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Our File: EB20180329

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attn: Christine Long, Registrar & Board Secretary

Dear Ms. Long:

Re: EB-2018-0329 – Marathon North Shore Project – SEC Submissions

We are counsel to the School Energy Coalition ("SEC"). Pursuant to Procedural Order No. 2, these are SEC's submissions on the application by Corporation of the Town of Marathon, in its own capacity as the representative of the Township of Manitouwadge, Township of Schreiber, the Township of Terrace Bay and the Municipality of Wawa (collectively the "municipalities" or the "Applicant").

This is an application for approvals to build a new greenfield natural gas distribution utility to service the municipalities (also known as the North Shore Project). The application seeks, in addition to the various approvals required to construct the pipeline assets required for the Utility, pre-approval of the cost consequences of a long-term Liquefied Natural Gas ("LNG") contract (the "LNG Services Agreement").

General Comments

SEC is generally supportive of the application and the proposed new Utility. It is a unique project that could bring another affordable energy option to the schools, businesses, and residents of the five municipalities it would serve, and could be a model for other northern communities. Due to the distance of the municipalities to existing natural gas transportation pipelines, the proposal is that the Utility distribution system will be supplied by way of LNG trucked to each municipality from a liquefaction facility, to be constructed near Nipigon, Ontario, by Nipigon LNG LP ("Nipigon LNG"). Nipigon LNG's facility will have an upstream connection to the TransCanada Mainline.

SEC's submissions are primarily centered around issues that it has with the Gas Supply Plan and the proposed LNG Services Agreement. Supplying a natural gas distribution utility exclusively through LNG is new to Ontario, and any sole-source supply arrangement for natural gas, LNG or otherwise, is unusual. The Board has only ever approved gas transportation arrangements that arrive to a distribution utility by way of a traditional pipeline. This new method raises new issues and risks.

While the municipalities should be commended for developing the proposal, the unique risks related to the project do not appear to have been sufficiently addressed in the evidence. The Board will need to consider how to deal with those risks. Moreover, SEC submits certain aspects of the LNG Services Agreement are unfair to the Applicant, and thus could end up being unfair to future customers.

Approvals

The Applicant has not incorporated the utility company (the "Utility") yet. It proposes that the approvals be granted to a related corporation[1], conditional on its ability to demonstrate to the Board, once it has formed the Utility, that it has the necessary technical and financial capacity required to construct, own and operate the proposed distribution network.[2] At that time, final approvals would be given to the Utility.

SEC understands the basis for this request, although it may be more appropriate to treat satisfaction of the conditions as simply a second phase of the approval process. Approvals, such as ensuring the Utility has the necessary technical and financial capacity, are more complex than the usual conditions attached to a leave to construct application. Public review and comment within the Board's process is appropriate.

LNG Supply Risk

The most unique aspect of the Application is the proposal that the natural gas will be supplied to the Utility by way of LNG that will be liquefied, trucked, and stored. The production of this LNG will be at a greenfield facility that has yet to be constructed, and whose affiliate company, Northeast Midstream LP, has never built or operated such a facility before.[3]

As noted by the number of interrogatories posed on the issue[4], there is an obvious question of what happens if Nipigon LNG is unable to meet its requirements under the LNG Services Agreement for a lengthy period of time because of repair, equipment breakdown, default, or closure. With limited exceptions, the Board does not regulate the operations of Nipigon LNG. For other natural gas distributors in Ontario, either the supply to them is regulated by the Board itself, or another utility regulator (e.g. Canadian Energy Regulator regulates operations of the TCPL Mainline) does. If things go wrong with Nipigon LNG, the Board can do little to help the Utility's customers.

SEC recognizes there is an inherent risk in this arrangement that is likely greater than a traditional pipeline natural gas connection. The question for the Board is whether the Applicant has sufficiently mitigated the risk so that it is at an acceptable level, i.e. the mitigated risk is outweighed by the considerable benefits that the proposal could yield for the five municipalities and their residents.

Furthermore, the gas supply risk is increased for each customer of the Utility. Today, while their heating needs are being met through other means (i.e. electricity, oil, propane etc.), those sources may be expensive, but they are less risky.

- With respect to electricity, the Board has significant authority to require electricity distributors to meet the needs of customers.

- For those on oil and propane, the markets for that fuel are mature and there are multiple sources of supply that can be drawn upon.

For the Utility, there is only one source of LNG supply, Nipigon LNG. If Nipigon LNG has a prolonged outage, or ceases to operate, customers cannot simply turn a switch and heat their building or home

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[1] The Marathon Economic Development Corporation (See Argument-in-Chief, para.4)

[2] Interrogatory Response SEC-1, VECC-1. Throughout these submissions, SEC refers to one distribution network for ease of understanding, even though it is clear that the intention is to build five distribution networks, one for each of the municipalities, and then operate them together.

[3] See Exhibit A, Tab 13, Schedule 1, Attachment 1. The only other listed project of Northeast Midstream is a "shovel-ready" LNG facility in Thorold, Ontario.

[4] See for example, Interrogatory Responses SEC-8, Certatus-8(g), OEB Staff-45, OEB Staff-52(b),(c),

using an alternative source. They would have already made significant investments in natural gas furnaces and/or boilers when they signed up for service.

The Applicant states that "[i]n the event of an extended interruption, replacement LNG supplies could also be sourced from Montreal or Minneapolis."[5] SEC is highly skeptical that either are solutions to extended interruptions, and definitely not if Nipigon LNG ceases to exist. As the Applicant itself notes, Montreal is 1,400km away and a 15-hour one-way trip, while Minneapolis is 900km and approximately a 9-hour trip.[6] To be supplied from these locations would require daily trucks travelling these long distances, through potentially difficult driving conditions depending on the time of year.

SEC is further doubtful that these other LNG facilities would even have the capacity to supply the Utility, especially if the extended outages occur during the winter months. The Applicant has not provided any evidence in this regard. All that it has said is that "[it is anticipated that emergency protocols would be in place in advance with these suppliers to minimize the delivery period."[7] Since the protocols are not in place, it is unclear what capabilities they do have to supply the Utility, and the cost to do so. SEC would assume that on the coldest winter days where supply is tight, the LNG spot price that would be offered at the alternative locations could be astronomical.

With respect to Nipigon LNG more generally, the only evidence the Board has regarding its financial and technical capabilities is the Applicant's summary of the conclusion of a report that an independent expert undertook for Infrastructure Ontario as a condition of financing under the Natural Gas Grant Program. The summary is positive:

> …its conclusions included the following findings: the Nipigon LNG Project adheres to industry standards and best practices and is technically feasible with a procurement strategy designed to minimize risk; Northeast Midstream has assembled a strong management team and the review of the personnel and history of Northeast Midstream suggest a reputable and credit worthy firm; and the financial forecast appears to be reasonable.[8]

Neither the Board nor SEC has seen the report, so neither can verify these findings, nor consider them in their entire context. While the Applicant appears to have a copy of the report, it has said it cannot produce it due to the "commercially sensitive nature of the information" contained within.[9] The Board should require the Applicant to produce a copy of the report, on a confidential basis pursuant to the *Practice Direction on Confidential Filings,* so that in the context of deciding on this application, the Board and the parties will be able to review, in a proper way, the assessment made of the Nipigon LNG Project.

SEC submits the Board must weigh the risks in granting approval of the application, and determine if any conditions of approval should be imposed. These could potentially include what communications the Utility will be required to provide to potential customers so that they are aware of the risks before they change their energy source. Those conditions could also include Board approval of appropriate emergency protocols and, as discussed later in these submissions, Nipigon LNG providing necessary financial security to the Utility.

Stability Period and Attachment and Cost Risk

SEC recognizes that this is not an application for approval of distribution rates. With that said, SEC submits that it is important for the Applicant to understand the risk they are going to bear, as it may impact how they may move forward with the proposed construction of the distribution system, formation of the Utility, and the terms of any required financing. The Applicant has taken the position

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[5] Exhibit A, Tab 8, Schedule 1, Attachment 1, p.39
[6] OEB-Staff-31(b)
[7] Interrogatory Response OEB-Staff-31(b)
[8] Interrogatory Response SEC-13(d),(e)
[9] *Ibid*

that if there is to be a mandated rate stability period, it would want a variance account to deal with any potential shortfall in revenue collected. The balance would presumably be sought for disposition at the end of the stability period.[10]

The Board should make clear to the Applicant, that consistent with the Board's Community Expansion Framework, that it will be required to propose a rate stability period of at least 10 years, and that the rates must allocate the attachment and construction cost risks to the Utility, and not to its customers.[11] Any revenue shortfalls during the rate stability period caused by attachment and construction cost variances would not be collected - during or after - from customers.

There is no reason that the Utility's customers should be treated any differently than other greenfield projects. For example, both EPCOR South Bruce and Enbridge Gas Inc.'s community expansion projects required the Utility to bear the risks associated with variances between forecast and actual customer attachments and related revenues.[12]

The municipalities may argue that, because they are local municipalities acting to benefit their communities in the public interest, they should not be required to bear what could be a very substantial commercial risk. SEC does not agree. The Utility will be engaged in a commercial enterprise that requires expertise, discipline, and risk management. It will seek to make a profit, and it will make commitments to its customers. It is not, in our submission, appropriate that this Utility – unlike other gas distribution companies – offload significant commercial risks onto its customers. It is the role of the Board to protect those customers, not the municipalities. Allowing the customers to be saddled with material risks is not, in our view, consistent with protecting them.

Large Industrial Customer Risk

The largest single customer of the proposed Utility will be the one industrial customer in Terrace Bay.[13] This industrial customer, which is a mill, has worked out an arrangement with the Applicant to be supplied by the Utility on an interruptible-only basis. The industrial customer has agreed in principle to an arrangement, where it would increase its natural gas use when not required by firm customers, and reduce it when it was required by those customers.[14]

The advantage of this arrangement is that the large industrial customer will be able to increase utilization of transportation arrangements that the Utility will have on the TCPL Mainline, and with Nipigon LNG. As the Applicant notes, the arrangement "will minimize the unutilized demand charge risk of the upstream delivery components to the firm customers, thereby increasing the cost effectiveness of the supply arrangements for firm customers."[15] The corollary of that is that, without the industrial customer, there will be significant cost impacts on firm customers.

The evidence is that without this large industrial customer, there would be a large increase in the non-distribution component of the bills of all other customers. The Applicant estimates that the landed cost of gas would <u>increase</u> by approximately $24.67/GJ for each rate class in 2020 dollars.[16] Based on the current forecast, this would increase the landed cost of gas by more than 200% from $11.96/GJ[17] to $36.63/GJ.

The impact of such an increase would be dramatic. First, as these amounts are traditionally pass-through amounts based on the actual demands, customers who have already been connected will see

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[10] Interrogatory Response OEB-Staff-12(c)
[11] *Decision with Reasons* (EB-2016-0004 - Community Expansion Framework), November 17 2016, p.20
[12] *Decision and Order* (EB-2017-0147 - EGD Fenelon Falls), March 1 2018, p.12
[13] Exhibit A, Tab 4, Schedule 1, p.6
[14] Exhibit A, Tab 8, Schedule A, Attachment 1, p.22
[15] *Ibid*
[16] Interrogatory Response OEB-Staff-13(i)
[17] Exhibit A, Tab 8, Schedule A, Attachment 1, p.32, Figure 6

200% increases in the commodity portion of their bills. This would be unaffordable to most customers in the community.

Second, for those potential customers who have yet to convert to natural gas, they are now almost certainly not going to connect, as there would no longer be a cost advantage over their existing sources.[18] This would have the impact of reducing the overall number of new customers, which will have the impact of increasing the costs even further for any existing customers. For existing customers, the rates may become so high that some will be unable to pay their bills. Others may convert off natural gas to another fuel source, as the cost will become prohibitive. This will likely lead to a death spiral.

In short, failure of the industrial customer to sign up, or to continue to be supplied by the Utility later, is likely to make the Utility non-viable. The costs and disruption to the local communities, both the municipalities themselves and the residents who became customers, could be considerable.

SEC's concern is the Applicant has not adequately mitigated the risk that this large industrial customer may at some point in the future no longer be a customer of the utility, or at levels that it has indicated today that it needs. This risk is not theoretical. The Applicant's own evidence is that this mill has already closed twice in the last 15 years: first in 2006, and then again in 2010.[19]

The Applicant's risk mitigation strategy for lower than forecast demand is primarily to increase sales to the demand response customer (i.e. the large industrial customer). It has no apparent mitigation strategy for what happens if that customer ceases to exist or significantly reduces its demand.[20] In response to a Board Staff interrogatory, the Applicant commented that while it did agree that a letter of credit or similar financial backstop would mitigate this risk, it did not view asking the customer for a 10-year letter of credit to be commercially feasible.[21]

SEC submits the Board should not approve the Gas Supply Plan or cost consequences of the LNG Services Agreement without ensuring that this risk is properly managed. This may mean requiring this large industrial customer to have signed some form of a financial backstop, or it may mean that the Applicant has to develop an alternative risk mitigation plan to backstop the customer's continued involvement. The viability of the Utility appears to hinge on this one large industrial customer, who has had financial difficulties in the past. The consequences to all other customers are so significant that the current mitigation approach is unreasonable and imprudent.

Pre-Approval of Cost Consequences of the LNG Services Agreement

The Applicant is seeking pre-approval of the cost consequences of the LNG Services Agreement. The contract provides that Nipigon LNG will liquefy natural gas delivered to it as a receipt point on the TCPL Mainline, truck that LNG to LNG depots that it will construct and operate in each of the five municipalities, and then re-gasify the LNG and inject it into the distribution system at those five delivery points.[22] The LNG Services Agreement is a 10 year agreement that commits the Utility to purchase 2,400 GJ/day of firm capacity in year 1, escalating to 3,700 GJ/day in year 10.[23] The total financial commitment of the Utility, and therefore its customers is $86.5M.[24] To put in perspective the size of that risk, the total annual tax revenue of the five municipalities is less than $20 million.[25]

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[18] Exhibit A, Tab 4, Schedule 3, p.1-6
[19] Exhibit A, Tab 4, Schedule 1, p.7
[20] Exhibit A, Tab 8, Schedule A, Attachment 1, p.57
[21] Interrogatory Response OEB-Staff-34(b)
[22] Exhibit A, Tab 13, Schedule 1, p.2-5
[23] Exhibit A, Tab 13, Schedule 6
[24] Interrogatory Response SEC-15(a); Exhibit A, Tab 13, Schedule 1, p.7, Table 2
[25] Taken from the most recent financial statements of the municipalities. Each municipality also has revenues from government transfers, user fees, and other smaller sources.

There are three major types of cost under the LNG Services Agreement. First, there is the Firm Capacity Charge, which is set at $7.03 GJ, and will increase by 1.5% per year.[26] Second, there is the Variable Charge, which is simply defined as the Utility's pro-rata share of the LNG facility's consumables, subject to a minimum monthly charge and adjusted from time to time.[27] Third, there is the Truck Transportation Services Charge, which is the cost, without markup, of Nipigon LNG trucking the LNG from its facility to each LNG Depot.[28]

SEC accepts that the LNG Services Agreement is a type of contract that is appropriate for pre-approval under the Board's *Filing Guidelines for the Pre-Approval of Long-Term Gas Supply.*[29] The contract is to support the development of new natural gas infrastructure[30], which includes both the Utility's distribution system and the Nipigon LNG Facility itself. There are also clearly potential benefits to customers of having the contract approved, as its approval is a pre-condition to the creation of the distribution system. Furthermore, SEC accepts that trucked in LNG appears to be the most cost-effective way to bring natural gas from the TCPL Mainline to the five municipalities. Due to the distance, it would not be cost-effective to bring natural gas by way of pipeline[31], nor does it appear that compressed natural gas ("CNG") was a viable option to serve the entire forecast customer base.[32]

However, the fact that LNG is the most appropriate type of supply for the Utility does not mean that the specific cost consequences of the LNG Services Agreement with Nipigon LNG are just and reasonable.

The Board's task in approving the Gas Supply Plan and the cost consequences of the LNG Services Agreement, are a bit different than would normally be the case with an existing utility. The Applicant, and the proposed Utility, have no customers to date. No potential customers are required to attach to the new distribution system. Each will have the opportunity to make their own calculations to determine if converting to natural gas is in their best interests, based on the approved distribution rates, and forecasts of commodity and transportation costs which will be based partly, on any pre-approved supply transportation agreements such as the LNG Services Agreement. Nobody will be captive to the monopoly distribution system until they decide to attach.

The Board does still have an important consumer protection role in ensuring that they have all the appropriate information so that they are able to make an informed decision on the costs, benefits, and risks for switching to natural gas. This is no different than how the Board requires certain information to be provided by gas marketers to potential customers of their services.[33] The Board should require communications to customers and potential customers with respect to attaching to the Utility's system, be approved by the Board, and must fairly and thoroughly explain the costs, risks, and benefits associated with customers switching from their current energy source(s) to the Utility's natural gas offering.

Once customers have made the informed decision to connect, the Board must ensure that those customers that have attached are protected from changes in rates, since the cost of switching back to a different fuel is prohibitive. They are now captive customers and the Board must act in its traditional role as a monopoly regulator.

[26] Exhibit A, Tab 13, Schedule 1, Attachment 5, p.37
[27] *Ibid*
[28] Exhibit A, Tab 13, Schedule 1, Attachment 5, p.20, Section 7.1(b)(ii); Exhibit A, Tab 13, Schedule 1, p.12
[29] Filing Guidelines for the Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts (EB-2018-0280)
[30] *Ibid*
[31] Exhibit A, Tab 13, Schedule 1, p.13
[32] Applicant Response to Certarus IRs, Foreword; A-13-1, p.12
[33] See Ontario Energy Board, *Code of Conduct for Gas Marketers*, Section 4

Therefore, the primary purpose of pre-approval of the cost consequences of the LNG Services Agreement, is to ensure that the *changes* or *potential changes* in transportation costs over the term of the contract are reasonable. While potential customers will have the opportunity to look at the initial costs of the contract and how it impacts their rates, they will not be reviewing the LNG Services Agreement itself, and understanding the potential impacts on their rates going forward.

SEC does have several concerns regarding the cost consequences of the LNG Services Agreement that need to be addressed before the Board should approve it. In commenting on specific terms in the LNG Services Agreement, on the surface it may seem that SEC is second-guessing commercial arrangements made by parties negotiating at arms-length. It is not actually concerned with the terms as commercial terms per se. While the terms may be unfair or unreasonable, the Utility and Nipigon LNG are free to make whatever deal they want, and live with the results.

However, when the Applicant seeks a Board order essentially making the customers responsible for the costs the Utility has to pay under the LNG Services Agreement, that is no longer about commercial arrangements. It is now about costs and risks to customers, and engages the Board's mandate to protect those customers. Whether or not the parties to the agreement had the best intentions, or were trying to be fair, or anything else, the Board's role is to look at it from the customers' perspective, and assess whether the agreement is fair and reasonable for the customers.

Therefore, SEC submits that in looking at each term of the LNG Services Agreement, that raises concerns, the Board's perspective should be: 'Is this a fair and reasonable cost or risk for the customers to bear?'

Variable Charge. Under the LNG Services Agreement, Nipigon LNG will charge the Utility a charge intended to recover its variable costs of the LNG Depots and a pro-rata share of those of the LNG Facility.[34] The amount of the charge will be updated annually.[35] Under the LNG Services Agreement, the type and quantity of those variable costs is not actually defined anywhere. Moreover, unlike other charges, such as the Trucking Services Charge, there is no prohibition on markups.[36]

While the Applicant confirmed that this is correct in response to SEC Interrogatory 13(f)(iii), it said something different in response to OEB Staff Interrogatory 41. In the latter response it says the variable charge is set without markup, and that it is the cost of natural gas, electricity, nitrogen and other items consumed in the liquefaction and regasification process.[37] Insofar as that is what the Applicant says is meant by the terms of the LNG Services Agreement, then the agreement should say so. On a plain reading of the relevant sections of the LNG Services Agreement, it does not actually define the types of costs to be included, nor whether they can include markups, nor whether there are any limits on markups.

The undefined nature of the Variable Charge, especially if Nipigon LNG is allowed to include a markup on its costs, is not reasonable. As currently drafted, the LNG Services Agreement would allow Nipigon LNG to increase the variable charge each year to essentially whatever amount it wants. If this is not the intent of the parties, as appears to be the Applicant's view, then they should clarify this by amending the LNG Services Agreement. The Board should not approve the LNG Services Agreement without changes to limit the costs to the types which the Applicant set out in response to OEB Staff Interrogatory 41(a), without markup.

Financial Security. SEC notes that the LNG Services Agreement requires that the Utility provide, upon request, a financial backstopping agreement. Considering that the Utility is required to pay for the fuel contracted capacity regardless of its actual demand, the amount that needs to be financially

[34] Exhibit A, Tab 13, Schedule 1, Attachment 5, Section 4.1(b); SEC-13(f)(ii),(iii)
[35] *Ibid*
[36] Interrogatory Response SEC-13(f)(iv)
[37] Interrogatory Response OEB-Staff-41(a)(b)

secured could be up to $86.7M.[38] This is a considerable sum, and the cost to obtain the security could be substantial. The Applicant has said that they expect to be required to provide this security, and that the cost consequences of providing financial security to Nipigon LNG are not known and will depend on what form it takes.[39]

Providing a financial backstop is not an uncommon requirement for large customers of a utility, but what makes this situation unique is that, if anything, it should be Nipigon LNG that provides financial security to the Utility. As discussed earlier in these submissions, Nipigon LNG, itself a greenfield entity, is at least as risky an entity than a Utility which is primarily composed of residential, small commercial, and institutional loads. The consequences of Nipigon LNG failing to provide services to the Utility and its customers are grave, as there is limited, if any, replacement LNG that can be cost-effectively procured in a timely matter.

SEC submits the LNG Services Agreement does not adequately protect the Utility from default by Nipigon LNG. Considering the health and safety implications of LNG not being available for heating in Northern Ontario, the Utility should have required financial protections in the LNG Services Agreement, such as a financial backstop. Yet it is the much less risker Utility that is likely required to provide security for the entire cost of the agreement. This is unreasonable in the context of the two greenfield entities.

Liability Provisions. SEC notes that the LNG Services Agreement contains several liability provisions that are asymmetrical in favor of Nipigon LNG. Section 12 states that Nipigon LNG is 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.[40]

When asked about this provision, the Applicant stated simply that the "LNG Service Agreement represents the terms and conditions required by Nipigon LNG as a condition to the design, development and construction of the LNG Depot and subsequent provision of the LNG Services to the Utility".[41] With respect, that is not a good answer. This is not a fair term that the Applicant should have agreed to, and in the context of this agreement it is not commercially reasonable. The Applicant has as much, or potentially greater, bargaining power than Nipigon LNG. The specific term exposes the Utility and its customers to potentially significant cost consequences.

Furthermore, the cap on liability provisions in the LNG Services Agreement has been left blank. The Applicants response to questions about this is that the "Nipigon LNG's cap on liability is to be finalized during the next phase of the project".[42] Insofar as the Board is approving the cost consequences of the LNG Services Agreement, it should not do so without understanding the proposed cap on Nipigon LNG's liability.

The Board should reject pre-approval of the cost consequences of the LNG Services Agreement unless the liability provisions are amended to ensure they are symmetrical and fair. In addition, the Board should make clear that the quantum and reasonableness of any recovery of costs from customers must be determined by the Board based on the specific facts of any incident, and a pre-approval is not a carte blanche to recover all such costs.

Termination Provisions. Under section 10.3(b) of the LNG Services Agreement, the Utility is able to terminate the agreement if Nipigon LNG has failed to satisfy any of certain defined Customer Conditions, which are described in section 3.1 and include Nipigon LNG obtaining all its required

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[38] Exhibit A, Tab 13, Schedule 1, p.7. Sum of annual totals.
[39] Interrogatory Response OEB-Staff -37(d)
[40] Exhibit A, Tab 13, Schedule 1, Attachment 5, Section 12
[41] Interrogatory Response OEB-Staff-44(a)
[42] Interrogatory Response SEC-13(e)

government and regulatory approvals.[43] Section 10.4 of the LNG Services Agreement provides that if the Utility does terminate the contract under section 10.3(b), it is still required to pay for certain costs, including construction of the LNG Depot.[44]

This would appear to be a very unfair provision for the Utility. It is not clear why it should bear any costs whatsoever of Nipigon LNG, if they are unable to construct the necessary LNG Facility. But more importantly, customers should not be connected, or even told they should switch their own equipment, until all of the necessary Nipigon LNG facilities and Utility assets are in place to serve them. These costs by definition should never be passed on to customers because there should not be any customers of the Utility until the Nipigon LNG Facility and Depots are fully operational.

Renewal Terms. The LNG Services Agreement provides the Utility with a right to renew for an additional 10 years. SEC submits the Board should be clear to the Applicant that it is not approving any cost consequences of the LNG Services Agreement beyond the initial 10-year period. The Firm Capacity Charge upon renewal would continue to be the previous year's rate escalated by 1.5%.[45] SEC submits that considering that it is likely that the total amount payable under the LNG Services Agreement during the initial 10 years will pay for most, if not all, the initial capital costs of the LNG Facility, it may be appropriate for the Utility to decline the renewal option, and seek to negotiate a different agreement with Nipigon LNG that would be reasonable at the time. The Board should assess the reasonableness of the situation at the time the Utility makes its decision and should not make a determination on the appropriateness of the renewal terms at this time.

***Other Issues – Rate Regulation of* Nipigon LNG**

While not directly at issue in this application, SEC does wish to point out that the Board may ultimately come to the conclusion that it does have rate-setting jurisdiction over Nipigon LNG. If so, the negotiated rates between the Utility (and its customers) and Nipigon LNG could be superseded by a cost based rate determined by the Board. Pursuant to section 36(1) of the *Ontario Energy Board Act (*"*ÓEB Act*"*)*, "No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract."[46] Section 36(2) and (3) require the Board to approve of or fix just and reasonable rates for these activities.[47]

While Nipigon LNG is not a gas transmitter under the *OEB Act*, as it does not transport gas through a hydrocarbon transmission line (i.e. pipeline), it may be a gas distributor, which is simply defined as a person "who delivers gas to a consumer".[48] The proposed Utility may not itself be a consumer, as it does not consume the gas, but any end-use customers of Nipigon LNG, who do consume the LNG may very well be. In that situation, Nipigon LNG, would be a gas distributor, and potentially all of its rates to all customers could be set by the Board, including rates charged to the Utility.

In response to interrogatory SEC-16, the Applicant provided a response on behalf of Nipigon LNG to a question posed about the Board's jurisdiction under section 36. In that answer, Nipigon LNG, cites the Board's decision in EB-2014-0012, where it says the "OEB determined to refrain from regulating natural gas liquefaction services on grounds that the LNG market is workably competitive."[49]

SEC disagrees with Nipigon LNG's interpretation of that Board decision. In EB-2014-0012 Union Gas sought approval for a rate to provide interruptible LNG service from its Hagar Facility. The Board determined on a motion for forbearance under section 29 of the OEB Act (brought in fact by Nipigon

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[43] Exhibit A, Tab 13, Schedule 1, Attachment 5, Section 10.3(b), section 3.1, 10.3
[44] Exhibit A, Tab 13, Schedule 1, Attachment 5, Section 10.3(b), section 10.3
[45] Interrogatory Response OEB Staff-37(f)
[46] *Ontario Energy Board Act, 1998*, section 36(1)
[47] *Ontario Energy Board Act, 1998*, section 36(2)(3)
[48] *Ontario Energy Board Act, 1998*, section 3
[49] Interrogatory Response SEC-16

LNG affiliate Northeast Midstream LP) that the specific Hagar Facility proposed LNG service, should not be regulated.

While the Board does say in the decision that it is forbearing from regulating the provision of LNG, it is clear that this is based on the Board's finding that the market for LNG, as a transportation fuel, was competitive.[50] As the Board noted:

> Northeast presented evidence that there is already a competitive market for liquefied natural gas as a transportation fuel, and that the OEB should forebear from regulation. Union did not dispute the fact that LNG as a transportation fuel competes with diesel fuel, but argued that the unique circumstances of the Hagar facility require that the new service be regulated by the OEB. For the reasons described below, the OEB finds that the new service that Union proposes to provide is already competitive and thus will not set rates or otherwise regulate this activity.
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> ….
>
> The OEB is satisfied that there is competition sufficient to protect the public interest for Union's proposed liquefaction service (which will chiefly be used as vehicle fuel), and it will not regulate Union's proposed provision of its liquefaction service.
>
> There does not appear to be any serious dispute between the parties that the LNG service Union proposes is or will be competitive. Most of the elements of the section 29 test are not actively contested. It is agreed by Northeast and Union that the relevant product market is the market for motor vehicle transportation fuel. Currently the chief competitor for LNG as a motor vehicle transportation fuel is diesel fuel, which is widely available. It is also generally agreed that the relevant geographic market is Ontario, Quebec, and portions of the Northeast and Midwest United States.
>
> ….
>
> The OEB will therefore not regulate Union's proposed new liquefaction service. As required by section 29(4), the OEB will promptly notify the Minister of Energy of this decision.[51]

The decision, read in its context and in light of the specific relief sought by Northeast Midstream LP[52], makes clear that the Board was forbearing from regulating LNG service at Union's Hagar facility only, because the evidence showed that its purpose, as a *transportation fuel*, was competitive. SEC notes that the Board only had the jurisdiction to forbear based on competition because it had the jurisdiction to regulate if there was insufficient competition to protect the public interest.[53]

The Hagar proceeding had nothing to do with LNG at-large, or for the purposes of serving non-transportation consumers. Insofar as Nipigon LNG plans on an LNG Facility providing LNG to end-use customers (especially if it is for non-transportation uses), then that service has been and is not forborne. By definition, it would be rate-regulated by the Board, at least until a broader section 29 approval is sought and decided. Given the lack of other LNG sources in Northern Ontario to serve the municipalities, SEC believes a section 29 forbearance that would cover them is unlikely.

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[50] *Decision with Reasons* (EB-2014-0012 - Union Gas), April 9 2014, p.3

[51] *Decision with Reasons* (EB-2014-0012 - Union Gas), April 9 2014, p.3-5

[52] See EB-2014-0012, Northeast Midstream Factum, dated November 18, 2014, para 85:

> "Northeast respectfully submits that it would be appropriate for the Board to grant an order pursuant to section 29 of the Act and refrain from regulating and approving the terms, conditions and rates for interruptible natural gas liquefaction service requested by Union.

[53] *Ontario Energy Board Act, 1998*, section 29(1)

Conclusion

SEC therefore submits that the Board should approve the Application, subject to the following conditions, each of which are to be reviewed by the Board in a second phase of this proceeding:

1. The Applicant should immediately file the Infrastructure Ontario expert report on the Nipigon LNG Facility project, with such redactions as may be necessary to comply with the Board's *Practice Direction on Confidential Filings*.

2. Before any final approvals are issued, the Applicant must propose a robust risk mitigation plan that minimizes the risk to customers that Nipigon LNG will fail to deliver sufficient LNG during the term of the LNG Services Agreement. The plan should include some component of financial security or backstop from Nipigon LNG.

3. Before any final approvals are issued, the Utility must provide:

    a. Evidence that the large industrial customer has signed a binding ten-year agreement for the supply of natural gas to its mill, including a copy of that agreement; and

    b. A robust risk mitigation plan that ensures that the Utility's customers are protected if the large industrial customer is unable or unwilling to fulfill the terms of its supply agreement, which plan may include some component of financial security or backstop from the large industrial customer.

4. Before any final approvals are issued, the Utility and Nipigon LNG must amend the LNG Services Agreement, in a manner satisfactory to the Board, to at least correct the following terms:

    a. The costs included in the Variable Charges must be clearly defined in detail, and the prohibition against any markup claimed by the Applicant must be spelled out.

    b. The financial security provision should be deleted and replaced with financial security provided by Nipigon LNG in favour of the Utility.

    c. All limitation of liability provisions in the agreement should be amended to be symmetrical and fair, subject to the specific types of liability and the control by the parties of the causes of that liability.

    d. Nipigon LNG should be required to certify in writing when its LNG Facility and Depots are completed and fully operational, and the Utility should have no obligation to pay any costs of that infrastructure until that has occurred.

    e. If Nipigon LNG fails to meet any of the Customer Conditions, the remedies of the Utility should be expanded to include recovery of all costs it has incurred with the knowledge of Nipigon LNG prior to that time.

5. The Utility should be prohibited from signing up any customers or recommending to any customers that they change their equipment, until Nipigon LNG has certified in writing that the LNG Facilities and Deports are completed and fully operational.

6. The rates charged by the Utility must include a rate stability period of at least ten years. The rates, during that ten years and thereafter, may not include any costs associated with cost

overruns in the capital spending on the Utility's system, nor any impact on rates as a result of customer attachments failing to meet the projections provided by the Applicant to the Board.

7. Communications to customers and potential customers with respect to attaching to the Utility's system must be approved by the Board, and must fairly and thoroughly explain the costs, risks, and benefits associated with customers switching from their current energy source(s) to the Utility's natural gas offering.

All of which is respectfully submitted.

Yours very truly,
Shepherd Rubenstein P.C.

Original signed by

Mark Rubenstein

cc: Wayne McNally, SEC (by email)
Applicant and Intervenors (by email)