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January 23, 2020

**VIA EMAIL: REGISTRAR@OEB.CA**

Ms. Christine E. Long
Registrar and Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Long:

**Re: Corporation of the Town of Marathon**
**Ontario Energy Board File Number: EB-2018-0329; Argument-in-Reply**

We are writing on behalf of the Corporation of the Town of Marathon in its own capacity and as the representative of the Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay and the Municipality of Wawa (together, the "**Municipalities**") to file the Argument-in-Reply of the Municipalities. This submission has been filed through RESS.

Two hard copies will be couriered to the OEB today.

Yours truly,
**Dentons Canada LLP**

*Original signed by Helen T. Newland*

Helen T. Newland

Encls.
cc: Daryl Skworchinski, *Corporation of the Town of Marathon*
Stephanie Ash, *Firedog Communications*
Parties to EB-2018-0329

**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the *Ontario Energy Board Act, 1998,* SO 1998, c. 15 (Sched. B), as amended (the **Act**) and the *Municipal Franchises Act* (the **MFA**), RSO 1990, c. M.55, as amended;

**AND IN THE MATTER OF** an application by the Corporation of the Town of Marathon under section 8 of the MFA for an order or orders granting Certificates of Public Convenience and Necessity to the Corporation for the construction of works in the Town of Marathon, Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay, and Municipality of Wawa;

**AND IN THE MATTER OF** an application by the Corporation of the Town of Marathon under section 90 of the Act for an order or order granting leave to construct natural gas distribution pipelines and ancillary facilities to serve the Town of Marathon, Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay, and Municipality of Wawa;

**AND IN THE MATTER OF** an application by the Corporation of the Town of Marathon under section 97 of the Act for an order or orders approving the form of easement agreements;

**AND IN THE MATTER OF** an application by the Corporation of the Town of Marathon for an order or orders for a gas supply plan to serve the Town of Marathon, Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay, and Municipality of Wawa;

**AND IN THE MATTER OF** an application by the Corporation of the Town of Marathon for an order or orders pre-approving the cost consequences associated with a long-term upstream liquefied natural gas contract to serve the Town of Marathon, Township of Manitouwadge, Township of Schreiber, Township of Terrace Bay, and Municipality of Wawa.

**Corporation of the Town of Marathon**

**Argument-in-Reply**

**January 23, 2020**

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## I. GLOSSARY

The following terms are defined in these submissions:

(a) **Anwaatin**: Anwaatin Inc.

(b) **Anwaatin First Nations**: The three First Nations communities that Anwaatin directly represents, consisting of Aroland First Nation, Animbiigoo Zaagi'igan Anishinaabek Nation, and Ginoogaming First Nation.

(c) **Applicant**: The Corporation of the Town of Marathon, on its own behalf and as a representative of the Township of Manitouwadge, The Township of Schreiber, the Township of Terrace Bay and the Municipality of Wawa.

(d) **Application** or **Phase I Application**: The application in the matter (EB-2018-0329), dated and filed by the Municipalities to the Board on August 15, 2019.

(e) **BNA**: Bingwi Neyaashi Anishinaabek.

(f) **Board**: the Ontario Energy Board.

(g) **Certarus**: Certarus Ltd.

(h) **CNG**: Compressed natural gas.

(i) **Cornerstone**: Cornerstone Energy Services, a North American engineering and design consultancy with offices across Canada and the United States.

(j) **CPCN** or **Certificate**: Certificate of Public Convenience and Necessity.

(k) **Corporation**: The Corporation of the Town of Marathon.

(l) **Distribution System**: In this Project, approximately 116.5 kilometres ("**km**") of low pressure MDPE (medium-density polyethylene) natural gas pipeline and associated facilities within the Municipalities.

(m) **Elenchus**: Elenchus Research Associates Inc.

(n) **Environmental Guidelines**: The Board's *Environmental Guidelines for Hydrocarbon Pipelines and Facilities in Ontario*, 7th Edition (2016).

(o) **Enbridge Gas**: Enbridge Gas Distribution Inc.

(p) **EPP**: Environmental Protection Plan.

(q) **ER** or **Environmental Report**: Environmental report prepared by Stantec Consulting Inc. for each of the Municipalities and filed to the Board in this matter on August 7, 2019.

(r) **Gas Supply Plan**: The Gas Supply Plan included in the Application at Exhibit A, Tab 8, Schedule 1, Attachment 1.

(s) **Generic Proceeding on Community Expansion**: The Generic Proceeding on Community Expansion (Natural Gas) bearing the file number EB-2016-0004.

(t) **Intervenors**: Collectively SEC, VECC, Certarus, Anwaatin, Long Lake, Red Rock and BNA.

(u) **Innovative**: Innovative Research, which carried out the design and survey of the residents of the Municipalities in connection with the Application.

(v) **IR**: Interrogatory.

(w) **IRR**: Response to interrogatory.

(x) **KPI**: Key performance indicators.

(y) **LDC**: Local distribution company.

(z) **Ledger Facilities**: The interconnection facilities and delivery point on the TC Energy Mainline in the Township of Ledger.

(aa) **LNG**: Liquefied natural gas.

(bb) **LNG Depot(s)**: The LNG storage and regasification depots to be built and operated in each of the Municipalities.

(cc) **LNG Services Agreement** or **Contract**: The LNG services agreement included in the Application at Exhibit A, Tab 13, Schedule 1, Attachment 5.

(dd) **Long Lake**: Long Lake #58 First Nation.

(ee) **LTC**: Leave to construct.

(ff) **Marathon**: The Town of Marathon.

(gg) **MECP**: Ministry of Environment, Conservation and Parks.

(hh) **MEDC**: Marathon Economic Development Corporation.

(ii) **MENDM**: Ontario Ministry of Energy, Northern Development, and Mines.

(jj) **MFA**: *Municipal Franchises Act*, RSO 1990, c M.55.

(kk) **Mill**: The pulp mill located in Terrace Bay.

(ll) **Mill Risk**: As described in paragraph 27.

(mm) **Mill Risk Mitigation Proposal**: As described in paragraph 31.

(nn) **Municipal Franchise Agreement**: An agreement that will be entered into by each of the Municipalities with the Utility, and which will grant the Utility the right to construct and operate the Distribution System in that Municipality subject to the terms and conditions in the Agreement, in respect of the construction and operation of the Distribution System.

(oo) **Municipalities** or the **North Shore Municipalities**: The Town of Marathon, the Township of Manitouwadge, The Township of Schreiber, the Township of Terrace Bay and the Municipality of Wawa.

(pp) **Nipigon LNG**: Nipigon LNG LP.

(qq) **Nipigon LNG Facility:** The Nipigon LNG liquefaction facility.

(rr) **NOHFC**: Northern Ontario Heritage Fund Corporation.

(ss) **NOHFC Strategic Economic Infrastructure Program**: The program that is run by NOHFC, which helps regions and communities advance economic development opportunities and supports investments through strategic infrastructure.

(tt) **North Shore Project** or the **Project**: The project which is the subject of the Corporation's Application in the within matter (EB-2018-0329), involving the construction and operation of local gas delivery works in each Municipality, including the distribution mains, service pipes and meters.

(uu) **Northeast** or **Northeast Midstream**: Northeast Midstream LP.

(vv) **OEB Act**: *Ontario Energy Board Act, 1998*, SO 1998, c 15, Sched B.

(ww) **OEB Staff or Board Staff**: Ontario Energy Board Staff.

(xx) **OEB's Framework for the Assessment of Distributor Gas Supply Plans** or **Gas Supply Framework**: As set out in EB-2017-0129.

(yy) **OPCC**: Ontario Pipeline Coordinating Committee.

(zz) **Phase 2 Application**: The application that will be filed with the Board for approval of evidence of the Utility's technical and financial capacity, the Mill Risk Mitigation Proposal and of any other matters arising from the Application that may require Board approval, save and except the Utility's inaugural rate application which will be separate from and not included in the Phase 2 Application.

(aaa) **Pre-Approval Guidelines**: The Board's *Filing Guidelines for Pre-Approval of Long-term Natural Gas Supply and/or Upstream Transportation Contracts* dated April 23, 2009.

(bbb) **Red Rock**: Red Rock Indian Band.

(ccc) **SEC**: School Energy Coalition.

(ddd) **Stage 2 AA**: Stage 2 Archaeological Assessment.

(eee) **Stantec**: Stantec Consulting Inc.

(fff) **TC Energy**: TransCanada Energy.

(ggg) **TCPL**: TC Energy Canadian Mainline.

(hhh) **Union**: Union Gas Limited.

(iii) **Utility**: The proposed local gas distributor for the distribution of natural gas within the Municipalities.

(jjj) **VECC**: Vulnerable Energy Consumers Coalition.

## II. INTRODUCTION

1. This is the Argument-in-Reply ("**Reply**") to the submissions of Board Staff and of SEC, VECC, Certarus, Anwaatin, Long Lake, Red Rock and BNA (collectively, the "**Intervenors**") on the Application of the Municipalities for certain OEB approvals and authorizations in respect of a proposed regional natural gas distribution system. This Reply addresses only those issues raised by Board Staff and Intervenors in their submissions and does not re-argue matters that are not in contention. It is organized on an issue-by-issue basis. Finally, terms not herein defined have the meaning ascribed to them in the Municipalities' Argument-in-Chief. A Glossary is included for ease of reference at pages 3-6 herein.

## III. OVERVIEW OF PRINCIPAL ISSUES

- ***Project Risk***

2. In deciding the Application, the Board must decide whether the benefits that will flow from the Project will outweigh Project costs and risks and, if so, how unmitigated risks should be allocated as between Utility ratepayers, on the one hand, and municipal taxpayers, on the other hand. This risk allocation calculus is not a straight-forward exercise because of the overlap between distribution ratepayers and municipal taxpayers, the ultimate investors in the Utility.

3. In their submissions, the Board Staff and most Intervenors expressed general support for the Project on the basis that it will benefit the five Municipalities by providing them with access to a less expensive source of energy, consistent with the energy and economic development policies of the government of Ontario.[1] The "knock-on" effects of lower energy costs will increase disposable income for residents who are distribution customers, revitalize the local economy, contribute to Ontario's gross domestic product and reduce greenhouse gases.

4. Notwithstanding their expressions of support, each of Board Staff, SEC and VECC expressed concerns that forecast, supply and contractual risks were not sufficiently mitigated and would fall, disproportionately, on future ratepayers. Each party proposed various conditions of approval to mitigate and/or reallocate these risks.

[1] See, e.g., Board Staff Submission, p. 4; VECC Submission, p. 2; SEC Submission, p. 1; Long Lake Submission, para. 26; Red Rock and BNA Submission, paras. 7 and 11; Anwaatin Submission, paras. 3 and 10; and Nipigon LNG Submission, para. 8.

5. It comes as no surprise that Board Staff, SEC and VECC should raise concerns about project risk. While the benefits of being able to access natural gas are significant, they come with a set of unique risks. For example, the prohibitive cost of constructing pipeline connections between the TC Mainline and northern Ontario communities requires new and innovative approaches, such as reliance on the kind of virtual natural gas pipelines that have been utilized in Alaska and other remote locations. The economies of most northern Ontario communities are inexorably bound to extractive and pulp and paper industries which compete in and are vulnerable to the vagaries of global markets. This means that changes in the demographic and employment profiles of one-industry towns over time, may translate into additional variances between actual and forecast attachments. Further, challenges are presented by the remote location and physical environment (e.g., weather, Canadian Shield) of northern communities. This means that, typically, construction budgets for infrastructure projects include a contingency of between 20 and 25 percent and the loss of a single construction season due to project delays can result in material increases in construction costs.

6. Many of these risks have already been identified and mitigated. For example, with respect to capital cost risk, it is expected that the Utility will give preference to construction contractors who are prepared to offer a stipulated or fixed price. Bid packages will be informed by detailed engineering designs and the results of geotechnical surveys; this should serve to reduce contingency amounts. Customer attachment risk has also been addressed through the use of conservative assumptions and by reliance on data received directly from potential customers through a series of customer surveys. The bottom line, however, is that it is not possible to entirely de-risk an isolated municipally-owned, greenfield gas distribution system located in northern Ontario.

7. In this Reply, the Municipalities respond to the forecast, gas supply and contract risk-related concerns raised by Board Staff, SEC and VECC by:

   (i) explaining the reasons why concerns about the attachment risk forecast are misapprehended and overstated;

   (ii) proposing to submit a Mill Risk Mitigation Proposal as part of the Phase 2 Application to address concerns about the Utility's reliance on a single industrial customer;

   (iii) agreeing to include, in the Utility's inaugural rates application, a Rate Stability Proposal that protects ratepayers from the effects of overages and underages, relative to forecasts of costs and customer attachments, respectively;

(iv) agreeing to prepare a study that examines the feasibility of constructing and operating the facilities required to enable the Utility to take receipt of CNG gas for use as a secondary source of system supply (i.e., for peak sharing or emergency backup) and including that study in the Phase 2 Application; to be clear and as discussed below in paragraphs 11 to 12, the Municipalities' agreement in this regard should not be construed as an agreement to the imposition of mandated open access for competitive CNG and LNG retailers;

(v) narrowing the scope of the Municipalities' request for approval of the cost consequences of the following terms in the LNG Services Agreement: the Firm Capacity Charge; the daily committed capacity; the contract term; and the *force majeure*/service interruption provisions; and

(vi) renegotiating the other aspects of the agreement (see paras. 15-17 and 72-84).

- ***Economic Feasibility***

8. The Municipalities have determined that the Project is economically feasible on the basis of the comprehensive and detailed projections and forecasts of customer attachments, Project costs (i.e., capital costs) and distribution revenues included in the Application. These projections and forecasts, together with the Applicant's agreements to accept the imposition of a rate stability period and submit a Mill Risk Mitigation Proposal for Board approval, should give the Board the confidence to make a similar determination on the Phase 1 Application.

9. The fact that the forecasts in the Application will be updated in the Utility's inaugural rate application to reflect information from later stage engineering and geotechnical activities and pipeline constructor bids, does not mean that these forecasts cannot be relied upon to determine economic feasibility for the purpose of issuing a leave to construct order. The rate estimates included in the Application are significantly lower than alternative sources of energy in the Municipalities. Accordingly, there is considerable latitude with respect to forecast variance, before arriving at the point where these cost savings would be completely eroded (see paragraphs 22 (ix) and 25, below).

10. Although the Applicant has a high degree of confidence in its forecasts, it would be unreasonable to expect the Applicant to have final and firm forecasts of costs and revenues sufficient for rate-making purposes, at this stage of the Project's development. The fact that the Applicant is willing to commit to the imposition of a rate stability period on the basis of rates submitted in its inaugural

rate application, should assuage any concerns the Board may have about the rate implications of forecast risk.

- ***Open Access***

11. While Certarus does not oppose the Application, *per se*, it takes issue with the fact that, although distribution customers may choose whether to directly purchase "gas" and arrange for its transportation on the TC Mainline (to the TCPL – Nipigon LNG interconnect), they must accept delivery of their gas at the burner tip via the Nipigon LNG virtual pipeline. Certarus urges the Board to reject this aspect of the Application and, instead, mandate an "equal" or "open access" framework whereby distribution customers may choose between the Nipigon LNG virtual pipeline and a speculative, undefined and uncosted Certarus option.

12. The Municipalities object, in the strongest possible terms, to Certarus' request for mandated equal or open access. This objection is on five main grounds:

    (i) the pool of potential customers within the five Municipalities is not sufficiently large to support an open access regime; a "level playing field" amongst competing suppliers and "consumer choice" are luxuries that cannot be afforded in respect of a municipally-owned Utility, located in an isolated region, with a small customer base;

    (ii) the economic feasibility of the Project is underpinned by the assumption that <u>all distribution customers</u> will pay their proportionate share of the fixed costs under the LNG Services Agreement; the cost and revenue forecasts included in the Application reflect this assumption;

    (iii) facilitating the by-pass of system gas supplied from the Nipigon LNG virtual pipeline in favour of a direct purchase supply option could trigger a "domino effect" and put the economic viability of the Utility at risk; <u>in the result, mandated open access could end up meaning no gas access at all</u>;

    (iv) under an open access framework, the Utility would be the gas supplier of last resort; as such, it would be required to maintain the ability to supply natural gas to distribution customers who choose to purchase their gas from alternative suppliers, in the event their supplier fails to deliver for any reason or the customer chooses to return to system gas (as has often been the case in Ontario); and

(v) there is no <u>evidence</u> on the record of this proceeding as to the feasibility, reliability, cost and benefits of mandated open access, including evidence as to how the Utility's costs would be allocated between its system gas customers and direct purchase customers.

13. These grounds are discussed below, in paragraphs 48-53.

- ***Supply Reliability and Diversity***

14. Board Staff[2] and some Intervenors[3] expressed concerns about the risks inherent in the Applicant's proposal to rely on a single source of natural gas supplied by Nipigon LNG, also referred to as a lack of "supply diversity". Presumably, their underlying concern is what would happen in the event that the Nipigon LNG liquefaction facility (the "**Nipigon LNG Facility**") or the LNG Depots were unavailable and the Utility was forced to curtail its firm service customers. As many communities in southern Ontario are supplied by a single pipeline distribution lateral, the Applicant assumes that Board Staff and Intervenors believe that the components of the Nipigon LNG virtual pipeline would be less reliable than a pipeline lateral. The Applicant does not know the basis of Board Staff and Intervenor's belief in this regard but, nevertheless, makes the following points by way of reply:

(i) Unlike a distribution system supplied by a single pipeline lateral (i.e., no back-feed supply), the Utility's distribution system will be able to call upon at least 10 days worth of peak demand supply, provided by the LNG Depots and the Nipigon LNG Facility, itself. [4] On non-peak days, this storage availability would last much longer. In contrast, a pipeline outage on a lateral pipeline that is the sole supplier of gas to a distribution system (or on pipelines upstream of the lateral), would result in immediate adverse consequences for customers.

(ii) In the event of an outage at the Nipigon LNG Facility, the Utility could also curtail its interruptible customers and in particular, the Mill, in order to continue to supply its heating load customers.

(iii) If necessary, additional storage could be constructed (at the LNG Depots and/or at the Nipigon LNG Facility) to increase the reliability of the system. The incremental

[2] Board Staff Submission, pp. 21-22.
[3] SEC Submission, pp. 2 and 8; VECC Submission, p. 9.
[4] Application, Exhibit A, Tab 8, Schedule 1, Attachment 1, p. 53.

capital cost to do so would be approximately $2 million for an additional 7,500 GJ at the Nipigon LNG Plant[5] and approximately $1 million for an additional 1,575 GJ at each of the LNG Depots[6].

(iv) As discussed below in greater detail in paragraph 58, the LNG Depots will be designed with very few moving parts (e.g., no pumps) and certain equipment, such as tanks and vaporizers, will be duplicated (i.e., installed in pairs). Accordingly, the overall reliability of the LNG Depots may be estimated as the probability of a major equipment failure which is estimated as extremely low, approximating several hundreds of years between failures.

(v) In the highly unlikely event of a major equipment failure at an LNG Depot, portable LNG storage and regasification equipment can be brought to the site from other locations in Canada.

(vi) The LNG Depots will be equipped with back-up power generators in order to mitigate against the risk of power outages on the local electricity grid.

(vii) As discussed below in greater detail in paragraphs 59-61, small scale LNG liquefaction plants exhibit very high availability, in the order of <u>over 99%.</u> Moreover, the average down-time of each forced outage of comparable equipment has been estimated to be 33 hours. Accordingly, the storage capacity available from the LNG Depots and the Nipigon LNG Facility, together with the Utility's ability to interrupt certain customers, will be more than sufficient to mitigate all minor and moderate plant outages.

(viii) As discussed below in greater detail in paragraphs 59-68, in the event of a catastrophic and prolonged outage of the Nipigon LNG Facility (an event with an extremely low probability), the Utility would make arrangements with alternate gas suppliers. This would not be an option in the case of a catastrophic failure of a pipeline lateral.

(ix) When considering the overall reliability of the Nipigon LNG Supply it is important to remember that deliveries of wood, fuel or liquid petroleum to the Municipalities are

[5] Gas Supply Plan 2.8.4.

[6] Gas Supply Plan 2.8.5.2.

also dependent on delivery by truck. The truck delivery risk associated with LNG supply would be no different than the truck delivery risk of these other supply options.[7]

(x) As discussed above in paragraph 7(iv) and below in paragraphs 69-71, the Applicant will examine the overall feasibility of constructing and operating the facilities required to enable the Utility to take receipt of CNG for use as a secondary source of backup and emergency system supply. The Applicant will include this feasibility study in its Phase 2 Application.

- ***LNG Services Agreement***

15. The Application requests that the Board pre-approve the cost consequences of the LNG Services Agreement for rate-making purposes. Both the Board Staff and those Intervenors who made submissions on the issue accepted that the LNG Services Agreement is the type of contract that is eligible for pre-approval under the Pre-Approval Guidelines. However, they expressed concerns about certain provisions in the agreement having to do with contract term, the Utility's fixed and variable cost responsibility under the agreement and the allocation of contractual risk and liability, as between the Utility and Nipigon LNG.

16. Following careful consideration of the submissions of Board Staff and Intervenors with respect to these issues, the Municipalities have decided that it would be in the interest of both the Utility and its future customers to renegotiate certain terms and provisions of the LNG Services Agreement, save and except provisions related to Firm Capacity Charges, the daily committed capacity, term and *force majeure*/service interruption. To be clear, the Municipalities continue to seek, in this phase of the proceeding, the Board's pre-approval of the cost consequences of provisions in the LNG Services Agreement that pertain to Firm Capacity Charges, daily committed capacity, term and *force majeure*/service interruption, as discussed further in paragraphs 72-84 below. This pre-approval is required by both the Municipalities and by Nipigon LNG in order to advance their respective projects to the next stage. We note that Board Staff, itself, identified this as one way to address concerns about contractual provisions unrelated to the Firm Capacity Charge.[8]

17. Counsel-to-counsel discussions between the Municipalities and Nipigon LNG have occurred and Nipigon LNG has advised that it is willing to commence such negotiations. The Municipalities will

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7 Truck delivery risk is discussed, in detail, in the Applicant's Argument-in-Chief at paragraph 97.

8 Board Staff Submission, p. 29.

include a revised LNG Services Agreement that reflects the renegotiated terms in their Phase 2 Application.

- ***Regulation of Nipigon LNG***

18. In their submissions, both SEC and VECC raised questions as to whether Nipigon LNG is subject to the Board's rate-making jurisdiction. The Municipalities take no position on this issue other than to note that the arrangement between the Utility and Nipigon LNG does not constitute delivery of gas to a "consumer", such that Nipigon LNG would be a "gas distributor" within the meaning of this term in the OEB Act. The issue is, in any event, out of scope of this proceeding. Even if the Board were to decide that this matter requires determination, to do so in this proceeding would be inappropriate. Moreover, the Board would need to establish processes for the receipt of evidence, interrogatories and argument on the issue, all of which would delay the issuance of a decision on the Application.

## IV. LEAVE TO CONSTRUCT

### A. Economic Feasibility

- ***Customer Attachment***

19. In its submission, Board Staff observed that the Applicant's customer attachment forecast methodology is consistent with the methodology employed by other greenfield projects proponents. Board Staff's submission included a table that clearly demonstrates that the Applicant's forecast attachment rates for the residential, commercial/institutional and industrial rate classes are comparable to the attachment forecasts of other recent community expansion projects.[9]

20. Notwithstanding this, Board Staff contended that the Applicant's forecast methodology had not sufficiently accounted for declining and aging populations on fixed incomes in the Municipalities, the impact of the lack of a conversion financing assistance program on conversion rates and the percentage of Terrace Bay and Schreiber residents who rely on the pulp mill in Terrace Bay (the "**Mill**") for employment.[10, 11]

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9 Board Staff Submission, p. 9, Table 1.
10 *Ibid*, page 6.
11 *Ibid*. page 10.

21. SEC made no specific submissions regarding forecast methodology or forecast attachment rates but argued that the Utility should not be permitted to offload significant commercial risks onto its customers.[12] VECC speculated that there was a significant risk that the customer attachment forecast would be as much as 10% lower than forecast but offered no support for this conclusion, other than to say that the customer surveys did not include the cost of natural gas (this is incorrect), implied that government funding might be available to assist with conversion costs and did not explain the "unique supply chain aspects of the proposal".[13] VECC also noted that electricity consumers in the Municipalities enjoy both Distribution Rate and Remote Rate Protection.[14]

22. The Applicant's response to the attachment forecast submissions of Board Staff, SEC and VECC is as follows:

(i) Contrary to Board Staff's view, the Applicant's conversion forecasts do reflect the demographic, socio-economic and employment profiles of the populations in the five Municipalities, inasmuch as survey respondents are best positioned to assess circumstances as to income, retirement and relocation plans, employment, and other considerations vis-à-vis the costs and benefits of conversion. This calculus undoubtedly informed their responses to survey questions. That is the whole point of a grass root forecast methodology as opposed to relying on forecasting models and algorithms.

(ii) Survey respondents would also know and take into account estimated costs of converting their particular heating system; for example, a simple and inexpensive change to convert a propane furnace to a gas furnace vs. an extensive house renovation to install ducts for a conversion from electric base-board heating to forced air, natural gas heating.

(iii) The Applicant's forecast conversion rates for residential and commercial/industrial customers are considerably lower than the average of the conversion rates of three recent community expansion projects.[15] This is strong evidence that the Applicant's attachment forecasts do, indeed, reflect the specific and unique circumstances of the five Municipalities. The average residential attachment rate of the three comparators

[12] SEC Submission, page 4.
[13] VECC Submission, p. 5.
[14] *Ibid*.
[15] Enbridge Fenelon Falls, Enbridge Scugog Island and South Bruce.

is 73% or almost 18% higher than the Applicant's residential attachment forecast of 62%.[16] Similarly, the average commercial and institution conversion rate for the comparator projects is 74%, compared with the Applicant's forecast conversion rate of 68%.

(iv) Decreases in populations are caused, *inter alia*, by migration of younger adults who live at home, to larger urban centres. The resultant and smaller family units still require dwellings in which to reside. In other words, not all declines in population would result in fewer distribution customers.

(v) Energy savings are a much more important consideration for families on fixed incomes concerned about keeping their energy costs to affordable levels.

(vi) While the Mill is a significant employer, it is not the only significant employer in the region; others include companies in the mining, forestry and tourism sectors, as well as railway, educational and retail employers.[17] However, access to natural gas will lower the Mill's energy cost and reduce its carbon costs, thereby enhancing its competitiveness and long-term sustainability.

(vii) Lack of access to affordable energy is a barrier to entry for new businesses seeking to locate in the region; conversely, access to natural gas may be enough to "tip the balance" for businesses considering whether to locate to the region.

(viii) Although provincial government homeowner grants for natural gas conversions are currently unavailable, the Municipalities are confident that its financing arrangements will make provision for a customer conversion supply program.

(ix) Assuming that variances in the attachment forecasts do not affect the landed costs of LNG (because lower-than-forecast residential and general service volumes are instead sold to the interruptible industrial customer) the Utility will remain financially viable provided actual customer attachments are at least 50% of forecast. If customer attachments are 20% lower than projected, total residential rates would be $21.45/GJ or 7.51% higher than the current rate forecast of $19.95/GJ.[18]

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16 (73% - 62%) ÷ 62%.

17 Application, Exhibit A, Tab 4, Schedule 1.

18 Response to SEC-8.

- ***Cost Risk***

23. The total projected capital cost of constructing the Distribution System, including contingency, is $40.5 million, net of grants.[19] This cost estimate will be refined at a later stage of development using information and data obtained from detailed engineering, design and geotechnical work as well as proposals from potential Project constructors pursuant to a competitive procurement process.

24. No party challenged the Applicant's Project cost estimates and Board Staff concluded that they were reasonable. VECC observed that these costs may vary significantly from the estimates in the Application and Board Staff and others referred to the risk of capital cost overruns as one reason to impose a rate stability period. As discussed above in paragraph 7 and below in paragraph 35, the Applicants have agreed to include a Rate Stability Proposal in its inaugural rate application.

25. As for variances between forecast and actual costs: increases in capital and annual OM&A costs for the Project do not significantly impact total bills. In a scenario where both capital and OM&A costs increase by 100% and, therefore, distribution rates increase by 100%, the total rate for residential customers would increase by only 33.5%. Provided the annual cost of natural gas continues to be less than the cost of other sources of energy available to the residents of the Municipalities (i.e., the propane, fuel oil, and electricity), the Project would remain financially viable and savings would continue to outweigh the costs of conversion.[20]

26. Board Staff recommended that at the time of its inaugural rate application, the Applicant should be required to report on and explain capital cost overruns and contingency usage.[21] The Applicant does not object to this recommendation, assuming this information is available at the time.

- ***Risk of Reliance on Single Industrial Customer***

27. In their submissions, Board Staff, SEC and VECC noted that the success of the Project was heavily reliant on a proposed demand response arrangement between the Utility and the Mill, whereby the Mill would replace a portion of its current fuel oil usage with natural gas when this gas was not required by the Utility's firm customers. This proposal would effectively result in a 100% Project load factor. Parties expressed concern about the risk of significant rate increases and erosion or

[19] Application, Exhibit A, Tab 9, Schedule 1, p. 1.
[20] Response to SEC-9.
[21] Board Staff Submission, p. 14.

elimination of customers' energy cost savings if, for whatever reason, the Mill were to significantly reduce or cease its consumption of natural gas under the arrangement (hereinafter referred to as the "**Mill Risk**").[22]

28. Board Staff submitted that the Leave to Construct application should not receive final approval until the Applicant or the Utility had filed both an executed contract with the Mill and a letter of credit or similar financial security from the Mill, both within six months of the OEB's decision on Phase 1 of the Application or as part of Phase 2 Application, whichever is earlier.[23] Board Staff acknowledged that it may not be commercially feasible to obtain a financial backstop from the Mill and suggested that if this were the case, the Applicant should, in Reply, set out an alternative mitigation plan based on the assumption that the Mill ceased to consume gas in year five of the Utility's operation.

29. SEC submitted that the Board should not approve the Applicant's Gas Supply Plan or the cost consequences of the LNG Services Agreement without ensuring that the Mill Risk was properly managed. This could mean requiring the Applicant to develop a risk mitigation plan or requiring the Applicant to obtain some sort of financial backstop from the Mill. In its submission, VECC argued that any leave to construct approval issued by the Board should be conditional on the conclusion of a contract between the Utility and the Mill.

30. The Applicant's response to the submissions of Board Staff, SEC and VECC on the "Mill Risk" issue is as follows:

(i) It is not possible to assign a percentage probability to the risk that, at some point in the future, the Mill closes or reduces its level of gas consumption. What can be said with certainty is that access to natural gas will improve the Mill's economic and environmental viability, thereby enhancing its long-term viability and competitiveness.

(ii) The Utility consequences of the Mill closing or materially reducing its consumption of natural gas will depend on timing and the quantum of the reduction. It is expected that in the medium to longer term, residential and commercial attachments will mitigate the Utility's exposure to Mill Risk. Access to natural gas is also expected to stimulate economic activity in the entire region which would, itself, lead to increased energy demand.

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22 See, e.g., Board Staff Submission, pp. 7-9.

23 Board Staff Submission, p. 9.

(iii) The Corporation has initiated discussions with at least one other large industrial enterprise with a view to securing another large load customer who could, in effect, act as a backstop to the arrangement with the Mill, in the event it were to cease operation or materially reduce its gas consumption. To the extent that the Mill maintains its current operations, the demand of one or more other larger load industrial customers would be accretive.

(iv) Finally, the Municipalities are currently engaged with potential lenders in respect of the provision of financing for the Project. It is possible that the outcome of these confidential discussions could result in a financing plan that addresses the concerns of parties about the Mill Risk issue.

31. In light of all of the above and in response to the submissions of parties on the issue of Mill Risk, the Municipalities agree to file, as part of their Phase 2 Application and for Board approval, a Mill Risk Mitigation Proposal. This plan may include one or more of the following:

(i) an executed contract with the Mill and/or one or more other large industrial customers;

(ii) a binding commitment from one or more large industrial customers to provide a financial backstop to their obligations under the contract;

(iii) the details of a financing plan that addresses/mitigates the Mill-related risk; and

(iv) a description of other mitigative measures that the Utility will implement.

- ***Inaugural Rate Application and Rate Stability***

32. In its submission, Board Staff proposed that any leave to construct approval be made conditional on approval of the Utility's inaugural rate application which should be required to be filed at the same time as the Phase 2 Application. Board Staff submitted that this condition of approval would prevent the Utility from commencing construction of the distribution system before it could determine whether its approved rates were attractive to potential customers, whether its customer forecast was achievable and whether the overall Project was feasible.[24] The Applicant disagrees with Board Staff's proposal in this regard for the reasons set out below in paragraph 34.

[24] Board Staff Submission, pp. 2 and 18.

33. On a separate but related issue, Board Staff, SEC and VECC all favoured the imposition of a "rate stability period" in order to hold Utility ratepayers harmless from the consequences of lower than forecast attachments, higher than forecast capital costs and the reduction or loss of the Mill load.[25] They suggested that the imposition of a rate stability period would be consistent with the decision in the Generic Proceeding and several subsequent community expansion projects. Board Staff suggested a 10-year rate stability period while SEC suggested a rate stability of at least 10 years and VECC recommended a rate stability period of between five and ten years, so as to align with the payback period for attaching customers. The Applicant's response to these rate stability submissions is set out below, in paragraph 35.

34. The Applicant's specific response to Board Staff's submissions about the timing of the rate application is as follows:

(i) The Applicant's phased approach to its leave to construct application is its response to the "chicken and egg" conundrum. It requires a Phase I approval, albeit with some conditions, to obtain financing which, *inter alia*, will support the establishment of the Utility.

(ii) The Applicant's intention is to bring a Phase 2 Application as soon as possible after the Utility is staffed and operational. The objective of the Phase 2 Application is to provide the Board with evidence of the Utility's technical and financial capacity, which evidence was unavailable at the time the Phase 1 Application was filed. The Phase 2 Application will also include a study that examines the feasibility of constructing and operating additional facilities to enable the receipt of CNG for use by the Utility as a secondary source of supply.

(iii) The Applicant will not be in a position to file its inaugural rate application when it files its Phase 2 Application. A rate application would require the Utility to have a higher degree of cost certainty than it will have at the time of the Phase 2 Application. Once the Utility is financed and up and running, it will enter into contracts for detailed engineering, design and geotechnical work. The result of this work will inform the bid packages that will be sent to potential construction contractors. The engineering work and the solicitation of construction bids will take some time to complete, certainly beyond the time when the Applicant contemplates filing its Phase 2 Application.

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[25] Board Staff Submission, pp. 10-12; SEC Submission, p. 4; VECC Submission, pp. 3, 7-8.

(iv) The mischief that Board Staff is attempting to address by proposing that a rate application be filed at the same time as the Phase 2 Application is to prevent the Utility from commencing construction and triggering customer conversion activities before there is greater certainty as to rates. The Applicant submits that these concerns about rate certainty can be addressed by appropriate conditions in the leave to construct order, such as requiring the Utility to include a Rate Stability Proposal in its inaugural rate application, and does not require the Board to tie the timing of a rate application to the timing of the Phase 2 Application.

35. The Applicant's response to submissions of Board Staff, SEC and VECC about a rate stability period is as follows:

(i) The Applicant appreciates the reasons why the Board staff and parties support the imposition of a rate stability period and agrees to include a Rate Stability Proposal in its inaugural rate application.

(ii) The Applicant will not be in a position to commit to a specific rate stability framework, including details with respect to permissible adjustments, term etc., at the time it files the Phase 2 Application. Although the Applicant has confidence in the cost estimates in the Application from the perspective of determining whether or not the Project is economically feasible, these estimates are not yet at the stage to serve as a basis for setting a revenue requirement and committing to a specific rate stability provisions.

## B. Land Agreements

36. Board staff submitted that the form of Working Area Agreement included in the Application for Board approval[26] was not acceptable and required revisions to remedy a number of omissions.[27]

37. The Municipalities have reviewed recent similar agreements filed by other gas distribution utilities in Ontario and approved by the OEB[28] and have revised its form of Working Area Agreement to address the Board Staff's comments and conform with other similar agreements that have been approved by the Board in prior proceedings. The revised agreement is included in a package of

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26 Application, Exhibit A, Tab 11, Schedule 1, Attachment 5, p. 1.

27 Board Staff Submission, p. 17.

28 See, e.g., EB-2018-0263, Application, Exhibit A, Tab 10, Schedule 2, pp. 12-17 of 20.

documents pertaining to the Application that is being filed with the Board separately, but concomitantly, with this Reply.

### C. Indigenous Consultation

38. The submissions of Anwaatin, Long Lake, Red Rock and BNA addressed the importance of meaningful, on-going consultation.[29] The Municipalities affirm their commitment to continue to engage with Indigenous communities about the Project in an open, transparent and respectful manner.[30]

- ***Red Rock and BNA***

39. In their submissions, Red Rock and BNA expressed support for the Project, advising that:

> "[t]o the extent that the Project will strengthen economic development in the region, which can responsibly bring economic opportunity and other benefits to [Red Rock and BNA's] population, [Red Rock and BNA are] supportive of the Project. [Red Rock and BNA are] also supportive of the Project insofar as it will make natural gas available to off-reserve [Red Rock and BNA] members who are or may in future reside in the Municipalities from time to time."[31]

- ***Anwaatin***

40. In its submission, Anwaatin requested that the Applicant be required to file a letter, from MENDM, attesting to the sufficiency of the Applicant's consultation activities. Anwaatin also requested the Municipalities to file an Indigenous Consultation Summary Report. (Board Staff made a similar request in its submission).

41. The Indigenous Consultation Summary Report has been completed and is included in the package of documents pertaining to the Application that is being filed separately, but concomitantly, with this Reply. The Applicant has been working closely with MENDM to finalize the requirements of the

29 Anwaatin Submission, para. 7; Long Lake Submission, paras. 11-18; Red Rock and BNA Submission, paras. 7-8 and 11.

30 Response to Anwaatin IR-8, p. 12 of 12.

31 Red Rock and BNA Submission, paras. 7 and 11.

Indigenous Sufficiency Assessment process. The Applicant undertakes to file the Sufficiency Letter with the Board when it is received.

42. In its submission, Anwaatin noted the need to address energy poverty issues in the Anwaatin First Nations through access to affordable, reliable and sustainable energy.[32] These are the same issues that are driving the need for the Project.[33] The Municipalities acknowledge Anwaatin's submissions regarding the potential beneficial impacts of an expanded distribution system. Clearly, there is a need for a broader conversation amongst all stakeholders about the feasibility and timing of potential future expansions.

- ***Long Lake***

43. In its submission, Long Lake asked the Board to impose the following four conditions on its leave to construct approval of the Project:

(i) a condition requiring the Municipalities to continue meaningful consultation throughout the life of the Project;

(ii) a condition that gives interested First Nations the right to select the archaeologist used for any further archaeological assessments, including Stage 2 work;

(iii) a condition requiring the Utility to provide Long Lake with a copy of the Environmental Protection Plan, in a timely manner[34]; and

(iv) a condition requiring the Utility to provide Long Lake with updates on environmental monitoring and mitigation activities.

44. The Municipalities have no objection to requested conditions (i), (iii) and (iv). They view the obligations that would be imposed by these conditions as integral to their ongoing duty to consult. With respect to condition (ii), the Municipalities propose to consult with interested First Nations with respect to their participation in further archaeological assessments, including the engagement on a remunerated basis, of an activity monitor, selected by the interested First Nations, to act in an observational capacity.

[32] Anwaatin Submission, paras. 8-15.
[33] Application, Exhibit A, Tab 1, Schedule 2, p. 2.
[34] Long Lake Submission, para. 16.

## V. MUNICIPAL FRANCHISES AND CERTIFICATES

- ***Certificates***

45. With respect to the request for certificates of public convenience and necessity, Board Staff asked that the Municipalities submit revised boundary maps, each scaled to fill one page with geographic features (e.g., major streets, lakes, railway lines) identified with legible font.[35]

46. The Municipalities have prepared new maps that indicate municipal boundaries and geographic features, as requested. The Applicant confirms that the boundary of the requested service area for each Municipality, is that Municipality's municipal boundaries. These maps are included in the package of documents pertaining to the Application that is being filed concomitantly with this Reply.

- ***MFA***

47. In its submissions, Certarus recommended that the Board direct the Municipalities to amend the forms of Municipal Franchise Agreements to explicitly provide for open access. The Municipalities oppose this recommendation for the reasons set out below in paragraphs 48-53.

## VI. GAS SUPPLY

### A. Open Access

48. Since the early days in 2015 when the Municipalities first conceived of a natural gas distribution system, no available, reliable and cost competitive CNG option has ever been identified. Despite one meeting and a few e-mails between representatives of Certarus and representatives of the Municipalities, Certarus has never put a concrete supply proposal on the table. Further, given that there were no replies or follow-ups from Certarus to the Corporation's agreement to further meetings (in September 2018 and then again in September 2019), the Municipalities have concluded that Certarus has no real interest in supplying "system" gas to the Utility's <u>residential</u> customers. Certarus' intervention in this proceeding should be seen for what it is: an exercise in advancing its own commercial interest by advocating for an open access system that would allow it to "pick off" the Utility's largest commercial and industrial customers at the expense of the Utility's smaller load customers.

35 Board Staff Submission, p. 19.

49. The Municipalities object, in the strongest possible terms, to Certarus' request for mandated open access. The cost and revenue forecasts included in the Application assume that the fixed costs under the LNG Services Agreement will be spread among all distribution customers and recovered in distribution rates, as a pass-through cost. Any change in this assumption would vitiate the economic feasibility analysis that underpins the Application.

50. There is no <u>evidence</u> on the record of this proceeding as to the feasibility, reliability, costs and benefits of mandated open access, including evidence as to how the Utility's costs would be allocated between its system gas customers and its direct purchase customers.

51. Critically, facilitating the bypass of system supply from the Nipigon LNG virtual pipeline in favour of some other direct purchase delivery option could trigger a "domino effect," as larger load customers are enticed to migrate to a Certarus supply option, leaving the Utility's fixed costs to be borne by residential and small commercial customers, most of whom would have no ability to switch fuels. The economic viability of the Utility, itself, would be put at risk, especially if it were operating under the constraints of a rate stability period pertaining to forecast risk. <u>The reality is that the pool of potential customers within the five Municipalities is not sufficiently large to support an open access regime. In the result, mandated open access could end up meaning no gas access at all</u>.

52. Under an open access framework, the Utility would be the gas supplier of last resort. As such, it would be required to maintain the ability to supply natural gas to distribution customers who choose to purchase gas from alternative suppliers, in the event that the supplier fails to deliver for any reason or the customer chooses to return to system gas (as has often been the case).

53. For all of the reasons set out above, the Board should reject each of Certarus requests related to mandated open access and confirm that the Utility will be the sole supplier of natural gas to customers in the five Municipalities, with no obligation to provide open access to its Distribution System for competitive natural gas suppliers, be they CNG or alternative LNG suppliers.

### B. CNG Cost Analysis

54. Certarus queried whether the Municipalities had properly assessed the merits of using CNG instead of LNG as a source of supply. Certarus raised this issue in the context of attempting to argue that

a CNG supply option was to be preferred to an LNG option. It is noteworthy that Board Staff[36] and SEC[37] have acknowledged that LNG is the preferred supply option:

> "In OEB Staff's view, the Applicant has made its case that <u>LNG is the most beneficial and cost-effective option</u>."[emphasis added]

55. While the Applicant has chosen not to reply in detail to all of the unsupported and untested assertions of fact in the Certarus submission, it offers the following general responses:

(i) A very early review of all supply options concluded that there was no economic alternative to LNG that could provide the volume of storage and security of supply (i.e., days of on-site storage) that would be required by the Utility. Accordingly, there was no identified option that could be subjected to detailed analysis in the Feasibility Study.

(ii) Certarus alleges that the Applicant's CNG cost analysis is based on unsupported data and incorrect assumptions. The Applicant rejects this allegation. The landed CNG cost analysis included in the Application[38] and discussed in the Applicant's interrogatory responses[39] was based on figures prepared by Cornerstone. Cornerstone is routinely involved in the design of CNG facilities and, through such experience, has acquired actual equipment pricing and electricity usage data in respect of various sized CNG plants, at various locations throughout North America. The capital cost of the CNG production facility that underpins the CNG landed cost analysis in the Application was based on information on the capital cost of a CNG production facility in New York. The capital cost of the CNG storage facilities was based on an actual price quote that Cornerstone received from a manufacturer of CNG storage units.

(iii) The Applicant cannot be expected to invent a CNG proposal where Certarus, itself, has chosen not to provide the Applicant with such a proposal. One can only speculate as to the reasons why; perhaps because Certarus has no interest in supplying the Utility's heating load?

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36 Board Staff Submission, section 4.5, p. 22.
37 SEC Submission, p. 6.
38 Application, Exhibit A, Tab 13, Schedule 1, pp. 11-14.
39 Responses to Board Staff IR-11 and Certarus IR-2.

56. Finally, it is Certarus who relies on unsupported, non-specific and untested cost estimates in its submission. Notably, Certarus' cost numbers do not include the cost of CNG storage in the Municipalities, a critical component required under any CNG delivery scenario in order to ensure supply reliability.

### C. Reliability of Supply

57. Board Staff[40] and some Intervenors[41] expressed concerns about the risks inherent in the Applicant's proposal to rely on a single source of natural gas supplied by Nipigon LNG, also referred to as a lack of "supply diversity". Presumably, their underlying concern is what would happen in the event that the Nipigon LNG Facility or the LNG Depots were unavailable and the Utility was forced to curtail its firm service customers. As many communities in southern Ontario are supplied by a single pipeline distribution lateral, the Applicant assumes that Board Staff and Intervenors believe that the components of the Nipigon virtual pipeline would be less reliable than a pipeline lateral. The Applicant does not know the basis of Board Staff and Intervenor's belief in this regard but, nevertheless, makes the following points by way of reply:

(i) Unlike a distribution system supplied by a single pipeline lateral (i.e., no back-feed supply), the Utility's distribution system will be able to call upon at least 10 days worth of peak demand supply, provided by the LNG Depots and the Nipigon LNG Facility, itself.[42] On non-peak days, this storage availability would last much longer. In contrast, a pipeline outage on any lateral pipeline that is the sole supplier of gas to a distribution system (or on pipelines upstream of that lateral), would result in immediate adverse consequences for customers.

(ii) In the event of an outage at the Nipigon LNG Facility, the Utility could also curtail its interruptible customers and in particular, the Mill, in order to continue its heating load customers.

(iii) If necessary, additional storage could be constructed (at the LNG Depots or at the Nipigon LNG Facility) to increase the reliability of the system. The incremental capital cost to do so would be approximately $2 million for an additional 7,500 GJ at the

40 Board Staff Submission, pp. 21-22.
41 SEC Submission, pp. 2 and 8. VECC Submission, p. 9.
42 Application, Exhibit A, Tab 8, Schedule 1, Attachment 1, p. 53.

Nipigon LNG Plant[43] and approximately $1 million for an additional 1,575 GJ at each of the Depots[44].

(iv) As discussed below in greater detail in paragraph 58, the LNG Depots will be designed with very few moving parts (e.g., no pumps) and certain equipment, such as tanks and vaporizers, will be duplicated (i.e., installed in pairs). Accordingly, the overall reliability of the LNG Depots may be estimated as the probability of a major equipment failure which is estimated as extremely low, approximating several hundreds of years between failures.

(v) In the highly unlikely event of a major equipment failure at an LNG Depot, portable LNG storage and regasification equipment can be brought to the site from other locations in Canada.

(vi) The LNG Depots will be equipped with back-up power generators in order to mitigate against the risk of power outages on the local electricity grid.

(vii) As discussed below in greater detail in paragraphs 59-61, small scale LNG liquefaction plants exhibit very high availability, in the order of over 99%. Moreover, the average down-time of each forced outage of comparable equipment has been estimated to be 33 hours. Accordingly, the storage capacity available from the LNG Depots and the Nipigon LNG Facility, together with the Utility's ability to interrupt certain customers, will be more than sufficient to mitigate all minor and moderate plant outages.

(viii) As discussed below in greater detail in paragraphs 62-68, in the event of a catastrophic and prolonged outage of the Nipigon LNG Facility (an event with an extremely low probability), the Utility would make arrangements with alternate gas suppliers. This would not be an option in the case of a catastrophic failure of a pipeline lateral.

(ix) When considering the overall reliability of the Nipigon LNG Supply it is important to remember that deliveries of wood, fuel or liquid petroleum gas to the Municipalities are also dependent on delivery by truck. The truck delivery risk associated with LNG

43 Gas Supply Plan 2.8.4.
44 Gas Supply Plan 2.8.5.2.

supply would be no different than the truck delivery risk of these other supply options.[45]

(x) As discussed below in paragraphs 69-71, the Applicant will examine the overall feasibility of constructing and operating the facilities that would be required to enable the Utility to take receipt of CNG for use as a secondary source of backup and emergency system supply. The Applicant will include this feasibility study in its Phase 2 Application.

- ***Reliability of LNG Depots***

58. The LNG Depots will not contain many moving parts. They will be designed to send out natural gas without the use of pumps or other similar machinery (a small pump is used to unload an LNG trailer into the LNG Depot storage tanks). As the LNG Depots will not be subject to reliability degradation due to degradation in mechanical pumps and as equipment will be provided in pairs (i.e., there will always be more than one tank, vaporizer, trim heater, etc. to facilitate repairs without interrupting gas send out), their overall reliability may be estimated in terms of the probability of major failures in piping and vessels. These probabilities are estimated as extremely low, the equivalent of hundreds of years between failures:

| ***Type of Failure*** | ***Failure Rate per Year**** |
|---|---|
| Pressurized Storage Tank (full failure) | $5 \times 10^{-7}$ |
| Small diameter piping (rupture) | $1 \times 10^{-6}$ per meter |
| Heat Exchangers (vaporizers, rupture) | $5 \times 10^{-6}$ |

* NFPA 59A -2019 Chapter 19

- ***Reliability of the Nipigon LNG Facility***

59. Generally, small scale LNG liquefaction plants exhibit high availability. Stabilis reports that George West, TX facility has recorded over 99% uptime since commissioning in 2015[46]. Cosmodyne, a leading supplier of small-scale LNG equipment, reports 99% uptime for their plants[47]. Cryopeak,

45 Truck delivery risk is discussed, in detail, in the Applicant's Argument-in-Chief at paragraph 97.
46 https://stabilisenergy.com/.
47 Commercial correspondence between NLNG and Cosmodyne, 2019.

an LNG virtual pipeline services provider, reports at least 99% uptime for their projects and 99.9% uptime for LNG for a utility pipeline project in Midwestern Canada.[48]

60. Specifically, the reliability of the liquefaction plants is similar to typical reliability of common rotating equipment such as power generation turbines, nitrogen refrigeration compressors, and turbo-expanders. In a directly relevant study conducted in 2004, gas turbine generators in the size range proposed by Nipigon LNG, exhibited an average downtime for each forced outage (all types) of 33 hours.[49] By stocking strategic spare parts and having service contracts in place in advance, Nipigon LNG would expect to achieve downtime superior to this average figure.

61. The storage of five to seven days of LNG in each Municipality's LNG Depot, plus several more days at the Nipigon LNG liquefaction plant effectively mitigates against all minor and moderate plant breakdowns. The Applicant expects Nipigon LNG to have in place, emergency response contracts from local contractors and equipment suppliers to ensure that all but the most major plant breakdowns can be remedied in a timely manner. In the event of a major breakdown that requires an extended period to repair, additional mitigations are available and are discussed below.

- ***Availability of Alternative LNG Supply***

62. In its submission, SEC expresses a high degree of skepticism about the availability and cost of alternative supplies of LNG from Montreal or Minnesota. These sources of supply are further away, and generally more expensive than the Nipigon LNG supply which was why the Nipigon LNG supply was proposed in the first place. However, the potential to access alternate sources of supply as a contingency is logical and rational.

63. The LNG market in Quebec has been operating safely and reliably for over 45 years and it is used to serve multiple markets, both for utility peak-shaving and for remote "virtual pipeline" operations (over 1,000 km away) within the province. Énergir also exports LNG to Northeast US markets. Énergir, both on its own and in conjunction with 'Investissement Quebec", has recently, (in 2017) tripled the LNG capacity at the LNG facility in Montreal to an annual production capacity in excess of 9 billion cubic feet (bcf) per year. This is equivalent to approximately 25,000 GJ per day, which is significant greater than the Utility's proposed contracted demand of 2,400 GJ per day to 3,700

[48] http://cryopeak.com/projects/.

[49] Energy and Environmental Analysis, Inc. Oak Ridge National Laboratory Subcontract No. 4000021456; Jan 2004.

GJ per day with Nipigon LNG.[50] Exports from Montreal to the US Northeast during 2017 and 2018 averaged about 1.5 bcf (1.6 million GJs) annually, with a trucking distance of ranging from 600 to 800 kilometres[51]. This is despite the fact that there are several bulk LNG import terminals currently servicing the Northeast US.

64. Minnesota has two large LNG providers, CenterPoint and Xcel. CenterPoint has a liquefaction plant and a 1 bcf (1.1 million GJ) LNG storage facility and Xcel has a liquefaction plant and a 2.1 bcf (2.2 million GJ) storage facility[52] for a total of 3.1 bcf (3.4 million GJ) storage capacity. The aggregate withdrawal of these facilities was less than 0.6 bcf (660,000 GJ) during the winter of 2017 (the latest year that data was available) or less 20 percent of the installed and working LNG storage capacity in Minnesota. It is worth noting that both CenterPoint and Xcel have liquefaction plants to refill or top-up the LNG storage tanks after volumes have been withdrawn.

65. During the development of this Project, discussions were held with these alternative LNG companies and they expressed interest in selling LNG supplies to the Utility, either as the primary gas supply or as a secondary gas supply.

66. While specific pricing information received from these companies was provided in confidence, the US Energy Information Administration (EIA) reports the volume and pricing of LNG imports by point of entry. Highgate Springs, Vermont, is the most common import point for Montreal-sourced LNG to enter the US, destined to utilities in New England and New York. The average price for LNG imports during 2017 and 2018 averaged approximately US $8.66[53] (or approximately C$11.25 to $11.75 depending on the exchange rate) at the point of entry, which includes the cost of the commodity, liquefaction and trucking charges to the Northeast US utilities. The Utility expects the landed of cost of LNG to the Utility from Montreal to increase by the incremental transportation costs (estimated to be $2.50 to $3.00 per GJ for the additional distance travelled), if replacement volumes had to be shipped to this region.

67. It is noteworthy that some of the Montreal produced LNG is sold and transported to utilities in the Northeast US. Since the US Northeast also has several bulk LNG import terminals, these LNG supplies also represent an additional source of LNG supply if necessary, to meet, the Utility's need

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50 1 Cubic Feet Of Natural Gas to Gigajoules = 0.0011.

51 US Energy Information Administration (EIA) https://www.eia.gov/dnav/ng/NG_MOVE_POE1_A_EPG0_IML_MMCF_A.htm.

52 Minnesota House of Representatives Research Department https://www.house.leg.state.mn.us/hrd/pubs/natgasmn.pdf.

53 https://www.eia.gov/dnav/ng/ng_move_poe1_a_EPG0_PML_DpMcf_a.htm.

should there be an extended outage of the LNG Plant. While these imported LNG supplies could be purchased and transported the entire distance to the Utility, it would be more cost effective and have a shorter delivery time if the Utility entered into a commercial spot swap arrangement with one of the utilities purchasing Montreal sourced LNG. Spot LNG purchased by the Utility at an import terminal could be delivered to the Northeast utility and the Montreal sourced LNG originally destined for the Northeast utility could be made available to the Utility for delivery to the Distribution System. These types of swap agreements are commonplace in the physical pipeline marketplace and could be used in this instance to increase access to additional replacement supplies if required.

68. The Applicant believes that sufficient replacement LNG supplies could be reliably sourced from alternate supplies in the unlikely event that Nipigon LNG experienced an extended outage.

- ***CNG Emergency and Backup Supply***

69. In its submission, Board Staff proposes that the Utility should be required, as a condition of approval, to: "[I]nstall facilities to receive secondary sources of CNG downstream of the LNG Depots" in order to ensure immediate open access to the Distribution System, mitigate lack of supply diversity and provide for peak-shaving or emergency back-up supply. [54] From this, it is not clear whether Board Staff is advocating for mandated open access for direct purchases of gas by Utility customers or is simply proposing that the Utility should have the technical capability to procure and deliver alternative supplies for backup/emergency purposes.[55]

70. In any event, the Applicant does not agree that it should be required to install CNG-related facilities in the absence of consideration by Board of a study that the Applicant intends to prepare and include in its Phase 2 Application. This study will examine the overall feasibility of constructing and operating facilities that would enable the Utility to take receipt of CNG for use as a secondary source of supply.

71. In response to Board Staff Interrogatory 11(c), the Applicant stated as follows:

> "It is technically possible for the Utility to have its system served by both LNG and CNG. The incremental cost to the Utility of adding an injection

[54] Board Staff Submission, p. 22.

[55] In its Submission, Certarus proposes that the Board require that the Utility design and construct interconnects in a manner that permits third-party providers of natural gas to connect to the municipally-owned gas distribution system.

> point for CNG would be minimal and is not expected to impact the schedule and budget of the Project.
>
> It is assumed that the CNG provider would be responsible for supplying natural gas in accordance with the Utility's temperature and pressure requirements. In addition, the CNG provider would own and operate all the necessary unloading, heating and regulation facilities as well as arranging for its own utility services to support its operations.
>
> Finally, whether or not the land parcels in each Municipality that have been set aside for the LNG Storage Depots could also accommodate the CNG trailers, unloading and injection equipment and truck traffic, would need to be determined. Additional lands in each Municipality may be required to accommodate CNG as a second gas supply source, which could extend the schedule and increase the cost of the Project, assuming that such lands could be secured."

The cost and other implications of these factors, as well as the actual need for CNG as a back-up source of supply having regard to the other risk mitigation measures that are already in place, should be considered before any decision is made requiring the construction of additional distribution facilities.

## VII. PRE-APPROVAL OF COST CONSEQUENCES OF LNG SERVICE AGREEMENT

72. Neither Board Staff nor any Intervenor have raised any objections to the Applicant's position that the LNG Services Agreement is eligible for consideration by the Board for cost pre-approval. It is agreed that the LNG Services Agreement is a long term contract which supports the development of new natural gas infrastructure and is not a usual or normal course contract. Further, it also appears settled that the needs and benefits of the LNG Services Agreement have been demonstrated.

73. With this background, Board Staff and intervenors have however raised certain issues with respect to the terms of the LNG Services Agreement:

    (i) Section 4.1(a) – the quantum of the "Firm Capacity Charge" which is payable on a take or pay basis, regardless of the amount of Nipigon LNG's capacity that is used by the Utility;

(ii) Section 4.1(b) – the undefined nature of the "Variable Charge", which is the charge per GJ payable to Nipigon LNG for each GJ of LNG produced and regasified by Nipigon LNG to recover the costs of consumables used in providing the LNG Services;

(iii) Section 4.1(c) – the uncapped nature of the "Truck Transportation Services" fees which are payable for transportation of LNG to the LNG Depots;

(iv) Section 8.1 – the cost to the Utility for provision of "Financial Security" to Nipigon LNG as security for its obligations under the LNG Services Agreement which at this time has not been determined;

(v) Section 10.1 – the length of the "Initial Term" being just 10 years, as opposed to 15 years;

(vi) Section 10.4 – liability of the Utility to make a termination payment in the event that Nipigon LNG fails to satisfy certain conditions precedent and the LNG Services Agreement is terminated;

(vii) Article 12 – the limitation of liability provisions which are not identical for each party and which seek to limit Nipigon LNG's liability under the LNG Services Agreement in a different way than the Utility's liability and the lack of an obligation on Nipigon LNG to provide financial security to the Utility for its obligations under the LNG Services Agreement; and

(viii) Article 13 – whether the *force majeure* provisions permit the Utility to procure alternative supplies of natural gas where Nipigon LNG declares *force majeure* and whether Nipigon LNG should have any other rights to interrupt the provision of the LNG Services.

74. While all of the matters referred to in paragraph 73 above do not pertain to the cost-consequences of the LNG Services Agreement, the Applicant acknowledges the comments made by the participants to this proceeding and following careful consideration, the Municipalities have decided to renegotiate the terms of the LNG Service Agreement, save and except provisions related to Firm Capacity Charge, daily committed capacity, term and *force majeure*/service interruption as explained further below.

- ***Section 4.1(a) – Firm Capacity Charge***

75. Although neither Board Staff nor any Intervenor has objected to the amount of the Firm Capacity Charge in itself, Board Staff, SEC and VECC raised a concern with respect to whether the Firm Capacity Charge is reasonable, having regard to Nipigon LNG's costs. This appears to be based on the view that over the 10 year initial term of the LNG Services Agreement, the Firm Capacity Charge payable to Nipigon LNG will (before any downward adjustment under section 3.6 of the LNG Services Agreement or escalation for inflation of 1.5%) total approximately $86.7m while Nipigon LNG's capital cost is, on a net basis, $27m (total $54m less a $27m grant from the Province). None of Board Staff nor any Intervenor has objected to the "Maximum Daily Quantity", which is the basis on which the Firm Capacity Charge is calculated.

76. Board Staff, SEC and VECC have misunderstood the quantum of Nipigon LNG's costs. As set out in the Applicant's response to SEC Interrogatory–15(b), the figure quoted by Board Staff, SEC and VECC for Nipigon LNG's capital cost of $54m does not include the capital costs of the five LNG Depots that it will construct, own and operate in the Municipalities; nor does it encompass significant annual fixed costs associated with the ownership and operation of all such facilities which will include financing costs, operations and maintenance costs and general and administrative costs, to name but a few.

77. Further, as described by the Applicant in its response to VECC Interrogatory–14, the Utility's "all-in" landed cost of gas under the LNG Services Agreement is reasonable relative to the price of LNG from other LNG facilities. Accordingly, the Applicant submits that the Firm Capacity Charge should be approved.

- ***Sections 4.1(b) and 4.1(c) – Variable Charge and Truck Transportation Services***

78. The Applicant acknowledges the concerns raised and agrees to renegotiate and seek clarification of these provisions with Nipigon LNG. Nipigon LNG has advised the Applicant that it agrees, in good faith, to engage in the renegotiation of this matter. Notwithstanding the foregoing, while the Applicant and Nipigon LNG will engage in renegotiation, it would be premature to anticipate the outcome of such renegotiation. The Applicant agrees to revert to the Board following the renegotiation and seek its approval with respect to the resolution of this matter on the terms agreed.

- ***Section 8.1 – Cost of Utility's Financial Security***

79. The Applicant acknowledges the concerns raised and agrees to conduct further diligence with respect to the form such security may take and the costs to the Utility of same. Such costs will be presented to the Board for approval, once determined.

- ***Section 10.1 – Length of Initial Term***

80. The length of the Initial Term of the LNG Services Agreement is 10 years which the Utility may extend for a further 10 years. Board Staff submits that a longer Initial Term of 15 years, "would better align the contract duration with the lifespan of the assets and would generate further annual savings for customers as fixed cost recovery would be spread over a longer period of time". This statement appears based, in part, on the mistaken belief that Nipigon LNG's aggregate costs are $27 million, on a net basis. As discussed above, such costs are significantly higher.

81. The Applicant submits that the term of the LNG Services Agreement should remain structured as an initial 10 year period, renewable for a further 10 years at the Utility's option. This will provide the Utility with the flexibility, after 10 years, to renegotiate the terms of the agreement to better align the terms to reflect the Utility's requirements and actual attachment rates at the time or to avail itself of alternative lower cost service that may be available, at the time. This flexibility will be of value to the Utility's ratepayers and, for this reason, the term of agreement should remain as drafted.

- ***Section 10.4 – Termination Payment***

82. The Applicant acknowledges the concerns raised and agrees to renegotiate this provision with Nipigon LNG to address some or all of the concerns raised as best as it is able. Nipigon LNG has advised the Applicant that it agrees, in good faith, to engage in the renegotiation of this matter. Notwithstanding the foregoing, while the Applicant and Nipigon LNG will engage in renegotiation, it would be premature to anticipate the outcome of such renegotiation. The Applicant agrees, however, to revert to the Board following the renegotiation and seek its approval with respect to the resolution of this matter on the terms agreed.

- ***Article 12 – Limitation of Liability***

83. The Applicant acknowledges the concerns raised and agrees to renegotiate the provision with Nipigon LNG to address some or all of the concerns raised as best as it is able. Nipigon LNG has

advised the Applicant that it agrees, in good faith, to engage in the renegotiation of this matter. Notwithstanding the foregoing, while the Applicant and Nipigon LNG will engage in renegotiation, it would be premature to anticipate the outcome of such renegotiation. The Applicant agrees, however, to revert to the Board following the renegotiation and seek its approval with respect to the resolution of this matter on the terms agreed.

- ***Article 13 – Force Majeure and Interruption of Provision of LNG Services***

84. Certarus submits that the *force majeure* provisions of the LNG Services Agreement do not permit the Utility to procure replacement natural gas delivery services where Nipigon LNG declares *force majeure*. Further, VECC appears to suggest that the right of Nipigon LNG to interrupt the provision of service to the Utility to be, "inconsistent with the Utility protecting its customers". While such provisions do not pertain to the cost consequences of the LNG Services Agreement, the Applicant notes that Certarus' interpretation of the *force majeure* provisions is incorrect and neither the Applicant nor Nipigon LNG[56] see any basis for the articulated concern. Further, VECC's concern regarding the right of Nipigon LNG to interrupt service, "for the purposes of maintaining, repairing or replacing its LNG facilities" appears to be based on a misapprehension that facilities, such as those that will be owned by Nipigon LNG, can be operated continuously, notwithstanding the requirement for maintenance which might require shutdowns. This would not be prudent and it would, in fact, be reckless for Nipigon LNG not to have certain shutdowns to conduct preventive maintenance. The Applicant submits that the Board should disregard this concern. Outages will, of course, be scheduled at times of low demand and with appropriate LNG storage inventory sized to manage such demand (note also the ability to curtail interruptible supply to the Mill).

[56] Nipigon LNG Submission, para. 28.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 23TH DAY OF JANUARY 2020.

**DENTONS CANADA LLP**

Per:

*original signed by Helen T. Newland*
Helen T. Newland

*original signed by Vivek Bakshi*
Vivek Bakshi