with a capital cost and maintenance trajectory that was rapidly on the rise. This complexity meant TIS spend was increasing, delivery times for the implementation of new solutions was growing, there was an increase in risk for critical systems outages, and an increase in cyber risk. The landscape was also not flexible, not nimble and misaligned with business priorities including innovation, cybersecurity, talent retention, growth and environmental, social and governance (ESG) targets. Industry trends showed data centers had become a commodity and thus a non-core competency for Enbridge Gas. Please see Figure 1 for an illustrative depiction.

Figure 1: Traditional TIS Core infrastructure vs Cloud



1. 2025 numbers have been forecasted. 10% and 8% CAGR were used for both compute and storage respectively

At that time, TIS formalized the decision to invest in Cloud computing as an alternative to on premise TIS core infrastructure. Cloud computing is the delivery of computing services over the internet to offer faster innovation, reliable, scalable, flexible resources, and economies of scale without the investment in TIS infrastructure assets. The benefits of leveraging the “As a Service” (AAS) model are improved business productivity through reduction of incidents, higher velocity of TIS projects, increased cybersecurity, the lowering of system failure risks caused by natural disaster, lower energy consumption and accommodates business as well as data growth seamlessly. Since that time, as technology solutions reach end of life, the only option is AAS as traditional on-premise solutions are not readily available or cost effective.

By moving to AAS, Enbridge and Enbridge Gas avoid the intense capital investment required and instead pay a subscription fee for a solution that drives economies of scale across many clients. The risks noted above are now passed onto the service provider, who is better equipped with the expertise, resources, and foresight to manage those risks. Upgrades and enhancements are seamless and patches that protect the Company’s operations and data as a result of cyber warfare are readily implemented for the benefit of Enbridge and all other clients of the service provider.

As Enbridge and Enbridge Gas technology approaches end of life, the avoided capital investment is a benefit to the Company and customers as it is no longer cost effective to maintain expensive data centres and on-premise solutions.

c) As noted above, AAS is the only option as the Company's technology reaches end of life, therefore the data to perform a comparable analysis between the AAS model and the traditional on-premise capital intensive model does not exist.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2022-0200**	**Enbridge Gas Inc.**
VOLUME:	**4**	
DATE:	**July 18, 2023**	
BEFORE:	**Patrick Moran**	**Presiding Commissioner**
	Allison Duff	**Commissioner**
	Emad Elsayed	**Commissioner**

So again, this discussion is not something that has just been brought forward by intervenors; in fact, it is something Enbridge has proactively brought to the Board, including through the report by Concentric?

MS. GIRIDHAR: That is correct, the investor perspective.

MR. MILLAR: And I understand, I think from Mr. Kitchen's opening remarks a few days ago -- and let me try and paraphrase Enbridge's view, and if I gets that wrong, you can correct me -- that you certainly need to be mindful of the energy transition. And you are taking steps now to mitigate risk. But, in Enbridge's view, many of the energy transition risks are more likely to occur over the medium or the long term? Is that fair to say, not so much for 2024?

MS. GIRIDHAR: That is correct. The impact on 2024 rates from energy transition in our application is in fact minimal.

MR. MILLAR: Yes. And indeed, if you look through your capex for example, you are forecasting continued customer growth; the load forecast is more or less flat. That is true all the way through 2028, which is the rate period we are discussing through this proceeding. Is that more or less fair?

MS. GIRIDHAR: My recollection is our customer additions decline somewhat, by 2028.

MR. MILLAR: I think they start to tail off towards the end.

MS. GIRIDHAR: Yes.

MR. MILLAR: But we are not looking at radically different numbers in 2028 from what we have now?

MS. GIRIDHAR: At this point, and based on the information we have to date, correct.

MR. MILLAR: Okay. But again, to give the company credit, certainly you are aware that there are energy transition risks that are on the horizon and, as such, you have developed an energy transition plan which focuses on a number of safe bets. And those are some of the things we have discussed over the past couple of days. Is that fair?

MS. GIRIDHAR: That is correct.

MR. MILLAR: And I think we have some of those materials here. If you could turn to page I believe it's 15 of the OEB Staff compendium. You see paragraph 33 there. You talk about the safe bet actions. And then, if we flip to the next page, at paragraph 37 -- again, these are direct screen grabs from Enbridge's evidence -- you talk about the safe bet actions that have shaped your energy transition plan. Is that correct?

MS. GIRIDHAR: That is correct.

MR. MILLAR: I just want to make sure I am clear on what the scope of the energy transition plan is here. That is what this entire exhibit is, exhibit 1, tab 10, schedule 6. But if we flip to page 17 of the compendium, which is again from that schedule, we see at the bottom of that page table 1, a summary of energy transition-related rebasing proposals. And, on the left there, you also see

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2022-0200**	**Enbridge Gas Inc.**
VOLUME:	**Technical Conference**	
DATE:	**March 31, 2023**	

the company's integrated resource plan, that utilities are adequately considering non-pipeline alternatives, so there's intervention around those issues.

All that makes it more difficult to build new infrastructure.

MR. POLLOCK: Certainly. I guess my question was a little bit more mechanical.

So I guess you have -- let's have a sort of thought experiment.

You have increased number of intervenors. You have this renewed sense of opposition, I suppose, to hydrocarbon or transmission.

Is the way that plays out is there is an increased number of intervenors, there's an increased number of awareness and opposition, therefore the OEB is less likely to approve the project?

Is that sort of how it sort of plays out in practical terms and that's what's worrying, sort of, investors and, sort of, feeding into the need for increased equity thickness?

MR. COYNE: Oh, I see. Your question was more narrow, wasn't it?

I would say, yes, less likely to approve the project A. B, more likely to approve the project with modifications and, thirdly, it's just more expensive. It's a more expensive process, more retracted with more uncertainty because it could take, what used to take -- let's just say, for example, two or three years for approval, it could take six of seven years for approval.

So we're seeing really doubling the amounts of time associated with getting these projects approved, so all that creates operating uncertainty for the utility.

MR. POLLOCK: Understood. Okay.

So there's a second -- or at least a second dimension which is, there's a cost for the regulatory side of it, even absent whether or not the OEB approves or approves with conditions.

Even if they approve it, there's another dimension that you're saying will increase risk.

MR. COYNE: That's correct. Both cost and uncertainty associated with new infrastructure projects.

MR. POLLOCK: Okay, thank you. So I guess my next question is for the Enbridge panel.

Is there anywhere in the evidence that has discussed or sets out the average regulatory costs of these projects between 2012 and 2022?

MR. SMALL: Ryan Small. Sorry, Ryan Small. Not to our knowledge.

MR. POLLOCK: Okay, could I ask you to undertake to provide the average cost and the average length of time between filing and a decision between 2012 and 2022 for all pipeline projects where leave to construct was sought as well as storage projects?

MR. O'LEARY: If I could just respond before the panel to just ask a couple of questions.

I'm trying to understand, given the variability applications in every year both in terms of size, number and value how a response could be of any assistance.

There would be so many caveats to it that a question of whether or not such a response is frankly worth the effort. Can you help us in that regard?

MR. POLLOCK: Well, I can certainly say that if it's Mr. Dane and Mr. Coyne's view that part of the risk that Enbridge is facing that is increased since the last time it was before the Board, is a regulatory expense both in cost and in terms of the number of days or months between filing and approval, then I think it's only fair and I'm entitled to be able to test what exactly the regulatory cost has been for these applications and how long it's taken from application filing to decision.

MR. O'LEARY: I'm having difficulty understanding how anything of any assistance to the panel could come from that undertaking, simply given the vagaries and the vastitudes of the applications that are filed every year so we're not prepared to give that undertaking, Mr. Pollock.

MR. POLLOCK: Okay.

MR. BROPHY: Mr. Pollock, it's Michael Brophy on behalf of Pollution Probe.

We'd also be interested in a response, given that the interrogatory response that Enbridge prepared and filed only includes some of the information on projects and this would certainly provide a more well-rounded answer to that set of questions.

MR. POLLOCK: Thank you, Mr. Brophy. I take Mr.

ONTARIO ENERGY BOARD

Adjudication Reporting Dashboard

Fiscal 2021-2022 Results (April 1, 2021 to March 31, 2022)

1. The OEB issued 273 decisions in Fiscal 2021-2022 – 99% of which met or surpassed OEB performance standards (the OEB target is 85%).
2. Of all decisions issued, 80% were issued early, more than 14 days in advance of the decision metric date.
3. The OEB, on average, performed well with respect to decision writing timelines partly due to 14 rate applications achieving full settlement.
4. December 2021 was the busiest month for decision issuance.

Click here for a print version (pdf)

273
Total Decisions

270
Within Target

3
Outside Target

61
Decisions Issued by Panels of Commissioners

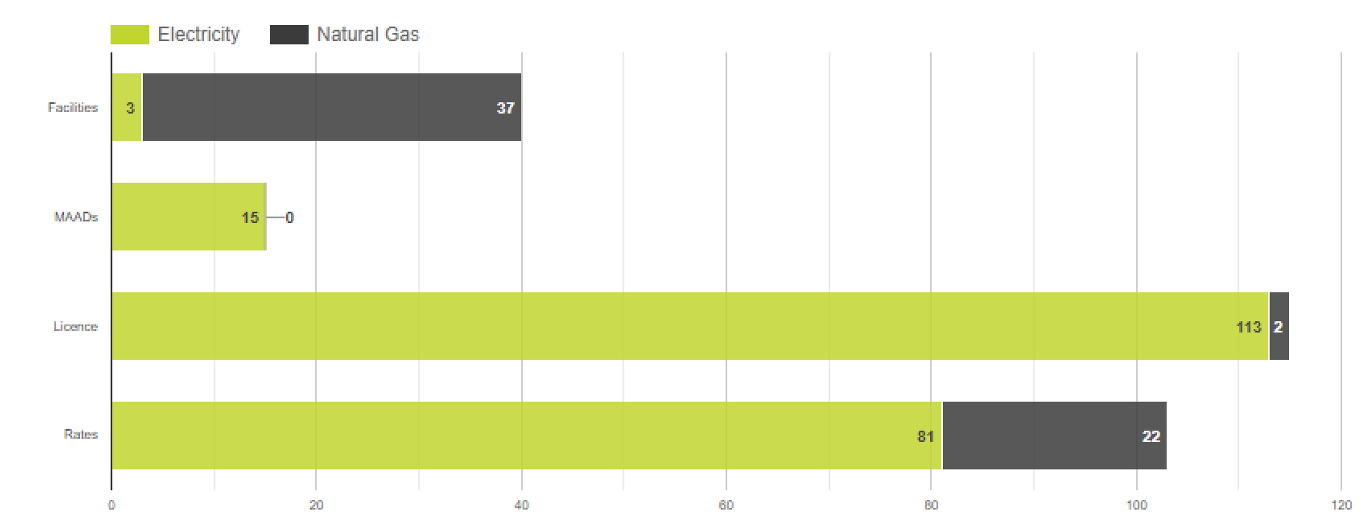
212
Decisions Issued by Delegated Authority

99%
Total Decisions Issued within Standard (Target = 85%)

80%
Total Decisions Issued More than 14 Days Early

100%
Decision Writing Time within Standard (for Decisions Issued by Panels of Commissioners)

Total Decisions Issued



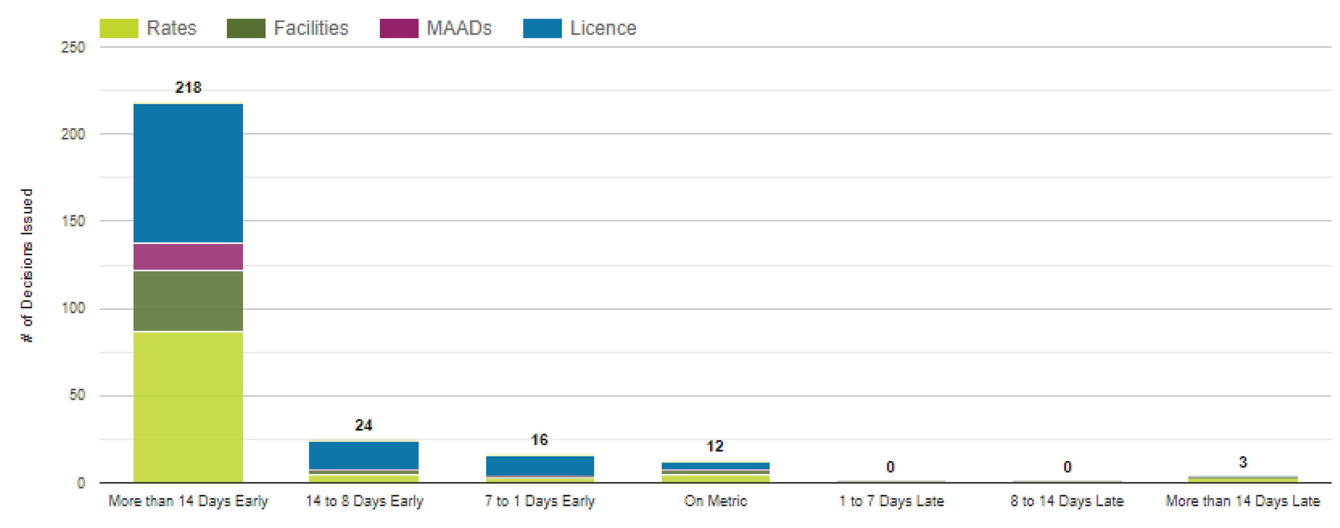
The majority of decisions (78%) issued by the OEB were heard by OEB staff who have been delegated the authority to make determinations for the OEB (Delegated Authority). This is consistent with historical trends. Over the last five fiscal years, on average 79% of decisions were issued by Delegated Authority.

78% of the decisions issued were for applications related to electricity.

42% of all the decisions issued were for Licence applications; Rates comprised 38% followed by Facilities (15%) and Mergers, Acquisitions, Amalgamations, and Divestitures or MAADs (5%).

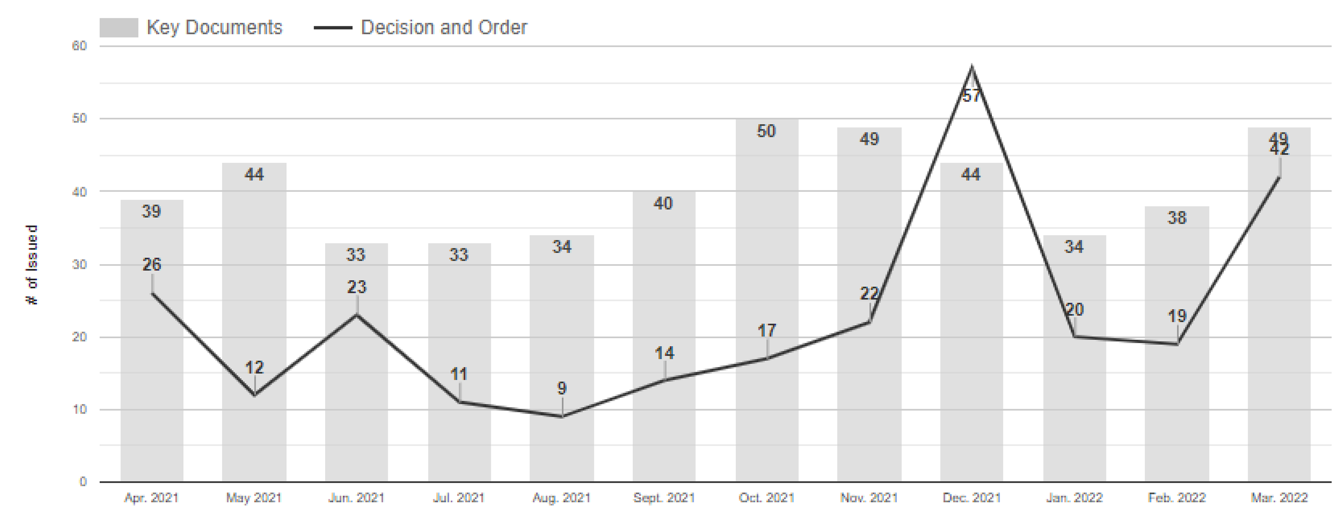
The OEB met the decision writing timelines 100% of the time.

Decision Issuance Spectrum



In addition to monitoring the timeliness of decision issuance, the OEB monitors the degree to which decisions were issued early or late relative to the decision metric date. This Decision Issuance Spectrum highlights the fact that 80% of decisions issued this reporting period were issued more than two weeks in advance of the metric date.

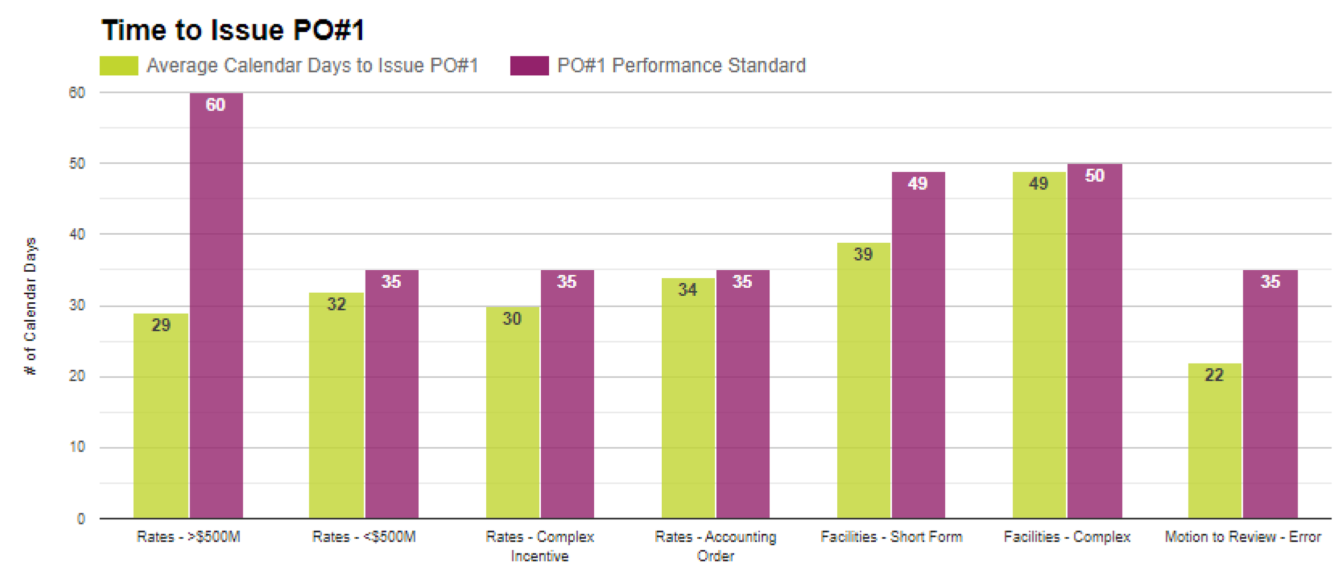
Key Documents Issued



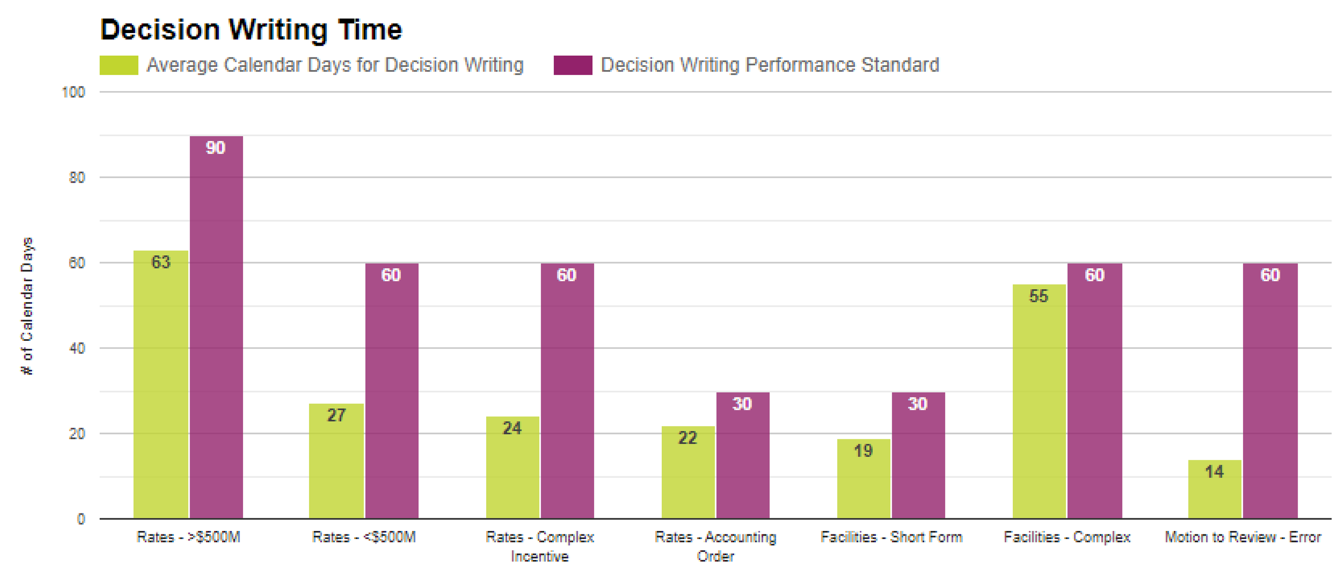
The OEB issues many documents aside from decisions each month. Key Documents refers to all other documents that are issued by the OEB, but are not a final Decision and Order (e.g., Notice, Procedural Order, Letter to Industry, etc.). The OEB issued 41 Key Documents on average each month in Fiscal 2021-2022.

Average Time for Procedural Order No. 1 (PO#1), Decision Writing and Total Cycle

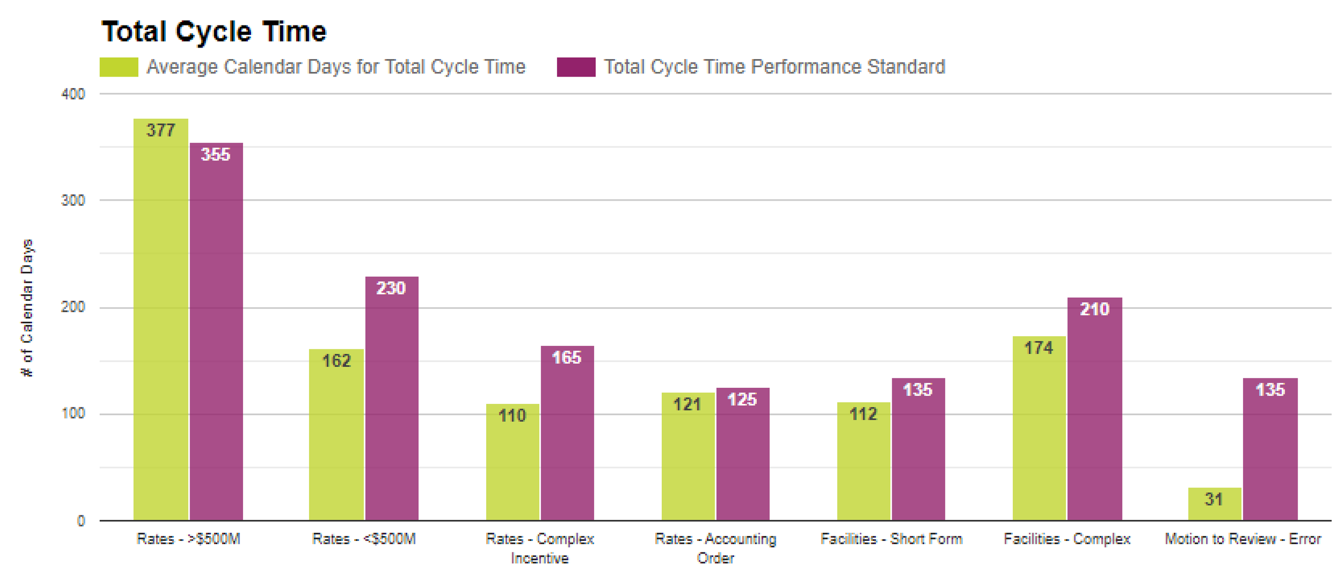
The OEB has committed to report on the performance of key milestones for applications heard by panels of Commissioners for major application types. The following three graphs illustrate the performance for the Time to issue Procedural Order No. 1, the Decision-writing Time and the Total Cycle Time.



This graph provides the average time from a complete application to the issuance of Procedural Order No. 1, and compares this to the performance standard. This fiscal year, the OEB issued all Procedural Order No. 1's within its metrics.



This graph provides the average time from the close of the record to the issuance of the decision, and compares this to the performance standard. This fiscal year, the OEB met its metrics for decision writing on every case.



This graph provides the average time from a complete application to the issuance of the decision, and compares it to the performance standard. In all but three cases, the OEB issued its decision within the Total Cycle Time metric .

There were 14 full and 4 partial settlement proposals filed for rates applications that were accepted by the panels of Commissioners this fiscal year. Full settlements generally reduce the amount of time required to adjudicate these applications relative to the performance standards.

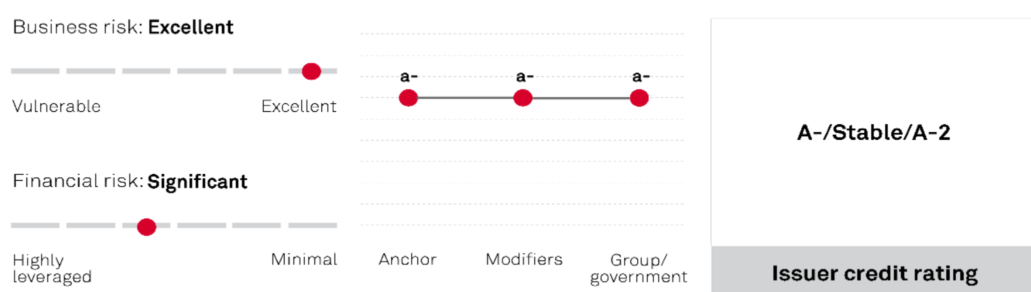
The Rates $500M category includes three decisions: Hydro One’s Elimination of Seasonal Rates (EB-2020-0246) and Enbridge’s Integrated Resource Planning (IRP) (EB-2020-0091), which did not meet the performance standard, and OPG Payments proceeding (EB-2020-0290), which achieved the performance standard. Together they had an average total cycle time of 377 calendar days exceeding the performance standard of 355 calendar days.

The OEB has introduced a new category of proceeding in which a generic policy or framework is being adjudicated, such as the now concluded Enbridge IRP proceeding, the current Enbridge DSM proceeding (EB-2021-0002) and the current generic proceeding on Uniform Transmission Rates (EB-2021-0243). Given the unique nature of these types of proceedings, starting in this fiscal year the OEB establishes an expected timeline at the beginning of the proceeding rather than adopting the performance standard for other application types. These types of proceedings will therefore not be counted towards the OEB’s total cycle time metric, but will be counted towards the OEB’s 90-day decision writing metric.

Enbridge Gas Inc.

July 14, 2023

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
A low-risk, rate-regulated natural gas distribution and transmission company.	Operates only in Ontario, Canada, thus it has limited geographic and regulatory diversity.
It derives about two-thirds of its distribution revenue from residential and small business customers, which provide stable cash flows.	Negative discretionary cash flow due to increasing capital expenditure (capex) activities indicates external funding needs.
It has the ability to pass commodity costs through to customers and recovers costs through a quarterly adjustment mechanism, which limits its exposure to commodity risk.	

We expect Enbridge Gas Inc. (EGI) to maintain its financial performance throughout our outlook period. This includes funds from operations (FFO) to debt of 11%-13% through 2025. We

ESG Credit Indicators

E-1	**E-2**	E-3	E-4	E-5	S-1	**S-2**	S-3	S-4	S-5	G-1	**G-2**	G-3	G-4	G-5

ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1-5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicator Definitions And Applications," published Oct. 13, 2021.

ESG factors have no material influence on our credit rating analysis of EGI.

Group Influence

Our rating on EGI incorporates our view of the company as a core subsidiary of parent Enbridge, meaning that we view EGI as highly unlikely to be sold and as integral to the group's overall strategy. In addition, EGI is closely linked to Enbridge's name and reputation, and it has strong long-term support from the group's senior management. In addition, we assess EGI as having one notch of insulation from its parent. Therefore, the issuer credit rating on the company is one notch above Enbridge's 'bbb+' group credit profile. Our assessment of EGI as an insulated subsidiary of Enbridge reflects the strength of the company's SACP and the cumulative value of the structural protections that insulate it from its parent. Key insulating measures include:

- EGI is a separate, stand-alone legal entity that functions independently (both financially and operationally), files its own rate cases, and is independently regulated;
- EGI has its own records and books, including stand-alone audited financial statements;
- EGI has its own funding arrangements, issues its own long-term debt, and has a separate committed credit facility that is distinct from that of its parent;
- We believe there is a strong economic basis for Enbridge to preserve EGI's credit strength, which reflects the utility's low-risk, profitable, and regulated nature; and
- We do not expect a default of other group entities to directly lead to a default of EGI.

Issue Ratings--Subordination Risk Analysis

Capital structure

EGI's capital structure comprises about C$1.40 billion of outstanding commercial paper and about C$10 billion of senior unsecured long-term debt.

Analytical conclusions

We rate EGI's senior unsecured debt 'A-', the same level as our issuer credit rating (ICR) on EGI, because the debt is issued by a qualifying investment-grade regulated utility. Our 'A-2' rating on the commercial paper program reflects our 'A-' ICR on EGI.

Rating Report
Enbridge Gas Inc.

DBRS Morningstar
September 27, 2022

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On September 21, 2022, DBRS Limited (DBRS Morningstar) confirmed the Issuer Rating and Senior Unsecured Notes rating of Enbridge Gas Inc. (EGI or the Company) at "A" and the Company's Commercial Paper rating at R-1 (low). All trends are Stable. The rating confirmations reflect the following considerations:

1. EGI maintained a stable business risk profile as it is in the fourth year of the five-year price-cap incentive regulations (IR) ending at the end of 2023. The IR framework for EGI has been stable and DBRS Morningstar does not expect any material changes during this IR period.

2. EGI's financial performance remained solid, with improved credit metrics for the 12 months ended June 30, 2022. Furthermore, DBRS Morningstar expects the credit metrics to improve modestly over the medium term as a result of rate base growth and synergy realization (see below).

3. EGI's liquidity remained solid despite a significant increase in the Purchase Gas Variance Account (PGVA), which captures the difference between actual and forecast natural gas prices. As of June 30, 2022, the PGVA balance was $780 million. The recovery of the PGVA balance was approved by the Ontario Energy Board (OEB). However, the recovery period extends to 24 months, instead of 12 months. At the end of June 2022, approximately $380 million of EGI's $2.0 billion credit facility was available. In August 2022, the Company's liquidity improved considerably as EGI issued $650 million in long-term debt, which was partially used to paydown the Company's short-term indebtedness. DBRS Morningstar expects that, as in the past, in the event that EGI requires more liquidity to finance its natural gas inventory for the winter distribution, its parent, Enbridge Inc. (rated BBB (high) with a Stable trend by DBRS Morningstar), will step in and provide temporary liquidity.

The Company's ratings are supported by a stable regulatory framework in Ontario and a very large and economically strong base of approximately 3.8 million customers across the province—the largest in Canada and one of the largest in North America. This large customer base is one of the key factors allowing EGI to achieve operating efficiency under the price-cap IR. Good synergy was realized in the past three years from the amalgamation of Enbridge Gas Distribution Inc. (EGD) with Union Gas Limited

ESG Factors

There are currently no environmental, social, or governance (ESG) factors affecting the ratings of EGI.

* A Relevant Effect means that the impact of the applicable ESG risk factor has not changed the rating or rating trend on the issuer.
A Significant Effect means that the impact of the applicable ESG risk factor has changed the rating or trend on the issuer.
If any factor is proposed to have a Significant Effect, this should be reflected in the Press Release

ESG Factor		ESG Credit Consideration Applicable to the Credit Analysis: Y/N		Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*
Environmental		**Overall:**	N	N
	Emissions, Effluents, and Waste	Do we consider that the costs or risks for the issuer or its clients result, or could result, in changes to an issuerÆs financial, operational, and/or reputational standing?	N	N
	Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs and/or will such costs increase over time affecting the long term credit profile?	N	N
	Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	N	N
	Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	N	N
	Climate and Weather Risks	In the near term, will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact? In the long term, will the issuer's or client's business activities and infrastructure be materially affected financially by a 2C rise in temperature?	N	N
Social		**Overall:**	N	N
	Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services could pose a financial or regulatory risk to the issuer?	N	N
	Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts that could result in a material financial or operational impact?	N	N
		Do violations of rights create a potential liability that can negatively affect the issue's financial wellbeing or reputation?	N	N
		Human Capital and Human Rights:	N	N
	Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	N	N
	Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could it result, in financial penalties or client attrition to the issuer?	N	N
	Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	N	N
	Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	N	N
	Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	N	N
Governance		**Overall:**	N	N
	Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	N	N
		Are there any political risks that could impact the issuer's financial position or its reputation?	N	N
		Bribery, Corruption, and Political Risks:	N	N
	Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	N	N
	Corporate / Transaction Governance	Does the issuer's corporate structure allow for appropriate board and audit independence?	N	N
		Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	N	N
		Does the Board and/or management have a formal framework to assess climate-related financial risks to the issuer?	N	N
		Corporate / Transaction Governance:	N	N
	Institutional Strength, Governance, and Transparency (Governments Only)	Compared with other governments, do institutional arrangements provide a similar degree of accountability, transparency, and effectiveness?	N	N
		Are regulatory and oversight bodies protected from inappropriate political influence?	N	N
		Are government officials exposed to public scrutiny and held to high ethical standards of conduct?	N	N
		Institutional Strength, Governance, and Transparency (Governments Only):	N	N
		Consolidated ESG Criteria Output:	N	N