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**Enbridge Gas Distribution Inc. (EGI)**
**EB-20189-0294**
**Low Carbon Energy Project**

Submission
of the
Vulnerable Energy Consumers Coalition
(VECC)

September 14, 2020

**Vulnerable Energy Consumers Coalition**

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## Summary of Submission

In our submission the Board should:

a) Approve the leave-to construct pilot project for Phase 1 (S1) only.
b) Approve the proposed “energy compensating” rate rider of $10.00 per annum.
c) Direct that the EGI report to the Board on any changes to the pilot project if and when Federal or Provincial related programs such as the Clean Fuel Standards impact its benefits or costs.
d) Direct that the Utility provide a detailed report on the pilot project no later than at the time of rebasing rates or when it proposes to make a change to the cost of hydrogen supply or adjust the compensating rate rider.
e) Direct that the Utility, in conformity with any similar finding by the Board in EGI’s proposed Renewable Natural Gas Program (EB-2020-0066), establish a variance/ deferral account to track any avoided costs realized as a result of reduced Federal Carbon Charges or any other federal or provincial credit arising from this project.

1. Below are our detailed arguments in support of these submissions.

## Need

2. The Low-Carbon Energy Project (LCEP) is a pilot project which requires the building of 750 metres of pipeline and a hydrogen storage and blending station in order to inject a 2% solution of hydrogen into a closed loop distribution system (the Blended Gas Area or ‘BGA’ ) The project will affect approximately 3,600 customers.

3. Hydrogen as a fuel gas has a number of drawbacks – it is expensive to procure, in limited available supply, has a lower energy content than natural (primarily methane) gas. Blended gas in concentrations above 5% hydrogen may cause damage to appliances. Hydrogen is a much smaller molecule than methane, so its leakage rate through pipe walls and joints may be greater. Hydrogen is also more explosive and potentially more dangerous to handle.[1]

[1] These observations can be found in the report of the National Renewable Energy Laboratory (NREL) “Blending Hydrogen into Natural Gas Pipeline Networks: A review of Key Issues, M.W. Melaina, O. Antonia and M. Penev, March 2013. This Report was not filed by EGI, but is referred to in their response to a number of interrogatories including I.FRPO.12. and I.ED.6 See also the discussion at I.VECC-12 & 13

4. However, the use of hydrogen does not imply another "Hindenburg." [2] Referring to work done by the Canadian Gas Association and the American Gas Association (CGA/AGA) the Technical Standards and Safety Authority (TSSA) noted:[3]

   *Many safety concerns mentioned in CGA\AGA report including following and all results show that blending 0-5% hydrogen do not adversely affect on these items:*
   *i) Fire and Explosion Risks*
   *ii) Hydrogen Embrittlement and Durability of Metal Pipes*
   *iii) Permeability of Hydrogen Through Metal and Plastic Pipes*
   *iv) Leakage*
   *v) Stationary Reciprocating Gas Engines: Up to 2% suggested for this item*
   *vi) Leak Detection: up to 5%, however further investigation suggested by report.*

5. Taken on the whole there are no compelling reasons of energy efficiency, security of supply or safety to blend hydrogen into the natural gas distribution system. In terms of pricing, while hydrogen itself is plentiful, because it is mostly found bound to other elements it is expensive to procure. In fact, while in this proceeding the costs of production are unknown, producing hydrogen through electrolysis, as proposed in this project, is dependent upon the cost of electricity. This makes it unlikely, at least under current market conditions, that hydrogen produced energy would be equal to or less than the equivalent energy cost of natural gas. This equation might change if greenhouse gas emissions (GHG) externalities were included in the price of natural gas. At this time the only benefit to adding a greater content of hydrogen to natural gas is environmental because of its zero-emission characteristic.

6. There is no obvious provision under the OEB Act that would argue for approving facilities for blending hydrogen with natural gas. However, while the Board does not have a specific "environmental" mandate, as VECC has argued recently, indirect authority can be found in the OEB Act objective "*to promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances*." [4] Rather than repeat those arguments in detail we would refer them to the Board (EB-2020-0066). In summary it is our view that there is sufficient latitude within that objective for the Board to act judiciously so as to be in harmony with government policy and to approve reasonable projects which aim to reduce greenhouse gas emissions.

[2] The Hindenburg was a dirigible air disaster that occurred on May 6, 1937, in Manchester Township, New Jersey and famously known photographically by the massive combustion of the hydrogen filled airship.
[3] Evidence of TSSSA, July 8, 2020, See also I.H2GO.1
[4] Submission of VECC, EB-2020-0066, July 15, 2020, pages 4-6

## Pilot Hydrogen Supply Costs

7. In this case we recommend the Board act cautiously because the case of "need" for the project is dependent upon whether the cost of hydrogen is commensurate with the "energy efficiency" or GHG emission reduction it provides. This project's long-term viability relies largely on the Government of Canada's Clean Fuel Standard policies. Enbridge states[5]:

   *The CFS for gaseous and solid fuel regulations will come into force January 1, 2023. Under the CFS, hydrogen is expected to be a means of compliance and a pathway for the generation of CFS credits. Enbridge Gas's leave to construct application to build the LCEP facilities which will facilitate the injection of hydrogen into the gas distribution system will prepare the natural gas grid for implementation of the CFS.*

8. One difficulty is that the CFS regulations are at an early stage and not expected to come into force until 2013. When asked about this the Utility responded[6]:

   *While the Clean Fuel Standard (CFS) compliance obligation for gaseous fuel parties is expected to come into force in 2023, Environment and Climate Change Canada have indicated that Early Action Credits from the production and use of low-carbon fuels, such as hydrogen, may begin upon the publication of the Final Draft Liquid Fuel Regulation expected in the fall of 2021. The CFS Proposed Regulatory Approach published in June 2019, identified hydrogen as a low-carbon fuel that will be eligible to create CFS credits.*

9. The uncertainty in government policy is similar to that faced by the Utility in its proposed in the RNG project. In this proceeding the Utility has removed the issue of supply cost risk in the immediate term by making the commitment that "*the price paid for hydrogen will be the same price paid for traditional natural gas and will fluctuate according to the market cost of natural gas. There will be no impact to customer bills as the cost of hydrogen will be the same as the cost of traditional natural gas*[7]." This commitment is made until rebasing or when CFS credits are implemented.

10. In our submission there is little risk in the near term on the price of supply. However, the nature of the supplier (an affiliate) and the likelihood of no alternative sources means there is significant long-term risk if Federal or Provincial tax credits or subsidies fail to materialize. This might leave ratepayers with an asset that can only be used to acquire a gas product at well above natural gas prices.

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[5] EGI, Argument-in-Chief, April 28, 2020, par. 17, page 5
[6] I.VECC.4
[7] EGI Argument-in-Chief, par. 43, page 14 and I.Staff.2

## Pilot Asset Costs

11. Given the absence in this proposal of any immediate cost implication in gas supply the application for relief is limited to the granting of a leave-to-construct (including form of easement agreements) and a rate rider developed to compensate customers in the BGA for the lower energy content gas they will consume.

12. The LCEP Facilities are located near Enbridge Gas's Technology and Operations Centre (TOC) on Honda Boulevard in Markham. The facilities include one section of nominal pipe size (NPS) 6" extra high pressure (XHP) steel (ST) Pipeline, one section of NPS 6" high pressure (HP) ST Pipeline and one section of NPS 8" intermediate pressure (IP) polyethylene (PE) Pipeline. The lengths of these pipeline sections are approximately 380m, 350m and 25m respectively. Other requirements are a hydrogen blending station, a hydrogen station, a district station and two pipe disconnections. The costs of the facilities are listed in the table below[8]:

| Item No. | | Description | | | Cost | % Contingency | Contingency | Cost + Contingency |
|---|---|---|---|---|---|---|---|---|
| **1** | | **Material Costs (Pipeline & Station)** | | | **$941,000*** | 25% | $235,250 | $1,176,250 |
| | | | Description | Cost + Contingency | | | | |
| | 1a | Pipeline material | 25 % contingency applied | $ 166,250 | | | | |
| | 1b | Other stns material | 25 % contingency applied | $ 143,750 | | | | |
| | 1c | Hydrogen Blending stn and Hydrogen Stn design build | 40 % contingency applied only to the station materials for Hydrogen Blending Stn and Hydrogen Station of this vendor's quote | $ 866,250 | | | | |
| | | | | $ 1,176,250 | | | | |
| **2** | | Labour Costs (Pipeline & Station) | | | **$1,284,000** | 25% | $321,000 | $1,605,000 |
| | | | Description | Cost + Contingency | | | | |
| | 2a | Pipeline labour cost | 25 % contingency applied | $ 1,183,750 | | | | |
| | 2b | Stations labour cost | 25 % contingency applied | $ 421,250 | | | | |
| | | | | $ 1,605,000 | | | | |
| **3** | | External Permitting, Land, Environmental & Regulatory Costs | | | **$20,000** | 25% | $5,000 | $25,000 |
| | | | Description | Cost + Contingency | | | | |
| | 3a | Overall External Permitting, Land, Environmental & Regulatory Costs | 25 % contingency applied | $ 25,000 | | | | |
| **4** | | Outside Services | | | **$761,000** | 25% | $190,250 | $951,250 |
| | | | Description | Cost + Contingency | | | | |

[8] I.CCC.17 see also Exhibit D, Tab 1, Schedule 1, page 13

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 4a | Outside services related to the design and installation of the pipeline | 25 % contingency applied | $ 895,000 | | | | |
| | 4b | Outside services related to the design of the station | 25 % contingency applied | $ 56,250 | | | | |
| | | | | $ 951,250 | | | | |
| **5** | | Direct Overheads | | | **$105,000** | 25% | $26,250 | $131,250 |
| | | | Description | Cost + Contingency | | | | |
| | 5a | Overall Direct Overheads | 25 % contingency applied | $ 131,250 | | | | |
| | | SUBTOTAL | | | $2,170,000 | | $777,750 | $3,888,750 |
| | | | | | | | | |
| **6** | | Contingency Costs (rounded up to nearest $1000) | | | **$778,000** | | | |
| **7** | | Project Cost (including contingency) | | | **$3,889,000** | | | |
| **8** | | Indirect Overheads | | | **$1,260,395** | | | |
| **9** | | Interest During Construction | | | **$82,870** | | | |
| **10** | | Total Project Costs | | | **$5,232,265** | | | |
| | | | | | | | | |
| | | | | Legend | material cost breakdown | | | |
| | | | | | amount reported in EX. D/T1/S1 – Table 8 | | | |

13. In addition to these distribution utility assets an affiliate of Enbridge Gas, 2562961 Ontario Ltd. has built a Power to Gas (PtG) facility at EGI's Technology and Operations Centre (TOC) in Markham. The PtG facility was developed in partnership with Hydrogenics Corporation. Hydrogenics Corporation is part owner of 2562961 Ontario Ltd.

14. The project has a contingency of 25% contingency applied to all direct capital costs except for the station material costs which have a 40% contingency reflecting the preliminary design stage of specialized equipment. This is unusually high[9], but in any event EGI is not seeking ICM treatment, so the actual costs of the project will be subject to scrutiny at the next rebasing proceeding.

15. We accept the rationale provided by Enbridge for the higher than normal contingency costs. In any event all costs will be subject to review upon rebasing. As part of that review at the next rebasing the Board might advise the Utility that it will be required to provide a detailed explanation of the final design of the project. This will be important if the Board is to clearly delineate between regulated related costs and costs that should accrue to the affiliate hydrogen provider.

[9] See for example I.PP.8 which shows that the contingency applied on recent EGI projects falling between 15-30%.

## Energy Compensating Rate Rider

16. Enbridge Gas is proposing to offset the Consumption Impact on customers within the BGA by way of an annual rate rider providing a credit of $10.00 per year. This amount is based on a calculation of the excess volumes needed to be consumed due to the lower heat content of the blended gas (1.38%). The calculation is shown in the table below[10]:

**Annual Residential Bill**

**(A) BGA Customer vs (B) Non-BGA Customer**

| | | **(A)** | **(B)** | **CHANGE** (A) - (B) |
|---|---|---|---|---|
| VOLUME | m³ | 2,433 | 2,400 | 0 |
| CUSTOMER CHG. | $ | 257.75 | 257.75 | 0.00 |
| DISTRIBUTION CHG. | $ | 211.96 | 209.20 | 2.76 |
| LOAD BALANCING | § $ | 136.19 | 134.33 | 1.86 |
| SALES COMMDTY | $ | 227.45 | 224.37 | 3.08 |
| FEDERAL CARBON CHARGE | $ | 95.13 | 93.84 | 1.29 |
| **TOTAL SALES** | **$** | **928.48** | **919.48** | **8.99** |

§ The Load Balancing Charge shown here includes proposed transportation charges.

17. We submit that the approach taken by Enbridge for the calculation of a compensating rate rider is a reasonable approximation of the impact to consumers in the BGA.

18. EGI did not make any proposal with respect possible future CFS credits. We note that this is different than in the RNG proceeding, EB-2020-0066. For that program the Utility proposed that any avoided costs realized as a result of reduced Federal Carbon Charges be tracked in OEB-approved Federal Carbon Charge – Customer Variance Accounts ("FCCCVA") for the EGD and Union rate zones (Account Nos. 179-502 and 179-421). Enbridge also proposed to dispose of final net balances in these accounts in future proceedings. In this case the absence of a similar treatment for any credits appears to be based on the

[10] I.Staff.4

uncertainty of government policy applying to hydrogen in a similar manner as to renewable gas, explaining that: [11]

*Enbridge Gas has reviewed the Greenhouse Gas Pollution Pricing Act and has spoken with the federal government on the imposition of the Federal Carbon Charge on the hydrogen portion of blended gas. Currently, the Company is unaware of any mechanism for hydrogen blended into the natural gas distribution system to be exempted from the Federal Carbon Charge. Enbridge Gas has continued to pursue conversations with the federal government on a mechanism to exempt hydrogen blended into natural gas. The Company is hopeful this exemption can be put in place, given that hydrogen injection into the natural gas distribution system is accepted as a GHG reduction in the federal Clean Fuel Standard ("CFS"), which is currently under development.*

19. The Board has yet to render a decision in EB-2020-0066. In our submission there should be no difference in the treatment of any credit that arise from the LCEP program and that is similar to that that may accrue under Renewable Gas proposal. In both cases the Utility is injecting into the distribution system alternative sources of combustible gas for reasons of GHG policies. It may ultimately be that hydrogen injection will not attract a credit. However, should that not be the case symmetry dictates that any benefit be treated in the same way as the Board finds in EB-2020-0066.

20. In our submission any avoided costs realized as a result of reduced Federal Carbon Charges or any other provincial or federal credit should be tracked in an OEB approved variance account similar or the same as requested by EGI in the Voluntary Renewable Natural Gas proceeding EB-2020-0066 (RNG). In that proceeding two accounts were proposed for the EGI and Union rate zones (Account Nos. 179-502 and 179-421). Enbridge Gas should be required to apply to dispose of balances in these accounts in future proceedings at the direction of the Board and no later than at the next rate rebasing application.

## Sharing of Information

21. The proposal is for EGI customers to assume the cost of this pilot. As such they are entitled to the information derived from the pilot project. Yet in this regard EGI has stated:

*The Company will disclose this information where required in order to attain any required approvals for expansion of hydrogen blending to other parts of its system. Enbridge Gas notes that some or all of the information about the pilot project may be commercially sensitive and valuable to other players interested in commercializing*

[11] I.H2GO.3

*hydrogen. In order to ensure that Enbridge Gas can retain the value of information and data collected through the pilot project, it may be necessary to seek confidential treatment of some or all of the information.* [12]

22. On the other hand, Enbridge Gas confirmed that intellectual property developed through the LCEP pilot project relating to hydrogen blending for gas distribution systems will be owned by the Applicant as utility assets.[13]

23. It is unclear to us what type of information might be considered commercially sensitive. We can understand the Utility being cautious in respect to information related to the supplier of hydrogen, however, any information with respect to the blending and distribution of that product and which is proposed to be funded by ratepayers should be made available to customers.

24. It is also not clear whether the Utility will in this pilot attempt to examine the effect of introducing hydrogen might have on residential appliances. We acknowledge the evidence to date suggests that 2% blending of hydrogen does not affect common household gas appliances. However, it may be prudent for the Utility to examine in detail and by way of small samples of equipment using blended gas and a control group of similar equipment in the non-blended area. Such an exercise might provide more consumer confidence if the program were to be expanded in the future.

## Project Risks

25. As we understand the proposal there is no immediate cost of the LCEP to ratepayers. The Utility does not intend to seek recovery of the proposed rate rider at this time. Like other leave-to-construct (LTC) projects which are not subject to rebasing or ACM/ICM mechanism there is no immediate adjustment to rate base and revenue requirement due to the construction of the new assets. However, unlike other "normal" distribution project the risks of stranded assets associated with a pilot project are much higher. It is possible that the project could fail on either technical or financial grounds. Government policy might change or Provincial policy might become at odds with Federal plans. EGI has noted that they have mitigated the asset risk in part by limiting the size of the BGA.[14]

[12] I.CCC.15
[13] I.SEC.2
[14] Exhibit B, Tab 1, Schedule 1, page 10

26. We are also concerned that while the immediate proposal is to keep the cost of hydrogen linked to the cost of natural gas in the long-run this may be unstainable. If so ratepayers may be asked to pay a much higher price for that product.

27. In our submission the Utility shareholder and ratepayer should share in the risk of the pilot. This means it should be open to the Board upon rebasing to examine the project and determine what amount of the project should be recovered from ratepayers (both capital and OM&A). In making that determination we believe the Board should consider the impact of future hydrogen costs especially if those supplies are provided by an affiliate. Specifically, we are concerned about the possibility of the usefulness of distribution assets associated with this project being dependent on a supply of hydrogen and the ability of the regulated utility's affiliate to profit from that business. In order to assure ratepayers are not exploited by an affiliate relationship Enbridge should be required to demonstrate upon rebasing and on examination of this pilot project either the cost basis of hydrogen supply or that the affiliate prices are comparable to available market alternatives.

28. Finally, we submit the Utility should be required to provide evidence at that time based on the experience of the pilot for the continuance of any 'hydrogen compensating' rate rider.

## Reasonably Incurred Costs

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

**THESE ARE OUR RESPECTFUL SUBMISSION**

**September 14, 2020**