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

BY E-MAIL

November 8, 2019

Christine E. Long
Board Secretary and Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
BoardSec@oeb.ca

Dear Ms. Long:

Re: Corporation of the Town of Marathon
North Shore LNG Leave to Construct Application
OEB Staff Interrogatories to Applicant
OEB File No. EB-2018-0329

In accordance with Procedural Order No. 2, please find attached the OEB staff interrogatories for the above proceeding. This document has been sent to the Corporation of the Town of Marathon and all intervenors.

The Corporation of the Town of Marathon is reminded that its response to the interrogatories are due by November 26, 2019.

Yours truly,

Original signed by

Ritch Murray
Project Advisor

CORPORATION OF THE TOWN OF MARATHON
NORTH SHORE LNG LEAVE TO CONSTRUCT APPLICATION
EB-2018-0329

OEB STAFF INTERROGATORIES

Background

The Corporation of the Town of Marathon (Corporation), on its own behalf and as representative of the Township of Manitouwadge, the Township of Schreiber, the Township of Terrace Bay and the Municipality of Wawa (collectively the Municipalities) filed an application with the Ontario Energy Board (OEB) seeking:

1. Leave to construct (LTC) approximately 116.5 km of natural gas pipelines
2. Approval of the form of land use agreements
3. Approval of the form of Municipal Franchise Agreements (MFAs)
4. An order granting five certificates of public convenience and necessity (certificates)
5. An order or orders for a gas supply plan
6. Pre-approval of the cost consequences of a long-term gas supply contract

For the purposes of providing natural gas service to the residents and businesses therein, the Municipalities have resolved to incorporate, finance and resource a local gas distributor (Utility) for the distribution of natural gas within the Municipalities (Project).

Leave to Construct

Project Need and Timing

Interrogatory No. 1.

Ref.: Exhibit A, Tab 4, Schedule 1

Preamble

The application states that the proposed Project would expand natural gas service to 5,540 potential customers across the five municipalities.

The application states that:

- In Manitouwadge there are 895 residential dwellings and 86 commercial / industrial buildings
- In Marathon there are 1445 residential dwellings and 110 commercial / industrial buildings
- In Schreiber there are 500 residential dwellings and 68 commercial / industrial buildings
- In Terrace Bay there are 745 residential dwellings and 76 commercial / industrial buildings, and one industrial building (the pulp mill)
- In Wawa there are 1275 residential dwellings and 173 commercial / industrial buildings

OEB staff have prepared Table S1, below, which sums the total building stock of the five municipalities.

Table S1: Building Stock

Community	2016 Pop.	Building Stock			Total
		Res.	Comm.	Ind.	
Manitouwadge	1,937	895	86		981
Marathon	3,273	1,445	110		1,555
Schreiber	1,059	500	68		568
Terrace Bay	1,611	745	76	1	822
Wawa	2,905	1,275	176		1,451
Total	10,785	4,860	516	1	5,377

The application states that the forecast attachments assume the following adoption rates:

- 62% of residential
- 65% of commercial
- 84% of institutional

OEB staff have prepared Table S2, below, which applies the assumed customer attachment rates to the building stock of the five municipalities.

Table S2: Forecast Attachments

Community	Building Stock			Capture Rate			Forecast Attachments			
	Res.	Comm. / Inst.	Ind.	Res.	Comm. / Inst.	Ind.	Res.	Comm. / Inst.	Ind.	Total
Manitouwadge	895	86		62%	65% - 84%		555	56 - 72		611 - 628
Marathon	1,445	110		62%	65% - 84%		896	72 - 92		968 - 989
Schreiber	500	68		62%	65% - 84%		310	44 - 57		355 - 368
Terrace Bay	745	76	1	62%	65% - 84%	100%	462	49 - 64	1	513 - 527
Wawa	1,275	176		62%	65% - 84%		791	114 - 148		905 - 939
Total	**4,860**	**516**	**1**				**3,013**	**335 - 433**	**1**	**3,352 - 3,451**

The Application describes the populations of the Municipalities as being in decline. The application states that the median household income of the Municipalities is between about $65,800 and $84,600

Questions

a) Please confirm that OEB staff has calculated the forecast customer attachments in Table S2 correctly. If not, please explain.

b) If OEB staff has calculated the forecast customer attachments in Table S2 correctly, and the total forecast attachments are between 3,352 and 3,451, please explain why the application states there are 5,540 potential customers.

c) Have the customer attachment forecast and the economics of the Project taken into consideration the general decline in population of the Municipalities? Please explain.

d) Have the customer attachment forecast and the economics of the Project taken into consideration the cost of conversions relative to the median household income of the Municipalities? Please explain.

e) Please describe any sensitivity analysis that the Utility has performed regarding the customer forecast?

f) What would be the impact on a typical annual residential customer bill if actual residential and commercial attachments are 20% less than forecast? What would be the corresponding conversion payback period under that scenario?

Interrogatory No. 2.

Ref.: Exhibit A, Tab 4, Schedule 1, pages 10, 14 and 17
Exhibit A, Tab 4, Schedule 1, Attachment 1, Table 5

Exhibit A, Tab 4, Schedule 1, Attachment 1, pages 20-22
Exhibit A, Tab 4, Schedule 3, page 4

Preamble

The Corporation filed a report prepared by Elenchus Research Associates Inc. (Elenchus) titled, *North Shore Community NG Forecasting Survey: Summary Report*, dated June 2016. Elenchus retained the services of Innovative Research (Innovative) to design and execute a survey of the residents of the Municipalities.

For the purposes of the survey, the cost advantage of natural gas relative to other fuels was communicated to survey participants using cost ratios that describe the how many times more expensive other fuels are when compared to natural gas. The cost ratios “represent the 5 year historical average fuel costs based on the amount of fuel required for equivalent output of heat energy.”

The results of Innovative Research’s residential market survey revealed that cost is a significant factor in a potential customer’s decision to switch to natural gas. The results also show that, although many potential customers would prefer to pay the full cost of conversion up front (43% of respondents), a material number of potential customers would be interested in financing (29% of respondents).

During the survey, a financing option was discussed with potential residential customers that featured monthly payments over a 10-year term at a 4% annual interest rate.

The Utility said that it will explore third-party on-bill financing to help customers realize the potential savings of conversion to natural gas earlier and reduce the payback period.

The availability of a grant to help pay the cost of converting to natural gas has the impact of increasing the likelihood of conversions.

Questions

a) Please confirm that the residential, commercial, and institutional survey samples sizes for each municipality are statistically significant. If not, please explain.

b) Please confirm that the cost ratios are based on the all-in cost of each fuel (i.e., inclusive of commodity, transportation, delivery and other charges). If not, please explain.

c) Please confirm the economics of the Project are consistent with the cost ratios provided to potential customers who were surveyed.

d) What role will the Utility play in terms of assisting potential customers in financing their appliance conversions? Please explain.

e) If the Utility is considering creating an affiliate that will offer financing options to potential customers, please confirm that the Utility is aware of the OEB's Affiliate Relationship Code for Gas Utilities.

f) What would be the impact on the customer attachment forecast if no form of conversion financing options were available to potential residential and commercial customers?

g) Has the Corporation or any of the Municipalities investigated the existence of, applied for, or been awarded any government grant funding to assist with conversions? Please explain.

Interrogatory No. 3.

Ref.: Exhibit A, Tab 4, Schedule 1, Attachment 2, Table 1, page 1
Exhibit A, Tab 4, Schedule 3, Table 2 and pages 2-3

Preamble

The Corporation provided a 25-year residential market forecast. The forecast total number of residential customers in year ten is 3,044 and in year 11 is 3,111.

The Corporation provides the projected total annual fuel savings for residential customers for natural gas compared with other fuels, and details the total annual regional savings with natural gas with the expected eventual total of 3,111 residential attachments, not including conversion costs, at the 2020 residential rate.

The application states that the annual residential energy savings will be $4.55 million as the Utility reaches its expected total of 3,111 residential customers in its tenth year of operation.

Questions

a) Please clarify whether the forecast total number of residential customers in year ten is 3,044 or 3,111.

b) Please provide a detailed calculation supporting the annual residential energy savings of $4.55 million in year 10.

c) Please provide in table form the annual and cumulative energy savings for residential customers for each year between years one and ten both with and without estimated conversion costs.

Interrogatory No. 4.

Ref.: Exhibit A, Tab 4, Schedule 1, Attachment 2, page 1
EB-2019-0193, Exhibit A, Tab 3, Schedule 1, page 1
EB-2019-0193, Exhibit D, Tab 2, Schedule 1, page 1

Preamble

Table one reports the Corporation's 25-year market demand forecast for residential customers. OEB staff have expanded on the table by adding another column for average volume per customer (see below).

Table S4: Average Volume per Customer

Year		Residential				
		Customer Additions	Total Customers	Annual Consumption (GJ)	Design Day (GJ)	Average m^3/yr per customer*
1	2020	857	857	24,215	590	725
2	2021	1,199	2,056	106,328	1,413	1,327
3	2022	400	2,456	184,826	1,691	1,931
4	2023	132	2,588	210,534	1,782	2,087
5	2024	85	2,673	219,782	1,841	2,109
6	2025	85	2,758	226,355	1,899	2,105
7	2026	85	2,843	232,894	1,958	2,102
8	2027	67	2,910	238,899	2,004	2,106
9	2028	67	2,977	243,874	2,050	2,102
10	2019	67	3,044	248,822	2,096	2,097
11	2020	67	3,111	253,745	2,142	2,092
…						
23	2042	67	3,915	310,800	2,696	2,037
24	2043	67	3,982	315,390	2,742	2,032
25	2044	67	4,049	319,955	2,788	2,027

* Conversion assumes 38.98 GJ / 10^3m^3.

Questions

a) Please confirm that the reason why the average volume per residential customer in year one is very low is the result of using a half-year assumption in which not all customers in that year take gas for the full year. If not, please explain.

b) Please explain why the average volume per residential customer ramps up to 2,109 m^3/yr in year 5 and then falls to 2,037 in later years.

c) The Corporation's average volume per commercial customer shows the same trend (i.e., ramps up to a peak in year 5 and then falls in later years). Please confirm that the Corporation's response to interrogatory b) applies equally to commercial customers. If not, please explain.

Interrogatory No. 5.

Ref.: Exhibit A, Tab 4, Schedule 2, Tables 1-3, pages 1-6

Preamble

The Corporation states that annual distribution revenue requirements have been levelized over the 20-year period, allowing introductory rates to be as low as possible and escalate steadily at an inflationary rate consistent with the escalation of other expected costs. The distribution rates are set to recover the net present value (NPV) of the revenue requirement in the first 20 years of operations while increasing at a rate of 1.5% per year.

The Corporation has provided a forecast of all-in rates (distribution plus pass-through) in Table 1 and delivery only rates in Table 2.

OEB staff has prepared a table based on Table 1 and Table 2 that shows the percent increase in all-in rates and distribution rates for residential customers.

Table S5: Percent Increase in Rates

Year	Residential All-In			Residential Distribution		
	$/GJ	$/m3	% ↑	$/GJ	$/m3	% ↑
2020	19.95	0.7431	--	6.68	0.2489	--
2021	20.75	0.7726	4.0%	6.78	0.2526	1.5%
2022	21.56	0.8030	3.9%	6.89	0.2564	1.6%
2023	22.12	0.8238	2.6%	6.99	0.2603	1.5%
2024	22.42	0.8350	1.4%	7.09	0.2642	1.4%
2025	22.73	0.8463	1.4%	7.20	0.2681	1.6%
2026	23.04	0.8579	1.4%	7.31	0.2722	1.5%
2027	23.35	0.8696	1.3%	7.42	0.2762	1.5%
2028	23.67	0.8815	1.4%	7.53	0.2804	1.5%
2029	24.00	0.8936	1.4%	7.64	0.2846	1.5%

Question

Please explain why the residential all-in rate grows more rapidly in the first few years than that of the distribution rate. In particular, please explain what is changing with respect to pass-through costs.

Interrogatory No. 6.

Ref.: Exhibit A, Tab 4, Schedule 2, page 2

Preamble

In the first year (2020), the projected residential rate, not including the federal carbon charge, is $19.95 per gigajoule (GJ); the small general service rate $17.63 / GJ; and, the large general service rate $17.12 / GJ.

Question

Please explain how the projected rates were derived, and explain why the residential rate is higher.

Interrogatory No. 7.

Ref.: Exhibit A, Tab 4, Schedule 3, page 4, Table 3

EB-2016-0004, Enbridge Gas Evidence, page 15[1]

Preamble

The Corporation provides estimated costs for converting residential home heating systems to natural gas from other fuels in the North Shore Municipalities. Based on those costs, and estimated fuel cost savings associated with conversion to natural gas, the Corporation estimates that the payback on residential propane, oil or electric forced air heating systems will be no more than 4.12 years.

In its evidence in the Generic Proceeding on Community Expansion, Enbridge Gas (then operating as Enbridge Gas Distribution Inc. or EGDI) provided estimated costs for converting typical residential home heating systems to natural gas from other fuels.

OEB staff has prepared a table that compares the estimates of the Corporation and Enbridge Gas.

Table S6: Residential Home Heating System Conversion Costs

Heating System	Enbridge Gas Inc. - Typical Residential	Corporation - North Shore Municipalities	Variance - Dollars	Variance - Percentage
Propane Forced Air	$ 1,525	$ 750	$ (775)	-51%
Oil Forced Air	$ 3,500	$ 5,500	$ 2,000	57%
Electric Forced Air	$ 7,250	$ 5,500	$ (1,750)	-24%

Questions

a) Please discuss the possible reasons for the Corporation's conversion costs for propane and electric forced air being significantly less than Enbridge Gas' conversion costs for the same heating systems.

b) Further to question a), could there be a difference between the energy efficiency of Enbridge Gas' propane conversion solution and that of the Corporation? If so, what impact could this difference in efficiency have on the Corporation's forecast annual residential natural gas consumption? Has this efficiency difference been accounted for in the Corporation's forecast annual residential natural gas consumption? If not, please explain why not.

[1] Filed March 21, 2016

c) What would be the payback period for a propane forced air system if Enbridge Gas' conversion cost were assumed?

d) Please discuss the possible reasons for the Corporation's conversion costs for oil forced air being significantly more than Enbridge Gas' conversion costs for the same heating system. If the energy efficiency of the converted system is part of the answer, please explain.

e) Further to question d), could there be a difference between the energy efficiency of Enbridge Gas' oil conversion solution and that of the Corporation? If so, what impact could this difference in efficiency have on the Corporation's forecast annual residential natural gas consumption? Has this efficiency difference been accounted for in the Corporation's forecast annual residential natural gas consumption? If not, please explain why not.

f) What would be the payback period for a oil forced air system if Enbridge Gas' conversion cost were assumed?

Interrogatory No. 8.

Ref.: Exhibit A, Tab 8, Schedule 1, Attachment 1, page 13

Preamble

Table 2 provides indicative costs of alternative fuels relative to natural gas.

Question

Please confirm that the indicative costs of the various fuels in Table 2, including natural gas, are all-in and not commodity only (I.e., inclusive of all upstream and delivery costs). If not, please explain.

Interrogatory No. 9.

Ref.: Exhibit A, Tab 7, Schedule 3, Schedule 1, page 1

Preamble

The Project is proposed to be in service for the 2020-2021 heating season. To meet this schedule, construction must commence by April 2020 to meet this in-service date and avoid winter construction. Therefore, the Corporation is requesting that the OEB issue a decision for this proceeding by the end of December 2019.

Question

How would the Corporation, Municipalities and Utility manage the Project in the event that a decision from the OEB were not received by the end of December 2019?

Proposed Facilities and Routing

Interrogatory No. 10.

Ref.: Exhibit A, Tab 2, Schedule 1, page 4

Preamble

In its application, the Corporation explains that the LNG virtual pipeline distribution model has been proven in numerous markets and that “the Project can be expanded to include additional Northern Ontario municipalities and First Nation communities.”

Questions

a) In this instance, does the “Project” that can be expanded refer to the trucking, storage and regasification of LNG in general, the activities of the Utility in particular, or both? Please explain.

b) Please provide references to at least three case studies where OEB staff can find information that demonstrate the success of the LNG virtual pipeline distribution model in other markets, including the long-term economic success of those projects and the number of days of LNG storage that is available on-site at the customer end of the virtual pipelines.

c) If the Utility were to expand into additional communities, what would be the expected impacts on costs for existing customers? Please explain.

Alternatives

Interrogatory No. 11.

Ref.: Exhibit A, Tab 13, Schedule 1, page 12-13
Exhibit A, Tab 2, Schedule 1
Exhibit A, Tab 8, Schedule 1

Preamble

The application states: “[t]he annual fixed cost of providing compression, storage and decompression services is forecast to be approximately 15% more than the annual cost for the LNG Services.” Table 4 then sets out the assumed costs for the compressed natural gas (CNG) option.

Questions

a) Please explain how the numbers in Table 4 were derived. Please provide any additional analysis that was done regarding the costs of the CNG option.

b) Do the numbers in Table 4 take into consideration the reliability of the alternatives? Please explain.

c) Can the distribution systems that the Utility proposes to build in the Municipalities pursuant to the LTC approval equally accept injections of regassified LNG and CNG? If not, what additional work is necessary to allow the system to accept CNG, and what approximate cost?

d) Has the Utility considered having its system served by both LNG and CNG? Please explain.

Economics and Feasibility

Interrogatory No. 12.

Ref.: EB-2016-0004, Decision with Reasons, page 20[2]
Exhibit A, Tab 13, Schedule 1, pages 15-16

Preamble

The application states: “[a]s with any greenfield natural gas project, actual attachments and demand may not match forecasts over the term of the proposed Contract and the discrepancy may be material, thereby creating financial risk to customers.”

[2] Issued November 17, 2016

It continues: "[a]ccordingly, the risks associated with the proposed Contract have been sufficiently identified and mitigated."

In its decision in the Generic Proceeding on Community Expansion, the OEB found that[3]:

> Competing utility companies would be incented to provide rates favourable to customers in order to be selected as the preferred proponent of the expansion project. The selected proponent would then be incented to maintain low rates in order to be attractive to potential customers which would in turn should increase its margins. A minimum rate stability period of 10 years (for example) would ensure that rates applied for are representative of the actual underpinning long-term costs. The utility would bear the risk for that 10-year period if the customers they forecast did not attach to the system. At present, once an expansion is approved, the utility bears little long-term risk if its forecasts were overly optimistic, or its actual costs higher than expected. The cost is absorbed into rates and paid for by other ratepayers.
>
> Where there is no competition, a proponent will still be incented to have as low a rate as it can afford to encourage customers to connect and provide the return on the proponent's investment during the rate stability period. The proponent will also have to obtain approval to adjust rates beyond the rate stability period.

Questions

a) Does the Utility propose that all of the attachment forecast risk and capital cost risk will rest with customers? If so, why?

b) Does the Corporation intend to implement a rate stability period as contemplated in the Generic Decision? If not, please explain why not.

c) What would be the implications to the Project if the OEB were to mandate a minimum rate stability period?

d) In the Corporation's view, does the roughly 1.5% annual increase to the distribution rate contribute to "rate stability"? Please explain.

[3] EB-2016-0004 Decision and Order, issued November 17, 2016, page 20

Interrogatory No. 13.

Ref.: Exhibit A, Tab 4, Schedule 3, page 6
Exhibit A, Tab 8, Schedule 1, Attachment 1, page 22
Exhibit A, Tab 8, Schedule 1, Attachment 1, Table 3, page 25

Preamble

There is one large industrial customer located in Terrace Bay that uses No. 6 residual fuel as its energy source. This customer is interested in using natural gas. The industrial customer has agreed in principle to a demand response program, where this customer would not be served on a firm basis. Under this arrangement, the industrial customer would increase its use of natural gas when gas supply resources were not required by firm customers, and reduce its consumption of No. 6 residual fuel oil provided that the delivered cost of gas was competitive. Similarly, as firm customers require increased natural gas supply, the industrial customer would reduce its dependence on natural gas and increase its use of No. 6 residual fuel oil.

It is assumed that the upstream gas resources (i.e., LNG capacity and upstream pipeline capacity) would be procured to meet the peak day requirements for the residential and General Service customers. Any capacity not utilized by the residential and General Service customers would be sold and delivered to the industrial market in order to minimize the total rate for all customer classes. This approach requires the industrial market to be connected to the distribution system and to utilize other fuel types when the supply of natural gas is less than total demand.

The Corporation indicates, in its Transportation Risk section, that if the industrial customer cannot purchase the excess gas, it will sell the excess gas in the secondary market.

Table 3 reports that the total forecasted annual consumption for all customers by year 11 is 1,255,135 GJ. The same table reports that the total forecasted annual consumption of one industrial customer is 816,000 GJ, or approximately 67% of the total for all customers.

Questions

a) What is the status of gas supply negotiations with the industrial customer located in Terrace Bay? When does the Corporation anticipate executing a contract with the industrial customer?

b) What is this large industrial customer getting in exchange for agreeing to a demand response program?

c) If the industrial customer cannot purchase the excess gas and it is sold in the secondary market, how will it be sold?

d) Please explain the rationale for upstream gas resources to be procured based on peak day requirements for residential and general service customers.

e) Please compare the benefits of a operating at 100% load factor and selling surplus gas in the secondary market with operating at less than 100% load factor and thereby reducing the Utility's exposure to surplus gas.

f) Who bears the financial risk of any cost difference between the purchase price of gas and the price at which any surplus gas is sold into the secondary market or sold to the industrial customer?

g) What would be the impact on the Project if, for several years in a row (e.g., 10 years), the industrial customer were not able to use all of the Contract Gas capacity not used by other classes of customers? Include in the answer the results of an assessment of the impact on residential, commercial and institutional rates.

h) What would be the impact on the Project if the industrial customer were to use natural gas to meet all of its energy needs? Include in the answer the results of an assessment of the impact on residential, commercial and institutional rates.

i) What would be the impact on the residential, commercial and institutional rates if the industrial customer were to permanently cease operations, or otherwise stop taking natural gas service, part way through the initial ten years of the Project? Please quantify the annual bill impacts in the response.

j) What would be the impact on the residential, commercial and institutional rates if the industrial customer were to permanently cease operations, or otherwise stop taking natural gas service, after the initial ten years of the Project? Please quantify the annual bill impacts in the response.

k) What would be the impact on the Project if a contract with the industrial customer were never to be executed? Include in the answer the results of an assessment of the impact on residential, commercial and institutional rates.

l) What are the short and long-term price forecasts for No. 6 oil? How does the price of No. 6 oil compare to the price of natural gas on an energy equivalent basis? What would be the impact on the Project feasibility if the cost of No. 6 oil were to go up or down in the short and long run?

Interrogatory No. 14.

Ref.: Exhibit A, Tab 4, Schedule 4, Table 1, page 1
EB-2016-0004, Generic Proceeding on Community Expansion, Decision with Reasons, page 4[4]
EB-2015-0179, Union Gas Limited, 2015 Community Expansion Application, Decision and Order, page 14[5]
EB-2017-0147, Enbridge Gas Distribution Inc., Fenelon Falls Application, Decision and Order, page 7[6]

Preamble

For illustration, the Corporation provides a monthly bill comparison based on its proposed rates and the rates of Enbridge Gas and EPCOR Natural Gas LP. The Corporation did not include the bill impact of system expansion surcharges in its comparison.

The OEB signaled its support for the use of stand-alone rates and system expansion surcharges for the purpose of natural gas system expansion into underserved areas in the Generic Proceeding on Community Expansion. Subsequently, in separate community expansion applications, the OEB approved a \$0.23 / m^3 system expansion surcharge (SES) for use by each Union Gas Limited (Union Gas) and EGDI. On January 1, 2019, Union Gas and EGDI amalgamated to form Enbridge Gas. The OEB approved SESs remain applicable to the former EGDI rate zone and certain parts of the Union Gas rate zones.

OEB staff expanded on the bill comparison provided by the Corporation by adding the equivalent of the SES to the lines for the Union North West and EGDI rate zones (i.e., \$0.23 / m^3 applied to 189.9 m^3 / month). For the purpose of this comparison, OEB staff has omitted the line for EPCOR as it does not currently have an OEB approved SES or stand-alone rate.

[4] Issued November 17, 2016
[5] Issued August 10, 2017
[6] Issued March 1, 2018

Table S7: Estimated Bill Comparisons

Distributor	Commodity & Passthrough Charges	Customer & Delivery Charges	System Expansion Surcharge			Total Monthly Charge	Variance from Utility
			m^3/mo	$ SES/m^3	SES Charge		
Utility	$ 47.26	$ 84.55	--	--	--	$ 131.81	--
Enbridge Gas Inc. - Union North West Rate Zone	$ 38.00	$ 32.84	189.9	$ 0.23	$ 43.68	$ 114.52	13.1%
Enbridge Gas Inc. - EGD Rate Zone	$ 40.81	$ 29.65	189.9	$ 0.23	$ 43.68	$ 114.14	13.4%
Average	$ 42.02	$ 49.01				$ 120.15	

Question

Please confirm that OEB staff correctly calculated and added the equivalent of an SES to the monthly bill estimates provided by the Corporation.

Interrogatory No. 15.

Ref.: Exhibit A, Tab 4, Schedule 4, Table 1, page 1

Preamble

Table 1 shows the estimated average monthly total bill for a residential customer consuming 7.07 GJ (189.9 m^3), which is the forecast average monthly consumption of a potential North Shore Utility residential customer. The average monthly bills for Union (North West), Enbridge and EPCOR come from the OEB Bill Calculator as of July 2019.

Table 1: Average Residential Natural Gas Bills in Ontario

Distributor	Total Bill			Delivery & Customer Charges	Commodity and Upstream Pass-Through Charges
	Average Monthly Bill	$/GJ	$/m3		
Utility	$131.81	$18.64	$0.694	$47.26	$84.55
Union (North West)	$70.84	$10.02	$0.373	$38.00	$32.84
Enbridge	$70.46	$9.96	$0.371	$40.81	$29.65
EPCOR	$78.86	$11.15	$0.415	$46.78	$32.08

Questions

a) Please provide a detailed explanation of how the $84.55 per month was calculated.

b) Please quantify the change to this monthly amount assuming that the residential and commercial attachment rates are 20% lower than forecast.

c) Please quantify the change to this monthly amount assuming that the industrial customer does not to execute a gas supply contract.

Interrogatory No. 16.

Ref.: Exhibit A, Tab 9, Schedule 1, Table 1, page 1
Exhibit A, Tab 9, Schedule 4, page 1

Preamble

The Corporation provide the following breakdown of the capital costs for the Project.

In Schedule 1, the Corporation states that, through its strategic Economic Infrastructure Program, the Northern Ontario Heritage Fund Corporation (NOHFC) contributed a grant of $3.45 million to the municipalities to assist with development costs. This funding is intended to offset costs associated with detailed engineering and design, regulatory approvals, and project management and administration.

In Schedule 4, the Corporation states that the Municipalities obtained funding from the NOHFC to help complete a feasibility study to assess the tangible economic and social benefits and capacity building opportunities that would result if the North Shore had expanded access to natural gas. Based on the positive results of this study, the Municipalities applied for a grant under the NOHFC Strategic Economic Infrastructure Program, which helps a region or community advance economic development opportunities and support investment through strategic infrastructure.

	Project Costs (in thousands of dollars)	**Column**					
		A	**B**	**C**	**D**	**E**	**F**
Row	**Description of Cost**	**Marathon**	**Schreiber**	**Terrace Bay**	**Wawa**	**Manitouwadge**	**Total**
1	Material Costs	315	183	200	245	190	1,134
2	Construction Costs	6,533	2,844	3,305	4,659	3,667	21,009
3	External Costs (e.g., Engineering, Environmental, Surveying, Inspection)	883	883	883	883	883	4,414
4	Other Project Costs (e.g., Project Management, Land, Approvals)	1,299	1,299	1,299	1,299	1,299	6,494
5	Contingency	3,057	1,547	1,735	2,289	1,875	10,502
6	Interest During Construction	80	80	80	80	80	400
7	**Total Project Costs**	12,167	6,836	7,503	9,454	7,993	43,954
8	Less NOHFC Grant	(691)	(691)	(691)	(691)	(691)	(3,454)
9	**Total Project Costs (Less Grant)**	11,476	6,145	6,812	8,764	7,303	40,500
	Note: Due to rounding, numbers presented may not add up precisely to the totals provided						

Questions

a) The contingency of $10.5 million represents approximately 31% of the Total Project Costs before contingency: $10,502 / ($43,954 - $10,502) = 31%. Please explain how the level of contingency was determined and why it is appropriate.

b) Does the Corporation intend to use a request for proposal process to select the pipeline constructor? If not, please explain why not.

c) Does the Corporation intent to use an Operator Engineer to assist in overseeing construction and to help manage costs? If not, please explain why not.

d) Please confirm whether or not the Corporation or any of the Municipalities has applied for or has been awarded government funding in addition to the NOHFC grant.

e) In table form, please provide the relative amounts of capital funding for the Project by sources (e.g., government funding, equity, debit). With the exception of government sources, the Corporation need not name the source of the funding in its answer.

f) Have the costs of tools and equipment for the Utility's Gas Technicians been included in the capital cost of the project? If so, where? If not, why not?

g) What sensitivity analysis has the Utility performed regarding the capital cost of the Project?

Environmental Matters

Interrogatory No. 17.

Ref.: Exhibit A, Tab 7, Schedule 1, page 4

Preamble

The Utility will develop an Environmental Protection Plan (EPP) that will incorporate the mitigating measures recommended in the Environmental Reports and will also incorporate comments provided during the Ontario Pipeline Coordinating Committee review process. This plan will help minimize the impact of construction activities on the surrounding environment and communities.

Questions

a) When does the Corporation anticipate that the EPP will be completed?

b) Has the Corporation circulated the EPP to the Ontario Pipeline Coordinating Committee (OPCC)? If not, when will this be done? If so, please file, in tabular form, any comments received on the EPP from the OPCC.

c) Will the Corporation file the EPP into evidence as soon as it is completed, or at some other time? If it will be at some other time, please explain why it will not be filed as soon as it is completed.

Interrogatory No. 18.

Ref.: Exhibit A, Tab 7, Schedule 1, page 5

Preamble

After major construction is complete along the Preferred Route, the clean-up crew will ensure that the site conditions are returned to pre-construction conditions as required. When clean-up is completed, the Utility will seek the approval of landowners or the municipal Public Works authority.

Questions

a) What form will the “approval of landowners” take (e.g., sign-off form)?

b) What conditions will be part of the “approval of landowners” (e.g., will landowners be expected to waive their right to seek damages from the Utility should any issues arise in future that may be associated with the Project)?

c) What actions will the Utility take if a landowner refuses to signify its approval?

Interrogatory No. 19.

Ref.: Exhibit A, Tab 10, Schedule 1, Attachment 1
Exhibit A, Tab 11, Schedule 2, page 1

Preamble

Stantec Consulting Ltd. implemented a comprehensive consultation program to drive awareness of the Project. Information on the consultation activities is provided in Section 3 of the various Environmental Reports. The consultation program allowed interested or potentially affected parties to provide input into the Project. Correspondence summary tables and copies of all written correspondence and responses are located in Appendix B5 of the Environmental Reports. Nine comments were received as of April 10, 2019 from the Information Sessions, and two comments were received via Canada Post regular mail as of June 10, 2019 from the public. These comments were considered in the preparation of the Environmental Reports.

Using the Marathon Environmental Report as an example, OEB staff observes that several entries in Appendix B5 indicate that concerns were raised but apparently not addressed. One example from the Marathon Environmental Report is line item 1.9 (reproduced below).

Concerns Line Item	Date of Communication	Name	Method of Communication	Comment	Date of Response	Response and Issue Resolution (if applicable)	Attachment
1.9	April 9th, 2019	Group Discussion	Wawa – Comment Recorded by Project Team	Noted that the depot site is too close to airport, should something happen (i.e., accident would block any access into Town). Former O&G bulk plant at the end of Government Road is a potential option for a depot site. Depot 3 is a blueberry farm and is therefore not an option. Algomatel owns the land in front of depot 1 and may not allow access. Depot 1 has recreational trails throughout it. Depot 2 does not have shallow bedrock but depot 1 does, noted potential for tougher construction. Question regarding number of full-time jobs to be created. What is the aftermarket service that would be needed to help service the infrastructure such as natural gas fireplaces etc.: it's a business case (i.e., "build it and they will come")? Are there any groundwater contamination issues? Requested to know what the carbon tax is for the Project. Carbon tax amount on the project website was provided. Stakeholder preference depot is site 2 or 3. The area of LNG depot 1 would be good for potential future development of the Town of Wawa.	N/A	N/A	IS_1.1

Questions

a) Please explain whether "N/A" means not applicable, not available, or some other meaning.

b) Regardless of the answer to part a), please explain why there is no record of each and every concern being addressed during the consultation process.

c) If some or all of the "N/A" responses have now been provided, please file updated versions of each Appendix B5, accordingly.

d) Have any additional comments been received since June 2019? If so, please update and refile Appendix B5 of the Environmental Reports, accordingly.

Indigenous Consultation

Interrogatory No. 20.

Ref.: Exhibit A, Tab 1, Schedule 2, page 6
Exhibit A, Tab 10, Schedule 1, page 118

Preamble

The Corporation engaged the Ministry of Energy Northern Development and Mines (MENDM) to determine if there is a duty to consult requirement triggered by the Project. The Corporation, as the project proponent, has been delegated the procedural aspects of consultation by the MENDM, on behalf of Ontario.

Question

Has the Corporation received a letter(s) from the MENDM regarding the sufficiency of its Indigenous consultation activities to date with respect to the procedural aspects of the Crown's duty to consult? If so, please provide a copy of the letter(s). If not, please provide an update on the status of the MENDM's review of the Corporation's Indigenous consultation program.

Interrogatory No. 21.

Ref.: Exhibit A, Tab 10, Schedule 1, Appendix B5, Table 5

Preamble

Table 5 provides a log of Indigenous community correspondence with entries than span March 2019 to July 2019.

Question

a) Please comment on the level of engagement with Indigenous communities to date.

b) Please provide an updated Table 5 that includes any additional Indigenous community engagement since July 2019. Please detail all concerns about the Project that have been expressed by any Indigenous community, and the Corporation's responses to those concerns.

Interrogatory No. 22.

Ref.: Exhibit A, Tab 12, Schedule 1
Tab 10, Schedule 1, Attachment 1

Preamble

Detailed information about the indigenous consultation program is found in the Environmental Reports (Tab 10, Schedule 1, Attachment 1).

The Environmental Reports state that consultation activities with the Indigenous Communities identified as part of the MECP Duty to Consult was documented through a comprehensive Indigenous Consultation Summary Report that will be submitted as part of the LTC.

OEB staff notes that the LTC application does not contain an Indigenous Consultation Summary Report.

Question

Please confirm that the Corporation will file an Indigenous Consultation Summary Report and when. If not, please explain.

Land Matters

Interrogatory No. 23.

Ref.: Exhibit A, Tab 11, Schedule 1, Attachment 1
Filing Requirements for Electricity Transmission Applications, Chapter 4[7]

Preamble

At the time the application was filed, the Township of Terrace Bay was in negotiations with a private landowner regarding the purchase / lease of a piece of property for the purposes of constructing the Township's LNG depot. The Township intended to finalize the land purchase/lease agreement in the coming months.

In the event that an agreement with the private landowner cannot be reached, the Township will authorize the lease of municipal property for the purposes of constructing the LNG depot.

The distribution piping follows the public road allowance. If permanent or working easement is determined to be required, it will be negotiated using a standard permanent or working easement agreement.

Questions

a) Please provide the status of the purchase / lease negotiations with the private landowner?

b) If the purchase / lease negotiations have been unsuccessful, please identify the location of the municipal property where the LNG depot will be situated.

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[7] OEB's Filing Requirements For Electricity Transmission Applications, Chapter 4 - Applications under Section 92 of the Ontario Energy Board Act, https://www.oeb.ca/oeb/_Documents/Regulatory/OEB_Filing_Req_Tx_Applications_Ch4_20140731.pdf

c) If the use of a municipal property will be required, please confirm that there will be no material impact on the proposed design of the LNG depot and distribution system in terms of cost, schedule or performance.

d) OEB staff notes that the standard forms of permanent and working easement agreements filed by the Corporation do not address all of the OEB's requirements for similar agreements on electric transmission applications. For example, the Corporation's forms of agreement do not: offer to cover the landowners cost of independent legal advice, required the Corporation to carry any insurance, or speak to an alternative dispute resolution process. Please discuss these differences and the extent to which the Corporation considered adding similar terms to its proposed agreements.

Other Matters

Interrogatory No. 24.

Ref.: Exhibit A, Tab 3, Schedule 1, Attachment 1, page 2
Exhibit A, Tab 13, Schedule 1, Attachment 5, Schedule D, page 39

Preamble

In 2016, Jenmar was awarded a contract to act as Code Champion for the development of a new Annex B to provide new requirements for small scale LNG facilities not adequately covered in the current CSA Z276 standard.

Schedule D of the Contract provides the LNG Depot Design Basis/Specifications. In addition to the LNG storage tanks and vapourizers, other equipment includes gas odourization equipment and supervisory control and data acquisition (SCADA) equipment.

Questions

a) Please confirm that the LNG depots contemplated in the application are considered "small scale LNG facilities"? If not, please explain.

b) Please provide a status update on the new Annex B. When is its anticipated publication date?

c) Please explain the role of the TSSA in approving all or part of the design of the LNG depots.

d) What is the status of discussions with the Technical Standards and Safety Authority (TSSA) regarding the design, siting, construction and operation of the proposed LNG depots?

e) Has the TSSA indicated that it intends to adopt the new Annex B? If not, please explain.

f) Please explain the role of any other authority having jurisdiction in approving all or part of the design of the LNG depots (e.g., Electric Safety Authority; Ministry of Labour; Ministry of Tourism, Culture and Sport).

g) Please identify the location and ownership of the control room from which the SCADA equipment will be monitored.

OEB Approvals

Interrogatory No. 25.

Ref.: Exhibit A, Tab 1, Schedule 2, pages 2 to 5
Exhibit A, Tab 6, Schedule 1, Attachment 2 and 3
E.B.O. 125

Preamble

The Corporation has applied for an order granting it five certificates – one for each of the Municipalities.

Each of the Municipalities, acting on its own behalf, has resolved to enter into a Municipal Franchise Agreement (MFA) with the Marathon Economic Development Corporation, a wholly owned subsidiary of the Corporation, for and on behalf of the Utility. Assignment of Municipal Franchise Agreements from the Marathon Economic Development Corporation (MEDC) to the Utility is conditional on the Project receiving all necessary approvals from the OEB.

The Corporation has applied for an order granting leave to construct natural gas distribution pipelines and ancillary facilities to serve the Municipalities.

Section 86 of the OEB Act does not permit the sale, lease or disposition of gas distribution assets without the OEB's approval. Section 18 of the OEB Act provides that no authority given by the OEB can be transferred or assigned without leave of the OEB.

Questions

a) Please confirm that all five of the requested certificates are to be awarded to the Corporation of the Town of Marathon. If not, please explain.

b) Please provide draft copies of the requested certificates.

c) Please explain why the MFAs were entered into with the MEDC and not the Corporation.

d) Please provide maps showing the boundaries of the municipalities and any exclusions, if applicable.

e) Please explain whether or not the Corporation believes an approval under either section 18 or section 86 of the OEB Act will be requiredfor the transfer of the certificates and the MFAs to the Utility.

f) Please confirm that the Corporation intends to transfer its LTC, if granted by the OEB, to the Utility.

g) Please confirm that the Utility will be formed and all certificates, franchise agreements and leave to construct will be transferred to it before any construction begins. If not, please explain.

h) Please describe the process by which the transfers of certificates, franchise agreements and LTC will occur. Please include in the response milestones and timelines for:

- The formation of the Utility
- The creation of any holding companies
- When the certificates, franchise agreements and leave to construct will be transferred, including the timing of all required OEB approvals authorizing these transfers
- The start date of construction

i) Please explain the legal relationship between each of the Municipalities, the MEDC, and the Utility.

Interrogatory No. 26.

Ref.: Exhibit A, Tab 3, Schedule 1, pages 4-6
Exhibit A, Tab 13, Schedule 1, page 3

Preamble

The Corporation proposes that its requested approvals be approved by the OEB conditional on it demonstrating to the OEB its financial and technical fitness to serve. The Corporation asserts that conditional approval is in the public interest for several reasons, one of which is that the risks of inaccurate projections of the Project's viability will be borne entirely by the Corporation in the interim. The Utility will seek final, unconditional, approvals at a later date.

The Corporation states that conditional approval will provide some regulatory certainty and confidence to lenders, potential investors, communities, potential customers and other regulatory entities as the Corporation further finalizes the technical and financial components of the Utility.

Questions

a) Please describe the process envisioned by the Corporation by which it would receive unconditional approval following receipt of conditional approvals. Please include milestones and timelines in the response.

b) Please elaborate on the meaning of "the risks of inaccurate projections". For example, does this refer to financial risks associated with inaccurate customer, volumetric, capital cost, and / or operating cost projections?

c) Please confirm that the word "interim" refers to the period between the OEB's conditional approval and its final approval. If not, please explain.

Gas Supply Plan

Interrogatory No. 27.

Ref.: Exhibit A, Tab 8, Schedule 1, Attachment 1, page 22

Preamble

A gas supply planning process will be completed annually based on an updated demand forecast including customer attachments. The updated demand will be compared to current supply and transportation assets to ensure assets are sufficient to meet projected demand.

Question

Please confirm that the Utility will file its annual gas supply plan updates for OEB review per the Gas Supply Framework[8].

Interrogatory No. 28.

Ref.: Exhibit A, Tab 8, Schedule 1, Attachment 1, page 22
Exhibit A, Tab 13, Schedule 1, Attachment 5, page 10

Preamble

The Utility will be retaining an agent to assist in the procurement of supply and transportation arrangements. The agent will have pre-approved authority limits (and require approvals for any transaction above these limits), will procure supply from reputable creditworthy suppliers, will procure gas on a monthly or daily basis depending on market demands, will use contracts that are price indexed or competitive fixed price, will evaluate opportunities to mitigate unused transportation capacity, and will procure supply in a phased-in approach to match increasing expected demand.

The Contract allows that the parties may agree that Nipigon LNG will act as a procurement agent for gas commodity for the Utility.

Questions

a) If the Utility does not intend to use Nipigon LNG as a gas commodity procurement agent, how does it expect that it will procure gas? Will the Corporation manage this function on its own or will it retain a different agent? Has the agent been retained yet?

b) How will the Utility ensure that there is appropriate oversight related to the agent’s procurement and management of the supply and transportation assets? Please address the following points in the response.

    - Please outline the governance, accountability, policies and processes that describe the checks and balances that will be put in place to ensure effective risk management and monitoring of the Gas Supply Plan. In the response, please address to whom the agent will report, and who will set the agent’s pre-approved authority limits.

[8] EB-2017-0129

- Will the agent be providing on-going monitoring of the gas market for the Utility? For example, will the agent provide the Utility a monthly report of market events and developments?
- Who will be providing the on-going monitoring of customer attachment rates? If it is not the agent, what will be the Utility's process to ensure that the agent is aware of any changes to customer demand?

c) What will be the share of monthly versus daily supply contracts? Would the Utility also consider assessing whether to buy longer-term supply contracts (e.g., one-year contracts)?

d) What will be the share of indexed price contracts versus fixed price contracts? Under what conditions would the Utility purchase fixed price contracts? Would the fixed price contracts be on a monthly basis? Daily basis?

Interrogatory No. 29.

Ref.: Exhibit A, Tab 8, Schedule 1, Attachment 1, page 31

Preamble

Nipigon is not currently an interconnection point on the TCPL system. TCPL will need to apply to the National Energy Board (NEB) for approval to construct the interconnection and metering facilities. TCPL's economic test that is applied in these circumstances is to ensure that the NPV of the contractual arrangements over the primary term (i.e., 10 years) at least recovers the incremental costs of providing the necessary incremental facilities.

Questions

a) Please provide an update on Nipigon LNG's application to the NEB.

b) What is the risk to the Project if the NEB does not approve the construction of the interconnection and metering facilities?

c) Would the Nipigon LNG project pass the NEB's NPV test if the one potential industrial customer were excluded from the evaluation?

d) What would be the implications to the Project if the Nipigon LNG project did not pass the NEB's NPV test?

Interrogatory No. 30.

Ref.: Exhibit A, Tab 8, Schedule 1, Attachment 1, pages 31-32

Preamble

Assuming the purchase of gas at Empress and contracted firm capacity on the TCPL Mainline, the projected landed cost of the gas is $11.80/GJ. This also assumes that Nipigon has 100% load factor.

Questions

a) Does the assumption that Nipigon has 100% load factor require that the Utility effectively has 100% load factor, which justifies the need for the one industrial customer's proposed demand response program?

b) If the one industrial customer were to cease operations, what would be the impact on the rates charged to remaining customers.

Interrogatory No. 31.

Ref.: Exhibit A, Tab 8, Schedule 1, Attachment 1, pages 37-38

Preamble

The Application states that, "The LNG Plant will have approximately 18,000 GJ of onsite storage, sufficient supply to meet approximately 6 days of design day demand (5th year)."

The Application also states that, "In the event of an extended interruption, replacement LNG supplies could also be sourced from Montreal or Minneapolis."

Questions

a) Is the purpose of the bracketed "5th year" to indicate that there would be six days of design day demand in year five only? If so, what is the number of days of design day demand in year 11?

b) How quickly could a truck load of LNG be delivered from i) Montreal and ii) Minneapolis to the Municipalities from the time it was determined that such delivery was needed to the time that the truck begins offloading? Please include in the explanation a description of each step of the process (e.g., indicate whether empty trucks would need to be dispatched from Ontario to Montreal or Minneapolis to be loaded and then return to Ontario). How could a winter storm affect the response to this question?

c) Does the Utility need or intend to proactively enter into emergency LNG supply contracts with the LNG producers in Montreal and Minneapolis?

d) Could Nipigon LNG's storage capacity help the Utility avoid spot gas purchases? If so, please explain how.

Interrogatory No. 32.

Ref.: Exhibit A, Tab 8, Schedule 1, Attachment 1, pages 42
Exhibit A, Tab 4, Schedule 1, Attachment 2

Preamble

The Application states that the amount of Depot storage will be based on the design day requirements of each municipality. Storage is modular and can be added in the future if required. The additional cost to facilitate additional storage would be recovered from end use customers.

In year five, the daily consumption at Terrace Bay is 2,400 GJ during the non-heating season.

Questions

a) Would the additional cost to facilitate additional storage be recovered from end use customers through the Utility's rates or as some form of capital contribution? Please explain.

b) If one municipality required additional storage but the others did not, would all of the Utility's ratepayers contribute to the cost of the storage, or only those ratepayers in the subject municipality?

c) What impact does the year five non-heating season demand at Terrace Bay have on trucking costs? Who is responsible for the costs associated with the impact, if any? Please explain.

Interrogatory No. 33.

Ref.: Exhibit A, Tab 8, Schedule 1, Attachment 1, pages 43-44

Preamble

The performance of the Gas Supply Plan can be assessed on several key performance indicators (KPIs), including:

1. Landed unit cost of gas delivered to the distribution system
2. Utilization rate on upstream transportation and LNG contracts
3. Additional demand served over forecast amount
4. Curtailments

The utilization rate metric will include the overall utilization rate on upstream transportation capacity and LNG capacity. Weather can greatly influence the utilization of the capacity in any year. The targeted utilization rate for the first year of service is 100%.

Reliability is one of the guiding principles of the Gas Supply Plan. The number of outages (curtailments) due to gas-supply-related events will be tracked as a measure to ensure that this principle is achieved. The targeted number of curtailments for the first year of service is zero.

Questions

a) How will the KPIs be reported to the OEB? How does the Corporation envision the OEB evaluating and responding to the reported KPIs?

b) Given that the utilization rate is weather dependent, is or should this metric be weather normalized? Please explain.

c) Given that the industrial customer will be on a demand response program, does it make sense for the curtailment metric to be zero? Please explain.

d) For the curtailment performance metric, will the Utility report the reason for the curtailment (e.g., pipeline problem, lack of gas supply from Nipigon LNG).

Interrogatory No. 34.

Ref.: Exhibit A, Tab 8, Schedule 1, Attachment 1, Appendix 2, page 57

Preamble

The Corporation provides an appendix in which the results of a risk analysis have been provided. Section 6 of the appendix lists risks and mitigates related to the Demand Forecast.

Questions

a) Please explain why Section 6 of the appendix does not assess the risk that the industrial customer in Terrace Bay goes out of business.

b) Would a letter of credit or some other vehicle be appropriate to manage the risk of the Mill going out of business? Please explain.

Cost Consequences of Long-Term LNG Supply Contract

Interrogatory No. 35.

Ref.: Exhibit A, Tab 13, Schedule 1, pages 1-6

Preamble

The Corporation has applied under section 36 of the OEB Act and the OEB's *Filing Guidelines for Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts* (Guidelines) to seek pre-approval of the cost consequences of a proposed long-term gas service contract (Contract) between Nipigon LNG and the Corporation on behalf of the Utility.

With respect to the proposed long term gas supply contract, the application notes: "the Rights and Authorizations with which the Utility intends to comply are expected to include, but not necessarily be limited to, an order or orders from the OEB pre-approving the cost consequences of the proposed Contract to receive the LNG service."

Question

What other authorizations is it expected that the Utility will require?

Interrogatory No. 36.

Ref.: Exhibit A, Tab 13, Schedule 1, page 7

Preamble

In discussing the costs of the proposed long-term gas supply contract, the application states, "Any applicable taxes will be in addition to the total cost of the LNG Services purchased."

Questions

a) What is the anticipated annual amount of taxes that the Utility will be responsible for with relation to the long-term gas supply contract?

b) Please confirm that the Utility would expect to pass these costs on to its customers through its distribution rates.

Interrogatory No. 37.

Ref.: Exhibit A, Tab 8, Schedule 1, Attachment 1, pages 3 and 30
Exhibit A, tab 13, Schedule 1, page 7

Preamble

The Utility will agree to pay the total cost of all natural gas purchased by Nipigon LNG on the Utility's behalf for liquefaction in addition to the charges indicated. Any applicable taxes will be in addition to the total cost of the natural gas purchased. Nipigon LNG may amend its proposed services and charges if the Utility revises the demand forecasts in this Application, and Nipigon LNG determines, in its reasonable judgment, that it must incur additional costs to serve the incremental demand.

The Utility will be required to provide and maintain evidence of satisfactory creditworthiness and provide the requisite financial assurances during the term of the proposed Contract, and the Utility may be required to execute a financial backstopping agreement, in form and substance reasonably acceptable to Nipigon LNG upon execution of the proposed Contract.

The proposed Contract would commit the Utility to the cost consequences of 2,400 GJ per day of firm capacity in Year 1 with an annual cost of the proposed Contract of approximately $6.2 million, escalating to 3,700 GJ per day of firm capacity in Year 10 with an annual cost of the proposed Contract of approximately $10.9 million. Any applicable taxes will be in addition to the total cost of the LNG Services purchased. The Corporation summarized this information in its Table 2, below. OEB staff notes that the cumulative total annual cost is approximately $86.7 million.

Table 2: Proposed Annual Quantities and Costs

	Maximum Daily Quantity GJ/Day	Minimum Annual Volume GJ/Year	Firm Capacity Charge $/GJ	Total Annual Cost
Year 1	2,400	876,000	7.03	6,158,280
Year 2	2,400	876,000	7.14	6,250,654
Year 3	2,800	1,022,000	7.24	7,401,816
Year 4	3,100	1,131,500	7.35	8,317,791
Year 5	3,200	1,168,000	7.46	8,714,899
Year 6	3,300	1,204,500	7.57	9,122,048
Year 7	3,400	1,241,000	7.69	9,539,451
Year 8	3,500	1,277,500	7.80	9,967,323
Year 9	3,600	1,314,000	7.92	10,405,885
Year 10	3,700	1,350,500	8.04	10,855,362

The Corporation states that the long-term contract with TCPL is for 3,000 GJ per day, and the capacity is to be phased equally over the first three years.

The Corporation indicates that if it requires additional transportation it will:

a) Increase the overall transportation contract volumes, or

b) Sign up for a short-term delivered service in the secondary market.

OEB staff have prepared the following table.

Table S9: Transportation Shortfall

	2020	**2021**	**2022**	**2023**	**2024**	**…2030**
Design Day (GJ)	1,031	2,321	2,788	3,021	3,177	3,693
Supply / LNG (GJ/d)	2,400	2,400	2,800	3,100	3,200	3,700
Transportation (GJ/d)	1,000	2,000	3,000	3,000	3,000	3,000
Additional Transportation Required to Meet Supply (GJ/d)	1,400	400	200	100	200	700

From the table above, it appears that the Utility will need to purchase additional transportation to meet its supply commitment.

Questions

a) Please confirm that under the proposed long term gas supply contract the Utility will be responsible for paying Nipigon LNG the total annual cost shown in Table 2, irrespective of the LNG volumes the Utility actually requires. For example, if in Year 1 the Utility only actually requires 2,000 GJ/day (as opposed to the 2,400 GJ/day provided for in the contract), please confirm that the Utility would be required to pay Nipigon LNG $6,158,280 through the firm capacity charge (plus applicable taxes).

b) The total annual costs shown in Table 2 do not include the commodity cost for natural gas. To the extent that the Utility, for example, requires only 2,000 GJ/day in Year 1 of the contract and assuming that the commodity is purchased from Nipigon LNG, how much gas commodity will the Utility be required to pay Nipigon LNG for? 2,000 GJ/day or 2,400 GJ/day?

c) The contract states that if the Utility revises its demand forecast, then Nipigon LNG may amend its proposed services and charges if Nipigon LNG determines in its reasonable judgment that it must incur additional costs to serve the incremental demand. Please confirm that this provision only applies if the demand forecast increases, and that there are no provisions for lower charges if the demand forecast decreases. What assurances does the Utility have that any increased charges for increased demand will be reasonable?

d) The contract allows Nipigon LNG to require the Utility to execute a financial backstopping agreement. Is it expected that such an agreement will be required? What are the expected annual costs to the Utility for such an agreement?

e) Beyond the Utility, how many other clients is Nipigon LNG forecast to be serving in the next five years? How much of the annual capacity from the Nipigon LNG facility are these customers forecast to consume?

f) Does the firm capacity charge of approximately $86.7 million over 10 years recover all of Nipigon's initial capital facilities investment? If it does recover all of Nipigon's initial capital costs, what will be the fixed costs after year 10? What benefit is there to the Utility if Nipigon LNG fully recovers the cost of the liquefaction facility by year ten?

g) Please confirm that in year one the contract is for 1,000 GJ per day, in year two the contract is for 2,000 GJ per day, and in year three it is for 3,000 GJ per day. How would these requirements change if customer attachments and volumes are less than forecast?

h) Please confirm that the Utility will need to purchase additional transportation to meet its supply commitment. Will this change relative to attachments?

i) Please clarify what the Corporation means by purchasing “delivered services” in the secondary market. Does this mean purchasing transportation capacity only in the secondary market?

j) Please explain what will be done to manage excess gas supply, in particular in the initial years of operation.

Interrogatory No. 38.

Ref.: Exhibit A, Tab 13, Schedule 1, Table 5, page 14

Preamble

The landed cost assessment assumes an average delivery distance of 200 km. That may be appropriate in winter when trucks are frequently traveling to all communities. However, in summer, most gas deliveries may be expected to go primarily to the Mill in Terrace Bay, which OEB staff estimates to be about 100 km away.

Questions

a) OEB staff is concerned that the 200 km may be an overstated average. Would it be better to split the landed cost analysis into a winter and summer analysis? Please explain. In the response, please comment on how an overstated average and/or using a winter/summer analysis would change the viability of the CNG alternative.

b) The “take or pay” long-term contract calls for a specified volume of gas to be delivered to each community every day. But, for half the year, most of the volume is going to Terrace Bay. How does this fact affect the landed gas cost analysis and conclusions?

Interrogatory No. 39.

Ref.: Exhibit A, Tab 13, Schedule 1, page 16

Preamble

The application states, “There is no affiliate relationship issues related to the Contract. The parties to the proposed Contract are arm’s length parties.”

Question

Is Nipigon LNG providing any financial support for the costs of this application?

Interrogatory No. 40.

Ref.: Exhibit A, Tab 13, Schedule 1, Attachment 5, page 12

Preamble

Section 3.1(a)(iv) of the Contract requires the Utility to provide financial security (which, as described in the definitions section, can come in various forms) to Nipigon LNG prior to the commencement of service.

Question

What form of financial security does the Utility expect to provide? What costs does the Utility anticipate incurring in order to provide this financial security?

Interrogatory No. 41.

Ref.: Exhibit A, Tab 13, Schedule 1, Attachment 5, page 16

Preamble

Section 4.1(b) of the Contract requires the Utility to pay a “Variable Charge” to cover Nipigon LNG’s variable costs in providing LNG Service. The Contract states, “The Variable Charge per GJ, will be re-determined by Nipigon LNG each Contract Year.” Neither the main body of the contract nor Schedule B (Table of Services and Charges) appear to state how much the variable charge will be.

Section 4.1(c) of the Contract requires the Utility to pay for all fees, charges and expenses, without mark-up, of the Truck Transportation Services. The Contract does not establish an actual amount for trucking transportation, nor does it appear as a line item in Schedule B.

Questions

a) What will the variable charge be for each year of the Contract?

b) Is the variable charge set solely by Nipigon LNG? Is the Utility required to pay whatever amount Nipigon LNG decides upon?

c) Is the variable charge "firm" in that the annual amount of the charge will be paid by the Utility irrespective of the volumes it actually requires? In other words would the total amount owing under the variable charge be lower if the Utility's demand is lower than expected?

d) How much does the Utility expect to pay for truck transportation service?

Interrogatory No. 42.

Ref.: Exhibit A, Tab 13, Schedule 1, Attachment 5, page 22

Preamble

Section 9.1(d) and (f) allow Nipigon LNG to suspend LNG service and/or terminate the Contract if the Utility fails to make any payment within 30 days of payment being due, fails to maintain creditworthiness in accordance with the Contract, or fails to correct any default to other Contractual terms within 30 days of Nipigon LNG giving note of the default.

Section 9.2 of the Contract allows Nipigon LNG to terminate the provision of LNG Service in the event that the Utility becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or insolvency, and various related scenarios.

Questions

a) Please confirm that Nipigon LNG has the sole right to terminate the Contract or suspend LNG Service for the defaults noted in the preamble and in section 9.1 of the Contract.

b) In the event that Nipigon LNG suspends LNG service, how will the Utility provide natural gas to its distribution customers?

c) What protections will the Utility's customers have if Nipigon LNG elects to discontinue service in the event of a default of payment by the Utility to Nipigon LNG? Are there any measures that can be put in place to ensure the continued provision of LNG to the Utility's service territory?

Interrogatory No. 43.

Ref.: Exhibit A, Tab 13, Schedule 1, Attachment 5, page 23

Preamble

Sections 10.3 and 10.4 of the Contract deal with termination of the Contract and termination payments. Section 10.3(b) allows the Utility to terminate the Contract if Nipigon LNG has failed to satisfy any of certain Customer Conditions, which are described in section 3.1 and include matters such as Nipigon LNG obtaining all its required government and regulatory approvals. Section 10.4 requires in the event of termination of the Contract, even by the Utility under section 10.3(b), the Utility will be required to pay Nipigon LNG its costs for the construction and development of the LNG Depot and various other costs.

Questions

a) If the Contract is terminated because Nipigon LNG fails to obtain necessary government or regulatory approvals (or because it fails to meet other Customer Conditions), why is the Utility responsible for Nipigon LNG's LNG Depot and other costs?

b) In the event of termination of the Contract and any associated costs that will be incurred by the Utility, will the Utility be seeking to pass these costs on to ratepayers?

Interrogatory No. 44.

Ref.: Exhibit A, Tab 13, Schedule 1, Attachment 5, page 26

Preamble

Section 12.1 of the Contract provides that Nipigon LNG is not responsible for any claims, losses, damages, etc. suffered by the Utility related to Nipigon LNG's provision of LNG Service except where there has been gross negligence or willful misconduct on the part of Nipigon LNG. Section 12.2 provides that the Utility will be responsible for any and all of Nipigon LNG's claims, losses, etc. related to any of the Utility's acts or omissions (irrespective of whether any negligence was involved), or any breach of representations, warranties, etc.

Questions

a) Why is Nipigon LNG responsible for losses suffered by the Utility only where Nipigon LNG has been grossly negligent or has exhibited willful misconduct, whereas the Utility is liable for losses suffered by Nipigon LNG irrespective of negligence?

b) Section 12.3 sets a cap on the amount of Nipigon LNG's liability, but that number is currently left blank. What is Nipigon LNG's liability cap? Why does the Utility not have a similar liability cap?

Interrogatory No. 45.

Ref.: Exhibit A, Tab 13, Schedule 1, Attachment 5, page 28

Preamble

Section 13.6 of the Contract allows Nipigon LNG to temporarily suspend LNG service for the purposes of maintaining, repairing or replacing its LNG facilities.

Question

How will the Utility procure gas for its distribution customers in the event that Nipigon LNG ceases service for an extended period of time?

Interrogatory No. 46.

Ref.: Exhibit A, Tab 13, Schedule 1, page 15 and Attachment 5

Preamble

The evidence states that the Contract is structured as a 10-year commitment with a renewal option. The only reference to renewal in the Contract itself is in Schedule B, which provides that the term is renewable at the Utility's option for an additional 10 years.

Questions

a) Are there any other provisions related to renewal of the Contract? In the event of renewal, will all contractual terms remain the same?

b) Did the Corporation consider entering into a contract with a term that more closely matches the life of the assets (whether distribution pipeline, LNG deport, or liquefaction facility)? If not, please explain why not. If so, please explain why a 10 year term was selected.

c) What would be the impact on residential rates if the contract had a term of 15, 20 or 25 years?

d) What is expected to happen to the rates charged to the Utility by Nipigon LNG in year 11 and beyond?

Interrogatory No. 47.

Ref.: Exhibit A, Tab 13, Schedule 1, Attachment 5, Schedule B

Preamble

Schedule B sets out the services and charges under the Contract.

Questions

a) Does Schedule B include all of the charges that the Utility will be required to pay to Nipigon LNG? If not, please provide details regarding any additional charges.

b) Is Schedule B (and the entire Contract) as provided in the application the most recent version of this document? If not, please provide the most recent versions.

c) When do the parties expect to execute the Contract?

d) Various items in Schedule B are identified but left blank (for example, gas quality and receipt pressure). When will these parts of the Contract be completed?

e) Schedule B identifies charges for “spot load LNG charge” and “LNG spot price”. OEB staff does not understand what these charges are for. How much is the spot charge per GJ? How is it determined by demand, and what is the “floor” that it is subject to? Who sets the amount of this charge? Is this a commodity charge?

f) Please confirm that Schedule B does not include the costs for the commodity itself. If it does, please explain.

g) Assuming the Contract is executed in substantially its current form, does the Utility know what the annual costs of the Contract will be? Does it match the information provided in Table 3 of Exhibit A, Tab 13, Schedule 1, page 12?

Please provide the expected annual costs for each of the 10 years of the Contract. Does this represent the entire amount that the Utility will be required to pay Nipigon LNG under the Contract?

Conditions of Approval

Interrogatory No. 48.

Preamble

The OEB Act permits the OEB, when making an order, to “impose such conditions as it considers proper.”[9]

Question

OEB staff has prepared the following draft Conditions of Approval. With the exception of the first two, these conditions are standard for most leave to construct applications. If the Corporation does not agree to any of the draft conditions of approval noted below, please identify the specific conditions that the Corporation disagrees with and explain why. For conditions in respect of which the Corporation would like to recommend changes, please provide the proposed changes and an explanation of the changes.

[9] OEB Act, s. 23

Corporation of the Township of Marathon
North Shore LNG Leave to Construct Application
OEB File No. EB-2018-0329

DRAFT CONDITIONS OF APPROVAL

The Corporation of the Town of Marathon (Corporation), the Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay and the Municipality of Wawa (Municipalities) have resolved to incorporate, finance and resource a yet to be created utility (Utility) to distribute natural gas within their municipalities.

1. Authorization for leave to construct is granted conditional upon the OEB's final approval of the Corporation's application for certificate of public convenience and necessity, which will be decided after the OEB has considered the information filed to demonstrate the Utility's technical and financial abilities.

2. Construction of the facilities shall not begin until all certificates, franchises and leave to construct have been transferred to the Utility.

3. The Utility shall construct the facilities and restore the land in accordance with the OEB's Decision and Order in EB-2018-0329 and these Conditions of Approval.

4. (a) Authorization for leave to construct shall terminate 12 months after the final decision is issued, unless construction has commenced prior to that date.

   (b) For each of the Municipalities, the Utility shall give the OEB separate written notice:

      i. Of the commencement of construction, at least ten days prior to the date construction commences

      ii. Of the planned in-service date, at least ten days prior to the date the facilities go into service

      iii. Of the date on which construction was completed, no later than 10 days following the completion of construction

      iv. Of the in-service date, no later than 10 days after the facilities go into service

5. The Utility shall implement all the recommendations of the Environmental Report filed in the proceeding, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee review.

6. The Utility shall advise the OEB of any proposed change to OEB-approved

construction or restoration procedures. Except in an emergency, the Utility shall not make any such change without prior notice to and written approval of the OEB. In the event of an emergency, the OEB shall be informed immediately after the fact.

7. Concurrent with the final monitoring report referred to in Condition 6(b), the Utility shall file a Post Construction Financial Report, which shall provide a variance analysis of project cost, schedule and scope compared to the estimates filed in this proceeding, including the extent to which the project contingency was utilized. The Utility shall also file a copy of the Post Construction Financial Report in the proceeding where the actual capital costs of the project are proposed to be included in rate base or any proceeding where the Utility proposes to start collecting revenues associated with the project, whichever is earlier.

8. Both during and after construction, the Utility shall monitor the impacts of construction, and shall file with the OEB one paper copy and one electronic (searchable PDF) version of each of the following reports:

   a) A post construction report, within three months of the in-service date, which shall:

      i. Provide a certification, by a senior executive of the company, of the Utility's adherence to Condition 1

      ii. Describe any impacts and outstanding concerns identified during construction

      iii. Describe the actions taken or planned to be taken to prevent or mitigate any identified impacts of construction

      iv. Include a log of all complaints received by the Utility, including the date/time the complaint was received, a description of the complaint, any actions taken to address the complaint, the rationale for taking such actions

      v. Provide a certification, by a senior executive of the company, that the company has obtained all other approvals, permits, licences, and certificates required to construct, operate and maintain the proposed project

   b) A final monitoring report, no later than fifteen months after the in- service date, or, where the deadline falls between December 1 and May 31, the following June 1, which shall:

      i. Provide a certification, by a senior executive of the company, of the Utility's adherence to Condition 3

      ii. Describe the condition of any rehabilitated land

      iii. Describe the effectiveness of any actions taken to prevent or mitigate any identified impacts of construction

      iv. Include the results of analyses and monitoring programs and any recommendations arising therefrom

v. Include a log of all complaints received by the Utility, including the date/time the complaint was received, a description of the complaint, any actions taken to address the complaint, the rationale for taking such actions