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Corporation of the Town of Marathon
Application for approval to construct a natural gas pipeline and associated facilities in the
Town of Marathon, the Township of Manitouwadge, the Township of Schreiber, the Township of Terrace Bay and the Municipality of Wawa

EB-2018-0329

Submission
of the
Vulnerable Energy Consumers Coalition
(VECC)

January 7, 2020

Vulnerable Energy Consumers Coalition

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Summary

VECC has had the opportunity to review the submissions of the School Energy Coalition (SEC). We agree with those submissions. Specifically, while we hold that the application is deficient in a number of aspects it is clear that current provincial government policy is to expand the benefit of lower natural gas energy costs to Northern Ontario communities. VECC is also in favour of reducing energy costs to low income residents in these communities.

The Ontario Government has provided $3.4 million in funding through the Northern Ontario Heritage Fund to help fund the necessary engineering and approvals for this project. It has provided a further $27 million investment in Nipigon LNG for the development of the supply facilities necessary for the project.

Furthermore the government has announced a $130 million ratepayer funded support program to expand natural gas to new communities where under existing Board policies they would be considered uneconomic. The government policy with respect to this type of project is clear. In our submission the Board should acknowledge that policy in making the necessary accommodations which would allow this project to proceed while continuing its role to protect these new ratepayers.

In our submission a rate stability period of ten years has been approved in similar types of projects and should apply in this case. The rate stability period should allow the majority of converting customers to recover their conversion investment, a period of about 10 years. Once a rate stability period has been designated by the Board the Utility should use this to inform the contracts it negotiates with the LNG gas supply and the large industrial customer.

While we support the application the proposal does contain a number of unusual aspects which increase the risk to ratepayers including:

- The Utility has yet to be constituted and therefore it is not yet possible to provide the OEB with evidence of its technical and financial capacity[1].

- The proposal poses significant risk with respect to forecast attachment, costs of building and operating the system and the reliability of natural gas supply.

- The viability of the proposal is tied to a single large industrial customer. If that customer ceases to be a distribution utility customer the resulting impact on both gas supply, other customer attachments and the economic health of the Utility may be catastrophic.

- The proposed agreement between the facilities for gas supply, Nipigon LNG LP (Nipigon LNG) and the Utility does not provide sufficient protections for ratepayers.

[1] SEC-1

In our submission the Board can mitigate theses risk in the following ways:

- The Applicant should file financial and technical information of the newly constituted Utility prior to beginning construction on the distribution system.

- The Board should include as a condition of approval the filing of a contract as between the Utility and the industrial customer.

- The contract with Nipigon LNG should be modified to address issues of liability should Nipigon LNG fail to perform, including the posting of security.

- The Board should indicate the need for a rate stability period of between five and ten and so as to better align the large customer and gas supply contracting with the conversion payback period for attaching customers (i.e. 5-10 years).

- The Applicant should submit a gas supply mitigation plan, which includes the consideration of alternative CNG supply in the case of LNG disruption.

<u>No fully formed Utility</u>

As it stands the Utility has yet to be constituted. The Corporation of the Town of Marathon ("Corporation") is the agent of the Marathon Economic Development Corporation ("MEDC") for the purpose of this Application only. The requested Certificates of Public Convenience and Necessity are proposed to be issued to MEDC or, in the alternative, to the Corporation, as the agent of MEDC[2]. When the Utility is formed, MEDC will transfer the Certificates to the Utility[3].

The Applicant has said it is not yet possible to provide the OEB with evidence of technical and financial capacity. As the Utility has not been formed at this time, the relevant governance, policies and processes related to the procurement of supply and transportation have not been defined.[4]

Since the Utility will be the monopoly provider for the home heating energy a fundamental test is whether the Applicant is technically and financially competent to undertake this task. In this case there is no basis upon which to make that assessment.

Unlike other greenfield proposals recently reviewed by the Board (i.e. EPCOR) there is no gas related organization standing behind the proposal. Instead a coalition of municipalities has made the proposal largely in conjunction with a private company seeking the business opportunity of LNG supply. MEDC has also not undertaken any steps to actually form a utility so even simple issues, like what form of billing system will be used has yet to be determined. Nor has a construction contractor for the distribution system been procured. The Applicant has not

[2] Staff-25
[3] In their Argument in Chief the Applicant states MEDC, will make an application to the Board under s. 18(1) of the OEB Act, for leave to transfer approvals and orders to the Utility.
[4] Staff-26

provided a detailed pro-forma derivation of its revenue requirement showing expected costs making it difficult to understand the long-term economic viability of the proposal.

We do know that when the Utility is constituted it will be owned, directly or indirectly, in equal parts by five Municipalities. Each Municipality will be allowed one nominee to the Board of Directors. However no employees of the Utility have been put forward, nor is the business constituted in a manner for the Board to consider the wherewithal of the ultimate holder of the franchise.

Given these deficiencies the Board might easily dismiss the application as premature. However there is a “chicken and egg” problem facing municipalities trying to form a greenfield utility. In order to make the steps necessary to form the utility they first need to achieve regulatory approvals. We also note the commitment by the Applicant to file technical and financial capacity information with the Board shortly after a decision on this Application has been issued. After that it expects to secure financing and hire employees hired and external consultants.[5] We endorse this commitment and include in our recommendations as a condition of approval that the Applicant file the necessary information with the Board prior to beginning construction.

<u>Customer Attachment Forecast</u>

The rates to be charged customers have yet to be determined. There are a number of factors which will affect these rates: the cost of gas supply, the number of customers who ultimately attach to the new system and the cost of building and maintaining the distribution system.

The forecast conversion rates[6] assumed by the Applicant are shown below:

Table 1

<u>North Shore Forecasted 11 Year Natural Gas Demand Forecast - By Customer Ttype</u>

Scenario: *Reference Case*

12-Nov-19		1	2	3	4	5	6	7	8	9	10	11
Year	**Building Count**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Residential		857	1,199	400	132	85	85	85	67	67	67	67
Customer Additions	5,028	857	2,056	2,456	2,588	2,673	2,758	2,843	2,910	2,977	3,044	3,111
Total Customers		17%	41%	49%	51%	53%	55%	57%	58%	59%	61%	62%
Conversion Percentage	455											
Commercial		44	59	59	44	30	14	14	14	14	5	5
Customer Additions	55	44	103	162	206	236	250	264	278	292	297	302
Total Customers		10%	23%	36%	45%	52%	55%	58%	61%	64%	65%	66%
Conversion Percentage												
Institutional	1	24	22	0	0	0	0	0	0	0	0	0
Customer Additions		24	46	46	46	46	46	46	46	46	46	46
Total Customers	5,539	44%	84%	84%	84%	84%	84%	84%	84%	84%	84%	84%
Conversion Percentage												
Industrial		1	0	0	0	0	0	0	0	0	0	0
Customer Additions		1	1	1	1	1	1	1	1	1	1	1
Total Customers		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Conversion Percentage												
Total		926	1,280	459	176	115	99	99	81	81	72	72
Customer Additions		926	2,206	2,665	2,841	2,956	3,055	3,154	3,235	3,316	3,388	3,460
Total Customers												

[5] Argument-in-Chief, December 11, 2019, page 9

[6] Exhibit A, Tab 4, Schedule 1, page 12-18

We would note that the conversion rates are slightly more optimistic than those proposed in the recent greenfield utility application of EPCOR Southern Bruce Gas Inc. (EB-2016-0137/138/139). EPCOR's forecast was a residential conversation rate of 60%, commercial 65% by the end of a ten year period.[7]

For both residential and commercial customers it is assumed that non-forced air heating equipment could be converted to natural gas. It is anticipated that some of the electricity customers would also convert to natural gas.[8] The survey upon which these estimates were based did not include a cost of natural gas and it was implied that government assistance might become available to aid in offsetting conversion costs.[9] The survey also did not specifically explain the unique supply chain aspects of the proposal.[10]

We also note that in explaining appliance conversion to potential customers the Applicant may have underestimated the costs as shown by a comparison with recent estimates of Enbridge[11]:

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%

Finally when considering the likelihood of conversion it is important to consider that electricity rates of all of the communities in question are subject both Distribution Rate protection and Rural and Remote Rate protection.[12]

In our view there is significant risk that the customer attachment forecast will not be met. Conversion forecasts for EPCOR Southern Bruce Gas were around 2% less than that estimated in this application. With the relatively low diversity of employment opportunities and the isolated locales in this proposal it is quite possible attachment rates will be up to 10% lower than expected.

A sensitivity analysis was done when the feasibility study was produced in 2016. The study found that a 10% decline in either demand or attachments would result in a 6% increase to residential rates and a 5% increase to general service rates.[13] The Applicant suggests if its

[7] EPCRO CIP , page 18
[8] VECC-3
[9] VECC-4
[10] VECC-9
[11] Staff-7
[12] VECC-5
[13] Staff-16

attachment forecast does not come to fruition it would seek to increase rates to any attached customers.[14]

Project Costs

The costs of the distribution project are preliminary. No AACE or other recognized estimation technique has been demonstrated for these capital cost projections. Nor has Applicant yet found a contractor.

	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						

Source Exhibit A, Tab 9, Schedule 1, page 1

It is difficult to gauge the accuracy of the forecast given the evidence provided. It is plausible that costs for the system could be higher than projected. There is also no evidence on projected operating costs.

The Board should consider that the cost of the project might vary significantly from that shown in Table 1. This would tend to decrease customer attachments.

Reliance on Industrial Customer

The proposal is highly dependent on one large industrial customer located in Terrace Bay. Though not noted we presume this to be AV Terrace Bay, a longstanding pulp and paper mill in

[14] Staff-12

the municipality operating under different ownerships and with a long history of "on and off" operations.

The proposal is to use LNG distributed gas to optimize the distribution system while providing lower energy costs to the industrial customer. The total forecasted annual consumption of the one industrial customer is approximately 67% of the total for all customers[15]. The Applicant notes:

"*Without the industrial customer, the annual residential distribution bill would increase by $3.72, the annual small general service bill would increase by $2.44, and the annual large general service bill would increase by $2.16, all in 2020 dollars. The impact on the landed cost of gas would be an increase in approximately $24.67/GJ for each rate class if the Utility does not seek alternate customers or deferred recovery.*[16]

It is clear that the economic viability of the entire distribution system is highly dependent on this one customer. Given this fact, it would be imprudent for the Applicant to begin construction or make any other major commitment prior to a finalized contract with the industrial customer. At a minimum entering into significant commitment prior to a satisfactory contract being concluded puts the Utility at a negotiating disadvantage.

In our submission the Board should provide leave to construct on the condition that a contract has been concluded between the utility and the industrial customer. In order to mitigate risk the Utility should contract in light of a ten year rate stability period.

Rate Stability

The Applicant states that the majority of costs embedded within rates, for both the distribution rate and the LNG service rate, are to recover the fixed costs and so independent of the number of customers or volume consumed. They then suggest that a slower natural gas adoption cycle would leave these fixed assets and expenses underutilized which would be recovered in rates paid by all customers[17].

The Applicant seeks unconditional approval for leave to construct this distribution system. It appears to resist being treated the same as that for the recently approved EPCOR South Bruce franchise. While the rates for this system are not being determined in this application it is important for the Applicant's assessment of the economic proposition to provide clarity as to how forecast errors both on the cost and revenues (attachments). In their argument- in-chief the Applicant states: "a *key driver of the Board's rate stability proposal is to incent utilities, competing to secure a distribution franchise, not to overstate their forecast of customer attachments nor understate their forecasts of long-term costs, in order to increase their chance*

[15] Staff-13
[16] Staff-13, page 35
[17] Cetarus-10

of being selected as the successful proponent." While forecast "gaming" is one reason for a rate stability period it is not the most important. Rate stability also ensures that attaching customers can confidently make the significant new investments in heating and other gas appliances that will make this distribution system economically viable. It is also a means of allocating the risk as between the ratepayers and the utility investors (in this case municipal taxpayers). The risks to investors (taxpayers) and those of ratepayers are important matters that should be clearly set out from the onset of the proposition. The setting of a rate stability period is a means of allocating that risk.

<u>Regulation of LNG Storage and Transmission of Natural Gas</u>

The proposal to supply the distribution systems by way of LNG presents certain risks not encountered with a typical pipeline connected system. One factor is the need to transport by truck the final leg of the transmission of gas into the distribution system. The other is the added complexity of liquefying and reconstituting natural gas. At the moment the LNG aspects of this proposal is neither regulated by the OEB or the Canadian Energy Regulator (formerly NEB). Nipigon LNG takes the position it does not require OEB approval for rates and charges for services under the LNG Services Agreement.

As for alternative supplies of LNG, in March 2017 and after the preliminary feasibility work had been completed (see discussion above), the Corporation met with representatives of Union Gas (now Enbridge) to discuss the feasibility of purchasing LNG at the closest other LNG facility located in Hagar, Ontario, about a nine hour drive from Marathon. Ultimately, and after a preliminary economic analysis was completed by Union, both parties agreed that the Hagar facility was not a viable supply option.[18] This leaves the closes alternative supplies some 1,300 kilometers away. This makes the LNG facility the defacto sole supplier to the proposed distribution system (or systems if considered by municipality). As it stands today there are no competitive alternative supplies to those of Nipigon LNG.

We recommend the Board consider whether pursuant to Section 36 of the *OEB Act* that the LNG facility be regulated as a transmitter of natural gas or storage facility. The LNG facility will form an integral part of a natural gas transmission, storage and distribution system. It is not being used (at least primarily) in the same fashion as suggested for the Hagar facility in EB-2014-0012, that is for services which can otherwise be offered competitively. In that case, and as noted by the Board in that decision Northeast Midstream (Nipigon LNG's parent) argued that the end use of the liquefied natural gas would be as motor vehicle fuel, and that the exemption therefore applies service under section 36[19].

While the Applicant suggested that LNG supply could be provided from other significantly distanced sites no specific emergency plan for natural gas supply was provided in the application. In our view such a plan is critical in order to ensure adequate supply for consumers. Northern Ontario consumers face severely cold winters where lack of heat is not just an inconvenience but it can also be life threatening.

[18] Preamble to Response to Cetarus IRs
[19] Reason with Decision EB-2014-0012, April 9, 2015, page 3

The Alaskan regulator requires of a similar (if somewhat larger) LNG facility in Fairbanks to maintain a minimum five-day LNG storage reserve based on projected daily demand for noninterruptible customers to minimize concerns related to gas supply.[20] It is also technically possible for the Utility to have its system served by both LNG and CNG. In fact the Applicant states the incremental cost to the Utility of adding an injection point for CNG would be minimal and is not expected to impact the schedule and budget of the Project. [21]

In our submission, in addition to the consideration of regulating the LNG facility the Board should require the Applicant Utility to produce a specific and rigourous emergency supply plan.

LNG Contract

The pre-approval of the cost consequences of the LNG Services Agreement is a requirement for Nipigon LNG to construct the LNG Depot. The Applicants and their consultants did not analyse whether the costs under the LNG Services Agreement were reasonable having regard to Nipigon LNG's underlying cost structure. This is because Nipigon LNG's costs were not provided being considered commercially sensitive by Nipigon LNG (notwithstanding a $27 million grant provided by the Ontario Government).

Pursuant to the LNG Services Agreement, the Applicant is committed to paying over the 10 year term of the contract $86.7M in capacity charges[22]. Based on information filed in Nipigon LNG's CPCN application (EB-2018-0248), the total capital cost of its facility is $54M. The LNG facility is also the recipient of $27 million in provincial funding. Infrastructure Ontario undertook a technical and financial review of the Nipigon LNG Project as a condition of funding advanced under the Natural Gas Grant Program. The report was completed by an independent expert and was not provided as part of this application.

It is clear that the LNG Service Agreement represents the terms and conditions required by Nipigon LNG to minimize its risk in the design, development and construction of the LNG Depot. What is less clear is how that agreement also protects the ratepayers. For example it is unclear why Nipigon LNG is responsible for losses suffered by the Utility only where it has been grossly negligent whereas the Utility is liable for losses suffered by Nipigon LNG irrespective of negligence. Likewise the LNG facility requires financial backstopping from the Utility even though the Utility faces catastrophic failure and its own financial liability (from ratepayers) if the LNG facility fails to provide the needed supply.

With respect to the interruption of gas (Schedule A of the form of the contract) in addition to the usual force majeure terms there are other terms inconsistent with the Utility protecting its customers including[23]?

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[20] Staff-10
[21] Staff-11
[22] SEC-15
[23] Exhibit A, Tab 13, Schedule 1, Attachment 5, page 35

(a) in the event of a temporary or permanent shortage of Gas, whether actual or perceived by Nipigon LNG, (emphasis added)

(d) in order to make repairs or improvements to any part of Nipigon LNG's pre-treatment, liquefaction, distribution, storage, control or loading systems,

That is, notwithstanding issues of force majeure 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

Also when asked by Board Staff as to whether in essence it was Nipigon LNG's sole client the Applicant responded: [T]*he Nipigon LNG undertaking is separate and distinct from the Applicants' undertaking that is the subject of this application. The Applicants do not have the information to respond to this question*. In our respectful submission this does not seem the response of a party who has done their due diligence to understand the business risk they might face given the single source supply nature of the arrangement.

SEC has made a number of suggestions as to how this agreement might be strengthened for the benefit of ratepayers. We agree with those suggestions. We also believe the Board should direct the Applicant to review the contractual terms related to the consequences of interruption of supply when that interruption is solely the result of Nipigon LNG actions.

We also believe that any agreement with respect to LNG supply should be aligned with rate stability periods.

Implementation

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. This is of course not possible. As such the Board should require the Applicant to produce a new proposed construction schedule in order to determine which winter season residents of the municipalities in question have gas service available them.

Reasonably Incurred Costs

VECC submits that it has acted responsibly and efficiently during the course of this proceeding and requests that it be allowed to recover 100% of its reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED