EB-2022-0157

Exhibit #K1.9

Enbridge Gas Inc.

Panhandle Regional Expansion Project

IGUA Compendium for Examination

GOWLING WLG

24. The ROS provided existing contract customers another opportunity to formally de-contract existing firm or interruptible capacity (see Attachment 9 to this Exhibit for the February 2023 ROS form). The ROS also provided existing customers the opportunity to request to convert existing firm service to interruptible service. It should be noted that regardless of formal ROS initiatives such as this, customers always have the ability to request changes to their existing contract parameters including de-contracting existing capacity, provided appropriate notice is given per the terms and conditions of their distribution contract. /U

25. To provide clarity and respond to any questions regarding the EOI and ROS process, Enbridge Gas account managers directly contacted each contract rate customer in the Panhandle Market. In addition to direct outreach, all existing contract customers were invited to attend an in-person meeting held on March 7, 2023, and/or a virtual meeting held on March 23, 2023. A meeting with local economic development officials was also held on March 2, 2023, to inform them of the process and timelines, and to answer any questions related to the forms. /U

26. The EOI and ROS process closed on April 6, 2023, thirty business days following its launch. All bids received were acknowledged via email from Enbridge Gas. A total of 42 EOI bid forms were received from 39 entities, indicating approximately 197 TJ/d of interest over the 2024-2033 period. The 197 TJ/d is incremental to the capacity that has already been contracted for by customers via the 2021 EOI process and through the normal course of business since the close of the 2021 EOI process. Of the 42 EOI bids received, 38 bids were from the greenhouse sector, 2 bids were from the power sector and 2 bids were from the commercial sector. The results of the EOI can be found in Table 1. /U

Table 1 – 2023 EOI Bid Summary by Year (m^3/hr) /U

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
New/Incremental Firm	52,432	84,503	37,807	25,802	32,952	17,204	13,732	12,547	7,277	2,325	286,581
Interruptible to Firm Conversion	66	8,484	-	-	-	-	-	-	-	-	8,550
Firm Turnback	-	-	-	-	-	-	-	-	-	-	-
Firm to Interruptible Conversion	-	-	-	-	-	-	-	-	-	-	-
Net New/Incremental Firm (by year)	**52,498**	**92,987**	**37,807**	**25,802**	**32,952**	**17,204**	**13,732**	**12,547**	**7,277**	**2,325**	**295,131**
Net New/Incremental Firm (cumulative)	52,498	145,485	183,292	209,094	242,046	259,250	272,982	285,529	292,806	295,131	
TJ/day (by year)	**33**	**71**	**24**	**16**	**21**	**11**	**9**	**8**	**5**	**1**	**197**
TJ/day (cumulative)	33	104	127	143	164	175	183	191	196	197	

Notes:
1) The volumes received through the 2023 Expression of Interest process were in cubic meters of gas per hour (m3/hr).
2) The 2023 Expression of Interest results, combined with the previously contracted volumes from the 2021 Expression of Interest process were used to generate an informed demand forecast.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, page 7, paragraph 20 and page 9, paragraph 26

Preamble:

The Project's incremental capacity is estimated to be 203 TJ/d. Approximately 98% of this capacity is expected to meet the demand of contract rate customers. Enbridge Gas asserted that, at the time of filing the application, 80% of the contract rate customer demand is subject to commitments by those customers. Binding commitments represent 159 TJ/d, including approximately 62 TJ/d of executed firm distribution contracts. Enbridge Gas noted that 100% of the 2023/2024 forecasted incremental demand on the Panhandle System is secured with binding customer commitments.

Question:

a) Please clarify what the "binding commitments" that are not firm distribution contracts entail.
b) Please provide any updates to the contract rate customers commitments or the executed contracts since filing the application.

Response

a) A Commitment Letter ("CL") and/or a Letter of Indemnity ("LOI") are "binding commitments" that are not firm contracts, and can be utilized prior to the execution of a distribution contract. These binding commitments demonstrate a customer's commitment to the capacity they have expressed interest in or have formally requested from Enbridge Gas.

   The use of CLs is a standard practice for Enbridge Gas and they have been used previously for the Chatham-Kent Rural Pipeline project (EB-

2018-0013). They are intended to provide further customer commitment to the requests for capacity received through an EOI process, prior to a customer executing an LOI or distribution contract.

There are no financial assurances required to execute a CL.

The use of LOIs is also standard practice for Enbridge Gas. They are commonly used prior to the execution of a distribution contract. Their usage allows Enbridge Gas to order long-lead time items and/or initiate project activities prior to the finalization of a distribution contract. Financial assurances are required for LOIs.

Refer to response to Exhibit I.PP.5 part b) for the LOI and CL templates.

b) Table 1 below outlines the customer commitments to the Project as at the June 10, 2022 LTC application filing date, as well as the updated commitment numbers as at September 22, 2022, organized by commitment type.

Table 1

	TJ/d	
PREP Capacity Commitments	**As at Jun 10, 2022 (LTC filing)**	**As at Sep 22, 2022 (IR Responses)**
Executed Distribution Contracts	62	63
Executed Letters of Indemnity / Commitment Letters	97	104
Total PREP Capacity Commitments	**159**	**167**

Was Page 0. See Image [OEB:11L1W-0:1]

E.B.O. 134 1

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1980, Chapter 332; 2

AND IN THE MATTER OF a Review by the Ontario Energy Board of the Expansion of the Natural Gas System in Ontario. 3

BEFORE: J.C. Butler, Vice-Chairman and Presiding Member 4

J.A. DeKort, Member 5

M.A. Daub, Member 6

7

REPORT OF THE BOARD

June 1, 1987 8

ISBN 0-7729-2610-7 9

Was Page i. See Image [OEB:11L1W-0:2] 10

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Was Page 1. See Image [OEB:11L1W-0:4]

1. INTRODUCTION 18

1.1 In the summer of 1986, the Ontario Energy Board (the Board) examined six applications by The Consumers' Gas Company Ltd. (Consumers') to provide service to the Town of Deep River, the Village of Chalk River and the Township of Rolph, Buchanan, Wylie and McKay (E.B.L.O. 216 et al.). The Board denied these applications and, in its Reasons for Decision, the Board concluded that the criteria used by the utilities to assess and justify system expansion should be reviewed. 19

1.2 On January 9, 1987, Notice of a Review by the Ontario Energy Board of the Expansion of the Natural Gas System in Ontario (the Review) was issued. 20

Was Page 2. See Image [OEB:11L1W-0:5]

2. BACKGROUND 21

2.1 There are three major gas distributors in Ontario which together serve approximately 1,500,000 customers: Consumers', ICG Utilities (Ontario) Ltd (ICG) and Union Gas Limited (Union). Each distributor operates within a franchised area. 22

2.2 Consumers' is Canada's largest natural gas distributor, serving about 850,000 customers in southern, central and eastern Ontario, western Quebec and northern New York State. The company has assets of about $1.4 billion and distributes about 9,000 10(6)m(3) of gas annually through its network of 18,657 kilometres of mains. 23

2.3 ICG operates a natural gas distribution system consisting of approximately 5,600 kilometres of 24 pipeline in northwestern, northern and eastern

Was Page 3. See Image [OEB:11L1W-0:6]

Ontario. ICG's utility assets are valued at almost $400 million. ICG delivers approximately 3,100 10(3)m(3) of gas annually and serves approximately 163,000 customers. 25

2.4 Union operates a fully integrated gas distribution system employing storage, transmission and distribution facilities in southwestern Ontario. It sells over 7,300 10(6)m(3) of gas annually. Union also transports and stores about 5,700 10(6)m(3) of gas annually for other utilities and is Ontario's largest operator of underground storage pools with a developed capacity of 2,700 10(6)m(3). Union's utility assets are approximately $900 million. 26

2.5 In 1958, TransCanada Pipelines Limited (TCPL) completed its interprovincial pipeline from the Alberta-Saskatchewan border to Quebec, and western Canadian natural gas became widely available in Ontario. During the next two decades, the demand for natural gas in Ontario grew rapidly due to its abundant supply and relatively low price. This demand in turn led to a major expansion of distribution facilities by Ontario's natural gas utilities. 27

2.6 By the late 1970's, most of the system expansion taking place pertained to new subdivisions, upgrading of existing pipeline capacity and development of storage facilities. 28

Was Page 4. See Image [OEB:11L1W-0:7]

2.7 In the early 1980's, expansion of the natural gas distribution network was stimulated by federal government programs designed to reduce Canada's dependence on imported oil. One of these programs, the Distribution System Expansion Program (DSEP), administered by The Department of Energy, Mines and Resources (EMR) provided funds to the gas utilities of Ontario in the form of contributions in aid of construction to assist in expansion of their distribution system. 29

2.8 DSEP was designed to facilitate specific types of system expansion projects. The key criteria for funding such projects were the lack of financial viability and the volume of oil that gas would displace. 30

2.9 Another program, the Canada Oil Substitution Program (COSP), provided a grant to homeowners who converted from oil to natural gas. This program encouraged oil customers to convert to natural gas. 31

2.10 These EMR programs which encouraged expansion of the natural gas distribution system were phased out in 1984 and 1985. 32

Need for Review 33

2.11 As noted above, in the summer of 1986 the Board examined six applications from Consumers' for 34

Was Page 5. See Image [OEB:11L1W-0:8]

leave to construct gate stations and pipelines and for franchises and certificates to serve the Village of Chalk River, the Town of Deep River and the Township of Rolph, Buchanan, Wylie and McKay, in the County of Renfrew. 35

2.12 The Board denied the applications as the project did not meet Consumers' fifth-year rate of return feasibility test. In its Reasons for Decision the Board noted that the impact on the public interest, through either granting or denying gas service to the municipalities in question, was not adequately presented in the evidence. 36

2.13 The Board indicated in its Reasons for Decision that certain important questions concerning system expansion to smaller communities should be considered: 37

o with DSEP discontinued, what are the means whereby marginally uneconomic areas of Ontario are to be served, if at all; 38

o what is the role of the Board in the light of the removal of DSEP and to what extent should it be encouraging gas service to marginally uneconomic areas; 39

o with Ontario utilities facing mature markets, is expansion into uneconomic areas appropriate; 40

o should the shareholders or customers of utilities subsidize uneconomic expansion into smaller communities; 41

Was Page 6. See Image [OEB:11L1W-0:9]

o are there lower limits of return that should be permitted on a project basis? Are size of project or amount of subsidy factors that should be considered in assessing a project; 42

o have the changing circumstances with respect to energy resulted in the test of public interest being changed; 43

o are the current methods used by the utilities for assessing the economic feasibility of projects appropriate and what changes, if any, should be made; 44

o should the economics of system expansion be considered on the basis of marginal/incremental costs or on a fully allocated cost basis? 45

2.14 The Board indicated that these issues would best be addressed outside the context of a specific application and that it would call a special hearing for this purpose some time in early 1987. The Board anticipated that the recommendations from that special hearing would assist in determining whether new guidelines should be developed for leave to construct applications. 46

5.10 Western Gas Marketing Limited stated that public interest is a dynamic concept and also argued that none of the public interest factors are necessarily fully quantifiable at any given point in time. 253

IGUA 254

5.11 IGUA indicated that the costs associated with uneconomic system expansion ought to be borne by the customer classes that directly benefit from that expansion. 255

Was Page 24. See Image [OEB:11L1W-0:27]

Kincardine and District Recreation Board and Parry Sound Area Economic Development Corporation 256

5.12 This group expressed concern that with the end of DSEP, smaller communities in Ontario may not receive gas service. 257

The Board's Findings 258

5.13 The Board finds that it has jurisdiction to review all matters relating to the production, distribution, transmission and storage of natural gas. Mr. Justice Keith in reviewing the history and origins of the OEB Act, stated: 259

In my review that statute makes it crystal clear that all matters relating to or incidental to the production, distribution, transmission or storage of natural gas ... are under the exclusive jurisdiction of the Ontario Energy Board 260

These are all matters that are to be considered in the light of the general public interest and not local or parochial interests. The words "in the public interest" ... which I have quoted would seem to leave no room for doubt that it is the broad public interest that must be served. (Union Gas Limited vs. Township of Dawn, (1977) 76 D.L.R. 613) 261

5.14 The Board reiterates that the concept of public interest is dynamic and it must change according to the circumstances. The Board considers that the relevant criteria from those listed above, 262

Was Page 25. See Image [OEB:11L1W-0:28]

and others depending on the circumstances, should be addressed as fully as possible so that the Board has complete information on which to base its determination as to whether or not a project is in the public interest. 263

5.15 There can be no firm criteria for determining the public interest and the Board will not attempt to define these criteria closely. The weighting the Board attaches to each criterion considered can also change with the circumstances of a specific application. 264

265

5.16 When considering the public interest in prior proceedings the Board has been satisfied if the welfare of the public is enhanced without imposing an undue burden on any individual, group or class. The Board will continue to be guided by this general principle in determining the extent to which gas service should be extended into other areas of the province.

266

5.17 The Board considers that system expansion should not be unlimited and that it is required to continue to determine whether the expansion of gas service is in the public interest.

267

5.18 The Board has concerns with the concept of "economic feasibility" as it has been used in these proceedings. These concerns will be examined in detail below. The Board considers

Was Page 26. See Image [OEB:11L1W-0:29]

268

that regardless of the "economic feasibility" test used to evaluate a project, it has not been, nor will it be, the sole criterion examined. Even though "economic feasibility" is an important factor, it may be given more weight in some situations, and less in others such as safety or security of supply projects.

269

5.19 Any application to the Board should include evidence on all public interest criteria considered relevant by the participants. Any data that can be quantified in a meaningful fashion should be presented that way with assumptions clearly stated.

270

5.20 The Board recognizes that the views of a local community may differ from those of an industrial customer or of a utility. In reaching its decision, the Board attempts to accommodate differing interests in its assessment of the public interest. The greater the number of interests that are represented at a hearing, the more confidence the Board can have in its judgement regarding the public interest.

271

5.21 The Board therefore encourages wide participation in hearings regarding these matters.

Was Page 27. See Image [OEB:11L1W-0:30]

272

6. TESTS OF ECONOMIC FEASIBILITY

273

6.1 Because of its important influence on how the public interest is viewed, the question of economic feasibility will be examined in detail and the existing and proposed "tests" to assist judgements about economic feasibility will be considered. In so doing, the Board's concerns with the concept of economic feasibility will be developed.

274

6.2 Over the years, the Ontario gas distribution utilities have refined the economic feasibility tests used to evaluate system expansion projects. These tests have been examined from time to time in rate application hearings before the Board. However, the examination of each utility's economic feasibility tests has been on an individual basis without benefit of a common public review. A summary of these economic feasibility tests is contained in Appendix A.

Was Page 28. See Image [OEB:11L1W-0:31]

275

6.3 In the Discussion Paper, Board staff outlined what it perceived to be the weaknesses of the feasibility tests currently employed by Union, Consumers' and ICG.

276

1. The tests are based on a measure of feasibility which is too narrowly defined. Therefore these tests fail to recognize many of the additional benefits which accrue to an individual customer and to the area served by a new project, such as, savings on energy costs and major regional or more macroeconomic benefits.

277

2. Existing customers are serviced by facilities built at historical capital costs which have been significantly depreciated. These are significantly lower than current costs used in project assessment. A new project where current capital costs are used and where the annual costs are tested at a point in time when depreciation is low (5th year) is obviously at a disadvantage.

278

6.4 The first group of these are the "Five-Year, Rate of Return Tests".

Was Page 29. See Image [OEB:11L1W-0:32]

279

Five-Year, Rate of Return Tests

280

6.5 Five-year, rate of return tests are presently employed by Consumers' and ICG to demonstrate the economic feasibility of projects submitted to the Board in leave to construct applications. ICG also uses this methodology to assess all extensions involving more than 60 metres per customer. The test is based on the rate of return on investment to be achieved in the fifth year. The forecast of the annual incremental revenue from the project less its annual incremental gas costs, operation and maintenance expense, municipal and capital taxes, depreciation and income taxes, divided by the estimated cost less accumulated depreciation, equals the estimated rate of return on investment. This estimated rate of return is then compared with the Board approved rate of return on rate base for the distributor to determine if a particular project will be self-supporting. Generally, a project is considered economically feasible if the fifth-year rate of return on rate base equals or exceeds the Board approved rate of return on rate base.

281

6.6 The "five-year rule" has traditionally been considered a reasonable time frame since this is the period in which it was considered that the majority of the customer attachments would occur. It has also been considered by the

Was Page 30. See Image [OEB:11L1W-0:33]

282

Board as a reasonable time period for existing customers to subsidize new projects.

283

Participants' Positions on the Five-Year Rule

284

Consumers'

285

6.7 Consumers' indicated that they continue to use this method because of the Board's preference but the company considered that its Discounted Cash Flow (DCF) tests used to assess feasibility for other projects provide a better measure of the benefits and costs to existing customers from such

6.64 Union recommended that the Board adopt its three-stage methodology as a framework for system expansion decision-making. 371

Consumers' 372

6.65 Consumers' agreed that Union's Alternative to the Benefit Test is preferable to Union's other proposals. 373

Was Page 45. See Image [OEB:11L1W-0:48]

ICG 374

6.66 ICG conceded that this test seems to be an improvement over the Benefit Test. However, ICG stated that it did not endorse any of the Alternative Tests but preferred to modify its existing fifth-year rate of return test. It considered that the proper forum for deciding whether or not to change the current test is a public hearing involving an application, not at a technical conference. ICG also expressed the hope that any new guidelines adopted by the Board would be restricted to information requirements only and that the utilities would retain the right to present this information as they see fit. 375

The Board's Findings on Economic Feasibility Tests 376

6.67 The Board finds that of the tests currently in use by the utilities, the DCF analysis provides a superior measure of the subsidy required from existing customers for a particular project. 377

6.68 The Board directs all utilities to employ DCF analysis as part of its assessment of the feasibility of projects for system expansion. 378

6.69 The Board encourages the use of more formal risk measurement in the feasibility test and it 379

Was Page 46. See Image [OEB:11L1W-0:49]

would not discourage the use of sensitivity analyses of variables being regularly employed in the test. 380

6.70 The Board finds that incremental costs should be used in evaluating the feasibility of system expansion. 381

6.71 The Board will continue to assess the adequacy of the DCF analysis and any other tests used for project evaluation at the time of a utility's rate case hearing. 382

6.72 The Board finds that Union's three-stage test has considerable merit. The Board requires each utility to develop a three-stage process as outlined below to aid the Board in its determination of the public interest. 383

384
6.73 The first stage is a test based on a DCF analysis.

385
6.74 The second stage should be designed to quantify other public interest factors not considered at stage one. All quantifiable other public interest information as to costs and benefits should be provided at this stage.

386
6.75 The third stage should take into account all other relevant public interest factors plus the results from stage one and stage two.

Was Page 47. See Image [OEB:11L1W-0:50]
387
6.76 A project could, therefore, be accepted if it passed the DCF analysis of stage one and if the disadvantages and quantifiable costs from stages two and three do not disqualify it. If a project is not acceptable because it fails the DCF analysis or has significant other disadvantages, then stages two and three must be completed before the project can be said to be fully evaluated.

388
6.77 The Board is aware that each utility will continue to approve internally projects that lie within areas for which a franchise and a certificate of public convenience and necessity have been issued. At subsequent rate hearings the Board may assess the analyses employed before approving the inclusion in rate base of any specific project.

389
6.78 Any project brought before the Board for approval should be supported by all data used by the Applicant in reaching its conclusion that the project is viable. The utilities and other interested parties may use alternative analyses, but these and the results must be presented at the relevant hearing. The Board will continue to weigh the various benefits against the various disadvantages as it always has in reaching its decision in the public interest.

Was Page 48. See Image [OEB:11L1W-0:51]
390
6.79 The Board continues to hold the opinion that it is appropriate for existing customers to subsidize, through higher rates, financially non-sustaining extensions that are in the overall public interest if the subsidy does not cause an undue burden on any individual, group or class.

Was Page 49. See Image [OEB:11L1W-0:52]
391
7. THE ISSUE OF SUBSIDY

392
7.1 One of the major reasons for this Review is that much of the remaining expansion available to a utility and the public in a mature market area is generally uneconomic as judged by existing tests and a subsidy or a contribution in aid of construction is required. The preceding sections have dealt with changes that should be made in the determination of the subsidy or contribution required, and the public interest considerations. This section considers the potential expansion available and who should be required to make the contribution or provide the subsidy should it be required.

393
7.2 Each distributor provided a list of projects or municipalities that are currently not being served with natural gas but might be considered for system expansion.

Was Page 50. See Image [OEB:11L1W-0:53]

7.3 Union indicated that approximately 37 communities in its franchise area fall into this category and expansion into a sample of 13 of these communities would represent an $8.8 million dollar investment. 394

7.4 Consumers' review of possible expansion in or adjacent to its franchise areas indicated that there were a possible 43 projects that could be considered for its long term system expansion program. A sample of 13 of these projects represented about $21 million dollars of investment. 395

7.5 ICG indicated that there were 80 communities in its distribution area, with a customer potential of about 21,000, that presently do not have gas service. ICG stated that it would not consider expansion in gas service to any of these communities in the absence of a capital contribution. 396

Participants' Position on Subsidies 397

The City of Kitchener 398

7.6 Kitchener considered that economic feasibility as currently determined should be paramount in any decision relating to system expansion. it recommended that the Board should not take into account many of the public interest factors 399

Was Page 51. See Image [OEB:11L1W-0:54]

proposed by Board staff. Kitchener submitted that it is the responsibility of government to make decisions regarding uneconomic expansion. It stated that it makes no sense to impose the burden of this expansion on existing customers. 400

Consumers' 401

7.7 In the case of significant economic burden, Consumers' observed that it is neither fair nor logical for existing customers to bear the entire burden of subsidy for expansion. 402

7.8 Consumers' nevertheless supported the concept that areas of Ontario that are marginal with respect to gas service should be served if there are public interest benefits (including economic) beyond pure financial feasibility and where the extra cost to existing customers resulting from the extension will not be onerous. 403

7.9 Consumers' indicated that when broad public interest benefits accrue to Ontario, consideration should be given to the use of provincially administered funds for subsidizing system expansion. It was Consumers' view that a provincial fund similar to DSEP could be used to encourage expansion of service to customers who would not otherwise receive natural gas. 404

Was Page 52. See Image [OEB:11L1W-0:55]

7.10 Another alternative discussed by Consumers' would be to recover some of the cost from the local 405 community benefiting from the project. This could be accomplished through a municipal contribution-in-aid of construction or in the form of a time-limited surcharge on the rates charged to gas customers within the municipality.

7.11 Consumers' advocated that costs resulting from uneconomic expansion strictly defined should 406
only flow through the utility's cost of service when the amounts involved will not impose a significant burden on existing customers.

ICG 407

7.12 With respect to subsidization, ICG proposed various alternatives. It noted that subsidization 408
could be a provincial government responsibility. It discussed the possibility of subsidizing projects through the total utility cost of service and ultimately through rates but noted that there must be a limit to the burden imposed on existing customers. In addition ICG noted that contributions-in-aid of construction could be collected from the customers that would benefit from the gas service.

7.13 ICG asserted that the concept of a fair return to the utility's shareholders and its ability 409

Was Page 53. See Image [OEB:11L1W-0:56]

to raise capital at the lowest cost possible should not be compromised when considering the public 410
interest aspects of system expansion.

Union 411

7.14 In terms of subsidization, Union stated that, in the absence of government funding, uneconomic 412
areas could only be serviced through rate increases or contributions-in-aid of construction as there is no justification for shareholder subsidization because a higher rate of return would then be required.

Energy Probe 413

7.15 Energy Probe stated that extending service to marginal areas should only occur where existing 414
customers are not asked to subsidize new ones. Energy Probe believes that government policy on this matter must be clear before decisions can be made regarding the subsidization of system expansion. It considered that it would be difficult to proceed without knowing what the provincial government deemed to be in the public interest.

7.16 Energy Probe asserted that the provincial government must not only determine whether or not 415
expansion is appropriate but also whether natural gas is the preferred energy alternative.

Was Page 54. See Image [OEB:11L1W-0:57]

If the government perceives a public interest in taxpayers or existing customers subsidizing extension, 416 the subsidy should be explicitly initiated by government.

7.17 In Energy Probe's view the Board must have explicit policy direction from the government regarding what constitutes the public interest before the Board incorporates broader public interest factors into the decision making. 417

Parry Sound Area Economic Development Commission 418

7.18 This group indicated that the government should determine the priority in which marginal areas are to be served and that a government subsidy should be provided. 419

Deep River 420

7.19 This municipality indicated the importance to a community of having natural gas service and stated that both the federal and provincial governments should encourage service of natural gas to small towns in Ontario by way of subsidies. It stated that it would not refuse to provide a contribution towards construction but that municipal funds for such projects would be difficult to raise. 421

Was Page 55. See Image [OEB:11L1W-0:58]

Public Interest Participants 422

7.20 This group stated that the policy of subsidization must be resolved by the government before any matters concerning feasibility tests should be considered. 423

City of Toronto 424

7.21 This municipality opposed system expansion which would impose an undue burden on existing customers. 425

Committee of Southwestern Ontario Municipalities 426

7.22 This group indicated that it is the role of federal and provincial governments to provide financial assistance where needed for system expansion into areas not currently served. 427

7.23 It submitted that municipal contributions in aid of construction would be inappropriate as such contributions would have implications on a municipality's financial integrity and would suggest the involvement of the Ontario Municipal Board. 428

The Board's Findings on Subsidy 429

7.24 As noted earlier, the Board considers that in general, the public interest is satisfied if 430

Was Page 56. See Image [OEB:11L1W-0:59]

the welfare of the public is enhanced without imposing an undue burden on any individual, group or class. 431

7.25 The Board has previously stated herein that the economic feasibility of a project should not be the sole criteria examined nor the determining factor in the approval process. 432

7.26 The economic feasibility tests currently employed by the utilities result in projects being accepted that require a degree of subsidy from existing customers. With the five-year rate of return test the project may require a subsidy from existing customers for the first four years. Similarly the DCF methodology may result in approval of a project which requires a subsidy from existing customers in its early years, with the subsidy being offset by the benefits in later years. The Board has, in the past, considered that subsidy as reasonable, recognizing that future benefits may offset the subsidy in later years. 433

7.27 The implication of accepting an economic test which has a broader definition of economic feasibility than that employed in the past is that the subsidy required may in general be greater than that which was deemed reasonable by the Board in the past. 434

Was Page 57. See Image [OEB:11L1W-0:60]

7.28 The Board notes that several projects that received DSEP funding did not meet the fifth year rate of return test. Nevertheless the Board accepted that the projects were in the public interest and approved these projects even though a subsidy would still be required from existing customers in the fifth year of the project. 435

7.29 The Board finds that a contribution-in-aid of construction should be required for those projects where the sole purpose is to supply gas into a new area and where the evaluation process demonstrates an undue burden on existing customers. 436

7.30 The Board would expect an agreement to be reached between the utility and the community regarding the contribution before an application is made to the Board. 437

7.31 In certain cases, the Board considers that special rates and/or loans by the utility to finance a contribution-in-aid of construction, may facilitate the expansion of the natural gas system. 438

7.32 A number of the participants strongly suggested that the provincial government encourage expansion of the natural gas system in Ontario by 439

Was Page 58. See Image [OEB:11L1W-0:61]

developing a program to fund uneconomic projects. The Board considers that, in addition to the methods of subsidy referred to above, some government support might be justified where the overall benefits to 440 the community as a whole warrant such action.

Completion of the Proceedings 441

7.33 The Board will issue a procedural order in future proceedings to adopt the Board's findings in this Report. 442

443

Dated at Toronto this 1st day of June, 1987.

<signed>
J.C. Butler
Vice-Chairman and
Presiding Member
<signed>
J.A. Dekort
Member
<signed>
M.A. Daub
Member

Was Page 59. See Image [OEB:11L1W-0:62]

Appendix A 444

Economic Feasibility Tests 445

Was Page 60. See Image [OEB:11L1W-0:63]

Economic Feasibility Tests: A Summary 446

Was Page 61. See Image [OEB:11L1W-0:64]

447

Was Page 62. See Image [OEB:11L1W-0:65]

Economic Feasibility Tests: 448

Details 449

A. Consumers' Gas Feasibility Cash Flow Test 450

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E.B.O. 188

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF a hearing to inquire into, hear and determine certain matters relating to natural gas system expansion for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc.

BEFORE: G.A. Dominy
Presiding Member

R.M.R. Higgin
Member

J.B. Simon
Member

FINAL REPORT OF THE BOARD

January 30, 1998

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Appendix B: Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario

1. THE PROCEEDING

1.1 THE BACKGROUND

1.1.1 In a Notice of Public Hearing dated July 31, 1995, the Ontario Energy Board ("the Board") made provision to hold a public hearing under subsection 13(5) of the Ontario Energy Board Act ("the OEB Act", "the Act") to inquire into, hear and determine certain matters relating to the expansion of the natural gas systems of The Consumers' Gas Company Ltd. ("Consumers Gas"), Union Gas Limited ("Union") and Centra Gas Ontario Inc. ("Centra"), (collectively "the utilities"). The proceeding was given Board File No. E.B.O. 188.

1.1.2 In Procedural Order No. 1 the Board ordered the utilities to file their current policies for determining the feasibility of proposed system expansions and the application of environmental study reports.

1.1.3 The Board held an Issues Day meeting on September 11, 1995 and heard submissions on a proposed Issues List. The Board finalized the Issues List in Procedural Order No. 2 dated September 14, 1995.

1.1.4 Procedural Order No. 3, dated October 27, 1995, made provision for parties to file evidence and interrogatories on the evidence. The Order also provided for an alternative dispute resolution ("ADR") conference to be held commencing December 11, 1995 (" the first ADR Conference").

1.1.5 The Board received the *Report to The Ontario Energy Board on The Alternative Dispute Resolution Conference in E.B.O. 188 A Generic Hearing on Natural Gas System Expansion in Ontario*, on December 21, 1995 ("the first ADR Report"). There were divergent views expressed in the first ADR Report by the parties with respect to the principles involved in system expansion.

1.1.6 Having reviewed the first ADR Report, the Board issued Procedural Order No. 4 on January 11, 1996. In that Order, the Board directed that the parties choosing to file argument and reply should focus their submissions on the following issues:

1.1 Should financial feasibility be the only determinant for expansion or should it include, apart from security of supply and safety:

(1) an obligation to serve in areas where existing service is available;
(2) externalities;

If externalities are to be included, what specific externalities, i.e. economic, social, environmental, should be considered? What tests should be applied and in what sequence?

1.2 Given the answer to 1.1, what level of financial subsidy, if any, should be applied to system expansion;

1.3 Should a portfolio of projects be utilized or should the utilities account for expansion on a project-by-project basis? How should the portfolio be defined?

1.1.7 Submissions were filed on February 2, 1996 and reply submissions were filed on February 19, 1996.

1.1.8 An Interim Report of the Board ("Interim Report") was issued on August 15, 1996. In that Interim Report the Board made a determination of the issues and set out the principles that would apply to system expansion projects. The Board directed the parties to develop guidelines and policies reflecting the Board's conclusions. The Board also determined that the continuation of the proceeding should be by way of written submissions and a further ADR Settlement Conference ("the second ADR Settlement Conference").

1.1.9 A written common submission was filed by the utilities on September 30, 1996, and submissions and comments on the utilities' common submission were received from Board Staff, Consumers' Association of Canada, Canadian Industry Program for Energy Conservation, Industrial Gas Users Association/City of Kitchener, Green Energy Coalition, Northwestern Ontario Municipal Association/Federation of Northern Ontario Municipalities, Pollution Probe and Ontario Federation of Agriculture/Ontario Pipeline Landowners' Association.

1.1.10 In January 1997, the second ADR Settlement Conference was held. This resulted in the submission of:

- an ADR Agreement filed with the Board on March 14, 1997, subscribed to by the utilities and supported by a number of other parties ("ADR Agreement"), which included proposed System Expansion Guidelines;
- a dissent in the form of a document entitled "Deficiencies of the E.B.O. 188 ADR Agreement and their Rectification" dated April 1, 1997 ("Dissent Document");
- letters of comment from various parties on the ADR Agreement and Dissent Document; and
- responses (dated July 25, 1997) to a set of Board clarification questions to the utilities.

1.1.11 The parties concurring with the ADR Agreement and those substantially supporting the Dissent Document are listed in Appendix A.

1.1.12 In preparing this Final Report, the Board has considered the above documents. The resulting *Guidelines for Assessing and Reporting on Natural Gas Distribution System Expansion in Ontario (1998)* ("the Guidelines") are issued as Appendix B to this Report.

1.1.13 The following chapters set out the issues and the principles established in the Interim Report by quoting directly from that document. The positions of the parties are outlined by referencing the ADR Agreement, the Dissent Document and the various comments and clarifications made.

1.1.14 The Board's comments and findings are structured as:

- The Portfolio Approach
- Common Methods for Financial Feasibility Analysis
- Customer Connection and Contribution Policies
- Environmental Planning Requirements for System Expansion
- Monitoring and Reporting Requirements

1.1.15 As of January 1, 1998, Union and Centra merged into a single company, Union Gas Limited. The Board's findings in this Report and in the Guidelines are applicable to the new company and to Consumers Gas.

1.2 INTERVENTIONS

1.2.1 The following parties intervened in the proceeding:

- Canadian Association of Energy Service Companies
- City of Kitchener
- Consumers' Association of Canada
- Energy Probe
- Federation of Northern Ontario Municipalities
- Green Energy Coalition
- Grenville-Wood
- The Heating, Ventilation, Air Conditioning Contractors Coalition Inc.
- Industrial Gas Users Association
- Municipal Electric Association
- Natural Resource Gas Limited
- Northwestern Ontario Municipal Association
- Ontario Coalition Against Poverty
- Ontario Federation of Agriculture
- Ontario Hydro
- Ontario Native Alliance
- Ontario Pipeline Landowners' Association
- Ottawa-Carleton Gas Purchase Consortium

2. THE PORTFOLIO APPROACH

2.1 INTERIM REPORT CONCLUSIONS

2.1.1 *The Board believes that utilities are in the best position to plan their distribution systems and, therefore, they should have flexibility in choosing the optimal system design for their distribution system expansions. The Board also believes that if the utilities are allowed to assess the financial viability of all potential customers as a group [using a portfolio approach] more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.*

2.1.2 *The Board is of the view that all distribution system expansion projects should be included in a utility's portfolio. This includes projects being developed for security of supply and system reinforcement reasons. The Board will be prepared on an exception basis to consider a utility's submissions as to why a proposed project should not be included in the portfolio but treated separately.*

2.1.3 *The Board believes that the issue of the timing of projects can be mitigated by the use of a rolling P.I. [Profitability Index] or benefit to cost ratio in the portfolio. The Board finds that using a rolling P.I. such as the approach used by Union will allow more opportunity for new projects to be added to the portfolio in a more timely fashion and that this is in the public interest. Union's rolling P.I. is a weighted average calculation of the cumulative net present value ("NPV") inflows divided by the cumulative NPV outflows during the preceding 12 months.*

2.1.4 *The Board expects the utilities to develop common policies on calculating rolling P.I.s. The forecast rolling P.I.s at a given point in time will be compared to the actuals in each utility's rates case to determine if any action needs to be taken with regard to forecast variances.*

2.1.5 *The Board recognizes that subsidization can be measured at both the project and portfolio level. An overall rolling portfolio P.I. of 1.0 means that existing customers will not suffer a rate increase over the long term as a result of distribution system expansion. The Board is therefore of the view that an overall portfolio P.I. of 1.0 <u>or better</u> (emphasis added) is in the public interest. Using this approach will obviate the need for the intense scrutiny of the financial viability of each project; will ensure that existing ratepayers are not negatively impacted by new projects (given the Board's proviso above on the sharing of risks); and assist communities to obtain gas service where otherwise it would not be financially feasible on a stand-alone basis.*

2.1.6 *However, at the present time the utilities calculate the DCF ["discounted cash flow"] for proposed projects over long periods of time. The P.I. or benefit to cost ratio is based on this calculation. In the early years, the costs shown in the calculation generally exceed the revenues and there is a greater impact on rates than in the later years when revenues generally exceed costs. The Board is concerned that even if a utility demonstrates that its portfolio of distribution system projects shows a P.I. of at least 1.0 the impact on rates in a given year may be undue. For this reason, the Board expects the utilities to demonstrate in their rates cases that the short-term rate impact of the cumulative effect of the portfolios will not cause an undue burden on existing ratepayers.*

2.1.7 *The Board has considered whether or not it should impose a minimum threshold P.I. for projects to be included in the portfolios. The Board is concerned that the utilities may proceed with a number of projects with low P.I.s even though the P.I.s of the portfolios remain at 1.0 or greater. The cumulative impact of these projects may result in economic inefficiencies that outweigh the public benefit of the portfolio approach. From time to time, the Board will review the project specific data to monitor the operation of the portfolios in order to determine whether the cumulative* *economic inefficiency of proceeding with financially unfeasible projects outweighs the public interest in using the portfolio approach.*

2.2 POSITIONS OF THE PARTIES

2.2.1 The ADR Agreement proposed that each utility group all proposed new distribution customers and new facilities to serve them, for a particular test year into one portfolio (the "Investment Portfolio"). The Investment Portfolio would be designed to achieve a NPV of zero or greater (including normalized reinforcement costs).

2.2.2 The ADR Agreement proposed that each utility also maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio"). The cumulative result of project-specific discounted cash flow ("DCF") analyses from the past 12 months would be calculated monthly. The costs and revenues associated with serving customers on existing mains would not be included. The Rolling Project Portfolio would be used as a management tool by the utilities to decide on appropriate distribution capital expenditures.

2.2.3 The Dissent Document listed three concerns with the Investment Portfolio proposed in the ADR Agreement:

i. service lines off existing mains are included;
ii. security of supply projects are not included; and
iii. reinforcement costs have been normalized rather than using forecast actual costs.

2.3 BOARD'S COMMENTS AND FINDINGS

Investment Portfolio

2.3.1 The Board accepts the ADR Agreement proposal that each utility would group into one portfolio, the Investment Portfolio, all proposed new distribution customer attachments and facilities for a particular test year. The Investment Portfolio would be designed to achieve a positive NPV (greater than zero) in the test year (including normalized reinforcement costs).

2.3.2 The Board considers that a primary purpose of the Investment Portfolio analysis is to provide the Board with sufficient evidence to decide whether a utility's test year system expansion plan will result in undue rate impacts.

2.3.3 The Board understands that the ADR Agreement's proposed Investment Portfolio contains the capital costs of facilities for all new customers added during a test year. The analysis of system expansion financial feasibility includes revenues and operation and maintenance ("O&M") costs associated with these new customers over horizons as proposed up to 40 years. The utilities propose to include an allowance for reinforcement costs to supply the new projects on a normalized basis.

2.3.4 Since the Investment Portfolio analysis is intended to predict the financial and rate impacts of test year incremental system expansion capital expenditures and associated revenues and expenses, it is inappropriate to include historic capital expenditures or revenues from attachments in prior periods.

2.3.5 The Board accepts the difficulty in isolating test year customers attaching to new mains only (versus those attaching to mains built in prior years). However, as specified in the Guidelines attached as Appendix B, an estimate of the NPV without attachments to prior expansions will be required. This will enable the Board to better monitor the overall economic feasibility of such projects.

2.3.6 The Board's interpretation of the Investment Portfolio analysis and its associated rate impacts was assisted by reference to Consumers Gas' interrogatory response [Exhibit I, Tab 7, Schedule 8] in the E.B.R.O. 495 Consumers Gas 1998 rates case. The Board directs the utilities to file future impact analyses in a similar form (see paragraph 6.3.4).

2.3.7 The Board sought further explanation for the proposed treatment of reinforcement costs in the Investment Portfolio in its letter of July 4, 1997 to the utilities. The utilities responded that "normalized" reinforcement costs were categorized into "special" reinforcement and "normal" reinforcement. The costs of the former are those associated with specific major reinforcements of the system and are amortized over a period of 10-20 years. The normal reinforcement costs are the residual of the total identified reinforcement costs after the special reinforcement costs are deducted. The historical average for the special and normal reinforcement costs will then be used as the normalized amount to be included in the portfolio analysis as a percentage of the total capital expenditure in the year.

2.3.8 The Board finds the proposed treatment of reinforcement costs to be included in the Investment Portfolio as proposed in the ADR Agreement appropriate for overall portfolio analysis purposes. Union currently includes an allowance related to the carrying costs for advancement of reinforcement expenditures resulting from a new project and the Board finds this approach to be appropriate.

2.3.9 The Board does not agree that a design target of zero NPV and a P.I. of 1.0 is appropriate given the forecast risks inherent in the Investment Portfolio analysis. As the Investment Portfolio NPV approaches zero the marginal projects will be those with long cash flow break-even periods. Such projects require subsidy for long periods and hence increase short term rate impacts disproportionately.

2.3.10 In addition, the Board notes that the Investment Portfolio includes the costs and revenues associated with attaching customers to existing mains (i.e. mains constructed prior to any given test year). These projects by their nature will be more profitable for the utilities, since the costs of the mains are not included in the Investment Portfolio calculation. The Board concludes that the Investment Portfolio should be designed to achieve a positive NPV including a safety margin (for example, corresponding to a P.I. of 1.10). The Board believes that a portfolio designed in this way will minimize the forecast risks and hence more likely achieve the desired results of no undue rate impacts.

Rolling Project Portfolio

2.3.11 The Board also accepts the ADR Agreement proposal to maintain a Rolling Project Portfolio. The Rolling Project Portfolio provides an ongoing method of determining the financial feasibility and rate impact of expansion projects over a previous 12 month period. The Rolling Project Portfolio excludes the costs and revenues associated with new customers attaching to mains built prior to the last 12 month period. The Rolling Project Portfolio also provides a basis to compare a utility's Investment Portfolio with actual system expansion. Union has used a Rolling Project Portfolio approach for some time and has filed rate impacts from significant individual projects in its rates cases (e.g. E.B.R.O. 493/494 Exhibit B1, Tab 4, Appendices C and D).

2.3.12 As noted above the Board finds the proposed treatment for reinforcement costs to be included in the Rolling Project Portfolio to be appropriate.

2.3.13 The Board finds the Rolling Project Portfolio as proposed by the utilities to be a useful management tool. This Portfolio provides a mechanism for facilitating review of the financial status of overall distribution system expansion at the time that individual major projects are before the Board for either franchise and certificate approval, or for approval of leave to construct and also for monitoring purposes.

2.3.14 The Board has previously expressed its position that inclusion in the Investment Portfolio, of revenues and costs for infill customers connecting to existing mains may provide a mismatch between periodic costs and revenue. The Board notes that the Rolling Project Portfolio, which is the utilities' primary management tool, does not include such infill customers. Therefore, the Board finds that the Rolling Project Portfolio does provide appropriate matching and that an NPV of zero (or greater) is appropriate.

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES

4.1 INTERIM REPORT CONCLUSIONS

4.1.1 *In the last few years, the Board has approved contributions in aid of construction in the form of periodic contribution charges for residential and small commercial customers in order to improve the profitability of projects when the P.I. or benefit to cost ratio is less than 1.0.*

4.1.2 *The Board notes that accidents of timing and geography can ... lead to inequitable situations where some ratepayers in similar situations may not have to pay a contribution while others are required to pay contributions.*

4.1.3 *The Board realizes that customers have indicated their willingness to contribute towards the cost of projects that are not financially feasible in order to obtain gas service. The Board also notes that there may be communities that would be so costly to serve and the P.I. so low that they are unlikely ever to be included in the portfolio. The Board accepts that in these special circumstances a contribution in aid of construction from a community would be acceptable on a case by case basis, but the Board will not expect the utilities to require contributions from all projects which do not meet a threshold P.I. of 1.0. In light of these considerations, the Board expects the utilities to prepare common guidelines on the treatment of customers currently paying periodic contribution charges.*

4.1.4 *The Board will review in the next phase of this proceeding the utilities' policies on requiring contributions in aid of construction where dedicated facilities are being constructed primarily for a single customer. In this regard the Board is interested in a policy that deals with all customer classes and expects the utilities to prepare a policy that is common among the utilities.*

4.2 POSITIONS OF THE PARTIES

4.2.1 The ADR Agreement states that the utilities will accept contributions in aid of construction for communities or projects that would otherwise not likely be included in the portfolio.

4.2.2 The ADR Agreement also proposed that existing contractual arrangements for the collection of contributions continue with the exception of Consumers Gas' projects for which contributions would be adjusted to achieve a P.I. of 0.8.

4.2.3 The ADR Agreement did not propose a definition to be used in determining when a facility is to be considered "dedicated".

4.2.4 The Dissent Document does not address the issue of customer contribution policies.

4.3 BOARD'S COMMENTS AND FINDINGS

4.3.1 The Board notes that the utilities wish to retain the ability to accept contributions in aid of construction for communities or projects that would not otherwise be included in the portfolio. However, no cost limits or P.I. thresholds have been recommended by the parties to assist the utilities in making such decisions. As stated in the Interim Report, the Board believes that the utilities should continue to make decisions on contributions in an even handed manner.

4.3.2 The Board recognizes that Union and Centra have been applying a P.I. threshold of 0.8 for the collection of customer contributions for new community attachments. The Board also notes that the utilities proposed this level as the basis for determining the treatment of customers currently paying periodic contributions. In order to ensure fairness and equity in the application and design of contribution requirements, the Board finds that all projects must achieve a minimum threshold P.I. of 0.8 for inclusion in a utility's Rolling Project Portfolio.

4.3.3 The Board directs the utilities to prepare and maintain a common set of Board-approved customer connection policies that shall, as a minimum, include:

i. the circumstances under which customers will be required to pay for all, or part, of their service line connection, including the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges; and

ii. the circumstances where the use of a proposed facility will be dominated by one or more large volume customers for which the utilities will retain the option of collecting contributions in aid of construction. The contribution amounts will be consistent with the cost allocation for such mains and accordingly based on the peak day demand and the cost allocators used by each of the utilities.

4.3.4 The Board agrees with the parties that the common criteria for contributions in aid of construction should apply to all customer classes. If there is a reasonable expectation of further expansion, the contribution in aid of construction is expected to take into account the future load growth potential and timing of any such expansion.

4.3.5 The Board expects the utilities to bring forward common proposals for customer connection and contribution policies for Board approval. These proposals will be reviewed in each of the utilities' rate cases.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2012-0431

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Union Gas Limited for an order pursuant to section 90 of the *Ontario Energy Board Act, 1998,* granting leave to construct a natural gas pipeline and facilities in the Municipality of Leamington and the Town of Lakeshore, in the County of Essex.

BEFORE: Paula Conboy
Presiding Member

Emad Elsayed
Member

DECISION AND ORDER
March 28, 2013

Union Gas Limited ("Union") filed an application with the Ontario Energy Board (the "Board") on November 23, 2012 under section 90 of the *Ontario Energy Board Act, 1998* (the "Act"), for an order granting Union leave to construct approximately 8.5 kilometres of Nominal Pipe Size ("NPS") 12 (inch diameter) natural gas pipeline (the "Proposed Pipeline") in the Municipality of Leamington and the Town of Lakeshore, in the County of Essex. The Board also notes that Union requires Board approval of the form of easement agreement provided in the application (as required by section 97 of the Act). The Board has assigned the application file number EB-2012-0431.

For the reasons set out below, the Board finds that the construction of the Proposed Pipeline is in the public interest and grants Union leave to construct subject to the Board's Conditions of Approval attached as Appendix A to this Decision and Order (the "Conditions of Approval"). The Board also approves the proposed form of Pipeline

Easement Agreement that has been offered or will be offered to all landowners affected by the approved route.

The Proposed Pipeline

The Proposed Pipeline will parallel the existing North Leamington Line from the Comber Transmission Station to the County Road 14 Station. The Proposed Pipeline will be constructed on a road allowance from the existing NPS 20 Panhandle Line to County Road 8 and on the abandoned railroad corridor south of County Road 8. There will be modifications at the Comber Transmission Station and a connection to the North Leamington Line at the County Road 14 Station to facilitate the Proposed Pipeline.

Construction of the Proposed Pipeline is planned to start in May, 2013 in order to meet the required in-service date of November, 2013.

A map showing the location of the Proposed Pipeline is attached as Appendix B to this Decision and Order.

The Proceeding

The Board issued a Notice of Application ("Notice") dated January 10, 2013. On February 6, 2013, the Board received a letter of comment from Brookfield Renewable Energy Group ("Brookfield"). Board staff filed interrogatories on February 8, 2013 and Union filed interrogatory responses on February 15, 2013. Board staff filed a written submission on February 27, 2013 and Union filed its reply submission on March 8, 2013.

Infrastructure Crossing the Proposed Pipeline

In its letter of comment, Brookfield stated that it has overhead and underground infrastructure crossing the Proposed Pipeline and would like to be included in the planning and construction stages of the project. Brookfield stated that it would like a crossing agreement developed where it has underground intersections.

In response to Board staff interrogatories, Union stated that it is aware that Brookfield has overhead and underground infrastructure crossing the Proposed Pipeline. Union stated that it has contacted Brookfield to begin planning the crossing of Brookfield's infrastructure. Union further stated that the planning process will develop protocols that will ensure that both Brookfield's and Union's facilities can co-exist without any negative impacts. Lastly, Union stated that it will contact Brookfield before crossing Brookfield's infrastructure during the construction stages of the Proposed Pipeline.

The Public Interest Test

This is an application under section 90 of the Act seeking an order for leave to construct a hydrocarbon pipeline. Section 96 of the Act provides that the Board shall make an order granting leave to carry out the work under section 90 if the Board finds that "the construction, expansion or reinforcement of the proposed work is in the public interest." When determining whether a project is in the public interest, the Board typically considers the following factors:

1. Is there a need for the Proposed Pipeline?
2. Has the economic feasibility of the Proposed Pipeline been demonstrated?
3. What are the environmental impacts associated with construction of the Proposed Pipeline and have they been adequately addressed?
4. Are there any outstanding landowner matters for the Proposed Pipeline routing and construction?
5. Is the Proposed Pipeline designed in accordance with the current technical and safety requirements?

Each of these issues is addressed below.

The Need for the Proposed Pipeline

In its application, Union stated that it has received a number of requests for firm and interruptible natural gas service from greenhouse growers in the Leamington, Kingsville, Mersea Township, and Gosfield South Township area. These requests have come from new greenhouse operations, existing greenhouses that operate on fuels other than natural gas, and from growers who want to switch from interruptible service to firm natural gas service.

Union has entered into negotiations with 18 customers ("Contract Customers") who would account for 51% of the capacity of the Proposed Pipeline. Union stated that it would continue to sign contracts with growers until the Proposed Pipeline is at full capacity. Union indicated that some growers have identified that they do not require additional natural gas service at the present time but will require additional service in the near future ("Forecast Customers").

Union stated that although it is possible to only build for the Contract Customers who have shown an interest in the Proposed Pipeline, a more practical and economic approach is to build for Contract Customers and Forecast Customers.

In its reply submission, Union filed a Revised Contract and Forecast Customer Growth Schedule. Union also stated that the Proposed Pipeline's capacity has now been substantially allocated in the first year of the project and there is a greater percentage of customers forecasted to switch from interruptible to firm service than what was originally forecasted.

The Board finds that Union has adequately substantiated the need for the Proposed Pipeline.

Project Economics – Feasibility of the Proposed Pipeline

The upfront capital cost for the Proposed Pipeline is estimated to be $8.2 million. Union has employed an economic feasibility test consistent with the "Ontario Energy Board Guidelines for Assessing and Reporting on Natural System Expansion in Ontario" set out in the Ontario Energy Board's EBO 188 "Report to the Board" dated January 30, 1998 ("EBO 188").

In EBO 188, the Board determined that all individual projects must achieve a minimum threshold Profitability Index (P.I.) of 0.8 for inclusion in a utility's Rolling Project Portfolio. In that decision, the Board also determined that an overall project portfolio P.I. of 1.10 (to include a safety margin) or better is in the public interest.

Union calculated that the project P.I. would be 1.0 with an expected $2 million contribution from growers. They also stated that when the Proposed Pipeline is included in Union's 2013 new business investment portfolio, the resulting portfolio P.I.

would be 1.14. Further, the company indicated that including the Proposed Pipeline in Union's Rolling Project Portfolio as at October 2012 would result in a P.I. of 1.43.[1]

In its interrogatory responses, Union stated that if contract negotiations are unsuccessful and the Proposed Pipeline is completed without any contribution from growers, the rate impact on a typical residential customer in Rate M1 would be less than $0.50 per year.

Board staff submitted that given the stated purpose of the Proposed Pipeline is commercial in nature, namely to provide additional natural gas service to greenhouse growers, Union should be required to collect the $2 million contribution before constructing the Proposed Pipeline. This would ensure that the Proposed Pipeline meets a P.I. of 1.0 on a stand alone basis and therefore not result in cross-subsidization from other ratepayers.

In its reply submission, Union indicated that capacity has now been substantially allocated in the first year of the project and that a greater percentage of existing customers are forecasted to switch from interruptible to firm service than what was originally forecasted, resulting in fewer new customers requiring additional distribution facilities.

The impact of these changes, in Union's submission, is that there are now additional revenues in the early years of the economic analysis as well as lower costs since there is no longer a need to construct new distribution facilities.

Union submitted that based on these changes, the calculated P.I. is 1.18[2] and the $2 million contribution from the greenhouse growers to be collected prior to the start of construction is no longer required

The Board accepts Union's evidence on the cost estimates and will not require Union to collect a contribution from greenhouse growers prior to constructing the Proposed Pipeline.

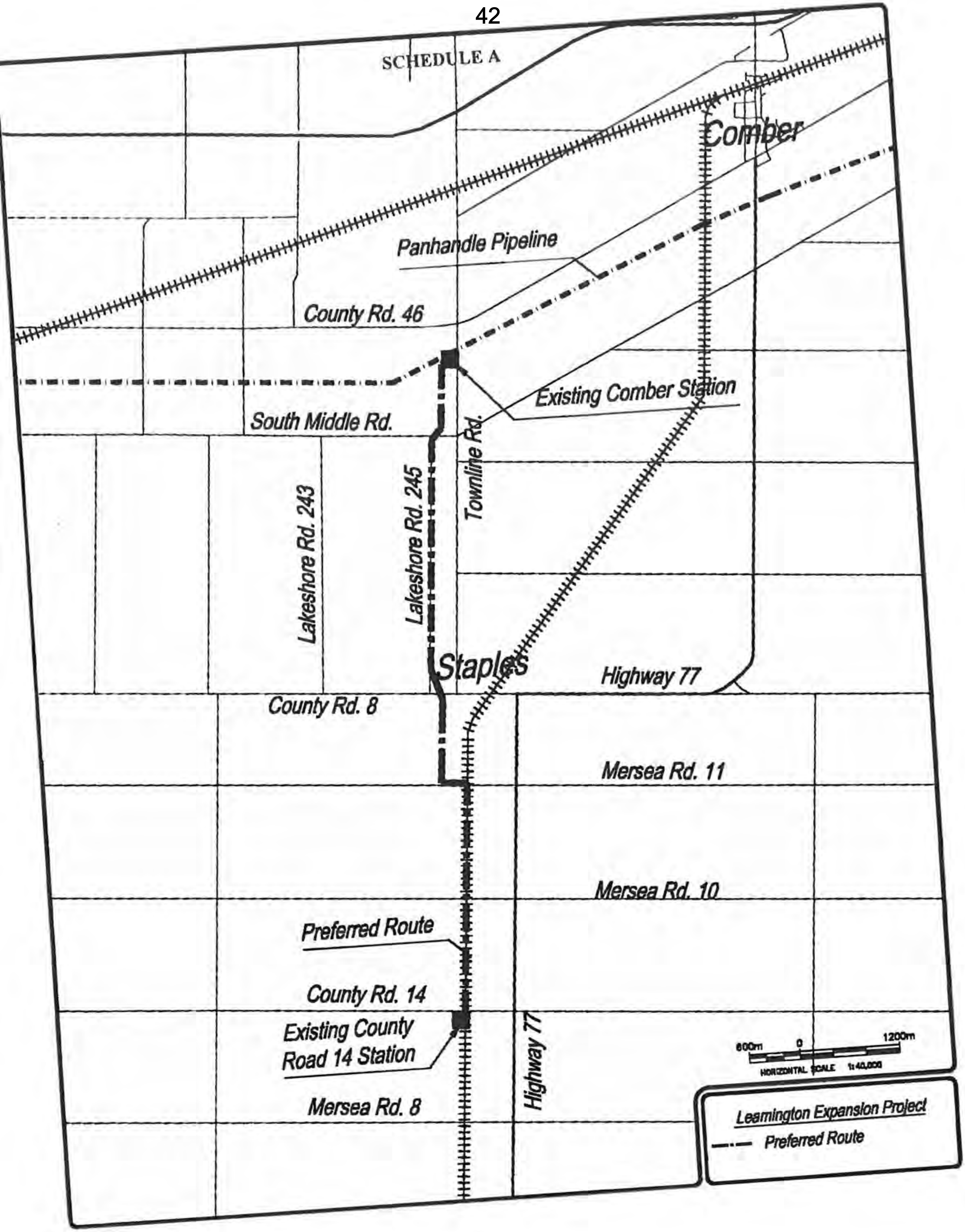
The Board will require Union to file a Post Construction Financial Report of the actual costs of the Proposed Pipeline once it is completed.

[1] EB-2012-0431, Pre-filed Evidence, page 6
[2] Union reply submission, attachment #2, March 8, 2013

Appendix B

Map of the Location of the Proposed Pipeline

SCHEDULE A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Panhandle Pipeline
County Rd. 46
Existing Comber Station
South Middle Rd.
Townline Rd.
Lakeshore Rd. 243
Lakeshore Rd. 245
Staples
Highway 77
County Rd. 8
Mersea Rd. 11
Mersea Rd. 10
Preferred Route
County Rd. 14
Existing County Road 14 Station
Mersea Rd. 8
Highway 77
600m 0 1200m
HORIZONTAL SCALE 1:40,000
Leamington Expansion Project
Preferred Route

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

EB-2013-0420

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Union Gas Limited for an order pursuant to sections 90 of the *Ontario Energy Board Act, 1998,* granting leave to construct a natural gas pipeline and facilities in the Town of Lakeshore, in the County of Essex.

BEFORE: Cynthia Chaplin
Presiding Member

DECISION AND ORDER
March 28, 2014

Union Gas Limited ("Union") filed an application with the Ontario Energy Board on December 17, 2013 seeking approval to construct approximately 13 kilometres of Nominal Pipe Size 20 natural gas pipeline in the Town of Lakeshore, in the County of Essex. The application was made under section 90 of the *Ontario Energy Board Act, 1998,* and the Board has assigned the application file number EB-2013-0420.

For the reasons set out below, the Board finds that the construction of the proposed pipeline is in the public interest. The Board grants leave to construct, subject to the Board's Conditions of Approval, which are attached as Appendix A.

The Proposed Pipeline

The proposed NPS 20 pipeline will replace approximately 13 kilometers of the existing NPS 16 Panhandle Line in the Town of Lakeshore from the west side of West Puce Road to the east of East Ruscom River Road. Union plans to start construction in May

2014 for completion and in-service date in November 2014. A map showing the location of the Proposed Pipeline is attached as Appendix B.

The Proceeding

The Board issued a Notice of Application and Written Hearing on January 22, 2014. Union served and published the Notice as directed by the Board. There are no intervenors in this proceeding.

Board staff filed a written submission on March 14, 2014, supporting Union's application. Union filed its reply on March 18, 2014, confirming its acceptance of the conditions of approval proposed by Board staff. On March 27, 2014 Union filed additional information on the cost difference between the proposed NPS 20 pipeline and an alternative of replacing the existing NPS 16 with the same size new pipeline. This information was provided upon request of the Board.

The Public Interest Test

This is an application under section 90 of the Act seeking an order for leave to construct a natural gas pipeline. Section 96 of the Act provides that the Board shall make an Order granting leave if the Board finds that "the construction, expansion or reinforcement of the proposed work is in the public interest". When determining whether a project is in the public interest, the Board typically examines the need for the project, the economics, the impact on the ratepayers, the environmental impact, the impact on land owners, and pipeline design technical requirements.

The following issues define the scope of the proceeding:

- Is there a need for the proposed pipeline?
- Are there any undue negative rate implications for Union's rate payers caused by the construction and operation of the proposed pipeline?
- What are the environmental impacts associated with construction of the proposed pipeline and are they acceptable?
- Are there any outstanding landowner matters for the proposed pipeline routing and construction?
- Is the pipeline designed in accordance with the current technical and safety requirements?

Each of these issues is addressed below.

The Need for the Pipeline

Union explained that the need for the pipeline is driven by integrity management requirements and by expected new customer growth in the service region served by the Panhandle system.

In accordance with provincial regulatory requirements, administered by the Technical Standards and Safety Authority "(TSSA"), Ontario natural gas utilities must implement pipeline system maintenance and integrity management programs to ensure safe operation of the system. Union identified safety and reliability issues with the pipeline during internal pipeline inspections conducted between 1999 and 2003 and again in 2011. Some of the identified deficiencies were eliminated between 1999 and 2013, however Union concluded that replacement of the existing pipeline should be implemented in 2014.

The Board accepts Union's evidence related to its integrity management program and pipeline inspections and the conclusions the company has reached as to the necessity of replacing the pipeline. The Board finds that Union has adequately justified the need to replace the existing pipeline.

Project Economics and Impact on Ratepayers

The estimated capital cost of the project is $29.597 million. Union stated it did not complete a discounted cash flow analysis for the project because the project is underpinned by system integrity requirements and there are no new contracts associated with this replacement.

Union considered two alternatives for the proposed pipeline. One alternative would be to replace individual sections of the pipeline which were identified as not meeting integrity or class location requirements. Union rejected this alternative on the basis that it would be an inefficient approach given the large number of replacements required. The Board agrees with Union that such an approach would be inefficient. The second alternative would be to replace the pipeline with a new pipeline of the same diameter (NPS 16). Union rejected that alternative because the capacity would not be sufficient to serve the forecast growth in the City of Windsor and the Leamington/Kingsville greenhouse market. Union estimated that cost of replacing the existing NPS 16 pipeline with the same size pipeline would be $26.340 million, which is $3.257 million less than the proposed pipeline. The Board finds that replacing the pipeline with a larger diameter pipe involves a modest incremental expense, but is an efficient means by which to meet expected incremental demand. The Board is satisfied that Union has considered a reasonable range of alternatives and that an appropriate alternative was selected.

The Board finds that the cost of the project is reasonable and that the impacts on ratepayers are acceptable. The Board will require a report from Union on the actual costs of the project, and this requirement is included in the Conditions of Approval.

Environmental Assessment

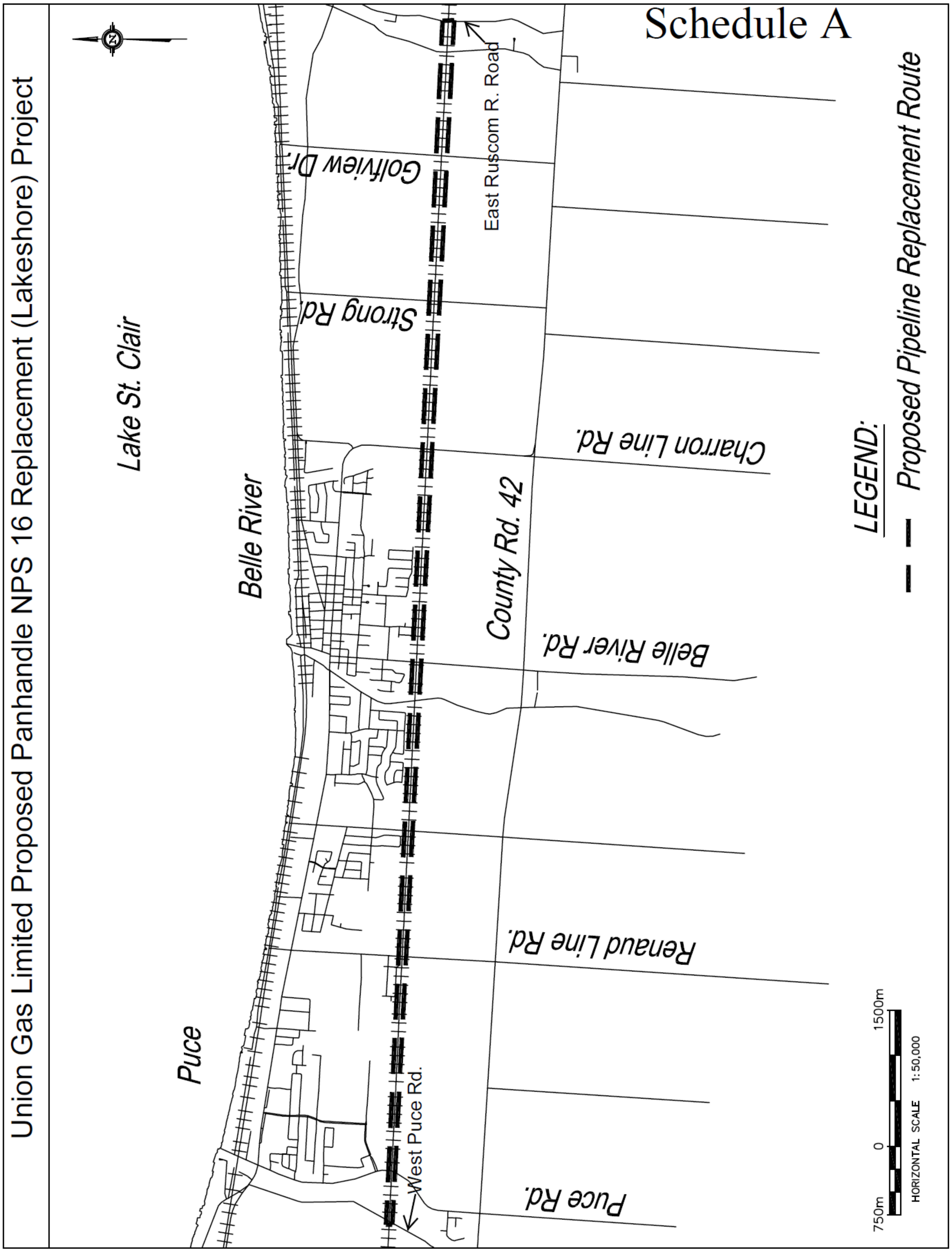
The pipeline route selection and environmental assessment were completed in accordance with the Board's *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 6th edition, 2011* ("OEB Environmental Guidelines"). The results of the routing and environmental assessment are presented in an environmental report entitled *NPS 16 Pipeline Replacement West Puce River Road to East Ruscom River Road Environmental Report, December, 2013*. The report was completed by Azimuth Environmental Consulting Inc. and was submitted as part of the application. Union stated that the pipeline will be constructed in accordance with Union's construction specifications and the recommendations set out in the report.

The evidence indicates that there was extensive public and agency consultation, Ontario Pipeline Coordinating Committee ("OPCC") review, and consultation with aboriginal groups. Union stated that the consultation was consistent with the OEB Environmental Guidelines. Union also stated that there are no outstanding or unresolved issues relating to any of the consultations.

The Board finds that Union has adequately addressed the environmental issues through its proposed mitigation and restoration program and its commitment to implement the recommendations in the environmental report. To ensure mitigation of impacts, and restoration of land and water resources, the Board has imposed monitoring and reporting requirements in the Conditions of Approval.

Appendix B

Map of the Project Location



Union Gas Limited Proposed Panhandle NPS 16 Replacement (Lakeshore) Project
Schedule A
Lake St. Clair
Belle River
Puce
Golfview Dr.
Strong Rd.
Charron Line Rd.
County Rd. 42
Belle River Rd.
Renaud Line Rd.
Puce Rd.
East Ruscom R. Road
West Puce Rd.
LEGEND:
Proposed Pipeline Replacement Route
750m
0
1500m
HORIZONTAL SCALE 1:50,000

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

DECISION AND ORDER

EB-2016-0013

UNION GAS LIMITED

Application for leave to construct natural gas pipelines and ancillary facilities in the Municipality of Leamington

BEFORE: **Emad Elsayed**
Presiding Member

Paul Pastirik
Member

June 29, 2016

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

Union Gas Limited (Union) is a major Canadian natural gas storage, transmission and distribution company serving about 1.4 million residential, commercial and industrial customers in communities across northern, southwestern and eastern Ontario.

Union filed an application with the Ontario Energy Board (the OEB) on January 14, 2016, in accordance with section 90 of the *Ontario Energy Board Act, 1998* (the Act), for leave to construct a natural gas pipeline and ancillary facilities to serve the growing greenhouse market in the Municipality of Leamington. The Leamington Expansion Project (the Project) consists of 6.7 km of NPS 12 natural gas pipeline, 250 metres of NPS 16 natural gas pipeline, 60 metres of NPS 8 natural gas pipeline and ancillary facilities.[1] A map showing the location of the Project is attached as Schedule A.

The Project will provide an additional 51,900 m^3/hour of firm capacity to greenhouse growers in the project area (which includes Leamington, Kingsville, Mersea Township and Gosfield South). The planned in-service date for the Project is November 1, 2016.[2]

For the reasons set out below, the OEB finds that the construction of the Project is in the public interest. The OEB grants Union leave to construct the Project, subject to the Conditions of Approval, which are attached as Schedule B.

[1] EB-2016-0013, Union Pre-Filed Evidence at p. 1.
[2] EB-2016-0013, Union Pre-Filed Evidence at p. 1.

2 THE PROCESS

The OEB issued a Notice of Hearing (the Notice) on January 26, 2016. Union served and published the Notice as directed by the OEB. The following parties were granted intervenor status in the proceeding:

- Enbridge Gas Distribution Inc. (Enbridge)
- Hydro One Networks Inc. (Hydro One)
- Independent Electricity System Operator (IESO)
- Ontario Greenhouse Vegetable Growers (OGVG)

The OEB initially proceeded to hear the application by way of a written hearing. However, after reviewing Union's responses to written interrogatories filed by OEB staff, OGVG and Hydro One, the OEB decided that it would benefit from further discovery on two main issues: (a) the project economics and Union's proposed method for cost recovery; and (b) the land issues raised by Hydro One (specifically, the routing proposed by Union which results in the proposed Leamington pipeline and Hydro One's previously approved SECTR transmission line being in close proximity).

On that basis, the OEB decided to hear the case by way of an oral hearing. The OEB also allowed Hydro One the opportunity to file intervenor evidence (as was requested by Hydro One). Hydro One filed intervenor evidence on April 12, 2016.

The OEB held an oral hearing on April 19, 2016. At the oral hearing, the OEB heard testimony from both Union and Hydro One regarding the land issues raised by Hydro One. Both parties agreed that an AC Interference Study would need to be completed to determine whether Union's proposed Leamington pipeline and Hydro One's SECTR transmission line could be safely constructed in close proximity.

The OEB directed that the AC Interference Study be filed with the OEB prior to parties making submissions on the land issues. On that basis, the OEB directed parties to make submissions on the non-land matters (including the project economics and Union's proposed method for cost recovery) in a first round of submissions prior to establishing a procedural schedule for addressing the land issues raised by Hydro One.

The OEB received submissions on the non-land matters from OEB staff and OGVG. The OEB also received a reply submission from Union.

The OEB received the AC Interference Study prepared on Union's behalf by Corrosive Service Company Limited (CSCL) on May 19, 2016.[3]

The OEB granted Union and Hydro One until June 3, 2016 to reach an agreement on the land issues and file a letter with the OEB advising whether an agreement has been reached.

On June 3, 2016, Hydro One filed a letter advising the OEB that Union and Hydro One had reached a preliminary agreement on the land issues that arose in this proceeding. On the same day, Union filed a letter advising that it was prepared to sign the agreement contemplated in Hydro One's letter.

On that basis, the OEB offered all parties the opportunity to file submissions on the land issues, the environmental assessment, First Nation and Métis consultation, and the Conditions of Approval (which were the remaining issues that were not addressed in the first round of submissions).

The OEB received submissions on the above noted matters from OEB staff. The OEB also received a reply submission from Union.

[3] On May 30, 2016, Union and Hydro One held a meeting to review the AC Interference Study and its findings. After the meeting, a number of changes were made to the AC Interference Study at the request of Hydro One and the final study was filed with the OEB on June 7, 2016.

3 THE PUBLIC INTEREST TEST

This proceeding concerns an application filed by Union under section 90 of the Act seeking an order for leave to construct a natural gas pipeline.

Section 96 of the Act provides that the OEB shall make an order granting leave if the OEB finds that “the construction, expansion or reinforcement of the proposed work is in the public interest”. When determining whether a project is in the public interest, the OEB typically examines the need for the project, project alternatives, the project cost and economics, the environmental impact, First Nations and Métis consultation, and impacts on land owners.

Each of these issues is addressed below.

4 NEED FOR THE PROJECT

Background

Union noted that there has been strong growth in the greenhouse market in the project area (which includes Leamington, Kingsville, Mersea Township and Gosfield South) and that the high pressure pipeline system in the area operates at capacity on a peak day. As a result, Union has been unable to provide new firm capacity, or convert existing interruptible service to firm service, in response to requests from greenhouse growers in the project area.[4]

Union held an expression of interest process for firm capacity related to the Project, which resulted in bids for firm capacity totaling 129,097 m^3/hour. The bids included both requests for new firm capacity and the conversion of existing interruptible service to firm service. The requested capacity exceeded the firm capacity available from the Project (51,900 m^3/hour).

As of April 8, 2016, 52 long-term contracts and 3 Letters of Agreement have been signed.[5] These long-term contracts and Letters of Agreement account for all 51,900 m3/hour of firm capacity that is created by the Project.

Union's application also included letters of support from the Corporation of the Municipality of Leamington and from OGVG. The letters stated that a natural gas service expansion is necessary to support the region's economic growth and development.[6]

OEB staff and OGVG agreed that there is a need for the Project and generally supported the OEB granting Union leave to construct the Project.[7]

[4] EB-2016-0013, Union Pre-Filed Evidence at pp. 1 and 4.
[5] EB-2016-0013, Union Reply Evidence, April 15, 2016 at Schedule 6 (Updated Response to OEB Staff 3).
[6] EB-2016-0013, Union Pre-Filed Evidence at Schedule 1.
[7] EB-2016-0013, OEB Staff Submission, May 3, 2016 at pp. 1-2; and EB-2016-0013, OGVG Submission, May 3, 2016 at pp. 2-3.

OEB Findings

The OEB finds that Union has adequately justified the need for the Project based on the increased demand in the project area from greenhouse growers for firm capacity. This demand significantly exceeds the available firm capacity. The Project is supported by the signed long-term contracts and Letters of Agreement.

5 PROJECT ALTERNATIVES

Background

Union stated that no alternatives to the Project were considered as the Project is a continuation of the Leamington Phase I Project (EB-2012-0431).[8]

In the Leamington Phase I Project proceeding, the OEB approved the construction of 8.5 km of NPS 12 natural gas pipeline in the Municipality of Leamington. The need for the Project is the same as the Leamington Phase I Project (i.e. providing requested incremental capacity to greenhouse growers in the region).[9]

OEB staff submitted that it has no concerns with Union not considering alternatives to the Project in this instance as the Project is a continuation of the Leamington Phase I Project and the requests for capacity exceed the firm capacity available from the Project.[10]

OEB Findings

Given that the Project is a continuation of the OEB-approved Leamington Phase I Project and that there is growing demand for incremental firm capacity in the project area, the OEB finds that there was no need for Union to consider alternatives.

[8] EB-2016-0013, Union Pre-Filed Evidence at p. 5.
[9] EB-2012-0431, Decision and Order, March 28, 2013.
[10] EB-2016-0013, OEB Staff Submission, May 3, 2016 at p. 3.

6 PROJECT COSTS AND ECONOMICS

Background

Union noted that the estimated capital cost for the Project (including pipeline and stations) is $12.3 million.[11] In addition, Union estimated $1.7 million in costs for the individual distribution facilities required to connect customers.[12]

Union included the total $14 million in capital costs (i.e. project costs of $12.3 million and individual distribution facility costs of $1.7 million) in the Discounted Cash Flow (DCF) analysis that Union completed for the Project. The DCF analysis completed provides a Profitability Index (P.I.) value of 1.11 and Net Present Value (NPV) of $1.5 million using a revenue term of 10 years.[13] The DCF analysis does not include any aid to construct payments.

The Project creates 17,500 m^3/h of incremental interruptible capacity and allows for currently contracted interruptible capacity to be re-sold as customers convert their existing interruptible service to firm service.[14]

The DCF analysis does not include any forecast revenues from the 17,500 m^3/h of incremental interruptible capacity created by the Project as customers did not contract for this capacity and Union stated that future demand in the region will be for firm capacity (which will be met through a system expansion in 2017). However, the DCF analysis does include revenues arising from the re-sale of converted interruptible capacity.[15] [16]

The DCF analysis highlights that the Project is economically feasible as the forecast revenues will more than fully recover the costs of the Project over a 10-year period.

Union proposed to recover from each customer their allocated portion of the pipeline expansion costs and the individual distribution facility costs through an aid to construct

[11] EB-2016-0013, Union Pre-Filed Evidence at pp. 5-6.
[12] EB-2016-0013, Union Pre-Filed Evidence at p. 7.
[13] EB-2016-0013, Union Pre-Filed Evidence at p. 7.
[14] EB-2016-0013, Union Interrogatory Responses, March 24, 2016 at OEB Staff 1(e).
[15] Union noted that it was able to re-contract for 11,691 m^3/h of the existing interruptible capacity made available by those customers that converted to firm service on the Project.
[16] EB-2016-0013, Union Reply Submission, May 17, 2016 at pp. 2-3.

payment and / or through a long-term contract.[17] In accordance with Union's original proposal, each customer would be required to pay their entire portion of the pipeline costs (and their individual distribution facility costs) within a 10-year period.[18]

Union used customer-specific DCF analyses to determine whether an aid to construct payment is required from the customers that will take capacity created from the Project. Each customer would be required to pay an amount over their contract term based on a minimum annual volume (MAV) and a contract duration (and in some cases an aid to construct payment) that results in a customer-specific P.I. of 1.0.[19]

There are three main issues that were addressed by the submissions of OEB staff and OGVG:

1. Requirements for Aid to Construct Payments
2. Union's Responsibility to Assist Customers with Long-Term Contracts associated with the Project
3. Treatment of Interruptible Revenues

Although Union's application for leave to construct the Project was filed under section 90 of the Act, OEB staff submitted that it is appropriate for the OEB to deal with the relevant rate matters in the current proceeding. OEB staff argued that the OEB has all of the necessary information to make comprehensive findings in this proceeding and there is nothing that would prohibit the OEB from making findings on rate matters, typically dealt with under section 36 of the Act, in a leave to construct proceeding.[20] OGVG took a similar position noting the OEB's findings in Union's 2014 rates proceeding[21] where the OEB stated that rate matters associated with a facility project should be explored within the relevant leave to construct proceeding.[22]

[17] EB-2016-0013, Union Pre-Filed Evidence at p. 3.
[18] There are no contracts of a duration greater than 10 years. EB-2016-0013, Undertaking Response J1.3.
[19] EB-2016-0013, Union Interrogatory Responses, March 24, 2016 at OEB Staff 2(g).
[20] EB-2016-0013, OEB Staff Submission, May 3, 2016 at p. 7.
[21] EB-2013-0365
[22] EB-2016-0013, OGVG Submission, May 3, 2016 at pp. 4-5.

Requirements for Aid to Construct Payments

Most customers have signed long-term contracts (with MAVs and contract durations) that generate sufficient revenues to pay their allocated costs within a period of 10 years in the absence of aid to construct payments. However, three customers would be required to make aid to construct payments as the revenues generated over the term of their contracts do not generate sufficient revenues to cover their allocated costs within a 10-year period. For these three customers, contract durations of 12 years, 13 years, and 25 years would be required to achieve a P.I. of 1.0 in the absence of aid to construct payments.[23]

OEB staff submitted that the EBO 188 Guidelines do not contemplate requirements for aid to construct payments from customers in situations where the P.I. of a project is greater than 1.0. Therefore, OEB staff submitted that no aid to construct payments should be required from any customers taking service associated with the Project.

OEB staff submitted that, instead, the contract duration for the three customers required to make aid to construct payments should be extended beyond 10-years to remove any requirement for aid to construct payments.[24] OGVG made similar arguments.[25]

Union submitted that it is prepared to extend the contract term for two of the customers that are required to make aid to construct payments from 10 years to 12 years and 13 years respectively. This will remove the requirement for aid to construct payments from these two customers.

However, for the third customer, Union stated that it is prepared to extend that customer’s contract to 20-years, which it submitted is the maximum period specified in the EBO 188 Guidelines for large volume customers. As the duration of the contract for this customer would need to be extended to 25 years to avoid the requirement for an aid to construct payment, this customer would still be required to make a reduced aid to construct payment. Union submitted that if this customer does not make an aid to construct payment and its contract is not extended to 25 years, the customer would be

[23] EB-2016-0013, Union Reply Evidence, April 15, 2016 at Schedule 6 (Updated Response to OEB Staff 3).
[24] EB-2016-0013, OEB Staff Submission, May 3, 2016 at p. 9.
[25] EB-2016-0013, OGVG Submission, May 3, 2016 at pp. 8-9.

treated differently than the other customers taking service on the Project as it will not contribute its allocated share of the costs of the pipeline.[26]

Union's Responsibility to Assist Customers with Long-Term Contracts associated with the Project

OGVG and OEB staff submitted that Union should be required to assist customers that need to reduce contracted firm capacity over the term of the contract find another customer to re-contract the capacity that is no longer required. OGVG stated that given the duration of some of the contracts, the ability to transfer the firm capacity to another willing customer is an important option to have available.[27]

OGVG also submitted that the OEB should require Union to adjust contract terms to account for Demand Side Management (DSM) activities to ensure that customers are not applied MAV-related penalty charges that are caused by their efforts to reduce consumption through DSM programs.[28]

In addition, both parties submitted that Union should offer customers the option to extend contract terms (even for periods beyond 10 years). This would allow customers to reduce their contractual MAVs if their consumption requirements have evolved over the term of the contract.[29]

In its reply submission, Union stated that it is willing to work with customers, if necessary, to reassign their contracts or to amend the term and volumes of those contracts. However, the assistance would be provided on a best efforts basis and the outcome of any assistance would need to be revenue neutral.[30]

Treatment of Interruptible Revenues

OEB staff and OGVG both submitted that Union should be required to track the revenues from the sale of interruptible capacity created by the Project. The two parties proposed different treatments for the interruptible revenues. OEB staff submitted that 90% of the revenues generated from the sale of interruptible capacity (for the November

[26] EB-2016-0013, Union Reply Submission, May 17, 2016 at pp. 3-4.
[27] EB-2016-0013, OEB Staff Submission, May 3, 2016 at p. 9; and EB-2016-0013, OGVG Submission, May 3, 2016 at p. 9.
[28] EB-2016-0013, OGVG Submission, May 3, 2016 at p.10.
[29] EB-2016-0013, OEB Staff Submission, May 3, 2016 at pp. 9-10; and EB-2016-0013, OGVG Submission, May 3, 2016 at pp. 9-10.
[30] EB-2016-0013, Union Reply Submission, May 17, 2016 at pp. 5-6.

1, 2016 to December 31, 2017 period) should be credited to the customers that will take firm service on the Project.[31] OGVG submitted that if any of the customers taking firm service on the Project incur charges as a result of falling below their contracted MAV, the interruptible revenues should be used to offset those charges.[32]

Union stated that it was willing to track the revenues from the sale of interruptible capacity from November 1, 2016 to December 31, 2018. Union submitted that, at the end of 2018, it would apply the interruptible revenues to the contracts held by customers taking firm service associated with the Project in order to reduce the term of those contracts on a going forward basis.[33]

OEB Findings

The OEB finds that the estimated capital costs for the Project are reasonable and it has no concerns with the overall economics of the Project.

The OEB finds that it has the necessary jurisdiction to determine the appropriateness of aid to construct payments in situations where the P.I. of a project is greater than 1.0. As set out in its February 7, 2013 Decision with Reasons in the EB-2012-0396 proceeding, the OEB determined that a capital contribution is a rate.[34] Rate setting is squarely in the jurisdiction of the OEB.

The OEB also finds that there is nothing to prohibit the OEB from making findings on rate matters (such as aid to construct payments), typically dealt with under section 36 of the Act, in a leave to construct proceeding. The OEB will therefore consider the appropriateness of the proposed aid to construct payments in this proceeding. Other rates matters (for example the amounts that will ultimately close to rate base) will be addressed in subsequent proceedings.

The OEB finds that Union's revised proposal regarding aid to construct payments, as articulated in its reply submission, is acceptable. The OEB notes that Union's proposal limits the requirement for an aid to construct payment to a single customer and offers that customer an extended 20-year contract duration.

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[31] EB-2016-0013, OEB Staff Submission, May 3, 2016 at pp. 10-11.
[32] EB-2016-0013, OGVG Submission, May 3, 2016 at p. 7.
[33] EB-2016-0013, Union Reply Submission, May 17, 2016 at p. 7.
[34] EB-2012-0396, Decision and Order, February 7, 2013 at p. 14.

However, for future expansion projects where the project-level P.I. is greater than 1.0 and customers are required to sign long-term contracts, Union shall apply mitigating measures to avoid requiring any customers to make aid to construct payments (e.g. extending the duration of the contract). In situations, where these mitigating measures are not sufficient to avoid aid to construct payments, Union shall seek OEB approval to require such payments as part of its leave to construct application.

The OEB also accepts Union's proposal, as set out in its reply argument, to assist customers that may need to release some, or all, of their contracted capacity related to the Project on a "best efforts" basis (including allowing for the extension of contracts beyond the initial 10-year term).

The OEB finds that Union's proposal is reasonable and will provide customers with the flexibility to adjust contracting terms when there are options for re-assignment or contract extensions that result in a revenue neutral outcome for Union and Union's other customers.

Finally, in regard to the appropriate treatment of interruptible revenues created by the Project, the OEB agrees with Union's proposal, as set out in its reply argument, to track the sale of interruptible capacity for the period November 1, 2016 to December 31, 2018 and to apply these revenues to the contracts held by customers at the end of 2018. The OEB notes that Union's proposal operates to reduce the contract terms for customers taking service on the Project on a going forward basis. The OEB finds that Union's proposal is reasonable as it has the same impact on customers' contracts as if the interruptible revenues were included in the economic analysis at the outset.

SCHEDULE A

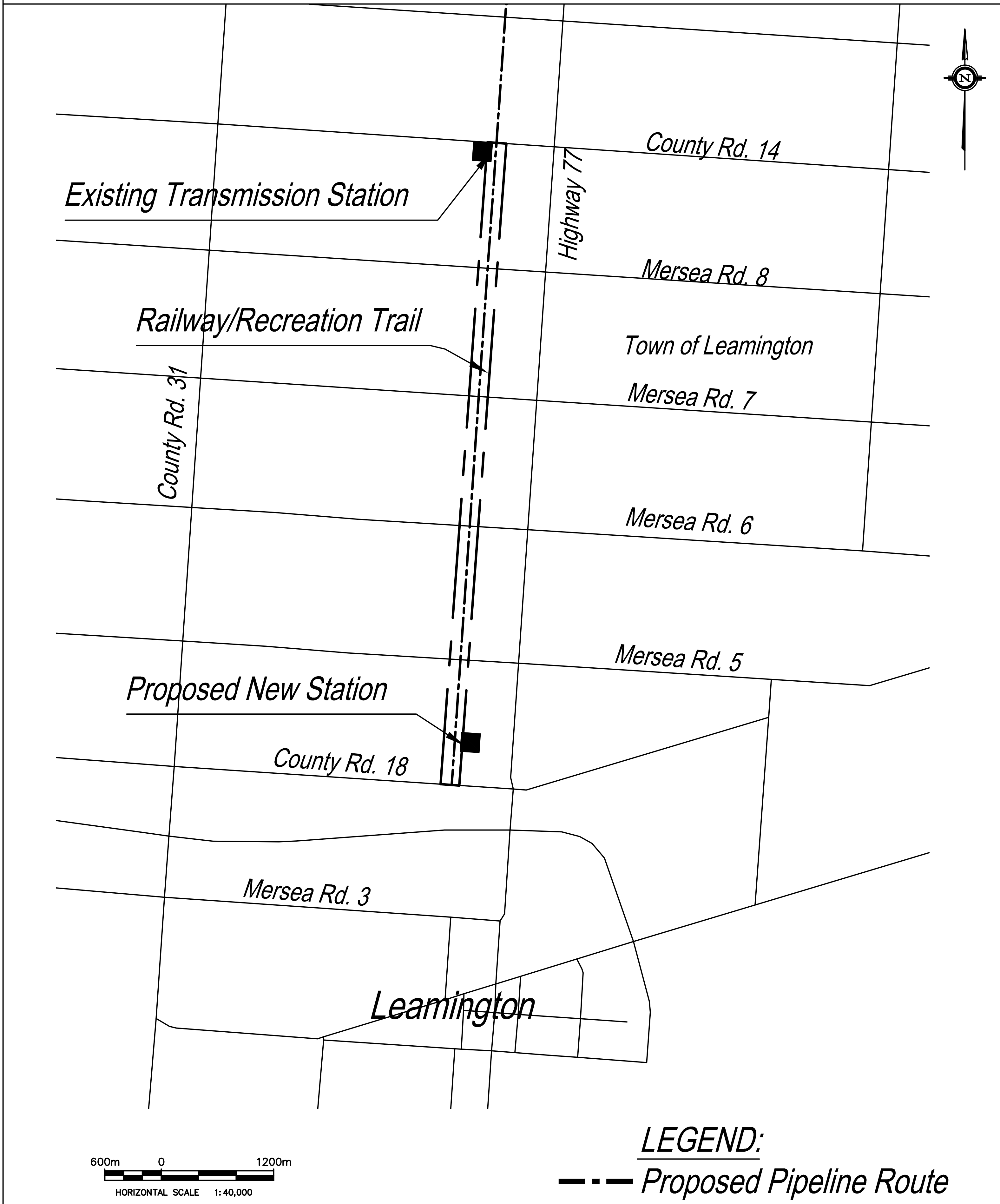
DECISION AND ORDER

UNION GAS LIMITED

EB-2016-0013

JUNE 29, 2016

Town of Leamington Phase II Pipeline Project



Ontario Energy Board
Commission de l’énergie de l’Ontario

DECISION AND ORDER

EB-2016-0186

UNION GAS LIMITED

Application for approval to construct a natural gas pipeline in the Township of Dawn Euphemia, the Township of St. Clair and the Municipality of Chatham-Kent and approval to recover the costs of the pipeline.

BEFORE: **Allison Duff**
Presiding Member

Cathy Spoel
Member

Paul Pastirik
Member

February 23, 2017

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

This is a decision of the Ontario Energy Board (OEB) on an application filed by Union Gas Limited (Union). Union applied under section 90(1) of the *Ontario Energy Board Act, 1998* (the Act) for leave to construct approximately 40 kilometers of 36 inch diameter pipeline from Union's Dawn Compressor Station in the Township of Dawn-Euphemia to its Dover Transmission Station in the Municipality of Chatham-Kent (the Project). A map of the Project is attached as Schedule A.

Union also applied for approval of the recovery of costs associated with the construction of the Project pursuant to section 36 of the Act; approval of a 20-year depreciation term; and approval of an accounting order to establish a Panhandle Reinforcement Deferral Account pursuant to section 36 of the Act.

Union's evidence is that the Project is needed to meet increasing demand for firm service on the Panhandle System in the Leamington-Kingsville area, from greenhouse operations, commercial and small industrial customers and anticipated residential growth.

One of the issues that arose in the proceeding was whether there were alternatives to the Project that did not require the construction of new pipeline facilities. Specifically, the issue is whether Union's customers are best served through the proposed pipeline's capacity or through capacity acquired on a contractual basis from Panhandle Eastern Pipe Line Company (Panhandle Eastern) through the Ojibway international connection point near Windsor. A map showing these interconnections is attached as Schedule B.

The OEB grants leave to construct the Project, subject to the Conditions of Approval, which are attached as Schedule C. For the reasons set out below, the OEB finds that the construction of the Project is in the public interest as it is the most reliable approach to meeting demand in the Leamington-Kingsville area.

2 THE PROCESS

A Notice of Application was issued on July 12, 2016 and was served and published by Union as directed by the OEB.

The OEB granted intervenor status to the following:

- Association of Power Producers of Ontario (APPrO)
- Building Owners and Managers Association, Greater Toronto (BOMA)
- Canadian Association of Energy and Pipeline Landowners Associations (CAEPLA)
- Canadian Manufacturers and Exporters (CME)
- Consumers Council of Canada (CCC),
- Enbridge Gas Distribution Inc. (Enbridge)
- Federation of Rental-housing Providers of Ontario (FRPO)
- Industrial Gas Users Association (IGUA)
- Liberty Oil and Gas Limited (Liberty)
- London Property Management Association (LPMA)
- Municipality of Chatham-Kent (Chatham-Kent)
- Ontario Greenhouse Vegetable Growers (OGVG)
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Coalition (VECC)

OEB staff also participated in the proceeding.

The OEB also found that APPrO, BOMA, CAEPLA, CCC, CME, FRPO, IGUA, LPMA, OGVG, SEC and VECC are eligible to apply for cost awards.

The OEB provided intervenors and OEB staff the opportunity to ask Union questions about its application through written interrogatories and a technical conference.

There was provision for intervenor evidence. No intervenors chose to file evidence.

The OEB held an oral hearing for all non-landowner issues and provided for the filing of written submissions on those issues.

Union informed the OEB that it had reached a comprehensive settlement with CAEPLA concerning all landowner issues. Union filed a summary of the settlement agreement and included a Form of Easement Agreement Addendum. Subsequently, the OEB accepted CAEPLA's request to withdraw as an intervenor in the proceeding.

2.1 Process Issues

In its submission, FRPO expressed frustration with the hearing process, alleging that the process did not afford it an adequate opportunity to test and analyze Union's evidence.

Findings

The OEB takes allegations of an applicant failing to disclose relevant information seriously and has carefully reviewed the procedural steps in this proceeding. FRPO's concerns appear to arise from the fact that it had to avail itself of many procedural steps to obtain some of the information it sought in relation to alternatives to Union's application. FRPO and some of the other intervenors expressed concern that if not for the motion brought by FRPO and requests by intervenors to have documents updated by Union, some of the evidence on the record would not have been disclosed.

In this proceeding, intervenors were afforded every opportunity to request additional information from Union, and they took advantage of those opportunities. This benefitted the OEB as it resulted in a more complete evidentiary record than might otherwise have been the case. That is the purpose of prehearing disclosure and of examination and cross-examination at the hearing. In the OEB's view, the intervenors fulfilled their role by participating actively in these processes.

While the OEB understands that being unable to persuade the applicant's witnesses that an alternative approach would be preferable may be a source of frustration, it does not demonstrate that the process was deficient. The process ultimately worked as the necessary evidence was placed on the record for the OEB to make a decision.

The procedural steps provided for by the OEB included the opportunity for intervenors to file evidence. None took advantage of that opportunity.

Several of the intervenors have filed arguments that purport to offer alternative scenarios to those presented by Union. Many of these scenarios were not part of the record, and Union did not have the opportunity to test these through cross-examination. While Union, as the applicant, has the onus of persuading the OEB that the Project should be approved, analysis of alternatives must be based on the evidentiary record. If intervenors want the OEB to accept an alternative other than ones put forward by Union, the intervenors must ensure that there is sufficient evidence on the record in this proceeding to support their case.

3 ISSUES

3.1 Are the proposed facilities needed?

In its evidence, Union forecast an increase in design day (peak) demand on the Panhandle System until 2034. Union's evidence is that the forecast is based on specific customer requests, anticipated conversion of interruptible to firm service based on unfulfilled requests from the 2016 expansion in the Leamington area, discussions with customers and growth in the general service market.

Table 1: Union's Design Day Forecast Growth for Panhandle System

Timeframe	Design Day Requirements TJ/day
November 1, 2016 (post Leamington expansion)[1]	565
2017 - 2021 Forecast Growth	106
2022 – 2034 Forecast Growth	99
2034 Total Design Day Requirements	770

Union expects that demand growth will occur across the entire Panhandle System, with the majority of the requests for firm contracts from greenhouse customers in the Leamington-Kingsville area. In particular, for the 2016 Leamington expansion project (2016 expansion), Union requested Expressions of Interest and received 80 TJ/day in firm demand. Union was able to satisfy 32 TJ/day with the 2016 expansion, leaving 48 TJ/day of unfulfilled firm capacity which is part of the forecast capacity to be served by the Project. This 48 TJ/day is currently served by interruptible service, but Union's evidence is that these customers want to convert to firm service, as much of their demand is for space heating, for example in greenhouses.

Union also identified incremental demand for firm service across its entire market including the New Windsor Mega Hospital, the new Gordie Howe International Bridge, CNG facilities and load increases from other industrial customers in the Windsor area.

[1] EB-2016-0013 OEB Decision, Union's Leamington Expansion Pipeline Project

Union also conducted a reverse open season in May 2016 with existing distribution customers currently served by the Panhandle System to determine if any would be willing to return their firm service to Union. No offers were received.

LMPA, OGVG and OEB staff agreed with Union's forecast. Union also received letters of support for its application from customers represented by OGVG and municipalities served by the Panhandle System, which were filed with the OEB.

Other intervenors argued that Union's design day forecast was overstated as it did not account for demand reductions due to demand side management (DSM) initiatives and the government's climate change initiatives. Regarding the conversion of interruptible customers, IGUA submitted that Union could have done more to work with these customers to find alternative supply arrangements and demand management options to reduce the demand forecast, thereby avoiding the need for the Project.

These intervenors also argued that Union's forecast was subject to risk as customers who expressed interest in 2015 had yet to enter into contracts for firm service with Union. APPrO suggested the OEB require Union to meet a threshold of 50 TJ/day as a condition of approval if the Application was approved.

Union submitted that there was as no available capacity to accommodate any incremental firm demand on the Panhandle System, whether from general service or contracting customers, as of November 2017.

Findings

The OEB accepts Union's forecast of 106 TJ/day of firm demand growth from 2017–2021. The OEB finds that Union is in the best position to assess firm demand growth, especially information sourced through its interactions with customers. Receiving expressions of interest are evidence of intent; signed five-year agreements are evidence of commitment.

The OEB finds that the risk that the forecast is overstated is further reduced by unsolicited demand requests Union received, which were not included in the forecast.

The OEB accepts Union's evidence and OGVG's submissions that the demand for firm service to replace interruptible is due to the heat sensitivity of greenhouses. These customers have every right to request the service they want and need for their businesses. These customers have interruptible service by default, and don't want it. Assuming these customers are rational and informed regarding alternative sources of supply, the OEB accepts Union's submission that it has worked with these customers to develop its forecast, and efficiency improvements are already built into the forecast.

The OEB does not find that the forecast is overstated based on the effects of DSM. There is no evidence to support a reduction to the forecast. Consistent with Union's evidence in the DSM proceeding, the OEB accepts that to date, annual volumes are most affected by DSM programs, not design day demand. Union indicated that while DSM had reduced average annual consumption by 920 TJ per year, design day demand on the Panhandle System continued to increase over the same period. In fact, the OEB directed Union to work jointly with Enbridge on how to include DSM in future infrastructure planning activities to address this issue, for the mid-term review in 2018.[2]

The OEB does not find that the forecast is overstated based on the government's climate change initiatives. A reduction to the forecast would be premature as the market has not had time to react and data is not available. The OEB agrees that such unknowns add uncertainty to any forecast yet are outweighed by the immediate need for firm service.

Union's demand forecast for 2017-2021 is tied to its application and the alternatives it analyzed. The alternatives will be covered later in this Decision. Union also filed a demand forecast to 2034. The OEB agrees that a longer-term forecast is subject to more risk with greater uncertainties and unknowns. However, it is important to note that Union expects the incremental capacity from the Project to be fully subscribed after five years. In fact, five year agreements are being signed, consistent with Union's demand forecast.

The OEB has reviewed Union's longer-term demand risk and the submission regarding risks to that forecast. The OEB has also considered the source of the firm demand, including conversion from interruptible service and incremental growth.

Union has started to sign demand contracts extending to 2021, and the greenhouse owners signing those contracts have made significant capital investments. In light of the significant investments made, the OEB finds it unlikely that the demand will cease in five years due to new DSM or climate change initiatives. The OEB expects the greenhouses converting to firm service and expanding operations in the Leamington-Kingsville area will continue to increase their demand for gas after 2021 assuming the facilities are in place. These sources of firm demand growth can counterbalance the longer-term demand risk.

[2] OEB's Decision and Order EB-2015-0029/0049, page 84

3.2 OEB's economic tests

Union's evidence is that the total cost of the Project was $264.5 M. Union assessed the economic feasibility of the Project by applying the OEB's economic tests.[3] Over a 20-year term, the net present value (NPV) for the Stage 1 test was negative $212 M based on the facilities required for five years of demand day growth. With a Stage 1 NPV less than zero, Union conducted a Stage 2 NPV test and estimated energy cost savings to be approximately $805 M, resulting in an NPV greater than zero.

Union compared the NPV of the Project to the NPV of all alternatives considered. Alternative 2 assumed incremental deliveries of 34 TJ/day or total deliveries of 94 TJ/d at Ojibway, plus new facilities. Alternative 2 was presented in Union's evidence as an alternative to the Project. The NPV's changed when Union considered the assets required after five and six years of demand day growth.

Table 2 - Stage 1 NPV of Proposal and Alternative 2 with 20-year term ($ Millions)

Description	NPV – Assets five years	NPV – Assets six years
Project	$(212)	$(239)
Alternative 2	$(207)	$(271)

Union's evidence is that incremental facilities were required for both scenarios to meet the increase in demand. Union stated that there was little difference in the NPVs of these alternatives looking at assets for five years, but the more economic option over the longer term is the Project.

Many intervenors who submitted the OEB should not approve the application did not comment on Union's NPV and economic tests. The submissions of these intervenors focused on the alternatives that Union did not consider and were not included in evidence.

VECC submitted that the cost difference and NPVs of Union's alternatives are a distraction to the important issues raised by the application and obfuscate the analysis. VECC noted that the additional costs of Alternative 2 only come into play in 2022 and are based on the accuracy of Union's forecast of demand.

[3] Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, Feb 21, 2013

LPMA submitted that the Project met the OEB's economic test in Stage 2. Although LPMA did not agree with all the assumptions used to calculate the NPV of the stage 2 benefits, LMPA agreed that the NPV is well in excess of the $212 shortfall in the Stage 1 NPV calculation.

Findings

The OEB finds that the Project meets the OEB's economic tests. The OEB finds that the Stage 2 benefits sufficiently exceed the Stage 1 net cost, and result in a positive NPV.

Union's Stage 1 NPV was negative $212 based on a 5-year forecast and 20-year term. The NPV changed slightly to negative $207 based on a 40-year term. With a 40-year term, the NPV for Alternative 2 changed from negative $207 to negative $201. The OEB finds the Stage 1 NPVs for the Project to be similar to Union's Alternative 2, despite a change in term.

The OEB agrees with LPMA that not all of Union's assumptions in its Stage 2 analysis may be adequately justified, but the OEB finds the $805 M in estimated benefits so large that even with some adjustments the benefits will exceed the net cost estimate in Stage 1.

Based on Union's forecast five-year demand, the OEB finds that Union has demonstrated that the economic tests required by the OEB's filing guidelines have been met.

3.3 Potential rate impacts to customers

Based on Union's proposed costs and rate recovery, the average total bill impact for Union South customers ranged from 1.2% for residential rate M1 to 5.8% for small rate M4[4].

Union's cost estimate included depreciation expense based on a 20-year depreciation period, which is shorter than the 50 years in the OEB's approved depreciation rates for these assets. The depreciation expense to be recovered from customers would be lower by $3.5 M in 2017 and $7.4 M in 2018 if depreciated over 50 years.[5]

Union submitted that a shorter amortization period was warranted given the uncertainties with Ontario's Cap and Trade program and the introduction of the government's Climate Change Action Plan (CCAP). Union submitted that these new

[4] Exhibit A, Tab 8, Schedule 6, p.2
[5] Exhibit J1.3

initiatives add significant risk to the return of any capital invested in natural gas infrastructure over the medium to long term. Union submitted that a 20-year period better aligns the recovery of the asset costs with the timing of government restrictions and potential elimination of natural gas heating of homes and businesses.

All but one of the intervenors disagreed with Union's proposal for a 20-year amortization period. They noted that the settlement agreement entered into at Union's most recent cost of service proceeding refers to OEB-approved 2013 depreciation rates. These intervenors argued that the terms of the settlement proposal prohibit the use of different depreciation rates, and that depreciation was not identified as a Y-factor in the settlement proposal. These intervenors also argued that if a change was to be considered by the OEB it should be during a rebasing year, not during the IRM term, based on a comprehensive review of all assets.

LPMA supported Union's proposal, submitting that a 20-year period reduced the risk for Union resulting from Cap and Trade and CCAP, and reduced the total net present cost to customers.

Union proposed two changes to the cost allocation methodology approved by the OEB when rates were established in 2013. The proposed cost allocation would determine how the Project costs would be recovered until 2019, the end of Union's current IRM term.

First, Union proposed to base the allocation on the Panhandle System's design day demand plus incremental design day demands of the Project. In 2013, the OEB had approved a cost allocation methodology based on design day demands from the combined Panhandle and St. Clair Systems.

Second, Union proposed to exclude ex-franchise Rate C1 and M16 firm contracted demands from the cost allocation. In 2013, the OEB had approved a cost allocation methodology that included in-franchise and ex-franchise rate classes.

Union's position is that using the combined Panhandle and St. Clair Systems to allocate costs no longer reflects the costs to serve customers on their respective parts of these Systems. In addition, Union submitted that C1 and M16 ex-franchise customers are not driving the need for the Project because their gas flows counter to the flow of design day volumes. Union's proposed allocation would result in a re-allocation of 15% of the Project costs to in-franchise customers, rather than allocating them to C1 and M16 customers. A full comparison of the current OEB-approved and the proposed allocation follows.[6]

		Design Day Demands		Project Cost Allocation Factors	
		St. Clair	Panhandle	OEB-Approved	Proposed
Line No.	Rate Class	System (%)	System (%)	Allocation (%)	Allocation (%)
		(a)	(b)	(c)	(d)
1	Rate M1	7%	40%	21%	40%
2	Rate M2	2%	14%	7%	14%
3	Rate M4	0%	14%	7%	14%
4	Rate M5	-	0%	0%	0%
5	Rate M7	-	4%	2%	4%
6	Rate T1	9%	5%	6%	5%
7	Rate T2	82%	23%	42%	23%
8	Total In-franchise	100%	100%	85%	100%
9	Rate C1	-	-	13%	-
10	Rate M16	-	-	3%	-
11	Total Ex-franchise	0%	0%	5%	0%
12	Total	100%	100%	100%	100%

All Intervenors except two disagreed with Union’s proposal to change the cost allocation methodology for the Project. These intervenors submitted that a change to cost allocation should only be considered in a rebasing year, not during an IRM term, as changes to one part of cost allocation affect all other customers. LPMA, VECC and OEB staff indicated that they were not opposed to Union’s proposal, but suggested further review of the impacts are required.

APPrO and IGUA supported Union, arguing that Union’s cost allocation proposals were in line with the principle of cost causality and consistent with how the Panhandle System is used.

Findings

The OEB will not approve Union’s proposals for a 20-year depreciation period and a revised cost allocation methodology. The OEB finds that both proposals should be deferred to Union’s next cost of service or custom IR application. It would be inconsistent to change the depreciation term and cost recovery for one project, while Union’s other assets are depreciated and recovered on different bases. A comprehensive review is required for parties to test, and the OEB to assess, the merits

[6] Exhibit J1.2 Attachment 2, page 3

and implications of these two proposals and this should be at Union's next cost of service or custom IR application.

While these proposals may have merit, they cannot be adequately considered during the IRM term, for one project in isolation. A leave-to-construct application requesting a capital pass-through mechanism for cost recovery over 14 months is not the appropriate forum to consider deviations from principles embedded in current OEB-approved rates.

A proper review of these issues will need to include the full range of possible amortization periods, and the impacts on all customer classes of a change to the cost allocation methodology

Given these findings, it is not necessary for the OEB to comment on whether Union's proposal is consistent with the settlement agreement.

3.4 Facilities and non-facilities alternatives to the Project

Exhibit A, Tab 6 of Union's evidence describes the alternatives to the Project that were considered by Union. Union defined an acceptable alternative as one which allows Union to maintain minimum inlet pressures on a design day and meet design day requirements to supply its downstream distribution systems. The alternatives considered by Union are intended to serve the five-year forecasted demand growth from 565 TJ/d to 671TJ/d by 2021, and further consideration for expected future growth beyond 2021.

Union's Alternative 1

This alternative involves construction of a new 30 or 36 inch pipeline from Dawn alongside the existing Panhandle pipeline which would continue to be used.

Union forecast the cost of this alternative at an NPV of negative $224 M which is $12M more expensive than the Project's estimate of negative $212 M. The Project also has the advantage of eliminating the need for additional land and easements and ongoing maintenance costs to preserve the integrity of the existing pipeline.

Union's Alternative 2

This alternative involves contracting for an additional 34 TJ/d of gas supply at Ojibway and installing incremental pipeline and station facilities along the Panhandle System to serve the remainder of the demand from Dawn.

Union's forecast of the NPV for this alternative was negative $207 M. When comparing this to the Project's NPV of negative $212 M, Union did not consider this small differential to be worth the added risk of this alternative. Union's evidence is that

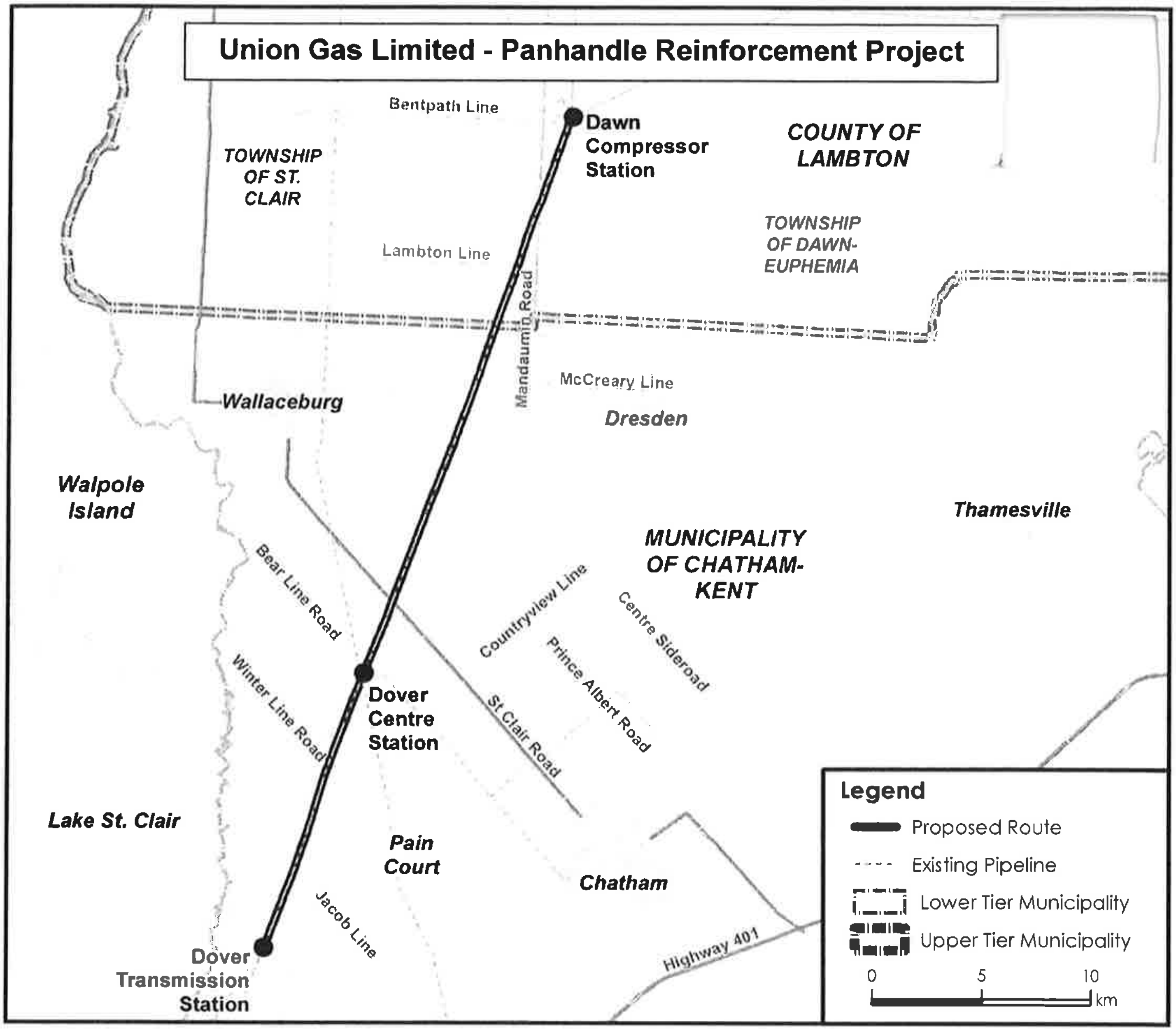
SCHEDULE A - PROJECT MAP

DECISION AND ORDER

UNION GAS LIMITED

EB-2016-0186

FEBRUARY 23, 2017


Union Gas Limited - Panhandle Reinforcement Project
Bentpath Line
Dawn Compressor Station
COUNTY OF LAMBTON
TOWNSHIP OF ST. CLAIR
TOWNSHIP OF DAWN-EUPHEMIA
Lambton Line
Mandaumin Road
McCreary Line
Wallaceburg
Dresden
Walpole Island
Thamesville
MUNICIPALITY OF CHATHAM-KENT
Bear Line Road
Countryview Line
Centre Sideroad
Prince Albert Road
Winter Line Road
Dover Centre Station
St Clair Road
Lake St. Clair
Pain Court
Chatham
Jacob Line
Highway 401
Dover Transmission Station
Legend
Proposed Route
Existing Pipeline
Lower Tier Municipality
Upper Tier Municipality
0
5
10
km

SCHEDULE B – AREA MAP

DECISION AND ORDER

UNION GAS LIMITED

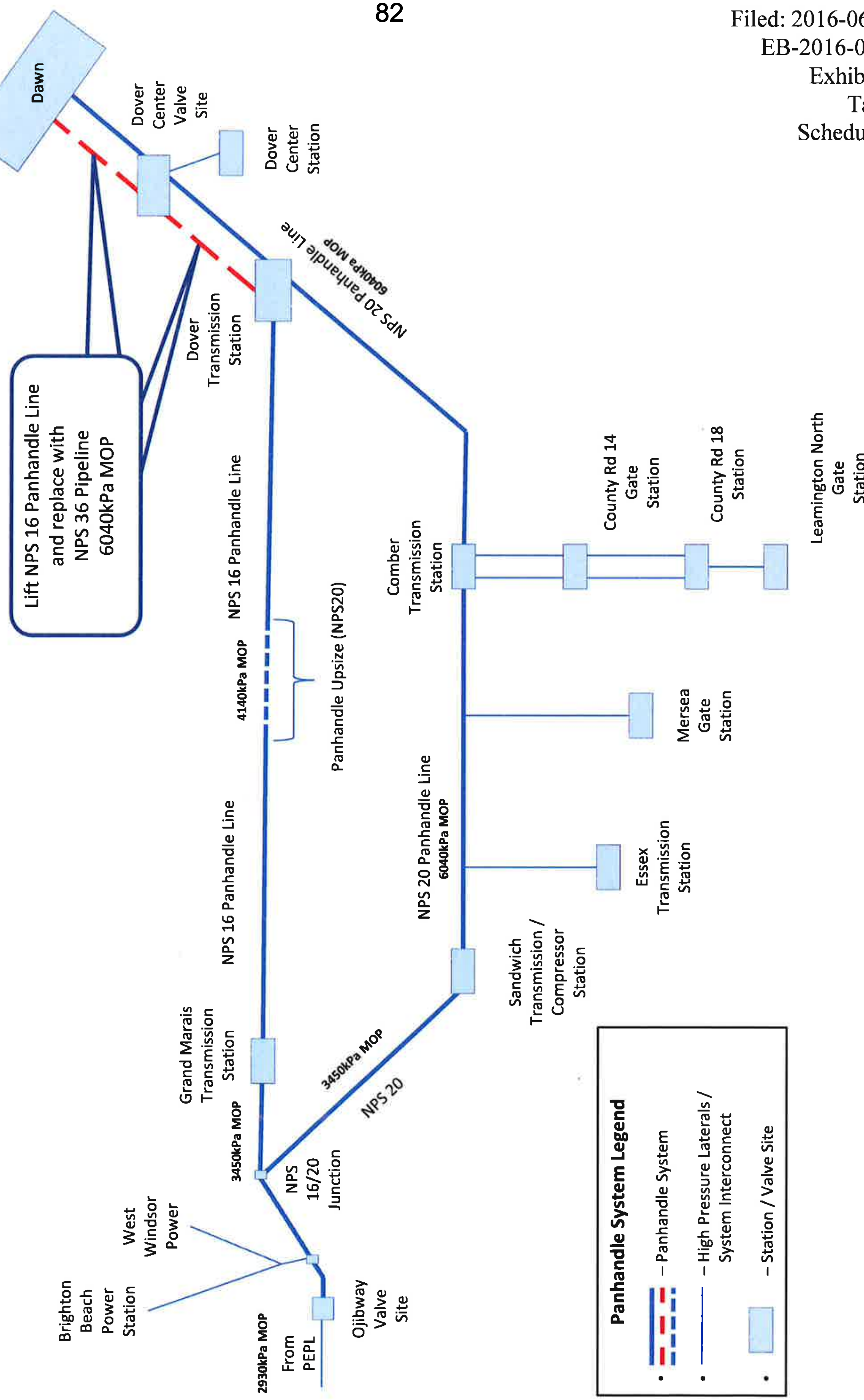
EB-2016-0186

FEBRUARY 23, 2017

Filed: 2016-06-10
EB-2016-0186
Exhibit A
Tab 4
Schedule 3

Panhandle Reinforcement Project

Panhandle System Schematic



Ontario

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

DECISION AND ORDER

EB-2018-0013

UNION GAS LIMITED

Application for leave to construct a natural gas transmission pipeline and associated facilities in the Town of Lakeshore and the Town of Kingsville in the County of Essex

BEFORE: **Susan Frank**
Presiding Member

Allison Duff
Member

September 20, 2018

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

Union Gas Limited (Union) applied to the Ontario Energy Board (OEB) under section 90(1) of the *Ontario Energy Board Act, 1998* (Act) for an order granting leave to construct approximately 19 kilometers of natural gas transmission pipeline in the Town of Lakeshore and the Town of Kingsville in the County of Essex (Kingsville Reinforcement Line or Project). Union proposed an in-service date of November 1, 2019 with construction beginning in the summer of 2019.

A map of the proposed Kingsville Reinforcement Line is in Schedule A.

The OEB approved the Building Owners and Managers Association, Greater Toronto (BOMA), Industrial Gas Users Association (IGUA) and the Ontario Greenhouse Vegetable Growers (OGVG) as intervenors, eligible to apply for cost awards. The OEB approved the City of Kitchener, an embedded gas distributor in Union's south franchise territory, as a late intervenor.

Pursuant to section 90 (1) of the Act, the OEB grants Union leave to construct the Kingsville Reinforcement Line, subject to the Conditions of Approval in Schedule B.

2 THE PROCESS

Union filed its application on January 26, 2018 and included a request for recovery of project costs through application of an Incremental Capital Module (ICM) mechanism. For reasons explained in the OEB's letter to Union dated February 27, 2018, the OEB decided not to hear issues related to an ICM mechanism in this proceeding and asked Union if it still wished to proceed with the remainder of the application. Union confirmed its intention to proceed with its application and seek leave to construct the Kingsville Reinforcement Line.

The OEB commenced its review of Union's leave to construct application on March 5, 2018. The OEB issued a Notice of Hearing on March 21, 2018.

In Procedural Order No. 1, the OEB approved the Building Owners and Managers Association, Greater Toronto (BOMA), Industrial Gas Users Association (IGUA) and the Ontario Greenhouse Vegetable Growers (OGVG) as intervenors, eligible to apply for cost awards.

The OEB proceeded by way of a written hearing. Intervenors and OEB staff filed questions regarding Union's application on May 7, 2018 and Union filed its answers on May 22, 2018.

After reviewing Union's evidence and interrogatory responses, the OEB determined that it required additional information and issued Procedural Order No. 2 with questions to Union on three issues:

1. Long-term system expansion plans for the Panhandle System
2. Multiple needs served by the Project
3. Economics of the Project

Union filed responses to the OEB's questions on July 9, 2018.

In Procedural Order No. 3, the OEB approved the City of Kitchener's request for late intervenor status and made provision for all parties to file written submissions. Union filed its reply submission on August 28, 2018.

3 LEAVE TO CONSTRUCT

Union's application seeks an order for leave to construct a natural gas pipeline under section 90 of the Act. Section 96 of the OEB Act provides that the OEB shall make an order granting leave if the OEB finds that "the construction, expansion or reinforcement of the proposed work is in the public interest". When determining whether a project is in the public interest, the OEB typically examines the need for the project, project cost and economics, alternatives considered, environmental impacts, Indigenous consultation, and landowner impacts.

3.1 Need for the Project

Union indicated that the Project was needed to respond to increasing natural gas demand in the Kingsville-Leamington market as well as increasing demand on the overall Panhandle Transmission System. The Panhandle Transmission System is the primary pipeline to transport gas from Dawn to the Ojibway Valve Site in Windsor. It feeds high pressure distribution pipelines servicing residential, commercial and industrial customers.

Union submitted that the Project reinforces the high-pressure Panhandle Transmission System to serve customers in the Kingsville-Leamington market area and serve future development in the market served by the Panhandle Transmission System.

Union confirmed that the forecast volumes supporting the need for the Project were distinct from the volumes that supported its reinforcement of the Panhandle Transmission System in 2016[1]. Union indicated that forecast design day capacity demand on the Panhandle Transmission System had accelerated since 2016, which advanced the timing of this Project from 2022 to 2020. To alleviate the forecasted constraint on the Kingsville-Leamington distribution system, Union proposed to move the Project's in-service date to 2019.

No party raised concerns with the need for the Project.

OGVG emphasized the importance of the 2019 proposed in-service date. OGVG submitted that to maintain growth in Ontario's greenhouse sector, it is important that the natural gas infrastructure is available on a timely basis.

[1] OEB Decision and Order, EB-2016-0186

Findings

The OEB finds that Union has demonstrated the need for this Project - a transmission line with broad benefits to the Panhandle Transmission System. The OEB is aware that Union has filed another leave to construct application for the Chatham-Kent area, which relies on the incremental capacity provided by this Project[2].

The Project addresses the forecast load growth in the Kingsville-Leamington area, growth that cannot be accommodated with the existing distribution system. Union identified 14 executed contracts for firm service and an additional 20 contracts under negotiation that were dependent on the in-service date of November 1, 2019.

3.2 Project costs and economic tests

Union estimated a total cost of $105.7 million to construct the Project. While the OEB deferred hearing Union's ICM request for recovery of this cost, a cost-benefit economic evaluation is in scope for this proceeding.

Union applied the OEB's economic test for transmission pipeline applications[3] (E.B.O. 134 test). Union's stage 1 discounted cash flow analysis indicated a profitability index (PI) of 0.44 and a net present value of negative $59.2 million. Given the PI was less than one, Union undertook a stage 2 analysis which considered the estimated energy cost savings as a result of customers using natural gas instead of other fuels to meet their energy requirements. The stage 2 net present value results over 20 years ranged from $283 million to $472 million, depending on the assumptions for the alternative fuel mix.

As the Project addressed both transmission and distribution needs, the OEB questioned Union's use of the E.B.O. 134 test exclusively, with no reference to the OEB's economic test for distribution applications[4] (E.B.O. 188 test). The OEB also asked Union whether it had sought contributions-in-aid of construction, an element of the E.B.O. 188 test.

Union responded that the E.B.O. 188 test for distribution applications did not apply to this application for a transmission line. Union stated that it was not appropriate to apply

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[2] EB-2018-0188
[3] Economic Test for Transmission Line Applications, E.B.O. 134, dated June 1, 1987, and amended on February 21, 2013 (EB-2012-0092), and referred to as the *Filing Guidelines on the Economic Tests for Transmission Pipeline Applications*
[4] *Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario*, E.B.O. 188, January 20, 1998

the E.B.O. 188 test as the incremental forecast demand extended throughout the Panhandle service area and no distribution customers would be connected directly to the new pipeline.

OEB staff submitted that it was appropriate for Union to apply the E.B.O. 134 test as the Project is defined as a transmission asset and results in a total positive net present value at a stage 2 analysis.

OGVG indicated that the OEB raised the possibility of contributions-in-aid-of construction for the first time in this application process, an issue not associated with transmission investments under the E.B.O. 134 test. OGVG submitted that its members need to know in advance their obligations with respect to the cost of natural gas infrastructure and that those obligations are based on consistent regulatory treatment of similar projects.

IGUA submitted that if the OEB concludes that the Project serves both transmission and distribution functions, a more nuanced approach to economic evaluation and associated cost responsibility requirements might be warranted. IGUA provided an example whereby 10% of the cost was recovered through contributions-in-aid of construction from the 34 customer contracts dependent on capacity enabled by the Project. IGUA submitted that contributions-in-aid of construction would reduce the shortfall in the stage 1 analysis and improve the PI for the Project.

Findings

The OEB finds that Union appropriately followed the OEB's E.B.O. 134 test for transmission projects. While the stage 1 analysis results in a net present value of negative $59.4 million and a P1 of only 0.44 over 40 years, broader economic benefits identified in the stage 2 analysis support the approval of the Project.

While the OEB has approved the Project, there are some concerns that the OEB would like to observe.

First, the new pipeline has ancillary distribution benefits according to Union in addition to the transmission functions. The distribution benefits are evident as Union identified 14 firm customer contracts executed and 20 customer contracts being negotiated which rely on the approval and construction of the Project. The OEB finds that the Project meets both distribution and transmission needs, yet the OEB's economic tests are exclusive, applicable to either distribution or transmission lines.

Second, the economic test for transmission, E.B.O. 134, does not attribute who should pay with each stage of testing. For distribution pipelines, the more recent E.B.O. 188 test recognizes that if there is insufficient new revenue generated by the project to cover its costs, capital contributions are required from the benefiting parties. Under E.B.O. 134, the stage 2 benefiting parties would be downstream connecting customers and the local economy. Currently there is no mechanism to have these parties make a contribution to the costs despite their substantial benefit.

For natural gas in Ontario, no economic test or ratemaking mechanism exists today to allow these discrepancies to be addressed.

The OEB acknowledges the creative thinking included in IGUA's submission. While it is not appropriate to split the costing between transmission and distribution pipelines as proposed by IGUA in this proceeding, such proposals may help inform future thinking on the treatment of dual function pipelines.

3.3 Alternatives

Union considered four alternatives to the Project by evaluating the capital costs, net present values, in-service dates and future facilities requirements from 2024 to 2036. The alternatives explore various sizes of pipe, increased deliveries from Ojibway and distribution options. Union submitted that the Project is the preferred alternative to address the need in both the five-year and longer-term horizon.

In defense of the proposed timing, Union submitted that if the Project were completed by November 1, 2019 additional distribution costs of $10.4 million could be avoided.

No party raised concerns with Union's evaluation of alternatives. OGVG was concerned that if the Project were delayed, then $10.4 million of additional distribution assets would be required.

Findings

The OEB finds that the Project is the preferred alternative. The Project has the highest net present value, addresses incremental demand in the Kingsville-Leamington area in 2019 and is consistent with other, longer-term considerations for the Panhandle Transmission System.

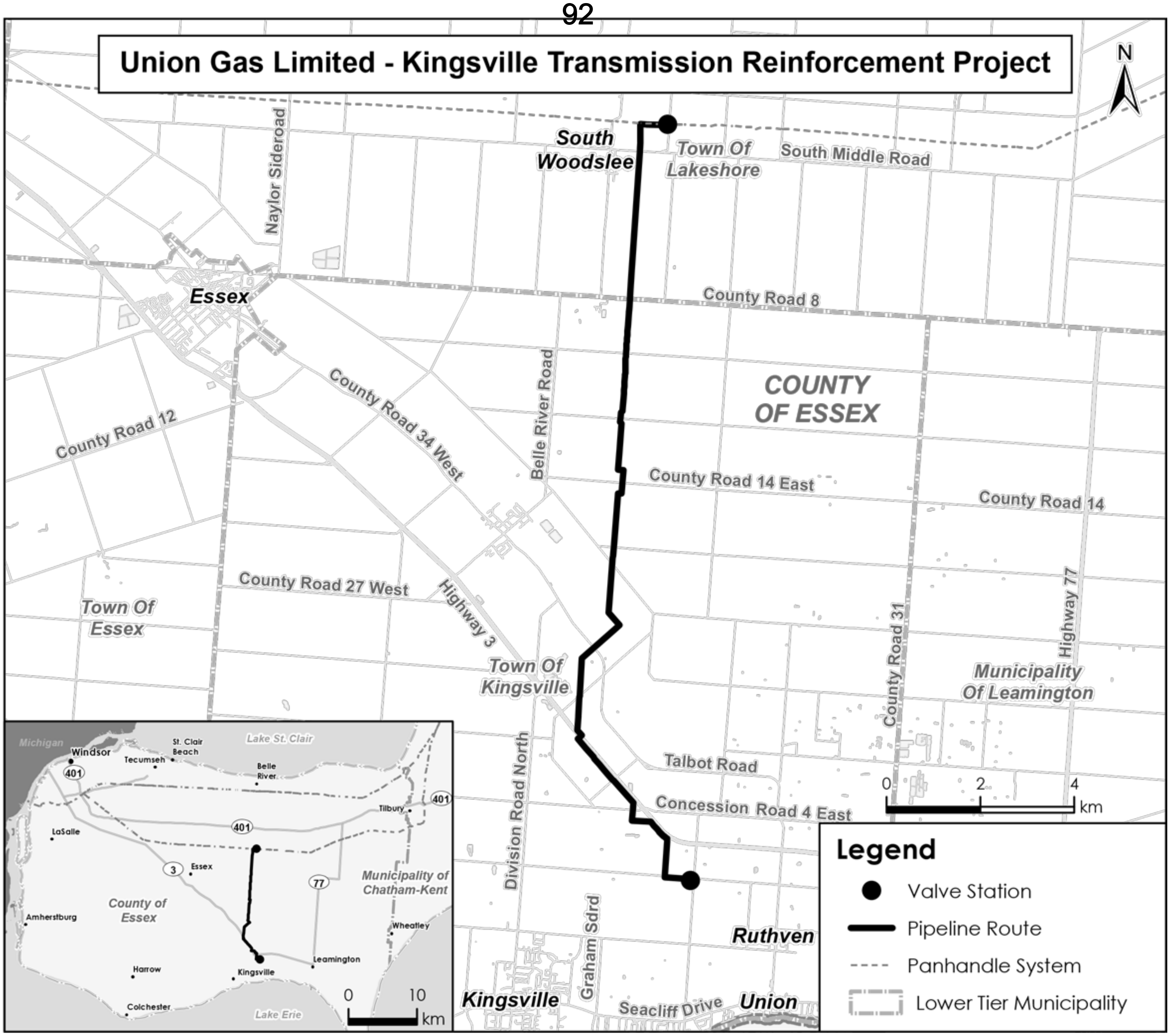
SCHEDULE A - MAP OF THE PROJECT

DECISION AND ORDER

UNION GAS LIMITED

EB-2018-0013

SEPTEMBER 20, 2018


Union Gas Limited - Kingsville Transmission Reinforcement Project
N
South Woodslee
Town Of Lakeshore
South Middle Road
Naylor Sideroad
Essex
County Road 8
County Road 34 West
Belle River Road
COUNTY OF ESSEX
County Road 12
County Road 14 East
County Road 14
County Road 27 West
Highway 3
Town Of Essex
Town Of Kingsville
County Road 31
Highway 77
Municipality Of Leamington
Talbot Road
Concession Road 4 East
Division Road North
Graham Sdrd
Ruthven
Kingsville
Seacliff Drive
Union
0 2 4 km
Legend
Valve Station
Pipeline Route
Panhandle System
Lower Tier Municipality
Michigan
Windsor
Tecumseh
St. Clair Beach
Lake St. Clair
Belle River
401
Tilbury
LaSalle
3
Essex
77
Municipality of Chatham-Kent
County of Essex
Amherstburg
Wheatley
Harrow
Kingsville
Leamington
Colchester
Lake Erie
0 10 km

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

DECISION AND ORDER

EB-2018-0188

ENBRIDGE GAS INC.

Application for leave to construct natural gas transmission pipeline and associated facilities in the Municipality of Chatham-Kent

BEFORE: Susan Frank
Presiding Member

Michael Janigan
Member

Robert Dodds
Member

July 11, 2019 (Revised November 19, 2019)

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

Enbridge Gas Inc.[1] (Enbridge Gas) applied to the Ontario Energy Board (OEB) under section 90(1) of the *Ontario Energy Board Act, 1998* (OEB Act) for an order granting leave to construct approximately 13.5 kilometres of natural gas transmission pipeline in the Municipality of Chatham-Kent (Chatham-Kent Rural Project or the Proposed Project). Enbridge Gas is also seeking approval for its proposed form of Temporary Land Use Agreement, pursuant to section 97 of the OEB Act.

The Proposed Project is composed of two high-pressure pipelines in a portion of Enbridge Gas' transmission system serving Southwestern Ontario: a 500 metre NPS 12 pipeline (Bear Line Section) and a 13 kilometre NPS 8 pipeline (Base Line Section). Maps detailing the Bear Line Section and Base Line Section are attached as Schedule A to this Decision and Order. Enbridge Gas characterizes the Proposed Project as a reinforcement of the Chatham Transmission System, which operates as a primary feed to several other downstream systems. Enbridge Gas plans to start construction in the summer of 2019 for an in-service date of no later than September 1, 2019 for the Bear Line Section and an in-service date in November or December 2019 for the Base Line Section.

The OEB examined all aspects of Enbridge Gas' leave to construct application and is satisfied that the Proposed Project is in the public interest. Leave to construct the Proposed Project is granted subject to the conditions of approval attached as Schedule B to this Decision and Order (Conditions of Approval). The OEB also approves the proposed form of Temporary Land Use Agreement.

[1] The application was originally filed by Union Gas Limited on June 5, 2018, under sections 90 and 97 of the *Ontario Energy Board Act, 1998*. Union Gas Limited and Enbridge Gas Distribution Inc. amalgamated effective January 1, 2019 to become Enbridge Gas Inc.

2 THE PROCESS

On June 5, 2018, Enbridge Gas filed its application with the OEB for an order granting leave to construct the Proposed Project.

Enbridge Gas was granted $8 million for the Proposed Project from the Ontario Ministry of Infrastructure's Natural Gas Grant Program (NGGP) on December 28, 2017. However, the Government of Ontario cancelled the NGGP in September 2018. On November 29, 2018, the OEB placed Enbridge Gas' application for the Proposed Project in abeyance. On March 11, 2019, the Government of Ontario announced funding for the Proposed Project through Bill 32, the *Access to Natural Gas Act, 2018*, which amended the OEB Act as of July 1, 2019. Ontario Regulation 24/19 – Expansion of Natural Gas Distribution Systems, made under the OEB Act, also came into force July 1, 2019.

In its updated application filed on March 14, 2019, Enbridge Gas requested that the OEB resume processing the application and issue a Notice of Hearing (Notice). A Notice was issued by the OEB on March 28, 2019. Both Anwaatin Inc. (Anwaatin) and the Industrial Gas Users Association (IGUA) applied for, and were granted, intervenor status.

The OEB proceeded by way of a written hearing. In accordance with Procedural Order No. 1, OEB staff, Anwaatin and IGUA filed interrogatories regarding the application on April 26, 2019. Enbridge Gas filed its responses to interrogatories on May 10, 2019. OEB staff, Anwaatin and IGUA filed written submissions with the OEB on May 24, 2019, and Enbridge Gas filed its reply submission on May 31, 2019.

3 LEAVE TO CONSTRUCT

This application seeks an order granting leave to construct a natural gas pipeline under section 90 of the OEB Act. Section 96 of the OEB Act provides that the OEB shall make an order granting leave to construct if the OEB finds that “the construction, expansion or reinforcement of the proposed work is in the public interest”. When determining whether a project is in the public interest, the OEB typically examines the need for the project; the project cost and economics; the environmental impacts; impacts on landowners; and Indigenous consultation.

3.1 Need for the Project

Enbridge Gas stated that the Proposed Project is required to reinforce the Chatham Transmission System, which serves a number of regions, including: Chatham, Blenheim, Dresden, Wallaceburg, Kent Bridge, Ridgetown and Dutton. Enbridge Gas established the need for the Proposed Project based on a number of inquiries it received for large quantities of additional gas service in the Chatham-Kent area that could not be economically served if individual customers were to fund the cost of multiple small-scale expansions. Enbridge Gas stated that the reinforcement is required in order to meet identified customer demand and potential growth. Further, the Proposed Project would eliminate pressure-related constraints resulting from the increased demand in the area.

In its submission, OEB staff agreed with Enbridge Gas that the currently contracted and identified (expansion) demand growth demonstrates that there is a need for the Proposed Project, while IGUA submitted that it does not oppose the granting of leave to construct the Proposed Project.

Findings

Enbridge Gas’ assessment of need included a survey of potential interest followed by signed commitment letters from six customers. The demand forecast includes the current demand of customers with signed commitment letters, future demand expectations of these customers, as well as general growth in the area. The OEB understands that the Proposed Project will allow Enbridge Gas to serve multiple customers who would otherwise not be served economically if those customers had to fund small-scale expansions individually, and that with government funding, the Proposed Project will be economically feasible. The Proposed Project has also received letters from the community supporting the project. The OEB finds that the Proposed Project is needed.

3.2 Proposed Facilities and Alternatives

Enbridge Gas is proposing to construct the following in the Municipality of Chatham-Kent:

- 500 metres of NPS 12 pipeline extending from the Dover Centre Transmission Station located on Bear Line in Dover Township to the Dover Centre Take-Off at the corner of Bear Line and Dover Centre Line (Bear Line Section)
- 13 kilometers of NPS 8 pipeline running from Enbridge Gas' existing Simpson Road Station (near the community of Tupperville) to an endpoint just south of the intersection of Base Line and Kent Bridge Road east of Dresden (Base Line Section)
- A new distribution station near the corner of Base Line Road and Kent Bridge Road

Enbridge Gas will also make upgrades to the take-off at the north end and the station at the south end of the Bear Line Section as part of the work completed for the Proposed Project.

Enbridge Gas indicated that geo-targeted demand side management (DSM) for existing customers will not satisfy the needs of the contract customers. Further, Enbridge Gas noted that while forecasted demands on the Base Line Section of the Proposed Project could be satisfied with an NPS 6 pipeline, upsizing that section to an NPS 8 pipeline would allow Enbridge Gas to economically serve future growth beyond the term of the initial forecast.

OEB staff noted in its submission that the other alternatives presented by Enbridge Gas appear to either be unable to handle system growth adequately, or may be underutilized, and/or result in significantly higher costs. While OEB staff expressed some concerns about whether sufficient demand will materialize to fully contract the total capacity of the Proposed Project, OEB staff was of the view that an infrastructure solution is appropriate.

Findings

Enbridge Gas applied a comprehensive approach to determine the preferred alternative as described in the *System Design Criteria for Reinforcement on the Chatham East Pipeline* report. The alternatives considered included different diameter pipeline, different design options, obtaining supply from other suppliers and DSM options. This comprehensive assessment determined that the 500 metres of NPS 12 (Bear Line Section) and 13 km of NPS 8 (Base Line Section) hydrocarbon (natural gas) pipeline are the best option.

OEB staff expressed concerns about whether sufficient demand will materialize to completely contract the total capacity of the Proposed Project. The OEB supports the use of the NPS 8 pipe to accommodate forecasted growth in the area. The original survey of customer need and the lack of current excess capacity support the selection of the larger pipe to provide future flexibility.

All parties who addressed the issue agreed that there is a need for additional capacity in the area. Enbridge Gas' preferred alternative – of the Proposed Project – is accepted by the OEB.

3.3 Project Costs and Economics

In accordance with the E.B.O. 188 Guidelines, Enbridge Gas determined the Proposed Project's Profitability Index (PI) to be 1.03. The economic assessment reflects that

- the Municipality of Chatham-Kent agreed to provide $500,000 to support the Proposed Project, and
- O. Reg. 24/19 sets out $8 million in funding for the Proposed Project.[2]

The total estimated pipeline and station cost for the Proposed Project is $19.1 million. Enbridge Gas stated that this project cost estimate included an increase in its Construction and Labour costs as Enbridge Gas and its contractor have refined the detailed design as well as the temporary land needs and construction plans for the Proposed Project since the original application filing. To maintain the overall cost at $19.1 million, Enbridge Gas stated that it had adjusted the contingency from 19% to 15%.

Enbridge Gas proposed that the upsizing cost associated with the NPS 8 pipeline is to be borne by Enbridge Gas' customers at large, rather than by the customers contracting in support of the Proposed Project. The incremental cost of such upsizing is approximately $510,000.

Enbridge Gas is proposing to allocate the net capital cost of the Proposed Project[3] to large volume customers in the identified Area of Benefit[4] through an Hourly Allocation

[2] See Schedule 1 to O. Reg. 24/19.
[3] The net capital cost is the total capital cost of the Proposed Project, net of the municipal and Expansion of Natural Gas contributions and "capital to be recovered from future customers", as described in Enbridge Gas' Updated Evidence, filed March 14, 2019, on page 16, paragraph 50.
[4] Enbridge Gas Inc. EB-2018-0188 Evidence, Schedule 4b.

Factor (HAF). The HAF was determined to be $287/m^3/hour which will be allocated to large customers that require 200 m^3/hour or greater.

In its submission, OEB staff raised two concerns relating to project costs and economics:

1) The HAF may be overstated, both because of a change in the demand forecast for large volume consumers and because the HAF does not reflect the entire capacity enabled by the NPS 8 pipeline
2) Ratepayers could be at risk for the additional cost associated with construction of an NPS 8 pipeline because the demand forecast filed in evidence would be sufficiently served by an NPS 6 pipeline

OEB staff proposed that the HAF rate be accepted as proposed but that true-ups occur at five, ten and fifteen years if load grows beyond the current forecast levels.

Enbridge Gas, in its reply submission, noted that "none of the customers in the project area have asked for a true-up mechanism…No customers are paying an up-front contribution in aid of construction ("CIAC") and the only impact would be on contract length."

IGUA agreed with Enbridge Gas that contributions required from future attaching customers should be applied to offset costs that all Union South rate zone customers will pay for the upsizing under Enbridge Gas' proposal. Further, IGUA submitted that given the level of incremental cost, and the significant growth observed in the area of the Proposed Project, the upsizing of the pipeline seems to be a prudent proposal.

Findings

The PI of 1.03 satisfies the OEB's economic test for this project. The OEB accepts the HAF proposed by Enbridge Gas and used in its contracting with large customers. The OEB will not require true ups as submitted by OEB staff which would be administratively costly without a material benefit to customers.

The OEB directs Enbridge Gas to continue to allocate the HAF to future attaching customers until Enbridge Gas has allocated the entire capital cost of the Proposed Project, net of the funding set out in O. Reg. 24/19 and the municipal contribution. The decision on who will pay for any remaining unfunded capital costs can be addressed at the next rebasing.

The OEB directs Enbridge Gas to provide a detailed review of the final costs of the Proposed Project as part of its next rate application. The review shall provide a variance analysis of project cost, schedule and scope compared to the original estimates, including the extent to which the project contingency was utilized.

3.4 Environmental Matters

Enbridge Gas retained Stantec Consulting (Stantec) to complete an environmental assessment and to propose a route for the pipeline. Enbridge Gas followed the OEB's Environmental Guidelines[5] to assess the potential environmental impact of the Proposed Project. The environmental assessment, including alternative routing and proposed mitigation measures, was documented in an Environmental Report (ER) completed by Stantec on behalf of Enbridge Gas. The ER was submitted to the Ontario Pipeline Coordination Committee (OPCC) in 2018. In response to OEB staff interrogatories, Enbridge Gas indicated that there were no outstanding concerns from OPCC members.

OEB staff submitted that it accepts the selection of the final preferred route compared to the other alternatives and that there should be no long-term environmental impacts from the construction and/or operation of the pipeline as long as Enbridge Gas adheres to the mitigation measures recommended in the ER and the OEB's Conditions of Approval. In its reply submission, Enbridge Gas noted that it would follow standard construction and environmental practices for the Proposed Project to ensure that construction can occur in a responsible manner and that there are no significant environmental impacts resulting from construction.

The Ministry of Tourism, Culture, and Sport (MTCS) reviewed the Proposed Project's Stage 1 Archaeological Assessment (AA); however, a Stage 2 AA is yet to be completed. Due to the outstanding Stage 2 AA, OEB staff submitted that leave to construct should be conditional on Enbridge Gas filing with the OEB a clearance letter from MTCS for the Proposed Project. In its reply submission, Enbridge Gas accepted the additional condition requested by OEB staff. However, Enbridge Gas noted that due to weather and ground conditions, it has been unable to complete the AAs to date. Enbridge Gas expects to receive a clearance letter from MTCS in early July 2019.

[5] *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines in Ontario*, 7th Edition, 2016 (Environmental Guidelines)

SCHEDULE A

DECISION AND ORDER

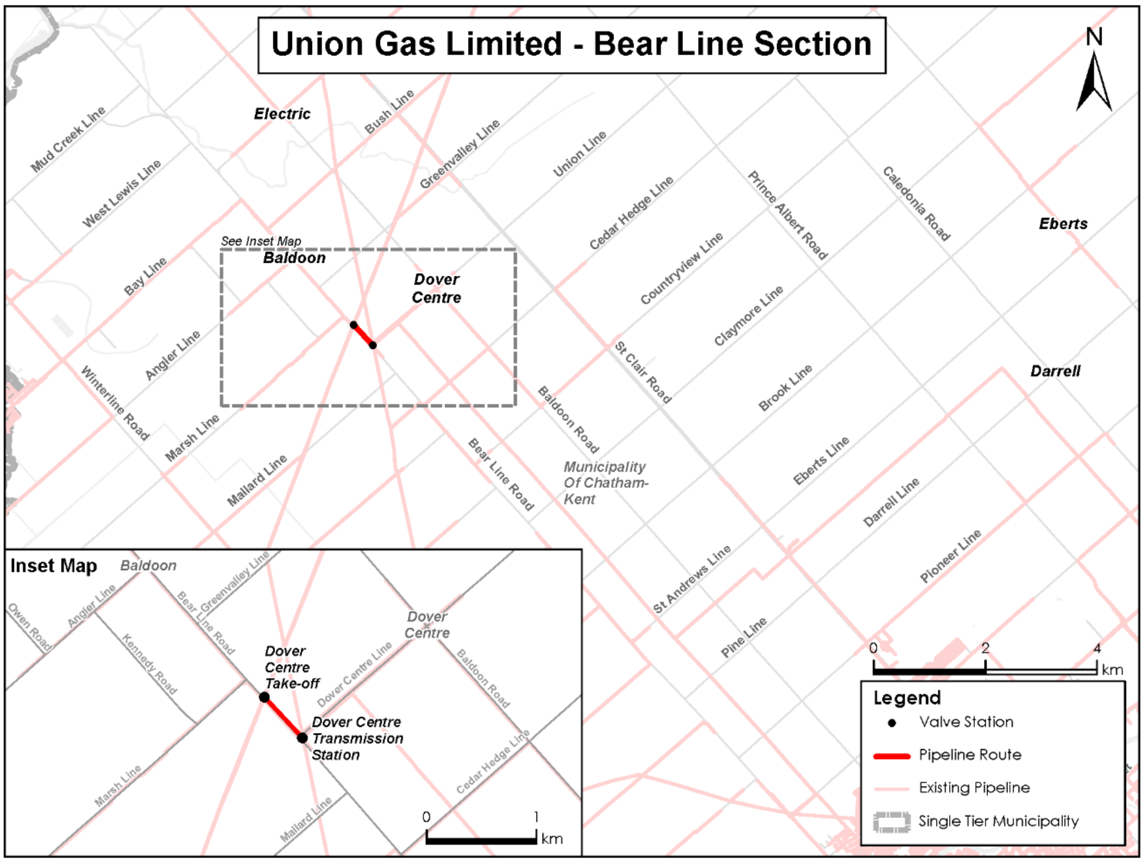
ENBRIDGE GAS INC.

EB-2018-0188

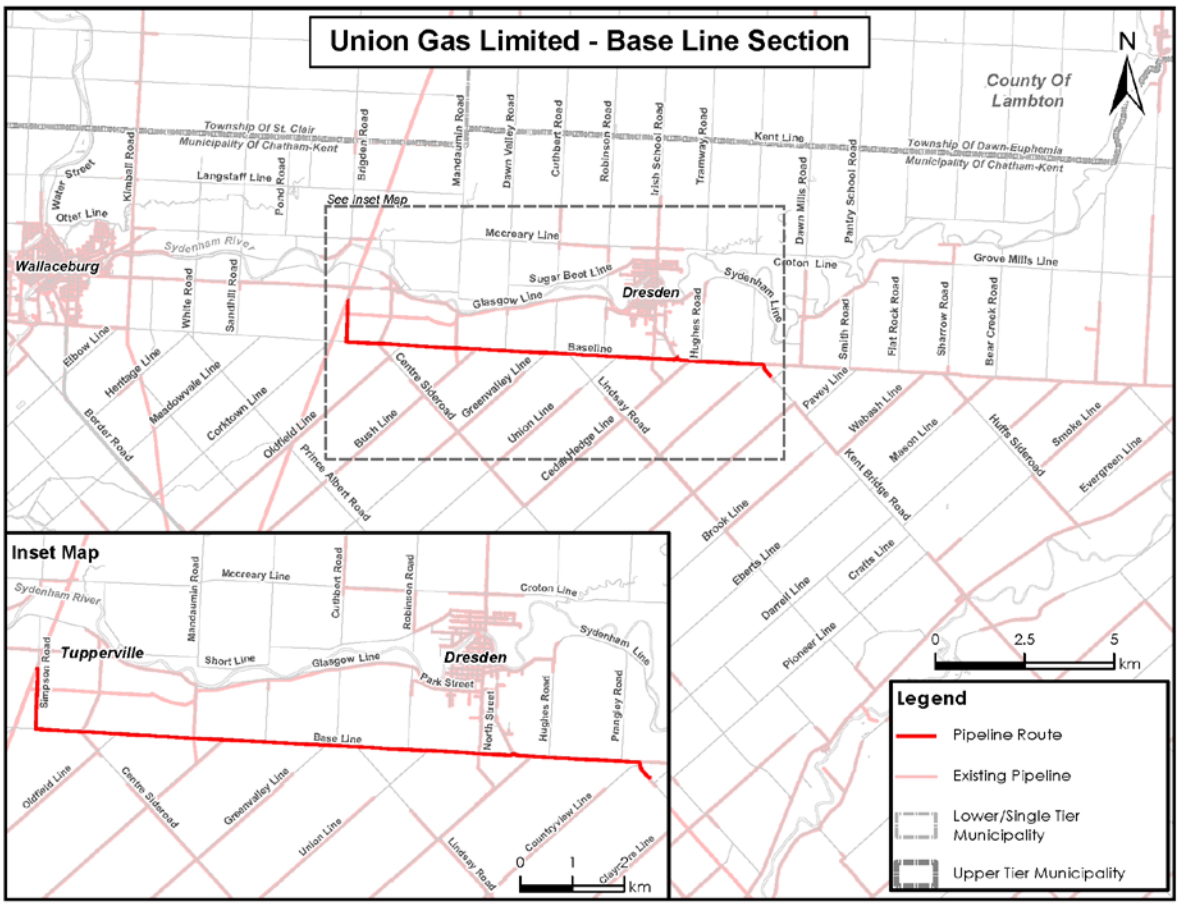
JULY 11, 2019

(REVISED NOVEMBER 19, 2019)

SCHEDULE A-1: MAP OF BEAR LINE SECTION



SCHEDULE A-2: MAP OF BASE LINE SECTION



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

DECISION AND ORDER

EB-2020-0094

ENBRIDGE GAS INC.

Application for approval of a System Expansion Surcharge, a Temporary Connection Surcharge and an Hourly Allocation Factor

BEFORE: Susan Frank
Presiding Commissioner

Robert Dodds
Commissioner

November 5, 2020

1 INTRODUCTION AND SUMMARY

On May 8, 2020, Enbridge Gas Inc. (Enbridge Gas) filed an application with the Ontario Energy Board (OEB) under section 36 of the *Ontario Energy Board Act, 1998*, as amended (OEB Act) for approval of:

- A harmonized System Expansion Surcharge (SES)
- A Temporary Connection Surcharge (TCS)
- An Hourly Allocation Factor (HAF) across its rate zones
- Amendments to Rider I of the Rate Handbook for the EGD rate zone and Rate Schedules for Rates 01, 10, M1 and M2 for the Union rate zones to implement the SES and TCS
- Amendments to the Company's feasibility policies to implement the HAF, SES and TCS

Enbridge Gas submitted that the proposed forms of SES, TCS and HAF are required for Enbridge Gas to achieve consistency regarding its use of these surcharges and the HAF capital allocation mechanism across its rate zones. Enbridge Gas also submitted it will allow Enbridge Gas to accommodate demand for future expansion projects more efficiently without having to seek OEB approval on a project-specific basis.

OEB Findings

The OEB approves the establishment of a harmonized SES and TCS across all of Enbridge Gas's rate zones. This approval will provide consistency across various system expansions with a predictable rate and approach to customer payments.

The OEB approves the establishment of a HAF across all of Enbridge Gas's rate zones. The use of the HAF results in the allocation of the capital costs of a project in a fair and equitable manner as the costs would be allocated over time to eligible customers seeking access to the incremental capacity generated by the project.

The OEB directs Enbridge Gas to file proposed amendments to the Rate Handbook and Rate Schedules for the EGD and Union rate zones to implement the SES and TCS changes approved in this decision. The draft Rate Order shall also include Enbridge Gas's revised feasibility policies to implement the HAF, SES and TCS for each of the EGD and Union rate zones.

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4 HOURLY ALLOCATION FACTOR (HAF)

Enbridge Gas requested that the OEB approve the HAF as a capital cost allocation method in calculating the economic feasibility of future Development Projects, which are defined as a system expansion project that will expand capacity over a certain area to serve increasing demands from existing and/or new customers.

Several intervenors noted that the proposed HAF definition did not appear to clearly account for the first step of the HAF calculation which is to split the project and capital cost into a large volume and small volume component based on proportionate demands. In reply, Enbridge Gas clarified that the first step of the HAF calculation is to split the capital cost into large volume and small volume component based on the forecast of respective peak hourly demands. Customer-specific capital costs such as dedicated distribution main, service lines, customer stations and meters are excluded from the feasibility analysis used for calculating the HAF.

The HAF is then calculated by dividing the forecast capital cost of the large volume component of the Development Project (net of any municipal or governmental funding) by the sum of the forecast firm hourly large volume customer demand (regardless of seasonality) that the project serves within the Area of Benefit. The Area of Benefit is determined by hydraulically modelling the pipeline network in the region around the proposed Development Project to determine the geographic extent of the area that will benefit from the incremental capacity of the project.

LPMA and FRPO raised concerns about the timing of connection of some large volume customers and how they could potentially avoid an allocation of the HAF if they delayed connecting or informing Enbridge Gas about their need for gas service. LPMA suggested that Enbridge Gas allocate the HAF to all large volume customers regardless of whether they were specifically forecasted. Enbridge Gas confirmed that this is how the HAF proposal would work and is consistent with how it has been implemented to date. Enbridge Gas further clarified in its reply that its forecast for the large volume component of a Development Project would be for up to 10 years, consistent with E.B.O. 188 Guidelines.

Enbridge Gas proposed to standardize its use of the HAF by establishing two thresholds:

- Threshold of Eligibility: For all new Development Projects, the HAF will only apply to customers within an Area of Benefit whose forecast hourly gas consumption demand is at least 50 m^3/hour.

- Contracted Commitment Threshold: Enbridge Gas will only proceed with a Development Project if it has secured contractual commitments for firm capacity for at least 50% of the large volume capacity available for the project.

Once determined, Enbridge Gas will allocate and apply the HAF as a capital cost to the individual economic analysis of customers that would receive incremental capacity as they commit to or contract for natural gas service. Enbridge Gas clarified that the HAF is not a charge or payment but an allocation mechanism, the employment of which may or may not result in a CIAC payment (and/or surcharge). Once the total incremental capacity has been fully allocated, Enbridge Gas will cease to allocate and apply the HAF to the economic feasibility of new customers requesting service in the Area of Benefit.

Enbridge Gas stated that it intends to use the HAF process on Development Projects that may involve a mix of distribution and transmission facilities. Enbridge Gas clarified that if the small volume component meets the criteria of a Community Expansion Project and has a PI of less than 1.0, then Enbridge Gas would apply the SES. If the small volume component meets the criteria for a TCS project, then Enbridge Gas would apply the TCS.

FRPO, IGUA, LPMA, SEC and OEB staff all generally supported the approval of the HAF proposal. IGUA also noted that the OEB had previously encouraged the consideration of a mechanism to have parties benefiting from "dual function" transmission projects to make a contribution to these projects[15]. SEC expressed a concern that there would be no testing of the attachment and demand forecasts for non-leave to construct projects prior to the project being constructed[16]. FRPO was concerned that Enbridge Gas's proposal to use the estimated capital costs and customer attachment and volumetric forecast for rate setting purposes appears to shift the risk from the utility to ratepayers without the benefit of better information or upside for ratepayers[17].

CCC accepted the HAF as an appropriate method to allocate a portion of project costs to large volume customers, and stated that it expects that HAF implementation will be

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[15] IGUA Submissions, p. 6
[16] SEC Submissions, p. 5
[17] FRPO Submissions, p. 4

considered by the OEB on a case-by-case basis to ensure that its implementation is fair to all customers[18].

OGVG submitted that it generally supported the use of an HAF to allocate the costs of a distribution project to large volume customers for the purpose of the required economic feasibility calculation under E.B.O. 188.

EPCOR also submitted that while the risk and benefits in the application and evidence may support the approval of the HAF for small, non-LTC projects, the same cannot be said for larger projects[19]. EPCOR proposed that over the course of three years, the impacts of HAF on LTC projects will be better understood, and that Enbridge Gas could apply for a blanket approval for all community development projects then.

VECC submitted that the OEB should reject the HAF proposal until such time that the OEB has completed a public review of the OEB's policies previously set out in E.B.O. 188. VECC submitted that the HAF is a method of calculating CIAC costs for large volume customers and represents a fundamentally new way of forecasting large system loads in projects[20]. VECC submitted that the HAF exposes all customers, including residential customers, to greater forecast risk, and that there is no proposal for compensating ratepayers for this new risk[21].

Environmental Defence opposed the HAF as it would place undue financial risks on existing customers, as it reduces the upfront contributions to natural gas expansion projects and increases the risk that existing customers would cover the costs if forecast future contractual commitments do not materialize.

Energy Probe submitted that the HAF proposal appears to deal with inequitable situations between large volume customers, but that it increases inequitable situations between new large volume customers and existing customers[22]. Energy Probe submitted that unless Enbridge Gas could address this concern in its reply argument, the OEB should turn down the HAF proposal.

[18] CCC Submissions, p. 4
[19] EPCOR Submissions, p.4
[20] VECC Submissions, p. 12
[21] VECC Submissions, p. 13
[22] Energy Probe Submissions, p. 6

OEB Findings

The OEB approves the establishment of a HAF across all of Enbridge Gas's rate zones. The use of the HAF results in the allocation of the capital costs of a project in a fair and equitable manner as the costs would be allocated over time to eligible customers seeking access to the incremental capacity generated by the project.

The OEB approves of the clarification of the HAF definition through Enbridge Gas's revised definitions in the EGD Rate Zone Economic Feasibility Procedure and Policy and the Union Rate Zones' Distribution New Business Guidelines.

While there is a general acceptance of the establishment of a HAF, there were submissions with respect to suggestions and clarifications to the application of a HAF and the OEB provides findings on these issues.

4.1 Timing of Rebasing and CIAC Collection

Enbridge Gas stated that rate treatment for Development Projects would be consistent with TCS and other system expansion projects (other than SES projects) – it would follow the same reporting requirements set out in E.B.O. 188, and that the Projects would be part of Enbridge Gas's Rolling Project and Investment Portfolios. This means that while it might take time for the new capacity generated by the Development Project to be fully utilized, as long as the Development Project is feasible as per E.B.O. 188 guidelines, its revenue requirement would be fully recoverable from customers in consideration of the regulatory mechanism in place. Enbridge Gas explained that regardless of how much capacity of a Development Project is utilized (or allocated) on the in-service date, the entire revenue requirement of the Development Project would be recovered from customers as follows:

- During the IRM period, Enbridge Gas would use existing rates to determine whether they are sufficient to cover the costs of the project. If the Development Project meets the Incremental Capital Module (ICM) criteria, Enbridge Gas would request approval for ICM treatment for that project.

- At cost-of-service rebasing, the Development Project's entire cost (net of any CIAC) and entire revenue requirement would be allocated to customers based on the approved cost allocation methodology and recovered from customers in rates accordingly.

FRPO proposed that actual capital costs and actual customer attachments should be evaluated to provide the OEB with information to test the on-going balancing of interests with the potential to allow only a partial incorporation of capital until the investment is reasonably used and useful[23].

EPCOR and CME submitted that Enbridge Gas's proposed application of the HAF has the potential to drive over-earning. Both EPCOR and CME noted that Enbridge Gas is proposing to include the entire cost of the project in rate base in the first rate case after the in-service date minus any capital contributions, and then continue to allocate the HAF and require capital contributions if the customer's contract does not result in revenue meeting their HAF allocation[24]. As a solution, EPCOR and CME suggested that Enbridge Gas could be directed by the OEB to deduct incremental CIAC/future HAF capital contributions from rate base at the time they are made, which should prevent over-recovery during the period in between rebasing [25].

In its reply, Enbridge Gas noted that to date, no CIAC payments have resulted from any projects for which a HAF has been applied, and that in Enbridge Gas's experience, large volume customers typically prefer to avoid CIAC payments by negotiating appropriate contract terms. Enbridge Gas stated that to the extent a feasibility analysis results in a CIAC payment, Enbridge Gas will offset the rate base value of the applicable assets at the time that CIAC payment is received. Enbridge Gas explained that depending upon when the project goes into service, Enbridge Gas may be perceived to either be under-earning or over-earning on the project. If a project goes into service within an incentive rate period, Enbridge Gas would have to wait until its next rebasing application to make any adjustments to rate base for the project. At rebasing, a project's entire revenue requirement would be allocated to rate classes based on the approved cost allocation methodology. Enbridge Gas argued that for any project for which Enbridge Gas has made the full investment, the total amount of the capital costs should be included in rate base at rebasing. Enbridge Gas submitted that unallocated capacity does not result in over-earnings, as during the incentive regulation term following rebasing, revenue from new customers taking the unallocated capacity form part of utility earnings that are subject to sharing based upon the incentive regulation model in place at the time. Enbridge Gas submitted that unallocated capacity

[24] EPCOR Submissions, p. 2; CME Submissions, p. 3
[25] Ibid.

is simply a short-term timing variance that, relative to all of the HAF benefits of efficient allocation of project capacity and cost, results in overall benefits to ratepayers.

OEB Findings

The OEB approves the proposed rate treatment for Development Projects since it is consistent with TCS and other system expansion projects (other than SES projects). It would follow the same reporting requirements set out in E.B.O. 188, and the Development Projects would be part of Enbridge Gas's Rolling Project and Investment Portfolios.

The OEB finds that unallocated capacity does not result in over-earnings over time and that Enbridge Gas will be permitted to earn an allowed rate of return on its investment. Unallocated capacity is a short-term timing variance that, relative to all of the HAF benefits of efficient allocation of project capacity and cost, results in overall benefits to ratepayers.

4.2 Economies of Scale

OGVG also proposed that in supporting the aggregation of large user capacity requirements over a forecast attachment horizon, Enbridge Gas should be prepared to demonstrate that: a) the inclusion of forecast large user capacity requirements results in a project with an HAF that is lower than the HAF that would have been experienced by the year, and b) the design of the project is tailored as closely as possible to the forecast capacity requirements over the ten-year attachment horizon so as to minimize the amount of unallocated capacity on the project[26].

In its reply submission, Enbridge Gas stated that its goal for Development Projects is to facilitate the connection of customers seeking service in a fair, efficient and economic manner. Enbridge Gas stated that in general, the higher the total capacity being served, the more economically efficient the costs. Enbridge Gas submitted that a long-term forecast and building the least cost facilities that can serve that forecast is in the best interests of the greatest number of customers.

[26] OGVG Submissions, pp. 3-4

OEB Findings

The OEB finds that Enbridge Gas's projection of capacity based on a long term forecast of larger users and building the least cost facilities to serve that forecast is acceptable and best serves the interests of the greatest number of customers.

Further, in its projections of capacity Enbridge Gas incorporates all available information into the formation of the forecast for Development Projects, including municipal information.

4.3 Forecast Risk

LPMA suggested that municipal zoning bylaws and past development history of an area should be incorporated into the Enbridge Gas ten-year forecasts.

IGUA noted that Enbridge Gas has emphasized a number of processes and tools to be used in applying the HAF to mitigate demand forecast risk aside from the 50% committed capacity threshold, including a formal expression of interest process to test large volume customers' demand forecasts, engaging directly with large volume customers to assess their demand forecasts, and validating their demand forecasts with other parties such as economic development groups and municipalities[27].

In its reply, Enbridge Gas also stated that it does incorporate all available information into the formation of the forecast, including municipal information, and will, where appropriate, include placeholders given the past development history of an area.

Environmental Defence submitted that if new customers convert away from using natural gas, remaining customers would be left to fund the balance of the unpaid portion. Enbridge Gas replied that the risk of existing and new customers migrating away from natural gas service appears to be very low given the CER's projections of increased natural gas demand over the next couple of decades and the significant Ontario municipal support for expanding natural gas distribution systems.

OEB Findings

The OEB finds that the forecast risk is acceptable since Enbridge Gas incorporates all available information into the formation of the forecast for Development Projects,

[27] IGUA Submissions, p. 6

including municipal information, and will, where appropriate, include placeholders given the past development history of an area.

The OEB finds that ED arguments regarding increased forecast risk are not supported by the evidence.

4.4 Use of HAF for Transmission Projects

OGVG stated that its primary concern with Enbridge Gas's HAF proposal was that it may be used inappropriately to underpin transmission projects, causing individual large users to become responsible for capital contributions where, under the OEB's current policies with respect to transmission level projects, no such capital contributions from individual customers would be required[28].

EPCOR submitted that applying the HAF to transmission projects amounts to a material policy shift that should be supported by a separate application with relevant evidence and input from a wide range of impacted intervenors[29].

Enbridge Gas stated in its reply that it is mindful of customers' perspectives regarding the higher costs associated with large transmission projects and the necessity to assess societal benefits under stages 2 and 3 of E.B.O. 134. Enbridge Gas submitted that in the case of the Chatham-Kent Rural project, although it involved transmission facilities, the HAF was appropriate due to the modest cost and the fact that customers were able to mitigate their costs and avoid a CIAC through reasonable contract terms and condition. Enbridge Gas stated that it is continuing to explore alternatives to applying E.B.O. 134 or E.B.O. 188 in an exclusive manner and how to reconcile the two sets of guidelines in an appropriate case, but that it does not have an alternative to present at this time.

OEB Findings

The OEB recognizes the concern of some parties about the use of HAF in transmission projects and finds Enbridge Gas's commitment to continue to explore alternatives to be acceptable. The OEB approves the use of HAF for projects that are primarily distribution and if there is a minor component of transmission then the OEB would still accept the use of HAF. For exclusively transmission projects, the OEB has not agreed to the application of HAF.

[28] OGVG Submissions, p. 4
[29] EPCOR Submissions, p. 3

4.5 CIAC Refunds

When asked about potential refunds for CIACs paid to a Development Project or true-ups to the HAF "rate" in the event that there was an increase in forecasted demand, Enbridge Gas stated it was not proposing to refund any CIACs collected for a Development Project.

EPCOR submitted that the HAF results in the discriminatory treatment of certain large volume customers vis-à-vis the ability to apply for a refund. Customers who have paid a contribution that was not determined through the HAF allocation process may be eligible for a refund, while Enbridge Gas has proposed that HAF customers who have paid a contribution will not have the option of applying for a refund[30].

Enbridge Gas explained that a Development Project is designed to cater to the load of forecasted customers, and as such it was unlikely that the actual load would exceed the original forecast to trigger a CIAC refund. Enbridge Gas also stated that true-ups to the HAF "rate" (in the event that there was an increase in forecasted demand) had also been previously considered in the Chatham-Kent proceeding, but had been rejected by the OEB. Enbridge Gas reiterated that customers generally had no interest in a provision for a refund, as symmetrically the customers could be liable for any potential capital overages.

OEB Findings

The OEB finds that provision for refunds for CIACs paid to a Development Project or true-ups to the HAF "rate" in the event that there was an increase in forecasted demand would not be appropriate given that (a) customers generally expressed no interest in such a provision and (b) this would require customers to assume liability for cost overages.

[30] EPCOR Submissions, p. 3

5 AMENDED FEASIBILITY POLICIES

Enbridge Gas sought approval for a revised Rider I for the EGD rate zone, revised rate schedules for the Union rate zones to implement the SES and TCS, and for related amendments to its feasibility policies to implement the HAF, SES and TCS.

OEB staff and LPMA submitted that the proposed amendments to Enbridge Gas's rate handbooks and feasibility policies should be approved.

OEB staff also requested that Enbridge Gas indicate in its reply submission whether it could harmonize its feasibility procedures and policy and extend the CIAC refund policy to all customers now rather than await until its next rebasing application[31].

Energy Probe submitted that Enbridge Gas's feasibility policies should be harmonized now into a single policy that references Rider I for the EGD rate zone and the rate schedules for Union Rate zones, and that Enbridge Gas should not wait for rebasing. Energy Probe submitted that the OEB should make its approval of the application conditional on Enbridge Gas filing within 90 days a consolidated set of feasibility policies based on Exhibits C, Tab 2 and Schedules 1 and 2[32].

In its reply, Enbridge Gas stated that it was not opposed to extending the refund option. However, Enbridge Gas submitted that in order to harmonize the CIAC policies, it would be necessary to consider and weigh the pros and cons of either 1) extending the refund policy to the Union rate zones, or 2) eliminating it from the EGD rate zones. Enbridge Gas also noted that the rules related to service lateral installations also differ between the EGD and Union rate zones, and that it would need to present additional evidence for the OEB to harmonize those policies. Enbridge Gas reiterated that it would bring forward evidence in a subsequent application or at its next rebasing application to address further harmonizing its customer connection policies.

OEB Findings

Intervenors' and OEB staff's concern that feasibility policies should be harmonized into a single policy is typically consistent with OEB expectations. However, the OEB has accepted in a previous decision[33] that changing policies and rate treatments across the EGD and Union areas should wait until the next rebasing. It is now only a short time

[31] OEB Staff Submissions, p. 12
[32] Energy Probe Submissions, p. 6
[33] EB-2018-0305

until rebasing and it would be beneficial to review the customer treatment across several areas at the same time. The OEB directs Enbridge Gas to submit revised feasibility policies as part of the rebasing application.

5.1 Minimum Profitability Index (PI) Required

Enbridge Gas is proposing to raise the minimum PI for all individual projects, which was previously considered feasible at 0.8, to a PI of 1.0[34]. OEB staff agreed with Enbridge Gas's view that E.B.O. 188 permits a utility to use a minimum PI of 0.8 for individual projects as long as its portfolio PIs were above 1.0, and that it does not preclude the utility from using a higher PI threshold. OEB staff supported raising the minimum PI to a PI of 1.0 as it further reduces the potential for cross-subsidization between new and existing customers.

OEB staff also noted that approving Enbridge Gas's current proposal would override the OEB's decision in the previous blanket SES approval in the Fenelon Falls proceeding that set the requirement for capital contributions from contract customers to achieve a PI at a minimum of 0.8" [35].

VECC submitted that under Enbridge Gas's proposal, if all projects are required to meet a financial threshold of 1.0 or greater, the concept of a portfolio would be irrelevant[36]. VECC submitted that the OEB should revisit E.B.O. 188 to satisfy itself that ratepayers are receiving fair treatment and that the policy is used to maximize the number of customers who can avail themselves of the benefit of natural gas service[37].

CCC also submitted that given climate change policies, new technologies and the changing economics of alternatives to natural gas, undertaking a wholesale review of the OEB's expansion policies and considering issues related to cross-subsidization and stranded assets, prior to Enbridge Gas's next rebasing, would be in the best interests of natural gas customers in Ontario[38].

Pollution Probe also argued that it would be useful to review the requested changes as part of a generic review of the EBO 188 Guidelines to ensure that all interrelated issues are considered and to reduce the risk of unintended consequences. Pollution Probe

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[34] OEB Staff Submissions, p. 14
[35] Ibid.
[36] VECC Submissions, p. 10
[37] VECC Submissions, p. 11
[38] CCC Submissions, p. 4

submitted that the proposed revised feasibility policy does not provide rules on how "exceptional circumstances" where a PI down to 0.8 could be applied and that this could provide more ambiguity than E.B.O. 188[39].

In its reply argument, Enbridge Gas stated that it had not proposed any feasibility policy amendments that are inconsistent with E.B.O. 188, and argued that the proposed PI threshold of 1.0 is fully supported by E.B.O. 188 and prior OEB decisions that have approved the SES and the HAF. Enbridge Gas submitted that the practical application of E.B.O. 188 has and continues to be to ensure that the utility is able to maintain an Investment Portfolio and Rolling Project Portfolio PI of 1.0 or greater. Enbridge Gas stated that this does not mean that it does not apply a PI of 0.8, but that this lower PI threshold is the exception generally reserved for system reinforcement projects, and not the rule.

OEB Findings

The OEB approves the amendments to the Enbridge Gas feasibility policies including changing the PI threshold to 1.0 rather than 0.8 for expansion projects that will be subject to an SES or TCS. The PI of 1.0 avoids current customers subsidizing new customers.

The decision to initiate a review of E.B.O. 188 as suggested by several parties is outside the scope of this panel's review.

[39] Pollution Probe Submissions, p. 5

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

EB-2020-0094 (November 5, 2020 Decision and Order on Application by EGI for approval of a System Expansion Surcharge, and Temporary Connection Surcharge and an Hourly Allocation Factor), page 20, last paragraph.

The OEB recognizes the concern of some parties about the use of HAF in transmission projects and finds Enbridge Gas's commitment to continue to explore alternatives to be acceptable. The OEB approves the use of HAF for projects that are primarily distribution and if there is a minor component of transmission then the OEB would still accept the use of HAF. For exclusively transmission projects, the OEB has not agreed to the application
of HAF.

Question(s):

(a) Please discuss alternatives for application of the HAF to transmission projects explored by EGI in accord with its commitment as acknowledged by the OEB in the EB-2020-0094 excerpt referenced.

(b) If the Commission were to direct application of the HAF to PREP, please confirm that the HAF could be applied on the basis of the information included in EGI's Application. If not confirmed please particularize any impediments to doing so.

Response:

a) For clarity, Enbridge Gas's Reply Argument within EB-2020-0094 stated the following:

"In the case of the Chatham-Kent Rural project,[1] although it involved transmission facilities, the HAF was appropriate due to the modest cost and the fact that customers were able to mitigate their costs and avoid a CIAC through reasonable contract terms and conditions, as recognized by OGVG. Enbridge Gas is continuing

[1] EB-2018-0188.

to explore alternatives to applying EBO 134 or EBO 188 in an exclusive manner and how to reconcile the two sets of guidelines <u>in an appropriate case</u>."

The statement was made in the context of the use of HAF for distribution projects which may have a minor transmission component, and where the use of HAF could be appropriate due to its modest cost. The proposed Project is entirely a transmission project (i.e., not a distribution project, and not a "dual-function" pipeline) and HAF is not appropriate.

Enbridge Gas will continue to evaluate opportunities where HAF may apply in an appropriate case involving "dual-function" facilities, however there are no such opportunities identified at this time.

b) Not confirmed. Please see the response at Exhibit I.STAFF.26, part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

INTERROGATORY

Reference:

Updated Application, Exhibit B, Tab 1, Schedule 1, Attachment 1, Panhandle Regional Expansion Projects-Expression of Interest and Capacity Request Form, February 17, 2021, pages 1-2; Exhibit B, Tab 1, Schedule 1, Attachment 8, Panhandle Regional Expansion Project -Expression of Interest and Reverse Open Season, February 23, 2023, pages 1-7; OEB Decision and Order, December 5, 2020, EB-2020-0094, pages 13-15

Preamble:

The OEB approved, on December 5, 2020, Enbridge Gas's Application for approval of a System Expansion Surcharge, a Temporary Connection Surcharge and an Hourly Allocation Factor. In that proceeding Enbridge Gas stated that it intended to use the Hourly Allocation Factor (HAF) process on development projects that may involve a mix of distribution and transmission facilities.

The OEB in its Decision found that the "…use of the HAF results in allocation of the capital costs of a project in a fair and equitable manner as the costs would be allocated over time to eligible customers seeking access to the incremental capacity generated by the project".[1]

Enbridge Gas's Expression of Interest and Capacity Request Form, February 17, 2021 informed the prospective contract customers that the HAF process would be used to charge the prospective contract customers for additional distribution facilities that may be required to serve demands provided by the transmission facilities and that the application of the HAF methodology would be subject to approval of the OEB. There is no mention of the HAF in the EOI 2023 form filed in the updated evidence.

[1] EB-2020-0095 Decision and Order, December 5, 2020, page 16

Question(s):

a) In addition to the Enbridge Gas's HAF process statement in the EOI 2021 form, please discuss Enbridge Gas's view on asking the contract customers that benefit from the Project to contribute to the capital cost of the transmission facilities applying the HAF process.

b) Please advise whether there was any further communication in regard to the HAF with prospective customers following the closing of the EOI process in 2023? If not, please explain why not. If yes, please provide a summary of customers' comments with respect to the application of the HAF.

Response:

a) The statement regarding the Hourly Allocation Factor ("HAF") was included in the 2021 EOI form because Enbridge Gas had not yet determined what facilities were required (i.e., distribution facilities or transmission facilities), and customer demands and their locations were unknown when the EOI was issued. Depending on the results of the 2021 EOI process, transmission and/or distribution facilities may have been required to meet customer demands. The statement within the 2021 EOI regarding the HAF was in relation to potential distribution facilities, not potential transmission facilities.[2]

   The 2023 EOI form did not include a statement regarding the HAF because the 2021 EOI process provided clarity that only transmission facilities were required for the Project.

   Enbridge Gas does not believe it is appropriate to apply the HAF to large volume customers as the Project consists exclusively of transmission facilities and does not include any distribution facilities. The OEB's Decision, which approved the conditions for the use for the HAF, was issued within the context of E.B.O. 188, which relates solely to the economic evaluation of distribution system expansions. The OEB reiterated the applicability of the HAF within its November 5, 2020 Decision regarding EB-2020-0094 (p. 20, emphasis added):

   > *The OEB approves the use of HAF for projects that are primarily distribution and if there is a minor component of transmission then the OEB would still accept the use of HAF. <u>For exclusively transmission projects, the OEB has not agreed to the application of HAF</u>.*

[2] For clarity, the statement within the 2021 EOI form regarding the HAF was as follows: "The Hourly Allocation Factor process recently approved by the OEB will be used for any **additional distribution facilities that may be required** related to the demands served by the transmission facilities [emphasis added]." (Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 1).

The HAF works properly for a distribution project since the capacity created by the distribution facilities can be localized to a very specific area where the hydraulic benefits of the project are spread evenly. Due to this localized nature of distribution project, Enbridge Gas can calculate a HAF that applies equally anywhere within that distribution project area of benefit. When a customer reserves capacity within that project's area of benefit, the specific location of that customer does not impact how much of the project capacity is used. In other words, two customers attaching in two different areas of that distribution project area of benefit will have the same impact on the project facilities. This allows Enbridge Gas to calculate a HAF that can be appropriately administered and results in a HAF that is applied equitably amongst customers over time.

Conversely, the use of the HAF is not appropriate for transmission projects due to the broad geographic area impacted by the facilities. The benefits of the transmission project are not spread evenly across that region, which prevents Enbridge Gas from calculating a HAF that is applicable across the entire area of benefit. A customer's location within that geographic area will have a major impact on how much of project capacity is needed to serve that customer, and therefore customers will not benefit equally from the transmission facilities. In other words, two customers attaching in two different areas of a transmission project area of benefit will not have the same impact on the project facilities. If these customers were to pay a HAF, they would not be contributing equally to the project costs. A transmission project serving multiple classes of customers that have varying impacts to project capacity over a multi-year attachment horizon makes the calculation and administration of the HAF complex and inequitable. This leads to significant risks related to the determination of an appropriate allocation between large and small volume customers in Southwestern Ontario.

b) No communication occurred during or after the close of the 2023 EOI regarding the HAF. The Project consists exclusively of a transmission facility (and no distribution facilities) and as such the HAF and/or CIAC are not appropriate. Please see the response to part a) above and Exhibit I.STAFF.25, part c).

C. Incremental Demand

6. The firm demand for natural gas from new and existing general service and contract rate customers has continued to grow on the Panhandle System over the past decade. Prior to 2017, Enbridge Gas was able to reinforce the Panhandle System by constructing downstream facilities, such as the Leamington North Loop (Leamington Expansion Phase I project in 2013[1] and Phase II project in 2016[2]), upsizing of pipeline between Ruscom and Patillo from NPS 16 to NPS 20 through the Panhandle NPS 16 Replacement Project between 2014 and 2016[3], and by relying on Enbridge Gas's firm gas supply arriving at Ojibway to serve markets within the Windsor region.

7. Starting in 2017, Enbridge Gas expanded the Panhandle System to meet increasing demands for firm service from Enbridge Gas's distribution systems which serve the in-franchise markets in the Municipalities of Dawn-Euphemia and St. Clair, Chatham-Kent, Lakeshore, Essex, Tecumseh, Leamington, Kingsville, LaSalle, Amherstburg and Windsor (together "the Panhandle Market"). The Panhandle Reinforcement Project ("PRP")[4] was placed into service on November 1, 2017, to serve forecasted demand growth out to Winter 2021/2022, including unfulfilled demand requests from the Leamington Expansion Phase II project.

8. In 2018, Enbridge Gas's Kingsville Transmission Reinforcement Project ("KTRP")[5] was advanced by 3 years from the initial forecasted in-service date of November 1, 2022 to November 1, 2019. The forecasted Panhandle System capacity shortfall at that time occurred in Winter 2020/2021, but the Project was placed into service in 2019 to alleviate the need for incremental downstream distribution system expansion. The KTRP facilities were designed to meet forecasted demand in the Panhandle Market out to Winter 2025/2026, based on the best information then available.

9. Consistent with these past experiences, significant growth has continued within the Panhandle Market and demand is forecast to exceed the Panhandle System capacity sooner than anticipated, resulting in the need to address a forecasted system capacity shortfall by November 1, 2024. /U

[1] EB-2012-0431
[2] EB-2016-0013
[3] EB-2013-0420
[4] EB-2016-0186
[5] EB-2018-0013

10. Enbridge Gas's current Panhandle System Design Day demand forecast is developed from the contract demand and customer attachment forecasts. Growth is forecast to occur across the entire Panhandle System with concentration in the Leamington-Kingsville and Windsor areas. Details of the Enbridge Gas growth forecast for contract and general service rate classes are provided in the sections below.

i. Contract Rate Growth Forecast

2021 Expression of Interest and Reverse Open Season – Approach and Outcomes

11. The contract rate (Rate M/BT4, Rate M/BT5, Rate M/BT7, Rate T-1 and Rate T-2) demand accounts for approximately 55% of firm demand served by the Panhandle System as of Winter 2021/2022. Based on early indications of incremental demand obtained by informal contract rate customer outreach, Enbridge Gas launched an Expression of Interest ("EOI") process in February 2021 to formally gauge interest for incremental growth on the Panhandle System[6]. An email notification announcing the EOI was sent to all existing contract rate customers, all large volume general service rate M2 customers within the Area of Benefit, and the direct purchase marketer community. The EOI and related bid forms were also posted on Enbridge Gas's website. The EOI is provided as Attachment 1 to this Exhibit. /U

12. The EOI included a map, shown in Figure 1 below, depicting the Area of Benefit. The Area of Benefit included all of Essex County as well as the western portion of the Municipality of Chatham-Kent.

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[6] Enbridge Gas's Expression of Interest process is intended to collect and aggregate all potential customer demand changes in a targeted Area of Benefit, so that an optimized facility or non-facility solution can be developed and implemented in a timely manner. In addition to soliciting requests for firm capacity and conversion of existing interruptible capacity to firm, it allows for customers to express interest in additional interruptible capacity. Existing customers are also provided an opportunity to turn back or de-contract existing firm or interruptible capacity. The net of all changes requested through the process supports the generation of an informed demand forecast for the Area of Benefit.

ENBRIDGE GAS INC.

Undertaking Response to IGUA

Enbridge to explain why it did not make a proposal to enable seeking of a contribution for the capacity sought.

Response:

The proposed Project is a transmission project (please also see the response at Exhibit JT1.2 for Enbridge Gas's definitions of transmission and distribution pipelines) that will increase capacity on the Panhandle System to meet forecast demand within a large area of benefit.[1] While the demand underpinning the need for the proposed Project is informed by customer demand throughout the area of benefit, there will be no customers directly connecting to the proposed Project (Panhandle Loop and Leamington Interconnect).

Distribution projects, in comparison, generally provide customer premises with direct access to natural gas. In the case of distribution projects, it can be appropriate to seek a financial contribution from customers whose premises will be directly benefiting from the project. These financial contributions can minimize cross-subsidisation by customers who will not benefit from the distribution facilities.

It is not appropriate to seek a financial contribution from specific customers for the proposed transmission Project because, as a transmission system, the Panhandle System transports natural gas for the benefit of all customers within the Panhandle Market – rather than individual or specific customers. Once in service, the proposed Project will serve all customers, whether or not they participated in the expression of interest. The proposed Project addresses system bottlenecks, which once relieved, will improve the reliability of service for existing customers, and will allow for growth from existing and new customers.

It should be noted that the Company's approach is consistent with previous Enbridge Gas applications to the OEB seeking leave to construct, including the Kingsville Transmission Reinforcement Project ("KTRP") (EB-2018-0013). Within the OEB's Decision in the KTRP leave to construct proceeding, the OEB found that the Company "appropriately followed the OEB's E.B.O. 134 test for transmission projects" and confirmed that "currently there is no mechanism to have these parties make a contribution to the costs."[2]

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[1] Exhibit B, Tab 1, Schedule 1, p. 5, Figure 1
[2] EB-2018-0013, OEB Decision and Order (September 20, 2018), pp. 5-6

The Company's approach is also in alignment with the OEB's Decision (less than two years ago) on Enbridge Gas's Application for Approval of a System Expansion Surcharge ("SES"), a Temporary Connection Surcharge ("TCS"), and an Hourly Allocation Factor ("HAF"), specifically:

> "The OEB approves the use of HAF for projects that are primarily distribution and if there is a minor component of transmission then the OEB would still accept the use of HAF. For exclusively transmission projects, the OEB has not agreed to the application of HAF."[3]

[3] EB-2020-0094, OEB Decision and Order (November 5, 2020), p. 20

UNION GAS LIMITED

Answer to Board Panel

ISSUE #2: Multiple needs served by this project

Question 7:

Please identify all of the costs that new contract customers will be required to pay to connect to Union Gas' system, including both one-time and ongoing costs.

Response:

The description below is the typical process applicable to connecting any contract sized distribution customer across Union's system. It is non-specific to E.B.O. 134 or E.B.O. 188.

Customers who contract for contract rate distribution service will be required to pay the applicable rates, billed monthly, for the contract service according to Union's rate schedules. These are ongoing costs for the term of the contract. Customers may also be required to make a one-time Contribution-in-Aid-of-Construction ("CIAC") payment.

An economic analysis to determine if a CIAC payment is required is completed for each contract customer prior to connecting to Union's system. For each connection a PI is determined based on the revenue stream and the cost specific to the customer to connect the load. These connection costs are directly related to attaching the customer and are the responsibility of the customer. These costs may include the cost of installing a new station or modifying an existing individual customer station, installing a service line and/or extend the main or reinforce the local distribution system.

The DCF will determine if the revenue is sufficient to recover these costs. If there is a shortfall a CIAC is collected from that customer. A CIAC is a one-time cost. The length of contract term that the customer chooses will influence the present value of the revenue stream. It is often an iterative approach with the customer to determine their preference for revenue parameters based on changing volumes and length of term; however if the outcome is shortfall relative to costs, the CIAC is collected to a PI of 1.0 for customers.

UNION GAS LIMITED

Answer to Board Panel

ISSUE #3: Economics of the Proposed Project

Question 9:

If the OEB were to require Union Gas to collect a contribution-in-aid-of-construction in order to increase the project's profitability index to 0.8, what would Union propose? Please explain the rationale.

Response:

As noted in the response to Board Panel Question 4, Union does not believe the OEB should require Union to collect a contribution-in-aid-of-construction ("CIAC") in order to meet a profitability index ("PI") of 0.8 as this is a transmission project and not a distribution project.

The PI of the Kingsville Transmission Reinforcement Project ("KTRP") as filed is 0.44 resulting in a negative NPV of $59 million (Exhibit A, Tab 9, Schedule 4). This includes the cost of KTRP and revenue from only the "Transmission Margin" as described beginning at Exhibit A, Tab 9, p.3.

The markets served by the Panhandle Reinforcement Project (EB 2016-0186) are similarly situated to KTRP; it allows demands to be met from Dawn through Windsor. The Panhandle Reinforcement Project was not attributed to individual customers in the form of a cost for a CIAC nor should KTRP. Both are common-use upstream facilities for a large geographic area.

As requested in the question above, applying an aid to KTRP for Panhandle Transmission System capacity would result in a geographic group of customers paying an aid while consuming Panhandle Transmission System capacity (those at the terminus of KTRP) while a similar customer consuming the same amount of Panhandle Transmission System capacity but not located at the terminus would not incur the aid cost. Such a situation may result in customer perception of bias or cost disadvantage to one group of customers relative to another.

However, to be responsive to the question, for illustrative purposes, in order to increase the project's PI to 0.8, approximately $53 million of CIAC or recovery of equivalent revenue would need to be collected from customers. In determining the amount to collect as CIAC, all capital costs – pipeline and individual customer distribution attachment costs - would need to be included to determine the PI. Union estimates that the total distribution costs to be recovered would be approximately $20 million. The total capital costs for the Project and any future distribution facilities would be estimated at $125 million. Including these costs along with transmission and distribution margin results in a PI of 0.57 prior to any CIAC or equivalent revenue.

Union's proposal would be to allocate the \$53 million to all large volume customers who consume more than 200 m^3/hour. The allocation would be based on an hourly allocation factor applied to each customer's economic analysis. The 200 m^3/hour is the approximate size that is large enough for a customer to qualify for a contract rate in Union south (350,000 m^3/year under Rate M4). This approach is consistent with that applied to the Leamington Expansion Pipeline Projects as well as the proposed Chatham-Kent Rural Expansion Project[1]. The amount of the hourly allocation factor resulting from the \$53 million economic shortfall is approximately \$501/m^3/hour. This hourly allocation factor would only be applied to large volume customers who require the Project to be placed into service in order to provide capacity for them to connect to the distribution system[2]. This amount is more than double what Union was able to contract with customers serviced from the Leamington Expansion Pipeline Phase II project[3].

Although Union has not included the hourly allocation factor of \$501/m^3/hour in any discussion with the expected large volume customers, Union expects it would result in customers being unable to afford to connect to the system for their business operations. The demand forecast for the Proposed Project would be at significant risk. Customers would choose to not attach at Greenfield sites and would not expand at existing operations. It is also possible some customers would move their total operations out of Ontario. As a consequence, Union believes that a requirement to achieve a PI of 0.8 would very likely result in cancellation of the Project and no opportunity to achieve the public interest benefits of \$341 to \$691 million as reflected in pre-filed evidence.[4]

[1] EB-2012-0431, EB-2016-0013, EB-2018-0188
[2] These customers would include any new large volume loads serviced in the Kingsville/Leamington market area until such time as the hourly capacity of 102,000 m^3/hour made available by the Project is fulfilled
[3] Union applied hourly allocation factors of \$230/m^3/hour, and \$287/m^3/hour for the Leamington Phase II, and proposed Chatham-Kent Rural Expansion Projects, respectively.
[4] Exhibit A, Tab 9, Table 9-2

23. This section of Reply Evidence is in response to Section 2 of the ED Evidence, titled *Analysis of Alternatives to Natural Gas for New Construction Greenhouses in Ontario*.

24. Throughout the ED Evidence, Dr. McDiarmid makes references to various greenhouse operations but does not distinguish between (i) small-scale commercial greenhouses, and (ii) large-scale greenhouse operations, and gives no consideration to the technical feasibility or viability of the alternatives referenced in this regard. The distinction is critically relevant, as the proposed Project is designed specifically to support the energy needs of several large-scale greenhouse operations, not small-scale commercial greenhouses.

25. Small-scale commercial greenhouses are fundamentally different than large-scale greenhouse operations. **Small-scale commercial greenhouses** are generally used as retail nurseries, school greenhouses, or recreational facilities, and are generally smaller than 1-acre in size. **Large-scale greenhouse operations** are mass-market vegetable farming facilities that span many acres. Examples of large-scale greenhouse operations constructed recently within the Project area include:

- Pure Flavor – Recently began construction of a **40-acre (or 1.7 million square foot)** greenhouse facility in Leamington, Ontario.[14]
- Pomas Farms – Recently constructed a **77-acre (or 3.4 million square foot)** greenhouse facility in Leamington, Ontario.[15]

26. Dr. McDiarmid makes numerous references to greenhouse operations throughout the ED Evidence but provides limited context as to the nature and scale of those operations.

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[14] https://www.pure-flavor.com/leamington-phase-4-expansion-distribution-center/
[15] https://www.hortidaily.com/article/9307584/construction-completed-on-pomas-farms/

according to the U.S. National Park Service),[28] “fertilizer and pesticide pollution, the impact of crop-filled fields on biodiversity and key habitats, and the working conditions of farmhands all impact a product’s overall sustainability”.[29]

D. Conclusion

42. The analysis provided by Dr. McDiarmid in the ED Evidence cannot be used to assess the economic feasibility of the Project as it selectively modifies and misuses the E.B.O. 134 economic test, resulting in an inherent inconsistency among the stages of the E.B.O. 134 cumulative three-stage economic assessment. Furthermore, the analysis relies on inappropriate simplifying assumptions.

43. In addition, the information provided by Dr. McDiarmid in the ED Evidence related to the technical viability of natural gas alternatives for greenhouses is not applicable to large-scale greenhouse operations driving the need for the proposed Project.

[28] https://www.nps.gov/articles/hydroponics.htm
[29] https://www.nationalobserver.com/2021/05/03/news/why-mexican-tomatoes-can-be-more-sustainable-canadian

gas instead of another fuel to meet their energy requirements. The difference in fuel cost is derived as:

[Weighted Average Alternative Fuel Cost - Cost of Natural Gas] × Energy Use

15. The Stage 2 NPV of energy cost savings are estimated to be in the range of approximately $226 million over a period of 20 years to $353 million over 40 years. A range is provided as the outcome can vary depending upon the assumptions for alternative fuel mix, energy use, fuel prices, and term. /U

16. The Stage 2 energy cost savings have only been calculated for the general service customer class. It is assumed that contract rate customers will not choose an alternative fuel if natural gas is not available to them. The non-availability of natural gas will cause contract rate customers to expand or move their operations to other jurisdictions, likely outside of Ontario, where their natural gas needs can be served. The resulting impacts to the Ontario economy are addressed in Stage 3.

17. The results and assumptions associated with this analysis can be found at Exhibit E, Tab 1, Schedule 6.

iii. Stage 3 – Other Public Interest Considerations

18. There are several other public interest factors for consideration as a result of the Project. Some are quantifiable and others are not readily quantifiable. Quantifiable factors include GDP, taxes, and employment impacts. Applicable other public interest factors are discussed below:

/U

Economic Benefits for Ontario

19. The construction of the Project will provide direct and indirect economic benefits to

Ontario estimated at approximately $257 million, as detailed at Exhibit E, Tab 1, Schedule 7. This figure is related only to the construction of the Project and does not include the similar direct and indirect economic benefits to Ontario when natural gas customers receiving this incremental supply invest and grow their operations. Customers who submitted EOI bids in 2021 were requested to provide economic development impacts related to their incremental natural gas needs. In the EOI bid responses, customers indicated that total direct capital investment into their business operations in Southern Ontario would exceed $6.37 billion. These figures were updated via the 2023 EOI bid forms. Although, the Company only received relevant feedback from 75% of customers who bid in 2023 (relative to 100% in 2021) the Project is still anticipated to result in total direct capital investment in Southwestern Ontario exceeding $4.5 billion.[3]

Employment

20. The construction of this Project will result in additional direct and indirect employment. There will be additional employment of persons directly involved in the construction of the Project. In addition, there will be a trickledown effect on employment as the Project is estimated to create approximately 1,093 jobs as referenced at Exhibit E, Tab 1, Schedule 7. /U

21. Customers who submitted EOI bids in 2021 indicated that a total of 11,526 jobs could be created through the investment into their business operations enabled by the incremental capacity of the proposed Project. These figures were updated via the 2023 EOI bid forms. Although, the Company only received relevant feedback from 75% of customers who bid in 2023 (relative to 100% in 2021) the Project is still anticipated to result in the creation of 6,900 jobs.[4] /U

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[3] Implying a comparable result to 2021, since $4.5 billion is 75% of $6 billion total potential.
[4] Implying a comparable result to 2021, since 6,900 jobs is 75% of 9,200 total potential.

Utility Taxes

22. A decision to proceed with this Project will result in Enbridge Gas paying taxes directly to various levels of government. These taxes include Ontario income taxes and municipal taxes paid by Enbridge Gas as a direct result of the Project and are included as costs in the Stage 1 DCF analysis. These taxes are not true economic costs of the Project since they represent transfer payments within the economy that are available for redistribution by federal, provincial, and municipal governments. The NPV of Ontario income taxes and municipal taxes payable by Enbridge Gas related to the Project over the Project life is approximately $45 million with a further $22 million paid to the federal government. These figures are further detailed at Exhibit E, Tab 1, Schedule 7.

Employer Health Taxes

23. The additional employment resulting from construction of the Project will generate additional employer health tax payments to aid in covering the cost of providing health services in Ontario.

iv. Summary of Stages 1 to 3 Analyses

24. Table 3 below shows the NPV calculated for the 3-Stage economic analysis completed for the Project.

Table 3: NPV Calculation /U

Stage	NPV ($millions)
1	($150)
2	$226 to $353
3	$257
Total	$333 to $460

25. As set out above, the Project is in the public interest and the tests set out in E.B.O. /U
134 are appropriate for the purposes of evaluating the Project. Based on these tests,

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

Exhibit A, Tab 3, Schedule 1, page 5, paragraph 12.
The revised estimated cost for PREP is $358.0 million.

Question(s):

(a) Please provide the forecast rate base for the Panhandle system as of the proposed in-service date for PREP and before addition of the PREP costs.

(b) Please explain the current basis for allocation of Panhandle costs to customers (confirming that such costs are allocated in aggregate with the costs of the St. Clair system and indicating the allocator(s) used).

(c) Please provide the forecast rate base for the St. Clair system as of the proposed in-service
date for PREP.

Response:

Enbridge Gas is not seeking cost recovery of the Project as part of this application.[1]

a) The forecast net book value that would be included in the determination of rate base for the Panhandle system prior to the PREP in-service date of November 1, 2024 is $422.2M.

b) Union's 2013 OEB-approved cost allocation study classifies the demand-related costs for the combined Panhandle System and St. Clair System as Ojibway/St. Clair demand.

   The OEB-approved cost allocation methodology of Ojibway/St. Clair demand costs is based on the maximum design capacity of the combined system which is determined as the Panhandle System capacity from Dawn to Ojibway (Dawn send out) plus the maximum firm import capacity at the St. Clair Pipeline and Bluewater

[1] Exhibit A, Tab 3, Schedule 1, para. 13.

Pipeline river crossings. The allocation of the maximum design capacity to ex-franchise Rate C1 and Rate M16 is based on firm contracted demands. The remaining capacity is allocated to Union South in-franchise rate classes in proportion to the combined Panhandle System and St. Clair System firm design day demands.

c) The forecast net book value that would be included in the determination of rate base for the St. Clair system prior to the PREP in-service date of November 1, 2024 is $3.7M.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

Exhibit A, Tab 3, Schedule 1, page 5, paragraph 13.

Enbridge Gas expects that, as part of its 2024 rebasing application, the recovery of costs associated with this project will be addressed. Enbridge Gas will allocate Project costs to rate classes according to the cost allocation methodology approved as part of that proceeding, or as otherwise approved by the OEB.

EB-2022-0200, Exhibit J13.2, part b).

The ratemaking implications of the largest projects to be implemented in 2023 and 2024 (Dawn to Corunna and PREP) will be determined by a subsequent regulatory process, Phase 2 for Dawn to Corunna and the LTC for PREP.

Question(s):

Based on the current approved cost allocation methodology for the Panhandle system, please provide the forecast PREP costs that would be allocated to each EGI rate class and the rate impact (¢/m3 and % impact) of such allocation.

Response:

Please see Attachment 1 to this response. Page 1 provides the cost allocation and unit rates for the Project using a levelized revenue requirement as proposed in Enbridge Gas's 2024 Rebasing application.[1] The cost allocation factor is based on Union's current approved cost allocation methodology for Ojibway/St. Clair demand costs updated for the 2024 forecast included in Enbridge Gas's 2024 Rebasing application. Page 2 provides rate impacts in the form of annual bill impacts for typical small and large customers as a percentage of the customer's delivery bill.

Enbridge Gas is not seeking cost recovery of the Project as part of this application.[2]

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[1] EB-2022-0200.
[2] Exhibit A, Tab 3, Schedule 1, para. 13.

Filed: 2023-09-26
EB-2022-0157
Exhibit I.IGUA.2
Attachment 1
Page 1 of 2

Cost Allocation and Unit Rates of Panhandle Regional Expansion Project
based on Current OEB-approved Cost Allocation Methodology

Line No.	Particulars	Current Approved Cost Allocation Methodology: Allocator (1)	Allocation ($000s) (2)	2024 Forecast Usage (4)	Billing Units	Unit Rate (cents/m³)
		(a)	(b)	(c)	(d)	(e) = (b / c x 100)
	EGD Rate Zone					
1	Rate 1	-	-	5,011,588	10³m³	-
2	Rate 6	-	-	4,799,240	10³m³	-
3	Rate 100	-	-	4,503	10³m³/d	-
4	Rate 110	-	-	75,654	10³m³/d	-
5	Rate 115	-	-	14,481	10³m³/d	-
6	Rate 125	-	-	111,124	10³m³/d	-
7	Rate 135	-	-	52,646	10³m³	-
8	Rate 145	-	-	6,138	10³m³/d	-
9	Rate 170	-	-	30,928	10³m³/d	-
10	Rate 200	-	-	15,025	10³m³/d	-
11	Rate 300	-	-	-	10³m³/d	-
12	Total EGD Rate Zone	-	-	10,121,328		
	Union North Rate Zone					
13	Rate 01	-	-	990,646	10³m³	-
14	Rate 10	-	-	328,117	10³m³	-
15	Rate 20	-	-	91,732	10³m³/d	-
16	Rate 25	-	-	126,831	10³m³	-
17	Rate 100	-	-	42,050	10³m³/d	-
18	Total Union North Rate Zone	-	-	1,579,376		
	Union South Rate Zone					
19	Rate M1	4,838	1,306	3,260,773	10³m³	0.0400
20	Rate M2	1,909	515	1,320,841	10³m³	0.0390
21	Rate M4 (F)	1,576	425	46,836	10³m³/d	0.9080
22	Rate M4 (I)	-	-	238	10³m³	-
23	Rate M5 (F)	20	5	432	10³m³/d	1.2722
24	Rate M5 (I)	-	-	55,087	10³m³	-
25	Rate M7 (F)	3,420	923	71,858	10³m³/d	1.2846
26	Rate M7 (I)	-	-	75,999	10³m³	-
27	Rate M9	-	-	6,040	10³m³/d	-
28	Rate T1 (F)	579	156	26,540	10³m³/d	0.5893
29	Rate T1 (I)	-	-	37,536	10³m³	-
30	Rate T2 (F)	13,553	3,658	308,713	10³m³/d	1.1850
31	Rate T2 (I)	-	-	41,762	10³m³	-
32	Rate T3	-	-	28,200	10³m³/d	-
33	Total Union South Rate Zone	25,895	6,989	5,280,856		
	Ex-Franchise					
34	Rate 331	-	-			
35	Rate 332	-	-			
36	Rate 401	-	-			
37	Rate M12	-	-			
38	Rate M13	-	-			
39	Rate M16	188	51			
40	Rate M17	-	-			
41	Rate C1 (F)	945	255			
42	Rate C1 (I)	-	-			
43	Total Ex-Franchise	1,133	306			
44	Total	27,027	7,295 (3)			

Notes:
(1) Ojibway/St. Clair demand allocation factor based on 2024 forecast maximum design capacity. Direct assignment to ex-franchise rates based on contracted capacity with remaining maximum design capacity allocated to Union South rate classes in proportion to Panhan System and St. Clair System design day demands.
(2) Allocated using column (a).
(3) EB-2022-0200, Exhibit 2, Tab 5, Schedule 4, Attachment 2, page 1, line 15, column (f).
(4) EB-2022-0200, Exhibit 8, Tab 2, Schedule 8, Attachment 2, column (a). General service volumes updated for Settlement Agreement.

Bill Impacts for Typical Small and Large Customers of Panhandle Regional Expansion Project
based on Current OEB-approved Cost Allocation Methodology

Line No.	Particulars	Unit Rate (1)	Billing Units (2)		Bill Impact ($)	EB-2022-0133 Current Approved Delivery Bill (3) ($)	Delivery Bill Impact (%)
		(a)	(b)		(c)	(d)	(e)
	Union South Rate Zone						
1	Rate M1 - Residential	0.0400	2,200	m³	0.88	433	0.2%
2	Rate M2	0.0390	73,000	m³	28.48	5,972	0.5%
3	Rate M4 (F) - Small	0.9080	4,800	m³/d	523	57,891	0.9%
4	Rate M4 (F) - Large	0.9080	50,000	m³/d	5,448	468,572	1.2%
5	Rate M5 (I) - Small	-	825,000	m³	-	38,793	0.0%
6	Rate M5 (I) - Large	-	6,500,000	m³	-	227,250	0.0%
7	Rate M7 (F) - Small	1.2846	165,000	m³/d	25,434	842,327	3.0%
8	Rate M7 (F) - Large	1.2846	720,000	m³/d	110,986	3,183,889	3.5%
9	Rate M9 - Small	-	56,439	m³/d	-	206,517	0.0%
10	Rate M9 - Large	-	168,100	m³/d	-	613,438	0.0%
11	Rate T1 (F) - Small	0.5893	25,750	m³/d	1,821	175,282	1.0%
12	Rate T1 (F) - Average	0.5893	48,750	m³/d	3,447	272,638	1.3%
13	Rate T1 (F) - Large	0.5893	133,000	m³/d	9,405	614,548	1.5%
14	Rate T2 (F) - Small	1.1850	190,000	m³/d	27,018	777,629	3.5%
15	Rate T2 (F) - Average	1.1850	669,000	m³/d	95,130	1,901,634	5.0%
16	Rate T2 (F) - Large	1.1850	1,200,000	m³/d	170,637	3,156,032	5.4%
17	Rate T3	-	2,350,000	m³/d	-	6,375,944	0.0%

Notes:
(1) Page 1, column (e).
(2) Billing units for typical small and large customers.
(3) Delivery charges per EB-2022-0200, Exhibit 8, Tab 2, Schedule 8, Attachment 10, pages 7-9, column (a).

Relative Rate Base

Panhandle System & St. Clair System

Before PREP: I.IGUA.1

Panhandle	**$422.2 million**	**99.13%**
St. Clair	**$3.7 million**	**0.87%**
Total	**$425.9 million**	

After PREP:

Panhandle	**$422.2 + 358 = $780.2 million**	**99.53%**
St. Clair	**$3.7 million**	**0.47%**
Total	**$783.9 million**	