1.0 ADMINISTRATIVE DOCUMENTS

1.1 Table of Contents

Exhibit 1 – Administrative Documents

1.2 Executive Summary

1. EPCOR Natural Gas LP ("ENGLP") distributes natural gas to over 9,000 customers in and around Aylmer, Ontario, with its service area stretching from south of Highway 401 to the

shores of Lake Erie, from Port Bruce in the west to Clear Creek in the east. It provides natural gas service to customers in Townships of Malahide and South-West Oxford; Municipalities of Bayham, Thames Centre and Central Elgin; and Norfolk County. The system serves the individual communities of Aylmer, Belmont, Brownsville, Port Burwell, Springfield, Straffordville, and Vienna. The gas demands in the ENGLP System are mainly for residential and commercial heating, small industrial users, and grain drying. In addition, the system provides service to IGPC Ethanol Inc. ("IGPC"), a large industrial customer that is served using a standalone distribution system.

2. This Rate Case ("Application") is the first filed by ENGLP since the acquisition of the utility from Natural Gas Resources Inc. ("NRG") on November 1, 2017 (EB-2016-0351). The utility's last cost of service proceeding was EB-2010-0018 to set rates for the 2011 Test Year. As a result, this Application includes historical information from the period 2011 to October 31, 2017 as provided to ENGLP when it acquired the assets of the utility. This historical data reflects the operations, capital investment objectives, corporate relationships, financial strength, and cost structure of the previous owner.

3. This Application is also the first that includes the change in the utility's fiscal year. NRG's fiscal year was October 1 to September 30. ENGLP's fiscal year is January 1 to December 31 and the utility reported its financials in alignment with that fiscal year as of the November 1, 2017 date at which ENGLP acquired the system assets.

4. ENGLP has historical audited financial statements covering the October 1 to September 30 fiscal periods during which the utility was owned by NRG and audited statements from November 1, 2017 forward for the periods during which ENGLP owned the utility. ENGLP does not have statements for the month of October, 2017 during which NRG owned the utility's assets as they have not been provided. As a result, when presenting financial detail in this Application ENGLP has included it for the twelve month periods representing the fiscal periods of the owner at the time (October 1 to September 30 for NRG and January 1 to December 31 for ENGLP) but has not included the October to December stub period in 2017, two months of which financial information is available. ENGLP did not include information regarding the three month stub period in the comparison tables of each exhibit as it would not be instructive in reviewing the historical data. However, in order to be helpful, ENGLP has included the financial data related to the two months of this stub period for which it owned the assets in Exhibit 1, Tab 2, Schedule 1.

5. Since acquiring the system assets, ENGLP has completed a fulsome System Integrity Study, developed a Utility System Plan and initiated an asset management program. ENGLP has also initiated implementation of its stakeholder consultation program. Each of these provided guidance as ENGLP developed the proposed capital and OM&A plans and prepared this Application. As an example, in addressing customers' top two most important aspects of service – keeping rates/bills low and service reliability, ENGLP is proposing rates that result in a reduction, or no increase, in the typical bill for customers in Rates 1, 2, 3 and 6. The typical customer in Rate 4 would see an increase of 3.42% and in Rate 5 an increase of 9.59%. ENGLP's proposed capital plan addresses concerns regarding system integrity, which will enable it to eliminate its reliance on locally produced gas used to support system pressure which has historically been purchased at higher prices. The increased use of cross training for its employees, and introduction of advanced SCADA and asset management systems is also expected to increase reliability of the system and continue to ensure the prudency of capital and OM&A expenditures.

6. In addition, starting in late 2017, ENGLP began implementing its shared service model that has enabled the utility to reasonably and prudently take advantage of economies of scale and scope by accessing an experienced core of management and subject matter expert resources and expertise that were previously unavailable to the utility. This expertise includes safety, information technology, engineering, regulatory, treasury, human resources and general management. The 2019 Bridge Year and 2020 Test Year for this Application therefore reflects the proposed cost structure of ENGLP under its new owner. This cost structure is also reflected in the forecast 2018 financials.

7. The capital plan proposed in this Application will allow ENGLP to continue to invest in its infrastructure to add customers, improve service quality, safety and reliability. This includes addressing historical system integrity concerns through undertaking reinforcement projects that are scheduled to be completed in 2019 and introduction of new technologies such as SCADA, GIS and workforce management that equip the utility with the tools necessary to strengthen its ability to operate its system in a safe, reliable and efficient manner.

8. Included in Exhibit 1, Tab 4, Schedule 1 is the Business Plan for ENGLP. In addition to topics fully addressed in other sections of this Application, the Business Plan provides detail as

to the utility's Mission, Vision and Values; its risk appetite objectives, the function and responsibilities of its Board of Directors; customer engagement and its Personnel Plan.

9. Since the last rate case, the customers served by the system have increased over 34% from approximately 7,155 in 2011 to a forecast 9,538 in the 2020 test year. The rate base has increased $2.671 million from $13.685 million in 2011 to a forecast $16.355 million in 2020. Underlying this increase in rate base is a decrease of $0.37 million in the rate base related to the system that supports IGPC, ENGLP's largest customer, from $4.16 million to $3.79 million. The decrease in rate base associated with IGPC is largely driven by an accelerated depreciation rate that allowed those assets to be depreciated over a 20 year period. This has been offset by capital expenditures in 2018 and proposed for 2019. ENGLP is proposing to align a number of the depreciation rates, including those of IGPC, with those of other gas utilities as detailed later in this Application.

10. ENGLP is requesting an increase to its revenue requirement of $1,167,792 over its 2011 Board approved revenue requirement. The revenue requirement of $6,665,600 is a 21.29% increase since 2011 and represents an annual increase of 2.17%. There are a number of drivers for the proposed change, including an increase in rate base, a change in depreciation rates, general inflation of approximately 16%[1], an increase in customers serviced of approximately 34%, and an increase in employee compensation to reflect market rates.

11. Based on current distribution rates and forecasted load, ENGLP is forecasting a 2020 Test Year revenue sufficiency of $352,267. The annual bill impact of the proposed tariff for a typical residential customer is -$5.24 or a 1.11% reduction.

Access to Historical Information

12. As discussed above, ENGLP has access to NRG's audited financial statements in addition to a limited number of more detailed records. However, ENGLP does not have access to extensive detailed historical financial records. In addition, at the November 1, 2017 closing of the asset sale to ENGLP, while 100% of operational individuals accepted positions with ENGLP,

[1] Cumulative of inflation factors for incentive rate setting under price cap IR 2011 – 2020, using 1.5% for 2020.

certain non-operational individuals did not. This included the company's executive, the Vice President of Administration and the Financial Analyst.

13. Access to available financial records, and operational personal, has allowed ENGLP to include the historical cost, capital and revenue information and the necessary comparisons as currently incorporated in this Application. However, lack of access to more detailed financial records, and certain executive/administrative personnel is an impediment to ENGLP's efforts to include explanations for certain variances in the historical information. As noted above, this historical data reflects the operations, capital investment objectives, corporate relationships, financial strength, and cost structure of the previous owner. Therefore, elements of the historical financial data are less indicative of the utility's future performance and ENGLP has included detailed variance and other information in the Application starting in January 2018 to support its proposed 2020 Test Year revenue requirement, OM&A costs and capital forecasts.

1.3 Administration

1.3.1 Primary Contact for Application

14. The Applicant's primary EPCOR contact and address for this Application is as follows:

Bruce Brandell
Director, Commercial Services
EPCOR Utilities Inc.
2000 – 10423 101 Street NW
Edmonton, Alberta T5H 0E8

Telephone: (780) 412-3720
Fax: (780) 441-7118
E-Mail: bbrandell@epcor.com

1.3.2 Legal Representation for Application

15. The Applicant's internal counsel is as follows:

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Associate General Counsel
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16. The Applicant's external counsel is as follows:

Richard King
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Suite 6200, PO Box 50
Toronto, ON M5X 1B8

Telephone: (416) 862-6626
Fax: (416) 862-6666
E-Mail: rking@osler.com

1.3.3 Applicant's Internet and Social Media Addresses

17. EPCOR will make a copy of this Application available at the following internet address https://www.epcor.com/about/news-announcements/notices/Pages/default.aspx. Confirmation that ENGLP has filed an Application and details as to where it can be accessed will also be communicated to customers via. a statement included in customers' bills.

18. ENGLP's general website address is as follows:
https://www.epcor.com/Pages/Home.aspx?mylocation=aylmer_ontario

1.3.4 Customer Email Addresses Retained by Applicant

19. ENGLP has retained approximately 1,645 customer email addresses that may be used to communicate a notice of application. This represents approximately 18.26% of the 9,007 customers forecast to be served by ENGLP year-end 2018. Table 1.3.4-1 below includes a breakdown by customer class.

Table 1.3.4-1
Email Addresses by Customer Class

		A	B	C	D
	Rate Code	**Revenue Class**	**Number of Customers**	**Number of Email Addresses**	**% of Customers**
1	R1	Residential	8,363	1,530	18.29%
2	R1	Commercial	477	97	20.34%
3	R1	Industrial	67	10	14.93%
4	R2	Seasonal	53	3	5.66%
5	R3	Industrial	6	1	16.67%
6	R4	Industrial	36	3	8.33%
7	R5	Industrial	4	0	0.00%
8	R6	IGPC	1	1	100.00%
9	**Total**		**9,007**	**1,645**	18.26%

1.3.5 Date Required for Bill Information

20. In order to provide customers with notice of increases that would be effective January 1, 2020, ENGLP would require bill insert information by December 2, 2019.

1.3.6 Proposed Location for Community Meetings

21. ENGLP is proposing that a community meeting be held at the East Elgin Community Complex. This facility is centrally located at 531 Talbot Street West, Aylmer.

1.3.7 Publication of Notice of Hearing

22. ENGLP proposes that the statement of notice for this application be published in the Aylmer Express. This weekly paper is the major publication in ENGLP's service area.

1.3.8 Bill Impacts

23. The proposed impacts are outlined in the table below. The typical annual impact is a reduction of $5.24 or -1.11% for the typical Residential customers. Approximately 93% of ENGLP customers are in that class. Further details on bill impacts is included in Section 1.5.9 below and Section 8.1 of Exhibit 8, Tab 1, Schedule 1. ENGLP has filed its Rate Model in conjunction with this Application.

Table 1.3.8-1
Annual Bill Impact
($)

	Rate Class	A **Change**
1	Rate 1 - Residential	(5.24)
2	Rate 1 - Commercial	(34.88)
3	Rate 1 - Industrial	(120.82)

1.3.9 Proposals that Constitute a Change in Status Quo or Those that Have a Material Impact

24. All customers in the ENGLP service territory described in Section 1.4 below that receive natural gas distribution services from ENGLP will be affected by this Application. Section 1.5.9 below provides forecast bill impacts related to the proposed changes in the tariff.

1.3.10 Hearing Request

25. ENGLP's preference is for a written hearing in order to expedite the proceeding. At this time ENGLP has made allotments in its budget assuming a written hearing. Should the Board decide to proceed with an oral hearing in this matter, ENGLP will respectfully request to amend the forecast to incorporate the incremental consultant, intervenor, OEB costs and legal fees, as well as travel and other expenses related with attendance at and preparation for an oral hearing.

26. In addition, if the Board determines it will hold an oral hearing ENGLP will provide the names of appropriate witnesses (and their curriculum vitae) prior to such oral hearing.

1.3.11 Proposed Components of Price Cap IR

27. ENGLP is proposing a five-year incentive rate-setting ("IR") plan, covering the period January 1, 2020 through to December 31, 2024. The proposed IR plan includes:

(a) an annual price cap adjustment based on two factors (an inflation factor ("I"), and a productivity factor + stretch factor ("X"));
(b) for Rate 1, the fixed monthly charge would be increased annually by $1.00 and the volumetric charges would be correspondingly adjusted;
(c) a Y-factor for costs associated with specific items that are subject to deferral account treatment and passed through to customers without any Price Cap Adjustment;
(d) an Incremental Capital Module ("ICM") to address the treatment of capital investment needs that arise;
(e) a Z-factor adjustment for unforeseen events outside of ENGLP's management control; and,
(f) a trigger mechanism for a regulatory review in the event of a 300-basis point deviation from the Board approved ROE.

1.3.12 Requested Effective Date

28. ENGLP requests that the Board make its Rate Order effective January 1, 2020. In the event that the OEB is not able to provide a Decision and Rate Order in time for ENGLP to implement its rates effective January 1, 2020, ENGLP requests that the OEB declare ENGLP's current rates interim effective January 1, 2020 and approve rate riders to recover any change between current and approved revenue between the implementation date of the OEB's 2020 Rate Order and January 1, 2020.

1.3.13 Deviation Statements

29. ENGLP has not, to the best of its knowledge, deviated from the Board's Filing Requirements for Natural Gas Rate Applications (February 16, 2017) and Handbook for Utility Rate Applications (October 13, 2016).

1.3.14 Methodology Changes

30. ENGLP has included the following methodology changes in this Application.

(a) Change accounting standard from Accounting Standards for Private Enterprise (ASPE) as used by NRG to modified International Financial Reporting Standards (MIFRS); and,

(b) ENGLP is proposing a number of changes to depreciation rates that would bring the utility's depreciation rates in line with Enbridge rates. In general this has resulted in a reduction in deprecation rates and a reduction of the revenue requirement. The proposed depreciation rates are included in Section 1.5.5 below and discussed further in Section 4.4 of Exhibit 4, Tab 1, Schedule 1.

1.3.15 OEB Directions from Previous Decision or Orders

31. In NRG's last cost-of-service proceeding (EB-2010-0018) the Board included directives as set out below. NRG has indicated it followed up on those directives as also detailed below. ENGLP's ongoing activities directed at addressing its understanding of the intent of the second directive, which is to determine and propose to implement the optimal solution to address system integrity issues, is also detailed below.

1. Directive re: IGPC Maintenance

"[T]he Board directs NRG to first retain the services of an independent expert in the development of maintenance programs for pipelines similar to that employed in the supply of gas to IGPC. That expert will be retained by way of tender, and all of the documentation associated with that tender will be filed with the Board and the intervenors of record. Following the development of a maintenance protocol NRG shall retain the services of an enterprise experienced in the provision of such services by way of tender predicated on the maintenance protocol. All of the documentation associated with the retention of the maintenance firm will be filed with the Board and the intervenors of record."

(EB-2010-0018, *Decision with Reasons*, December 6, 2010, p.12)

32. This Directive was issued in the first phase of EB-2010-0018, and was superseded by the Settlement Agreement in Phase 2 of that proceeding. Section 4.6 of the Settlement Agreement stated that: "For the purposes of obtaining a settlement, the Parties agree that the annual maintenance costs for the pipeline serving IGPC will be set at $56,055. For greater certainty, there will be no pipeline maintenance deferral account to be established for the purposes of any adjustments to these maintenance amounts." (see Settlement Agreement, EB-2010-0018, Phase 2, filed with the Board on November 11, 2011).

> **2. Directive re: System Integrity and Competitive Market**
> *"[T]he Board will require the formation of a steering committee comprised of Board staff, intervenors and NRG that will be responsible for drafting an RFP and terms of reference for an independent study, the findings of which will be presented to the Board. .... The Board expects the study to look at the technical and engineering aspects of NRG's system and arrive at firm conclusions with respect to the amount of system integrity gas that NRG may require under different scenarios, including, but not limited to a single design day. The Board also expects the consultant to review the gas supply available within NRG's franchise area and provide an analysis on whether a competitive market can exist within NRG's franchise area and if so, the mechanics of establishing such a market. This includes identifying other potential suppliers within the area and determining if they can be a viable and reliable supply option. The study could also examine if the Union Gas system could provide any cost effective solutions. The cost of the study will be borne by ratepayers. ... Based on the recommendations of the study, the Board may order NRG to issue an RFP that would solicit alternative suppliers within the NRG franchise area."*
> (EB-2010-0018, *Phase 2 Decision with Reasons*, May 17, 2012, pp. 10 and 11)

33. NRG has indicated that it complied with this directive as follows.

34. The steering committee was formed and included NRG's representatives (initially Bob Cowan, former Co-Chair and Anthony Graat, President), Board Staff (Khalil Viraney) and a representative from VECC (James Wightman). The first meeting of the steering committee

occurred in the fall of 2012, and terms of reference for the work to be done were finalized over the winter of 2012/2013. Finding companies willing to bid for the work proved more difficult than anticipated, but ultimately two RFPs were issued in 2013 (one RFP to retain an independent consultant to carry out the system integrity study, and a second RFP to retain an independent consultant to carry out the competitive market study). Two separate RFPs were issued because initial discussions with engineering firms capable of conducting the system integrity made it clear that these firms were less comfortable conducting a competitive market study. Two consultants were ultimately chosen to carry out the work in the spring of 2014.

35. A draft System Integrity Study ("SIS") prepared by SNC-Lavalin was released in January 2016. NRG's interpretation of the draft SIS was that it confirmed that without NRG Gas Corp. wells producing, additional pipelines would be required to move gas from Union Gas Limited stations to the south of NRG's service territory (see Section 6.3.1 of the SIS). NRG has suggested that the simulations run by SNC-Lavalin demonstrate that NRG's system on peak days requires additional volumes in order to maintain system integrity. The draft SIS prepared by SNC-Lavalin is attached as Exhibit 1, Tab 4, Schedule 2.

36. The Competitive Market Study ("CMS") was completed on December 1, 2014 by Dr. Philip Walsh, P. Geo, of SmithWalsh & Associates and filed under EB-2010-0018 on July 30, 2015. NRG's interpretation at the time of the release of the CMS is that it concluded that there would appear to be sufficient physical natural gas supply from six local natural gas pools other than NRG Corp. that could meet NRG's system integrity needs but that these other suppliers (at that time delivering natural gas into Union Gas Limited's system) were not subject to any firm supply requirement (which is what NRG requires). As noted in the CMS, the lack of any firm commitment to supply gas lowers the financial risk for these other natural gas producers, as well as the price per unit paid to them, which serves as a disincentive to making arrangements to supply NRG. The CMS ultimately concluded that only an RFQ would be able to confirm local natural gas producer interest.

37. As noted in the CMS, some of the officers and directors of the two companies that ultimately own the wells are common (i.e., the two potential suppliers were really the same). In advance of issuing an RFQ to the potential supplier (with respect to all of its wells in the area), NRG indicated that it met with the eligible candidate and provided the candidate with the RFQ document. NRG followed up twice with the eligible candidate (in May and June 2015), and has

indicated that no response had been received. NRG advised the Board of this in a letter dated July 28, 2015. This letter is attached as Exhibit 1, Tab 3, Schedule 2.

38. After ENGLP acquired the system assets of NRG in November, 2017 it conducted a review of the draft SIS and concluded that, while it provided supporting rational for the Springwater Project that addressed integrity issues in the Southwest area of system and increased pressure around Aylmer, it did not sufficiently explore potential solutions that would allow ENGLP to also address integrity issues in other areas of the system. Development of a complete solution is a necessary step in order for the utility to confirm a timeline and prudent capital expenditures that would allow it to exit from the current contract under which the utility purchases a maximum annual quantity of 1.0 million cubic meters of gas from NRG Corp. (recently purchased by On-Energy) at the Board approved price of $8.486 per mcf. As a result, ENGLP commissioned a System Integrity Study by Cornerstone Energy Services that examined a wider range of potential solutions, including the potential for injecting gas at additional locations in the Southern area of the system. A copy of this study is included in Exhibit 2, Tab 3, Schedule 2. As further detailed in the Utility System Plan (Exhibit 2, Tab 3, Schedule 1), ENGLP is proposing a plan that includes a cost effective capital project, including construction of a new custody transfer station that will address integrity issues in the Southern areas of the system.

39. In recognition of the Board's and ENGLP's concern that the utility should be accessing natural gas at the optimal value, ENGLP has been working to confirm the availability of market priced gas. ENGLP has had preliminary discussions with an arm's length third party as to the terms and conditions of a long term supply agreement that is expected to tie the cost of gas to an established reference price such as the Dawn Hub. This gas will be sourced at the Southern part of the system, thereby allowing ENGLP to address outstanding system integrity issues. As further detailed in Section 4.1 of Exhibit 4, Tab 1, Schedule 1, ENGLP will ensure that any supply agreement entered into will meet the requirements of the utility and include market terms and conditions. This new supply agreement is intended to support the above referenced capital expenditure.

1.3.16 Conditions of Service

40. ENGLP is proposing to update the schedule of miscellaneous and service charges as included in its Conditions of Service. A summary of the proposed changes is included in Table 1.3.16-1 below.

Table 1.3.16-1
Proposed Changes to Schedule of Miscellaneous and Service Charges

	Service	A Current Fee (2011)	B Proposed Fee
1	Service Work		
2	During normal working hours		
3	Minimum charge (up to 60 minutes)	$90.00	$100.00
4	Each additional hour (or part thereof)	$90.00	$100.00
5	Outside normal working hours		
6	Minimum charge (up to 60 minutes)	$115.00	$130.00
7	Each additional hour (or part thereof)	$95.00	$105.00
8	Miscellaneous Charges		
9	Returned Cheque / Payment	$20.00	$48.00
10	Replies to a request for account information	$20.00	$25.00
11	Bill Reprint / Statement Print Requests		$20.00
12	Consumption Summary Requests		$20.00
13	Customer Transfer / Connection Charge	$30.00	$35.00
14	Disconnection and Reconnection Charge	$78.00	$85.00
15	Inactive Account Charge		ENGLP cost to install service
16	Late Payment Charge	1.5% /month, 19.56% /year (effective rate of 0.04896% compounded daily)	1.5% / month, 19.56% / year (effective rate of 0.04896% compounded daily)
17	Meter Tested at Customer Request Found to be Accurate	Charge based on actual costs	Charge based on actual costs
18	Installation of Service Lateral	$100 first 20 meters. $10/meter thereafter	$100 (minimum). Additional if pipe length exceeds length used to set fee.

41. ENGLP is proposing to update its Conditions of Service, which were last filed as part of EB-2010-0018. The proposed new Conditions of Service are attached as Exhibit 8, Tab 3, Schedule 2. The existing Conditions of Service are attached as Exhibit 8, Tab 3, Schedule 1 and can be accessed at the Aylmer administrative office or online.[2]

42. In addition to the above proposed changes in service and miscellaneous charges, the proposed new Conditions of Service:

(a) adjust formatting, layout and wording for additional clarity and consistency;

[2] https://www.epcor.com/products-services/natural-gas/Documents/aylmer-customer-service-policy.pdf

(b) references where information can be found on EPCOR's website; and
(c) addresses additional sections not covered in the current document, including as detailed below.

43. Substantive updates from the last approved Conditions of Service are as detailed below:

44. General updates:

(a) Removal of all terms, forms and charges related to NRG's hot water tank rental business which was disposed of in 2015, prior to the sale of the distribution system assets to ENGLP.
(b) Addition of service terms for eligible low-income customers.
(c) Addition of sections, as required per the Gas Distribution Access Rule ("GDAR"), on the allocation of payment between gas and non-gas charges, arrears management programs, management of customer accounts and privacy, and the customer service and complaints process.
(d) Modification to customer forms to reflect changes to input sections, add ENGLP reference, and align terms and conditions wording with the Conditions of Service.
(e) Addition of clarity for:
    (i) the criteria used to review economic feasibility of a main
    (ii) when a service line would be installed
    (iii) meter locations and protection of a meter with the associated customers' responsibilities
(f) Clarity for timing of bill due date and disconnection notice to align with the notice period for customers as proposed in OEB's EB-2017-0183 Review of Customer Service Rules for Utilities.
(g) Additional detail for gas meter testing process and notification steps with the customer.
(h) Additional clarity in description of :
    (i) alterations or service relocations
    (ii) rate schedules
    (iii) resale prohibited
    (iv) delivery and use of gas
    (v) gas distribution services and supply interruptions
    (vi) setting up an account

(vii) meter reads and access to meter
(viii) management of landlord/tenant accounts

45. Security deposits:

(a) Removal of the credit check for security deposit for residential customers.
(b) Adjustment of interest on security deposits calculated and paid out monthly rather than annually.
(c) Addition of provisions allowing security deposits to be paid over a period of up to 6 months.
(d) Modification to include the provision to allow ENGLP to require a security deposit of 2.5 times the highest monthly consumption for customers that have been disconnected for non-payment in the most recent 12 months.
(e) Modification to the threshold for good payment history to one disconnection notice or payment returned for insufficient funds to be consistent with other gas utilities in Ontario.

46. Billing and payment options:

(a) Additional clarity to budget billing plan description and plan calculation adjustment methodology and timing.
(b) Adjustment of the date at which late payment charges apply on overdue accounts to after 20 days from 16 days from the billing date.
(c) Addition to reflect option of payment by automatic withdrawal which is already in place.
(d) Addition of electronic billing and online payment options which are expected to be implemented by 2020.
(e) Adjustment to the timeline for billing corrections for under-billing to be the same as for overbilling (up to 2 years for residential and 6 years for all other customers).
(f) Adjustment to the disconnection notice period from 12 to 14 days' notice to align with the OEB's proposed Customer Service Rule recommendations EB-2017-0183.

47. Within the proposed Conditions of Service, reference is made to electronic billing and online payment options. The functionality of the billing system required for these options has not yet been implemented. This functionality is expected to be in place by 2020. As such, ENGLP has proposed language regarding this functionality in its Conditions of Service. In the event the functionality is not in place for January 1, 2020, commencement date of the revised Conditions of Service, ENGLP is requesting approval to remove and re-insert the language once the online functionality is established.

1.3.17 Conditions of Service Confirmation

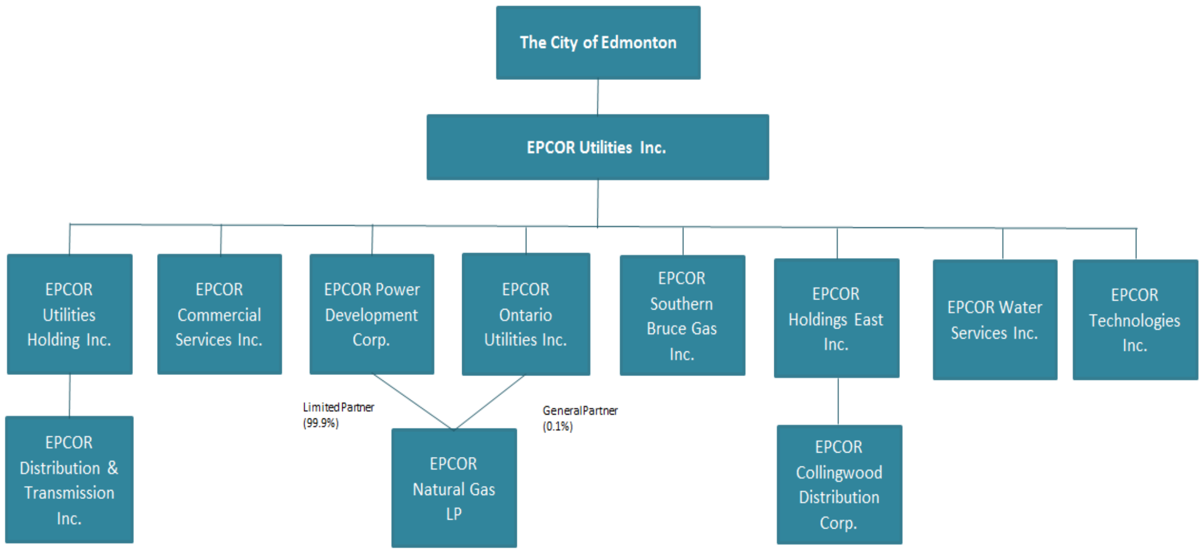
48. ENGLP confirms that there are no rates or charges listed in the Conditions of Service or other policies and regulations that are not included in ENGLP's rate schedules.

1.3.18 Organizational Structure

49. On November 7th, 2016, NRG and ENGLP entered into an Asset Purchase Agreement whereby NRG agreed to sell and ENGLP agreed to purchase NRG's natural gas distribution system. The Asset Purchase Agreement transferred to ENGLP all of the property and assets needed to operate the gas distribution system currently owned and operated by NRG. ENGLP's acquisition of the natural gas distribution assets of NRG received regulatory approval from the Ontario Energy Board in August 2017 (EB-2016-0351) and ENGLP acquired the assets from NRG on November 1st, 2017.

50. ENGLP is an Ontario limited partnership and is a wholly owned indirect subsidiary of EPCOR Utilities Inc. ("EPCOR"). The general partner of ENGLP is EPCOR Ontario Utilities Inc. and the sole limited partner is EPCOR Power Development Corporation, which are both subsidiaries of EPCOR. ENGLP was formed pursuant to a limited partnership agreement which provides that EPCOR Ontario Utilities Inc., as general partner, will control and have the full and exclusive power, authority and responsibility for the management and day-to-day operations of ENGLP. In accordance with the limited partnership agreement, EPCOR Power Development Corporation, as limited partner, has an economic interest in the partnership but will not control or otherwise play a role in the day-to-day operations and management of ENGLP. Figure 1.3.18-1 below is a simplified EPCOR organizational chart.

Figure 1.3.18-1
Simplified EPCOR Organisational Chart



51. The General Manager of ENGLP reports to the Vice President of Ontario Operations. Currently, there are 17 employees that report to the General Manager. ENGLP employees fit within the categories of System Technicians, Field Technicians (Emergency Coordinators), Construction Technicians (Pipeline Inspector and Gas Technicians), Sales/Business Development and Administration (Billing, Collections, Service Dispatch, Reception and Data-Entry). Further, ENGLP also relies on third party consultants and contractors for the maintenance of the distribution system and assistance with meeting regulatory requirements.

As a member of the EPCOR group of corporations, one of the advantages for ENGLP is that it can access and leverage expertise across EPCOR's entities through a shared services model. ENGLP has structured its business operations to reasonably and prudently take advantage of economies of scale and scope through the appropriate use of corporate and affiliate services. As such, ENGLP receives certain shared services from and is expected to provide certain services to, other members of the EPCOR group.

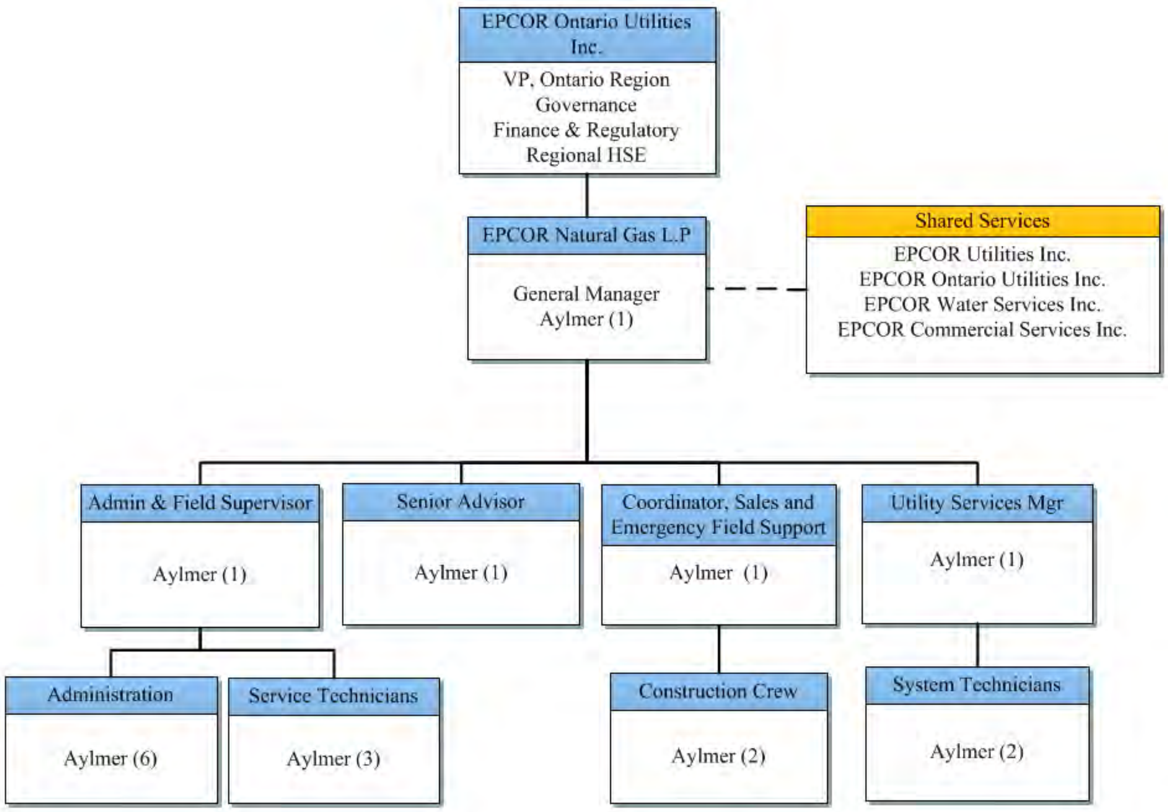
52. ENGLP receives shared services from its parent EPCOR Utilities Inc. (Corporate Shared Services) and EPCOR affiliates: EPCOR Water Services Inc., EPCOR Commercial Services Inc. and EPCOR Utilities Ontario Inc. The intent is that ENGLP (Aylmer) will provide certain services to ENGLP (Southern Bruce) when that business unit has received all the necessary

regulatory approvals. The services that ENGLP receives are governed through Service Level Agreements (SLA) between ENGLP and each EPCOR entity. ENGLP only receives and only pays for the services it requires to operate its utility. The delivery of these services using the shared services model approach achieves economies of scale benefits and cost efficiencies for ENGLP.

53. On November 29, 2018 ENGLP received approval (EB-2018-0247) to transfer certain Certificates of Public Convenience and Necessity ("CPCN") to ENGLP. These CPCNs are related to ENGLP's Southern Bruce activities. ENGLP has also filed a leave to construct (EB-2018-0263) and Rate application (EB-2018-0264) for the Southern Bruce gas utility. These applications have been placed in abeyance subject to confirmation of funding for the utility. On December 21, 2018 ENGLP received confirmation that the Southern Bruce expansion project is eligible for rate protection as available through Bill 32. Subject to receiving OEB approval and other factors, ENGLP intends to initiate construction on the utility's system in 2019. ENGLP will have separate business units for the former NRG gas distribution system (ENGLP Aylmer) that is the subject of this Application and the Southern Bruce system (ENGLP Southern Bruce). These two utilities will operate as separate business units, with separate accounting, reporting and financials. In addition, these two gas distribution systems will operate under separate rate tariffs. Any sharing of resources between these two utilities will be governed by SLAs, the financial impact of which has been identified throughout this Application. Unless otherwise indicated, any reference in this Application to ENGLP is related to the utility which is the subject of this Application, namely the Aylmer operation.

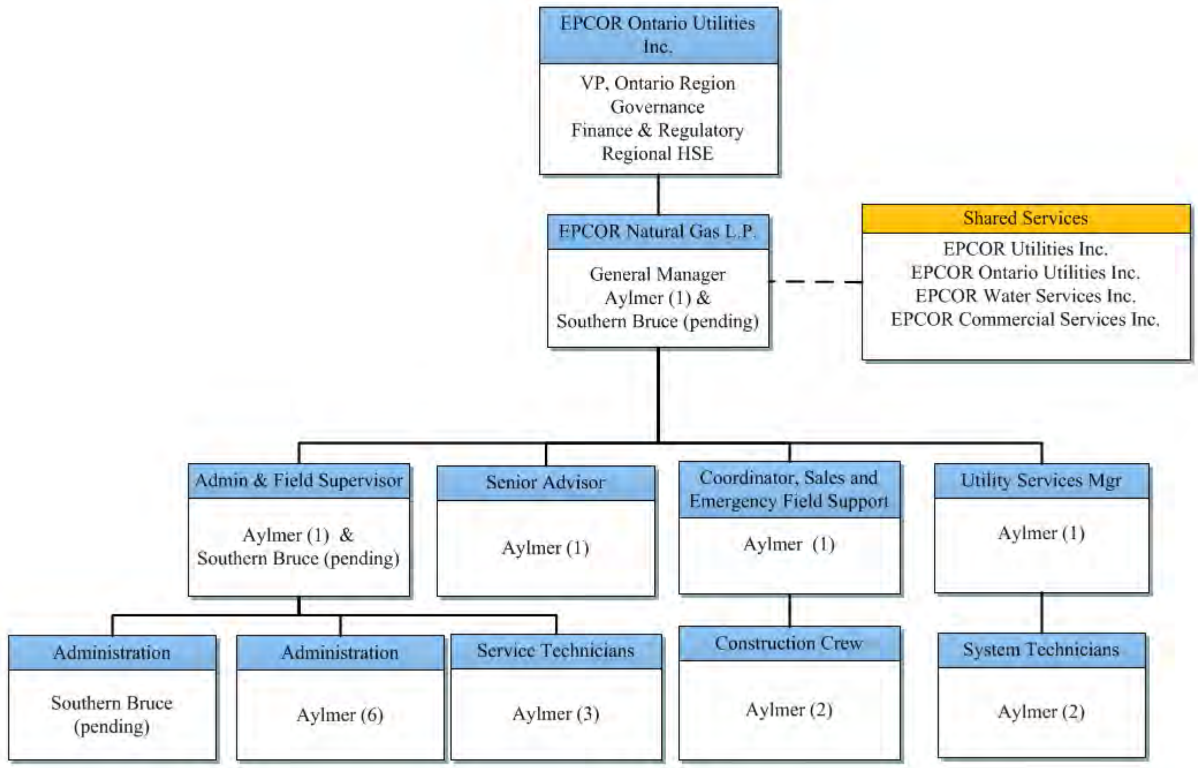
54. Figure 1.3.18-2 below details the organizational chart for the ENGLP business unit and the shared services it is accessing at this time.

Figure 1.3.18-2
ENGLP Organizational Chart



55. Figure 1.3.18-3 below details the organizational chart for the ENGLP business unit and the shared services it will be accessing in 2020. This chart includes the sharing of two positions (General Manger and Admin & Field Supervisor) with the Southern Bruce operation. The costs detailed in this Application include the charging of these costs to the Southern Bruce utility through offsets in OM&A. The Administrative (Southern Bruce) position reporting to the Admin & Field Supervisor will be a new full time Southern Bruce employee funded by the Southern Bruce utility and is expected to be located in Kincardine.

Figure 1.3.18-3
ENGLP (2020) Organizational Chart With Shared Positions



1.3.19 Requested Approvals and Accounting Orders

56. ENGLP applies for an Order or Orders of the Board, issued pursuant to Section 36 of the *OEB Act* approving:

(a) ENGLP's forecasted 2020 Test Year revenue requirement of $6,652,600;

(b) ENGLP's proposed 2020 Test Year distribution rates, to address a $352,267 revenue delivery related revenue sufficiency;

(c) ENGLP's proposed five-year incentive rate-setting ("IR") plan (covering the period through December 31, 2024), which IR plan includes:

   (i) an annual price cap adjustment based on two factors (an inflation factor ("I"), and a productivity factor + stretch factor ("X"));

   (ii) for Rate 1, the fixed monthly charge would be increased annually by $1.00 and the volumetric charges would be correspondingly adjusted to achieve a total projected revenue for Rate 1 equivalent to the prior year OEB approved revenue for Rate 1 increased by the Price Cap Adjustment;

(iii) a Y-factor for costs associated with specific items that are subject to deferral account treatment and passed through to customers without any Price Cap Adjustment;

(iv) an Incremental Capital Module ("ICM") to address the treatment of capital investment needs that arise;

(v) a Z-factor adjustment for unforeseen events outside of ENGLP's management control; and,

(vi) a trigger mechanism for a regulatory review in the event of a 300-basis point deviation from the Board approved ROE.

.

(d) the continuation of the following deferral and variance accounts:

(i) Purchased Gas Commodity Variance Account ("PGCVA");

(ii) Gas Purchase Rebalancing Account ("GPRA");

(iii) Purchased Gas Transportation Variance Account 1 - 5 ("PGTVA 1 - 5");

(iv) Regulatory Expense Deferral Account ("REDA");

(v) Transportation Service Charge Deferral Account ("TSCDA");

(vi) Greenhouse Gas Emissions Compliance Obligation – Customer-Related Deferral Account ("GGECRDA");

(vii) Greenhouse Gas Emissions Compliance Obligation – Facility-Related Deferral Account ("GGEFRDA"); and,

(viii) Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA").

(e) ENGLP is proposing the disposition of the following deferral and variance account balances:

(i) PGTVA 1 – 5 - The total projected disposition amount is a debit balance of $42,649 which ENGLP is proposing to recover from the customers in Rate Classes 1-5 through the implementation of a twelve-month volumetric rate rider commencing on January 1, 2020 of $0.001498/m^3;

(ii) Purchased Gas Transportation Variance Account 6 ("PGTVA 6") - The total estimated disposition amount is a debit balance of $184,821 which ENGLP is proposing to recover from the customer in Rate Class 6 through the implementation of a twelve-month fixed-rate rate rider commencing on January 1, 2020. The estimated fixed-rate monthly rate rider is $15,401.75; and,

(iii) REDA account balances - The REDA balances are proposed to be recovered through the implementation of a twelve-month fixed-rate rate rider commencing on January 1, 2020. The total estimated disposition amount is a debit balance of $31,218. The estimated fixed-rate monthly rate rider is $0.27 for Rates 1 – 5 and $0.25 for Rate 6.

(f) ENGLP is proposing the following deferral and variance accounts be closed and discontinued from use:
(i) PGTVA 6;
(ii) IFRS Conversion Cost Deferral Account ("IFRSDA"); and,
(iii) 2019 Rebalancing Deferral Account.

(g) ENGLP is proposing the following deferral and variance accounts be established and the associated draft accounting orders be approved:
(i) Unaccounted for Gas Variance Account ("UFGVA");
(ii) Loss on Disposition of Meters Deferral Account ("LDMDA"); and,
(iii) Recovery of Income Taxes Deferral Account ("RITDA").

(h) New fixed monthly charges as follows:
(i) Rate 1 increase from $15.50 to $17.00;
(ii) Rate 2 increase from $17.25 to $20.00;
(iii) Rate 3 increase from $172.50 to $190.00; and,
(iv) Rate 5 increase from $172.50 to $190.00.

(i) a new Schedule of Service Charges;

(j) for natural gas purchased by ENGLP from On-Energy Corp. (previously NRG Corp.), the recovery from system gas customers of a maximum annual quantity of 1.0 million m^3 of natural gas at a rate of $8.486 per Mcf. This rate and volume would be authorized until September 30, 2020. At that time, as a result of proposed capital improvements and new gas supply contracts, ENGLP does not anticipate the requirement to acquire gas for system integrity purposes at this rate;

(k) approval to use the Dawn reference price, in place of the Landed Reference Price which Union Gas ceased calculating effective January 1, 2017, to determine the cost of gas purchases in excess of 1.0 million cubic meters from NRG Corp. (and its successor On-Energy Corp.) for the period January 1, 2017 to the end of the term of the Gas Supply Agreement (September 30, 2020) and requests that the QRAM pricing that became interim as of January 1, 2017 as a result of the replacement reference price be made final; and,

(l) a change to a number of ENGLP's depreciation rates as detailed in 1.5.5 below and Section 4.4 of Exhibit 4, Tab 1, Schedule 1.

1.3.20 Draft Issues List

57. ENGLP is proposing the following Issues List for this proceeding:

Issue 1 Administration

(a) Has ENGLP complied with the OEB Directives issued in the utility's last cost of service proceeding (EB-2010-0018)?

(b) Are the proposed changes to ENGLP's Conditions of Service appropriate?

Issue 2 Rate Base

(a) Were amounts closed (or proposed to be closed) to rate base since the utility's last rate proceeding prudently incurred?

(b) Is the forecast level of capital spending in the 2019 Bridge Year and 2020 Test Year appropriate?

(c) Is the amount proposed for rate base in the 2020 Test Year appropriate?

(d) Is the working capital allowance for the 2020 Test Year appropriate?

Issue 3 Operating Revenue

(a) Are the customer addition forecasts for the 2019 Bridge Year and 2020 Test Year appropriate?

(b) Are the volume throughput and revenue forecasts for the 2019 Bridge Year and 2020 Test Year appropriate?

Issue 4 Operating Costs

(a) Are the operations, maintenance and administration (OM&A) cost forecasts for the 2020 Test Year appropriate?
(b) Are the IGPC Operating Support Costs for the 2020 Test Year appropriate?
(c) Are the depreciation costs for the 2020 Test Year appropriate?
(d) Is the property tax forecast for the 2020 Test Year appropriate?
(e) Is the income tax forecast for the 2020 Test Year appropriate?
(f) Is ENGLP's Gas Supply Plan, including the proposal for gas purchases from On-Energy Corp. appropriate?
(g) Is the gas transportation cost forecast for the 2020 Test Year appropriate?

Issue 5 Deferral and Variance Accounts

(a) Is ENGLP's proposal to establish an Unaccounted for Gas Variance Account ("UFGVA"), Loss on Disposition of Meters Deferral Account ("LDMDA"), and a Recovery of Income Taxes Deferral Account ("RITDA") appropriate?
(b) Is ENGLP's proposal to continue certain existing deferral and variance accounts appropriate?
(c) Are ENGLP's proposals for clearing certain deferral and variance accounts appropriate?
(d) Are ENGLP's proposals close and discontinue certain deferral and variance accounts appropriate?

Issue 6 Cost of Capital

(a) Is ENGLP's proposed capital structure of 60% debt (56% long-term and 4% short-term) and 40% equity appropriate?
(b) Is ENGLP's adoption of the Board-approved ROE appropriate?
(c) Is ENGLP's proposed cost of long-term debt for the 2020 Test Year appropriate?
(d) Is ENGLP's cost of capital for the 2020 Test Year appropriate?

Issue 7 Cost Allocation and Rate Design

(a) Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?
(b) Are the proposed rates appropriate?
(c) Are the proposed changes to ENGLP's Schedule of Service Charges appropriate?

Issue 8 Incentive Regulation Plan

(a) Is ENGLP's proposed five year Incentive Regulation ("IR") Plan appropriate?

Issue 9 Score Card

(a) Is ENGLP's proposed Score Card appropriate?

1.4 System Overview

58. ENGLP distributes natural gas to customers in and around Aylmer, Ontario, with its service area stretching from south of Highway 401 to the shores of Lake Erie, from Port Bruce in the west to Clear Creek in the east. It provides natural gas service to customers in Townships of Malahide and South-West Oxford; Municipalities of Bayham, Thames Centre and Central Elgin; and Norfolk County. The system serves the individual communities of Aylmer, Belmont, Brownsville, Port Burwell, Springfield, Straffordville, and Vienna. A map of the system is shown in Exhibit 1, Tab 3, Schedule 3.

59. ENGLP holds franchises for areas south-east of London which includes the towns of Aylmer, Belmont, Brownsville, Port Burwell, Springfield, Straffordville, and Vienna. A map showing ENGLP's franchise areas is attached in Exhibit 1, Tab 3, Schedule 4.

60. Gas is supplied into the ENGLP System from Enbridge Gas Inc. (Enbridge Gas) at 7 different locations: Belmont Station, Harrietsville Station, Brownsville Station, Bayham Station, Eden Station, and North Walsingham Station. Gas is also supplied from gas wells in the ENGLP system franchise area.

61. The gas demands in the ENGLP System are mainly for residential and commercial heating, small industrial users, and grain drying. The residential and commercial heating demand occurs during the winter months, the small industrial users include heating which means that they peak in the winter, while the grain drying demand usually occurs in autumn or winter, but can occur at any time. Additionally, a 30 km dedicated 6 inch steel pipeline operating at a higher pressure feeds the largest industrial customer, IGPC. A pressure regulating and metering station is located on the downstream end of this pipeline.

1.4.1 Economic Overview

62. The Town of Aylmer is a vibrant community located in Southwestern Ontario close to the city of London. The community is strategically located with ready access to the 400 series highways, Buffalo and Detroit borders, and the major airports in London and Toronto.

63. The town is home to a busy commercial district and diverse industrial area, serving approximately 7,500 residents and a trade area of approximately 18,000 people.

64. The Town of Aylmer is home to a number of different businesses and industries primarily including green technology such as ethanol production, food processing, composites and advanced manufacturing. The Ontario Police College is also located within the service area. The unemployment rate as of November 2017 was 9.1% which saw an average rate of decline of 3.9% from 2011 to 2016. Declines in unemployment rates reflect positive economic conditions in the community, as more people are finding jobs and businesses are likely thriving.

1.5 Application Summary

65. Following is a summary of the material elements of ENGLP's Application. Further details are available in Exhibits 2 – 10 following this exhibit.

1.5.1 Revenue Requirement

66. ENGLP is proposing a revenue requirement for the 2020 Test Year of $6,652,600. The revenue requirement reflects an increase of $1,167,792 or 21.29% from the $5,484,808 approved in 2011 (EB-2010-0018). This represents an annual increase of approximately 2.17%.

67. Table 1.5.1-1 below highlights the main drivers of revenue requirement and the change from the previous cost of service application.

Table 1.5.1-1
Summary of Changes in Revenue
($)

	Driver	A 2011 Board Approved	B 2020 Test Year	C Variance	D % Change
1	Transportation Cost	732,360	675,544	(56,816)	(7.76)%
2	OM&A	2,629,207	3,359,102	729,895	27.76%
3	Depreciation	1,171,585	1,136,086	(35,499)	(3.03)%
4	Property Taxes	400,776	632,000	231,224	57.69%
5	Income Taxes	256,437	4,536	(251,901)	(98.23)%
6	Cost of Capital	1,146,310	958,244	(188,066)	(16.41)%
7	Other Revenue	(851,867)	(112,913)	738,954	(86.75)%
8	**Revenue Requirement**	**5,484,808**	**6,652,600**	**1,167,792**	**21.29%**

68. The increase is driven by an increase of $729,895 in OM&A costs which reflect general inflation of approximatly16%[3], an increase in customers serviced of approximately 34%, and an increase in compensation to reflect market rates. The increase in depreciation is driven by an increase in the proposed rate base of $2,670.7 thousand and partially offset by ENGLP's proposal to change deprecation rates. The decrease in income taxes reflects that ENGLP is forecasting to pay substantially lower cash taxes in 2020. The increase in property taxes is understood to be driven by an increase in the length of pipe in the ground as well as an increase in the property tax rate. The decrease in cost of capital is driven by the reduction in OEB approved RoE from the 9.85% approved in the last rates application to a forecast 8.98% and the cost of long term debt from 7.67% to 3.85%. This is offset by the increase in short term debt from 2.07% to 2.82% and the above referenced increase in the proposed rate base. The reduction in Other Revenue is driven by the divestiture of the water heater business by NRG in 2015.

69. ENGLP has determined that the revenue sufficiency for the 2020 Test Year is $352,267. As detailed in Table 1.5.1-2, the major drivers for the revenue sufficiency include depreciation and income taxes. The reduction in depreciation expense is largely driven by ENGLP's proposal to reduce depreciation rates to reflect those used by gas utilities in Ontario. The reduction in

[3] Cumulative of inflation factors for incentive rate setting under price cap IR 2011 – 2020, using 1.5% for 2020.

income taxes is the result of lower revenues due to the proposal to decrease rates combined with taxable deductions (e.g., CCA).

Table 1.5.1-2
Cost Drivers of Revenue Sufficiency
($)

	Description	A 2020 Revenue at Existing Rates	B 2020 Proposed Revenue Requirement	C Variance
1	Transportation Costs	700,200	675,544	(24,656)
2	Distribution OM&A	3,360,306	3,359,102	(1,203)
3	Depreciation and Amortization	1,334,155	1,136,086	(198,069)
4	Property Taxes	627,917	632,000	4,083
5	Income Taxes	157,265	4,536	(152,729)
6	Return on Rate Base	942,214	958,244	16,030
7	Other Revenue	(117,190)	(112,913)	4,277
8	**Total**	**7,004,867**	**6,652,600**	**(352,267)**

1.5.2 Budgeting and Accounting Assumptions

70. The inflation forecasts used in this Application are as detailed in Table 1.5.2-1 below. Section 1.5.5 and Section 4.3.1 of Exhibit 4, Tab 1, Schedule 1 provide details regarding the source of these values.

Table 1.5.2-1
Inflation Forecasts

	Expense Category	A 2019 Bridge Year	B 2020 Test Year
1	Management Salary	0.0%	2.8%
2	Non-Management Salary	0.0%	2.8%
3	Contractors	2.3%	2.7%
4	Materials	2.4%	2.2%
5	Other	2.3%	2.1%

71. Customer counts in 2020 are forecast by applying the geometric mean annual growth rate from 2009 to 2018 to the 2018 average customer count. Additional information is contained in Weather Normalized Distribution System Load Forecast: 2020 Cost of Service report included as Exhibit 3, Tab 2, Schedule 1.

72. In the previous rate filing, and subsequent filings of financial information by NRG, the Canadian Accounting Standards for Private Enterprises (ASPE) standard was used. The accounting standard used for ENGLP's general purpose statements is IFRS. ENGLP's ultimate parent, EUI, adopted this standard in 2011. Upon acquisition of the assets of the utility on November 1, 2017, ENGLP prepared and reported results to the OEB under Modified International Financial Reporting Standards (MIFRS). The basis of accounting for the preparation of this rate application is MIFRS. In the transition from ASPE to MIFRS for reporting to the OEB, there were no impacts to the revenue requirement or overall application as MIFRS requires the tracking of deferral accounts and recognition of rate base assets at net book value.

73. ENGLP's accounting policies are discussed in Exhibit 2 and include the following:

- Capitalization policy – This policy functions as a guide in respect of what should be recognized as a tangible asset or intangible asset other than goodwill. The intent is to ensure that the fixed assets are properly reported in the financial statements in accordance with International Financial Reporting Standards (IFRS). See Exhibit, Tab 2, Schedule 1.

- Capitalization for Regulatory Accounting Purposes - The capitalization policy functions as a guide in respect of what should be recognized as a tangible asset or intangible asset other than goodwill for regulatory accounting and reporting. The intent is to ensure that fixed assets are properly reported in accordance with applicable regulatory accounting pronouncements. See Exhibit, Tab 2, Schedule 2.

- Capital Overhead Policy - The purpose of this policy is to identify the types of overhead costs that can be capitalized in the course of acquiring or constructing an item of property, plant and equipment (PP&E) in accordance with International Financial Reporting Standards (IFRS). See Exhibit, Tab 2, Schedule 3.

- Project Development Costs Policy (including preliminary feasibility research, site inspections, permitting, etc.) – The intent is to properly classify such costs as either an asset or an expense, given the nature and tenure of the particular project. See Exhibit, Tab 2, Schedule 4.

74. ENGLP is unaware of any written accounting policies that NRG may have applied during the period that the utility was owned by that entity. To the extent reasonable, ENGLP has reviewed the historical records of the utility and is of the view that implementation of ENGLP's accounting policies will not have a material impact on the revenue requirements of the utility.

1.5.3 Throughput Forecast

75. The OEB last approved volumes for ENGLP in the utility's most recent IRM application (EB-2018-0235). ENGLP included updated volumes in the IRM application as the previous OEB approved volumes were as in the 2011 Test Year of its last Rates Application (EB-2010-0018). Volumes for its most recent IRM application were the most recent actual values available at the time (October 2016 to September, 2017). These volumes had increased by 14.0% not including Rate 6 volumes (38.4% including Rate 6 volumes) from those approved in EB-2010-0018. Further details regarding throughput volumes are included in Table 1.5.3-1 below and Section 3.2 of Exhibit 3, Tab 1, Schedule 1.

Table 1.5.3-1
Change in Volume Throughput

		A	B	C	D
		OEB Approved Jan - Dec	**Test Jan - Dec**	**Change**	
	Rate Year Year	**2011**	**2020**	**Volume**	**Percent**
1	Rate 1 - Residential	14,699,145	17,043,677	2,344,532	16.0%
2	Rate 1 - Commercial	4,326,736	4,851,704	524,968	12.1%
3	Rate 1 - Industrial	1,544,914	1,743,215	198,301	12.8%
4	Rate 2	1,454,147	1,280,413	(173,734)	(11.9)%
5	Rate 3	1,485,572	1,721,684	236,112	15.9%
6	Rate 4	912,931	1,149,006	236,075	25.9%
7	Rate 5	553,894	685,748	131,854	23.8%
8	**Total (Excluding Rate 6)**	**24,977,339**	**28,475,447**	**3,498,108**	**14.0%**
9	Rate 6	38,423,518	59,243,876	20,820,358	54.2%
10	**Total**	**63,400,857**	**87,719,322**	**24,318,466**	**38.4%**

76. The forecasted change in customer count from 2011 is detailed below in Tables 1.5.3-2 and 1.5.3-3. The total year end customers have increased 34.98% from 2011. The total mid-year number of customers has increased by 34.16% from 2011.

Table 1.5.3-2
ENGLP Customer Counts (Year End)

	Rate Year Year	A 2011	B 2020	C Change Connections	D Percent
1	Rate 1 - Residential	6,625	9,011	2,386	36.02%
2	Rate 1 - Commercial	401	498	97	24.28%
3	Rate 1 - Industrial	43	69	26	59.69%
4	Rate 2	68	49	(19)	(27.56)%
5	Rate 3	4	6	2	50.00%
6	Rate 4	22	38	16	74.60%
7	Rate 5	5	4	(1)	(22.91)%
8	Rate 6	1	1	0	0.00%
10	**Total**	**7,169**	**9,677**	**2,508**	**34.98%**

Table 1.5.3-3
ENGLP Customer Counts (Mid-Year)

	Rate Year Year	A 2011	B 2020	C Change Connections	D Percent
1	Rate 1 - Residential	6,568	8,877	2,309	35.16%
2	Rate 1 - Commercial	404	494	90	22.25%
3	Rate 1 - Industrial	41	68	27	65.52%
4	Rate 2	64	50	(14)	(21.77)%
5	Rate 3	4	6	2	50.00%
6	Rate 4	23	38	15	67.03%
7	Rate 5	5	4	(1)	(20.00)%
8	Rate 6	1	1	0	0.00%
10	**Total**	**7,110**	**9,538**	**2,428**	**34.16%**

77. The methodology used to forecast throughput is largely consistent with the methodology used by NRG in previous rates applications, most recently approved in EB-2010-0018. The regression equations used to normalize and forecast ENGLP's weather sensitive load use monthly heating degree days as measured at Environment Canada's London CS weather station to take into account temperature sensitivity. This location is the closest weather station to ENGLP's service territory with strong historical weather data. ENGLP experiences peak loads in winter months, though certain rate classes are not weather sensitive. In addition to the weather, economic variables, a time trend variable, number of days and number of working days in each month, number of customers, and month of year variables, have been examined for weather sensitive rate classes. For further information regarding the forecasting methods used, see the Weather Normalized Distribution System Load Forecast: 2020 Cost of Service report. A copy is provided as Exhibit 3, Tab 2, Schedule 1.

1.5.4 Rate Base and Utility System Plan

78. ENGLP is requesting a rate base of $16,355.8 thousand for the 2020 Test Year. This represents an increase of $2,670.7 thousand from the $13,685.0 thousand approved rate base in the previous rate application. The following Table details the derivation of respective rate bases.

Table 1.5.4-1
Summary of Changes in Rate Base
($ thousands)

		A	B	C	D
	Driver	**2011 Board Approved**	**2020 Test Year**	**Variance**	**% Change**
1	Net Fixed Asset	13,564.4	16,355.8	2,791.3	20.58%
2	Working Capital and other adjustments to rate base.	120.6	0.0	(120.6)	(100.00)%
3	**Rate Base**	13,685.0	16,355.8	2,670.7	19.52%

79. ENGLP is proposing a capital plan for the 2020 Test Year of $1,340.0 thousand. This is a $732.7 thousand increase from the $607.3 thousand capital plan approved for 2011 in the previous rate case. Proposed Expenditures by type, including System Access, System Renewal, System Service and General Plant are as in Table 1.5.4-2 below. The Utility System Plan described in Section 2.6 of Exhibit 2, Tab 1, Schedule 1 provides additional details on ENGLP's proposed capital plan.

Table 1.5.4-2
Proposed 2020 Test Year Capital Expenditures and 2011 Board Approved
($ thousands)

		A	B	C	D
		2011 Board Approved	**2020 Test Year**	**Change**	
	Category			**$**	**Percent**
1	System Access	322.5	450.6	128.1	39.7%
2	System Renewal	114.0	490.4	376.4	330.2%
3	System Service	-	269.0	269.0	100.0%
4	General Plant	373.5	130.0	(243.5)	(65.2)%
5	**Total**	**810.0**	**1,340.0**	**530.0**	**65.4%**

80. In developing its Utility System Plan ENGLP's asset management activities in the first year of ownership have included gaining a better understanding of the current system constraints and seeking solutions to address these. In May 2018, ENGLP contracted Cornerstone Energy

Services ("Cornerstone") to complete an engineering study to review the distribution system and identify system constraints that are likely to lead to unacceptable low pressure conditions through to 2024. Options to addresses the system constraints were then identified, evaluated and the most prudent included in the proposed capital budget plan.

81. ENGLP then reviewed the five year outlook for the system. This determined that the utility expects to continue expanding services within its existing franchise areas over the next five-year period of operations. In particular, this expansion is likely to occur south of Aylmer within the north shore Lake Erie region and also in the southwest Oxford area. Further growth in residential customers can also be anticipated in Belmont, which serves as a bedroom community for London, Ontario. ENGLP then determined that certain System Service investments were required to improve reliability, mitigate risk or introduce efficiencies. These included implementation of SCADA and GIS systems. These activities supported the following capital budget.

Table 1.5.4-3
ENGLP Planned Capital Budget
($ thousands)

		A	B	C	D	E	F	G
	Category	**2018 F -2**	**2019 Bridge Year**	**2020 Test Year**	**2021 F 2**	**2022 F 3**	**2023 F 4**	**2024 F 5**
1	System Access	1,433	1,181	451	451	461	468	479
2	System Renewal	510	502	490	501	512	520	532
3	System Service	149	1,275	269	187	190	194	198
4	General Plant	168	453	130	319	76	78	79
5	**Total**	**2,261**	**3,410**	**1,340**	**1,457**	**1,239**	**1,261**	**1,288**

1.5.5 Operations, Maintenance and Administration (OM&A) Expense

82. ENGLP is proposing an OM&A cost for the 2020 Test Year of $3,359,102. This is an increase of $729,894 from the 2011 Board approved cost of $2,629,208. This represents an increase of 27.8%. Total compensation costs have increased from $1,260,853 to $1,781,170. This represents an increase of $520,317 or 41.3%. Offsetting the increase in total compensation is an increase in transfers to capital. Transfers to capital increased from $41,796 to $349,047. ENGLP does not have access to the detailed records necessary to provide explanations as to overall drivers of OM&A costs between the 2011 Board Approved costs and the 2020 Test Year (Explanations are included in Section 4.3.3.1 of Exhibit 4, Tab 1, Schedule 1 for 2018 and the 2019 Bridge and 2020 Test Years). ENGLP notes that the 2011 Board Approved OM&A costs

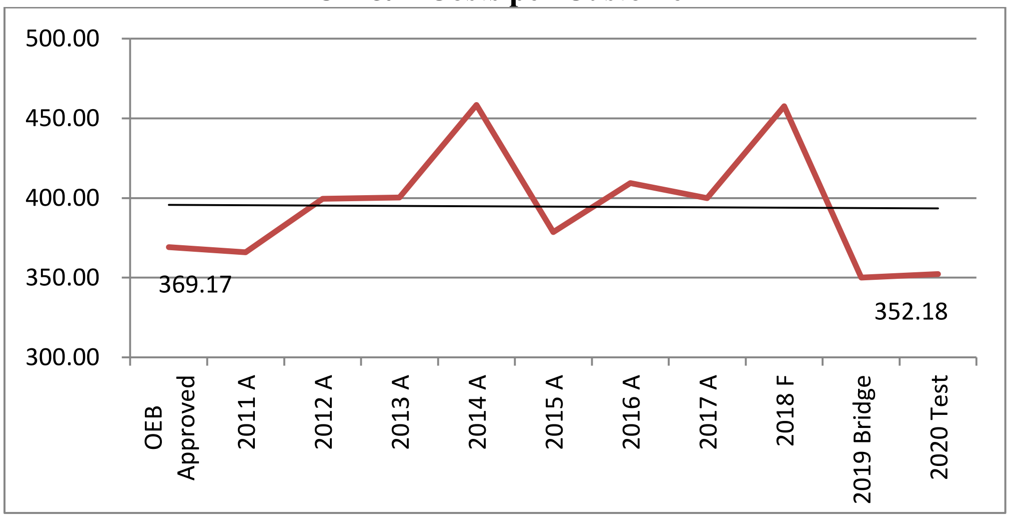
include a non-regulated water heater business operated by NRG. Table 1.5.5-1 provides details as to the changes by expense category.

Table 1.5.5-1
Change in OM&A Costs from 2011 Board Approved to 2020 Test Year
($)

	Expense Category	A 2011 OEB Approved	B 2020 Test Year	C Variance	D %
1	Wages & Benefits	1,260,853	1,781,170	520,317	41.3%
2	Transfers to Capital	(41,796)	(349,047)	(307,251)	735.1%
3	Insurance	259,345	86,211	(173,134)	(66.8)%
4	Utilities	18,061	17,443	(618)	(3.4)%
5	Advertising	56,500	34,240	(22,260)	(39.4)%
6	Telephone	65,159	36,000	(29,159)	(44.8)%
7	Office & Postage	127,928	127,394	(534)	(0.4)%
8	Repair & Maintenance	226,054	198,122	(27,932)	(12.4)%
9	Automotive	71,000	45,748	(25,252)	(35.6)%
10	Dues & Fees	41,705	31,185	(10,520)	(25.2)%
11	Mapping Expense	919	-	(919)	(100.0)%
12	Regulatory	111,000	211,852	100,852	90.9%
13	Bad Debts	60,000	34,200	(25,800)	(43.0)%
14	Interest - Security Deposits	6,432	-	(6,432)	(100.0)%
15	Bank Charges	17,749	6,019	(11,730)	(66.1)%
16	Collection Expense	20,000	-	(20,000)	(100.0)%
17	Travel & Ent.	4,150	15,145	10,995	264.9%
18	Legal	54,432	34,468	(19,964)	(36.7)%
19	Audit	20,000	31,334	11,334	56.7%
20	Consulting Fees	64,560	116,913	52,353	81.1%
21	Management Fees	235,157	-	(235,157)	(100.0)%
22	Correction on CCA issue	(75,000)	-	75,000	(100.0)%
23	Miscellaneous	25,000	-	(25,000)	(100.0)%
24	Affiliate Services	-	453,505	453,505	100.0%
25	Corporate Shared Services	-	439,217	439,217	100.0%
26	**Total**	**2,629,208**	**3,359,102**	**729,894**	**27.8%**

83. In regards to the longer term trend for OM&A costs, Figure 1.5.5-1 below provides a summary of OM&A costs per customers from the 2011 OEB approved costs to the proposed 2020 Test Year. ENGLP notes that the cost per customer has decreased from $369.17 in 2011 to $352.18 in 2020. As noted above, the 2011 costs include NRG's water heater business, however that business was sold in 2015 and ENGLP notes that the cost per customer increased in 2016. The increase in cost per customer in 2018 reflects the cost to ENGLP of several rates filings for the Alymer utility that were completed that year. Further discussion regarding OM&A costs is included in Exhibit 4.

Figure 1.5.5-1
OM&A Costs per Customer



84. The following inflation rates were used for OM&A expenses.

Table 1.5.5-2
Inflation Rates

	Expense Category	A **2019** **Bridge Year**	B **2020** **Test Year**
1	Management Salary	0.0%	2.8%
2	Non-Management Salary	0.0%	2.8%
3	Contractors	2.3%	2.7%
4	Materials	2.4%	2.2%
5	Other	2.3%	2.1%

85. For Management and Non-Management salary escalation, 2019 salary escalation projections from across Canada and Ontario were reviewed. These ranged from 2.5% to 2.8%[4]. It was noted that Ontario's unemployment rate was the 2nd lowest across Canada at 5.4%[5] which may put upward pressure on labour in Ontario for 2019 and continue into 2020.

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4 https://www.benefitscanada.com/news/salary-increases-to-rise-slightly-in-2019-survey-119372
https://www.conferenceboard.ca/press/newsrelease/2018/10/31/slightly-higher-salary-increases-expected-for-canadian- workers-in-2019
https://www.newswire.ca/news-releases/morneau-shepell-survey-shows-salaries-expected-to-increase-by-26-per-cent-in-2019-690803551.html
5 https://www150.statcan.gc.ca/n1/daily-quotidien/190104/dq190104a-eng.htm

86. For Contractor, Materials and Other escalation rates ENGLP used the same escalators that were developed by Robert Fairholm Economic Consulting Inc., an independent third party. This study was used by affiliates of ENGLP for its Regulated Rate Tariff Application and Transmission Tariff Application.

87. Additional detail regarding derivation of inflations rates is included in Section 4.3.1 of Exhibit 4, Tab 1, Schedule 1.

88. ENGLP has provided a 2019-2024 Gas Supply Plan in Exhibit 4, Tab 4, Schedule 1. ENGLP notes that it obtains gas, storage and transportation service from Enbridge Gas through its M9 contract.

89. Tables 1.5.5-3 and 1.5.5-4 include the proposed gas supply, transportation and storage costs for the 2019 Bridge Year and 2020 Test Year.

Table 1.5.5-3
ENGLP 2019 Gas Supply and Transportation Costs

		A	B	C
	Gas Commodity	**m3**	**$**	**cent / m3**
1	Enbridge Gas	25,118,971	4,031,695	16.0504
2	Local Production A	1,000,000	160,504	16.0504
3	Local Production B	657,417	105,518	16.0504
4	**Total Gas Commodity Cost**	**26,776,388**	**4,297,717**	**16.0504**
5	Unaccounted For Gas	-	-	-
6	**Total Gas Transportation Cost**	**43,169,007**	**970,411**	**2.2479**
7	**Total Gas Commodity and Transportation Cost**		**5,268,128**	

Table 1.5.5-4
ENGLP 2020 Proposed Gas Supply and Transportation Costs

		A	B	C
	Gas Commodity	**m3**	**$**	**cent / m3**
1	Enbridge Gas	24,309,669	4,366,867	17.9635
2	Local Production A	1,000,000	179,635	17.9635
3	Local Production B	657,417	118,095	17.9635
4	**Total Gas Commodity Cost**	**25,967,085**	**4,664,597**	**17.9635**
5	Unaccounted For Gas	-	-	-
6	**Total Gas Transportation Cost**	**26,325,152**	**674,644**	**2.5627**
7	**Total Gas Commodity and Transportation Cost**		**5,339,242**	

90. In the process of reviewing the depreciation rates after acquiring the system assets from NRG, ENGLP completed a review of existing depreciation rates as compared to other gas utilities. As a result of this review, ENGLP is proposing to adopt the Enbridge Gas OEB-approved depreciation rates (EB-2011-0210[6]) as ENGLP believes theses depreciation rates are more reflective of the useful lives of the assets. The two exceptions to the adoption of Enbridge Gas' rates are Meters, which are described below, and Vehicles – Transportation Equipment for which ENGLP has left the rate unchanged as it best represents the useful life the utility has experienced for this type of assets. Table 1.5.5-5 includes a summary of the proposed change in deprecation rates in addition to a change in the asset description to align descriptions with the USoA. With the exception of Meters, where a change in deprecation rate is proposed that change is a reduction in the rate. For Meters, the proposed depreciation rate reflects the change in process where at certain prescribed intervals these units are no longer tested, resealed and placed back into service. Rather they are replaced at the end of their initial estimated useful life.

91. In advance of implementing the proposed change in depreciation rates for the system assets providing service for Rate 6, ENGLP will confirm the extension of the terms of the Irrevocable Letter of Credit (EB-2006-0243) for the net book value of the assets in the rate base for this rate class. Additional information on proposed change in depreciation rates is included in Section 4.4 of Exhibit 4, Tab 1, Schedule 1.

[6] EB-2011-0210, Depreciation rates per Union Gas 2013 Rate Case Evidence, Exhibit D3, Tab 4, Schedule 1.

Table 1.5.5-5
Proposed Changes to Depreciation Rates
(%)

	Current Asset Description	A Proposed 2020 Test Year Asset Description	B 2011 OEB Approved	C 2020 Proposed
1	Land	Land	0.00	0.00
2		Structures & Improvements - General Plant	2.22	1.92
3	Buildings	Structures & Improvements – Distribution Plant		2.22
4		Structures & Improvements – Transmission Plant		2.03
5	Furniture & Fixtures	Furnishing / Office Equipment	6.75	6.67
6	Computer Hardware	Computer Equipment	33.33	25.00
7	Computer Software	Software - Acquired	20.00	10.00
8	Machinery & Equipment	Tools and Work Equipment	9.22	6.67
9	Communication Equipment	Communication Equipment	7.73	6.67
10	Automotive	Vehicles - Transportation Equipment	16.60	16.60
11		Vehicle - Heavy Work Equipment		6.92
12		Meters - Residential	3.62	10.00
13	Meters	Meters - Commercial		5.00
14		Meter – IGPC		16.67
15		Regulators	3.67	5.00
16	Regulators	Regulator and Meter Installations		2.80
17		Measuring and Regulating Equipment		3.66
18	Plastic Mains	Mains - Plastic (Distribution Plant)	3.24	2.31
19	Steel Mains	Mains - Metallic (Distribution Plant)	13.45	2.83
20	Ethanol Pipeline - IGPC Project	Mains - Metallic IGPC (Transmission Plant)	5.00	1.98
21	Plastic Services	Plastic Service Lines (net of contributions)	3.33	2.51
22	Franchises and Consents	Franchises and Consents	4.80	4.80
23	Franchises – Aylmer & Appeal	Franchises – Aylmer & Appeal	5.00	5.00

1.5.6 Cost of Capital

92. ENGLP presents cost of capital evidence in Exhibit 5 of this Application consistent with the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* issued December 11, 2009 (the "2009 Report") as well as the Board's direction on the cost of capital for 2019 filings in its letter dated November 22, 2018.[7] No deviations from the Board's cost of capital methodology are contemplated.

93. Table 1.5.6-1 below identifies the weighted average cost of capital proposed for the 2020 Test Year as well as the rates of return respective of short-term debt, long-term debt and equity. ENGLP understands that these rates will be updated once the 2020 cost of capital parameters are issued by the Board.

[7] https://www.oeb.ca/sites/default/files/Ltr-2019-Cost-of-Capital-Update-20181122.pdf

Table 1.5.6-1
Weighted Average Cost of Capital

		A	B	C
	Capital Component	**Ratio**	**Cost Rate**	**Return Component (WACC)**
1	Equity	40%	8.98%	3.59%
2	Long-term Debt	56%	3.85%	2.15%
3	Short-term Debt	4%	2.82%	0.11%
4	**Total**	**100%**		**5.86%**

1.5.7 Cost Allocation and Rate Design

94. ENGLP is proposing to change the rate design for rates 1 – 6 as follows.

(a) Rate 1 – Increase the monthly fixed charge from $15.50 to $17.00 to reflect a rate closer to the $21.00 charged by Enbridge in the surrounding territory. The variable charges are adjusted downwards to improve the revenue cost ratio. ENGLP is also proposing as an element of its IRM to increase the fixed charge by $1.00 per year from 2021 to 2024, bringing the fixed charge to $21.00. These proposed changes will also improve recovery of Customer costs through the fixed fee.

(b) Rate 2 – Increase the monthly fixed charge from $17.25 to $20.00 to improve recovery of Customer costs through the fixed fee. The variable charges are adjusted downward in order to improve the revenue cost ratio.

(c) Rate 3 – Increase the monthly fixed charge to from $172.50 to $190.00 to improve recovery of Customer costs through the fixed charge. The variable charges are adjusted downward in order to improve the revenue cost ratio.

(d) Rate 4 – Increase the variable charges to improve the revenue cost ratio.

(e) Rate 5 – Increase the monthly fixed charge from $172.50 to $190.00 to improve recovery of Customer costs through the fixed fee. Variable charges are increased in order to improve the revenue cost ratio.

(f) Rate 6 – Reduce the monthly fixed fee in order to reflect recovery of the costs caused by this customer. This rate does not include a variable component.

95. ENGLP has completed a cost allocation study (the "Study") that apportions the proposed 2020 Test Year rate base and proposed 2020 Test Year revenue requirement to each of the existing six customer rate classes. The Study uses a methodology that is consistent with the last cost allocation study approved by the Board for 2011 rates (EB-2010-0018). The inputs to this study have been updated to reflect current accounting and operating data and to derive allocation factors. Table 1.5.7-1 summarizes the allocations and proposed revenue requirement by rate class and the resulting revenue cost ratios. Updating the costs, load profiles and customer mix has resulted in notable increases in the revenue to cost ratios for Rate 2, bringing the ratio closer to 1 and Rate 1 Industrial. Notable decreases in the revenue to cost ratios are seen in Rate 1 Commercial, bringing the ratio closer to 1. The revenue cost ratio of Rate 1 overall has seen a minor change from 0.99 to 1.00.

Table 1.5.7-1
Distribution Revenue to Cost Comparison
($)

		A **Total**	B **Rate 1**	C **Rate 1 - Residential**	D **Rate 1 - Commercial**	E **Rate 1 - Industrial**	F **Rate 2**	G **Rate 3**	H **Rate 4**	I **Rate 5**	J **Rate 6**
1	Proposed Revenue	6,652,600	5,262,636	4,303,350	731,833	227,452	158,957	172,071	142,754	65,767	850,416
2	Cost	6,652,600	5,254,091	4,387,928	697,776	168,387	161,267	179,031	170,745	108,793	778,673
3	Over (Under) Contribution	0	8,545	-84,578	34,057	59,066	-2,311	-6,960	-27,991	-43,026	71,742
4	Proposed Revenue to Cost Ratio	1.00	1.00	0.98	1.05	1.35	0.99	0.96	0.84	0.60	1.09
5	EB-2010-0018 Approved	0.98	0.99	0.94	1.47	0.72	0.37	0.93	1.14	0.61	1.06

96. ENGLP is proposing to increase the amount of revenue generated through the fixed monthly charge in order to increase coverage of Customer costs for Rates 1, 2, 3 and 5. Tables 1.5.7-2 and 1.5.7-3 summarize the proposed changes in the split between the fixed and variable revenue generated by rate class.

Table 1.5.7-2
Fixed and Variable Revenue Under Current vs Proposed Distribution Rates in 2020
($)

		A	B	C	D	E	F
			Current			**Proposed**	
	Rate Class	**Fixed**	**Variable**	**Total**	**Fixed**	**Variable**	**Total**
1	Rate 1 - Residential	1,651,122	2,713,274	4,364,396	1,810,908	2,510,523	4,321,431
2	Rate 1 - Commercial	91,884	655,538	747,422	100,776	633,491	734,267
3	Rate 1 - Industrial	12,648	215,939	228,587	13,872	214,000	227,872
4	Rate 1 Subtotal	1,755,654	3,584,750	5,340,404	1,925,556	3,358,014	5,283,570
5	Rate 2	10,350	149,068	159,418	12,000	146,957	158,957
6	Rate 3	12,420	161,436	173,856	13,680	158,391	172,071
7	Rate 4	7,866	129,422	137,288	7,866	134,888	142,754
8	Rate 5	8,280	51,732	60,012	9,120	56,647	65,767
9	Rate 6	1,133,887	0	1,133,887	850,416	0	850,416
10	**Total Revenue**	**2,928,457**	**4,076,409**	**7,004,867**	**2,818,638**	**3,854,897**	**6,673,534**

Table 1.5.7-3
Fixed and Variable Revenue Proportions Under Current vs Proposed Distribution Rates in 2020
(%)

		A	B	C	D	E	F
			Current			**Proposed**	
	Rate Class	**Fixed**	**Variable**	**Total**	**Fixed**	**Variable**	**Total**
1	Rate 1 - Residential	37.83%	62.17%	100.00%	41.91%	58.09%	100.00%
2	Rate 1 - Commercial	12.29%	87.71%	100.00%	13.72%	86.28%	100.00%
3	Rate 1 - Industrial	5.53%	94.47%	100.00%	6.09%	93.91%	100.00%
4	Rate 1 Subtotal	32.87%	67.13%	100.00%	36.44%	63.56%	100.00%
5	Rate 2	6.49%	93.51%	100.00%	7.55%	92.45%	100.00%
6	Rate 3	7.14%	92.86%	100.00%	7.95%	92.05%	100.00%
7	Rate 4	5.73%	94.27%	100.00%	5.51%	94.49%	100.00%
8	Rate 5	13.80%	86.20%	100.00%	13.87%	86.13%	100.00%
9	Rate 6	100.00%	0.00%	100.00%	100.00%	0.00%	100.00%
10	**Total Revenue**	**41.81%**	**58.19%**	**100.00%**	**42.24%**	**57.76%**	**100.00%**

97. ENGLP is not proposing any mitigation measures for its proposed rate design. ENGLP does note that its proposal to increase the fixed monthly charge for Rate 1 to $21.00 in 2024 by $1.00 per year increments during the IRM period, rather than increasing it to $21.00 in the 2020 Test Year is intended to mitigation the impact of moving to this level of fixed charge.

1.5.8 Performance and Reporting

98. ENGLP is proposing a new scorecard for its operations. In alignment with the Renewed Regulatory Framework as detailed in the Handbook for Utility Rate Applications dated

October 13, 2016, the proposed scorecard includes a total of 20 measures related to customer focus, operational effectiveness, public policy responsiveness and financial performance. The proposed scorecard explicitly includes the Service Quality Requirements ("SQR") outlined in the OEB's Gas Distribution Access Rule ("GDAR") as amended January 1, 2017. As detailed in Table 1.7.2-1 below, over the last five years, NRG and ENGLP have consistently exceeded the SQR requirements as included in the GDAR. ENGLP proposes to file the results of the scorecard annually. An example of the proposed scorecard is included in Exhibit 1, Tab 3, Schedule 5. See Section 1.7 below for details on the proposed scorecard and measurements.

1.5.9 Bill Impacts

As detailed in Table 1.5.9-1, the rate design proposed by ENGLP results in a zero or negative typical bill impact for customers in Rates 1, 2, 3 and Rate 6. The bill impact for a typical customer in Rate 4 is an increase of 3.42% and Rate 5 is an increase of 9.59%.

Table 1.5.9-1
Summary of Annual Bill Impacts

		A	B	C	D
		$ / Year Change		**% Change**	
	Rate Class	**Typical**	**Bottom Decile**	**Typical**	**Bottom Decile**
1	Rate 1 - Residential	(5.24)	11.59	(1.11)%	4.39%
2	Rate 1 - Commercial	(34.88)	8.30	(4.19)%	2.73%
3	Rate 1 - Industrial	(120.82)	(11.95)	(5.81)%	(2.17)%
4	Rate 2	0.01	29.43	0.00%	6.73%
5	Rate 3	1.44	192.74	0.00%	2.00%
6	Rate 4	78.16	8.09	3.42%	0.84%
7	Rate 5	1,430.98	630.73	9.59%	9.71%
8	Rate 6	(283,471.86)	(283,471.86)	(25.00)%	(25.00)%

99. ENGLP has provided a full set of billing impacts schedules in Exhibit 8.

1.5.10 Deferral and Variance Accounts

100. ENGLP is proposing the following accounts be established during the 5 year period covered by this Application, including the 2020 Test Year and the subsequent years covered under the proposed Price Cap IR Plan:

(a) Unaccounted for Gas Variance Account ("UFGVA");

(b) Recovery of Income Tax Deferral Account ("RITDA"); and,

(c) Loss of Disposition of Meters Deferral Account ("LDMDA").

101. ENGLP is proposing the disposition of the following deferral and variance account balances:

(a) PGTVA 1 – 5 - The total projected disposition amount is a debit balance of \$42,649 which ENGLP is proposing to recover from the customers in Rate Classes 1-5 through the implementation of a twelve-month volumetric rate rider commencing on January 1, 2020 of \$0.1498/m^3; and

(b) REDA account balances - The REDA balances are proposed to be recovered through the implementation of a twelve-month fixed-rate rate rider commencing on January 1, 2020. The total estimated disposition amount is a debit balance of \$31,218. The estimated fixed-rate monthly rate rider is \$0.27 for Rates 1 – 5 and \$0.25 for Rate 6.

102. ENGLP is proposing the following deferral and variance accounts be closed and discontinued from use:

(a) PGTVA 6 – As per the approved settlement reached in EB-2018-0235, the actual transportation costs invoiced to ENGLP by Union Gas are now a direct flow-through to the customer in Rate 6, IGPC, and therefore this account is no longer required. ENGLP is proposing to recover the balance of this account from the customer in Rate Class 6 through the implementation of a twelve-month fixed-rate rate rider commencing on January 1, 2020. The total estimated disposition amount is a debit balance of \$184,821. The estimated fixed-rate monthly rate rider is \$15,401.75.

(b) IFRSDA – ENGLP has reported under IFRS since the acquisition of the assets from NRG in 2017 and therefore this account is not required to track any IFRS conversion costs.

(c) 2019 Rebalancing Deferral Account – this account was created specifically to address the 2019 rate rebalancing from proceeding EB-2018-0235, the balance of which was approved for disposal in December 2018.

103. Following the end of each fiscal year, ENGLP may file a separate application(s) requesting a process for the review and proposed clearance of any or all of the deferral and variance accounts as soon as feasibly possible following the completion of the audit of its annual financial statements.

1.5.11 Rate Schedules

104. Following is a summary of any other changes to the current OEB approved rate schedules that are being proposed in the new rate schedules.

(a) ENGLP is proposing to change the System Gas Fee from \$0.000363 m^3 to \$0.000435 m^3. This change is the result of a review of the costs to supply this function. Additional detail is included in Exhibit 7.

(b) Previous versions of the utility's rate schedule did not have a schedule of miscellaneous and service charges included. ENGLP has included these it the proposed rate schedule.

(c) ENGLP is proposing to make changes to the wording for the Transmission Service schedule to apply Transmission Services charges more broadly (i.e., not specific to one natural gas producer) in the event that natural gas producers commence using ENGLP's distribution system to transport gas into Enbridge Gas' Union South system.

1.5.12 Incentive Rate-Setting

105. ENGLP is proposing a five-year incentive rate-setting ("IR") plan, covering the period through December 31, 2024. The proposed IR plan includes:

(a) an annual price cap adjustment based on two factors (an inflation factor ("I"), and a productivity factor + stretch factor ("X"));

(b) for Rate 1, the fixed monthly charge would be increased annually by \$1.00 and the volumetric charges would be correspondingly adjusted to achieve a total projected revenue for Rate 1 equivalent to the prior year OEB approved revenue for Rate 1 increased by the Price Cap Adjustment;

(c) a Y-factor for costs associated with specific items that are subject to deferral account treatment and passed through to customers without any Price Cap Adjustment;

(d) an Incremental Capital Module ("ICM") to address the treatment of capital investment needs that arise;

(e) a Z-factor adjustment for unforeseen events outside of ENGLP's management control; and

(f) a trigger mechanism for a regulatory review in the event of a 300-basis point deviation from the Board approved ROE.

106. Additional detail of the proposed Price Cap IR method is included in Exhibit 10.

1.6 Customer Engagement

107. NRG had communicated with the Southwestern Oxford Council and Aylmer community on a number of issues, including its 2016 Cost of Service Application (EB-2016-0236), system integrity and gas supply. The NRG presentations are included as Exhibit 1, Tab 3, Schedules 6 and 7, respectively. NRG's customer engagement related to the 2016 Cost of Service Application ceased in November, 2016 when it filed a request with the OEB to place the cost of service application into abeyance. On November 30, 2017 NRG filed a MAAD Application (EB-2016-0351) that proposed the transfer of the utility's assets to ENGLP.

108. In December 2016 and throughout 2017, NRG's customer engagement included a focus on notifying and informing customers of the proposed sale of NRG assets to ENGLP and the OEB procedural steps of the MAAD Application[8]. Meetings were held with representatives from NRG and ENGLP with IGPC and local municipalities to inform customers of the Asset Purchase Agreement and NRG's intent to seek MAAD application approval. After receiving the OEB's decision and approval of the MAAD application on August 3, 2017, ENGLP notified all customers by direct mail of the change in ownership, details regarding their account and assured them of continuity service. A copy of the customer letter is attached as Exhibit 1, Tab 3, Schedule 8.

[8] Natural Resource Gas Sale to EPCOR Natural Gas Limited Partnership MAAD Application EB-2016-0351.

109. ENGLP has reviewed the customer engagement practices of NRG as the previous utility owner and is working to strengthen its customer engagement as the new utility owner.

110. ENGLP's ongoing commitment is to communicate and engage with customers to ensure ENGLP's customer service and capital investment is prudent, appropriate and aligns with the needs of its customers. Engagement with customers and stakeholders is tailored to the community and key themes such as:

- education about natural gas;
- safety;
- system reliability;
- billing; and
- ENGLP community presence.

111. ENGLP intends to use the following methods for customer engagement:

- Bill inserts
- Bill notices
- Email blasts
- Print advertisements
- News media
- Regular web content updates
- LEAP Program and support
- Charitable investments
- Community events
- Safety-focused partnerships
- Employee engagement in the community
- Customer face-to-face meetings
- Local access at the Administration office
    - In-person service at local office
    - Inbound and outbound phone calls
    - Email correspondence
- Meetings with municipal and regional orders of government

112. Customers manage their accounts or inquire about their services during business hours by phone, email, facsimile, or in person at the Administration office in Aylmer, Ontario. During non-business hours, inbound calls are managed by a third party call center that allows customers to report an emergency or inquire about account services. In 2017, customer service representatives received and responded to 7,443 customer inquiries to the ENGLP general inquiry telephone number. For 2018, ENGLP is forecasting a reduction of customer inquiries to approximately 7,200. Customer representatives make outbound calls to customers to coordinate service arrangements, meter replacements or to schedule locate services for gas lines.

113. The following provides examples of the types of customer engagements ENGLP has undertaken:

- In advance of planned outages, ENGLP calls affected customers and for unplanned outages, ENGLP Field Technicians will attend in-person to the outage area to attempt to notify customers. If unsuccessful, an "Emergency-Line Break Notice" is left at the customer's premises to direct the customer to contact ENGLP. A copy of this notice is included as Exhibit 1, Tab 3, Schedule 9.
- ENGLP responds at all times to emergency calls for reports of carbon monoxide; natural gas odor; or gas leak within the OEB's response standard.
- ENGLP performs annual leak testing in areas of public assembly and engages facility owners when leaks are identified to inform and educate them on safety, gas codes, and if remediation is required.
- ENGLP engages with local industry, agricultural associations and municipalities to discuss safety and construction practices. In 2017, meetings were held with municipalities to share best practices and educational material to redistribute to residents and contractors about working in proximity to natural gas distribution lines. ENGLP provides information in the form of newsletters, Dig Safe videos to Ontario Regional Common Ground Alliance (ORCGA) in direct response to natural gas line strikes. A copy of the publication is included in Exhibit 1, Tab 3, Schedule 10.
- ENGLP supports programs that provide education essentials for at-risk youth to inspire an employment path towards a poverty-free future. ENGLP and its employees participate and volunteer in the community and contribute to not-for-profit and charitable organizations. For example, ENGLP sponsors local hockey

associations and provides a scholarship for East Elgin Secondary School. Employees also donate to the United Way Campaign with EPCOR matching employee contributions.

- ENGLP supports sponsorships in the community to increase awareness of natural gas safety, the organization and understanding of who to contact for natural gas services. In 2018, ENGLP supported the East Elgin Community Complex, Aylmer Spitfires Hockey Club and Kinsmen Club Santa Clause Parade.

114. ENGLP will continue to complete the implementation of a new billing system that NRG initiated in 2017. The new billing system modernizes the application software and increases reliability through improved network design, data server redundancy and implementing business recovery processes. Connection to ENGLP's network as a result of the change in ownership has also enhanced cyber security and security standards that protect customer information. The design options of the new billing system provide flexibility to meet future functionality required for the OEB or government programs, such as the Green Button Initiative. Also, the technology enhancement of the new billing system improves the customer bill format by including historical gas consumption (i.e., bar graph) to show customers their consumption patterns over a 12-month period. A sample bill is provided in Exhibit 1, Tab 3, Schedule 11. Feedback from ENGLP customers includes requests for additional billing features such as access or to receive bills electronically and to expand upon current bill payment options (i.e. online payment). ENGLP has considered this feedback and is planning to complete these further billing enhancements (i.e., e-billing, account management and online web portal payment options) for customers in 2019.

115. In November 2018, ENGLP undertook a customer engagement survey to gather feedback from customers. This survey included questions regarding their view as to the most important aspects of natural gas services. The responses have guided ENGLP in a number of areas of customer service, including investment in the distribution system and services. The survey was open to all customer rate classes and issued as a non-blind survey (ENGLP's name was transparent to the respondent).

116. The survey notice was distributed by email to 1,776 customers, promoted on bill notices and accessible through EPCOR's website (epcor.com). The survey received 439 responses from residential, business, commercial, builder/developer and agribusiness customers. 80% of respondents responded with "satisfied" or "very satisfied" with the level of service they receive; however, 75% were not familiar or only somewhat familiar with ENGLP. When asked about the

most important aspect of their natural gas service, 64% of respondents stated it was keeping their rates/bills low while the second highest group of respondents (25%) stated service reliability was most important. Customers indicated they would like to use an online account management system, see an increase in email communication and receive more information about rebates and cost savings. When asked if they would like to receive more information about EPCOR's Cost of Service application, 26% of respondents provided their contact details. Details of the survey questions and results are included in Exhibit 1, Tab 3, Schedule 12.

117. ENGLP has incorporated the results from customers' requests and the 2018 Survey, implementing cost-sensitive customer engagement methods and technology options. ENGLP chose to conduct an online Survey rather than mail a written survey to customers thereby saving approximately $9,000 in paper and postal costs. ENGLP is planning to implement customer online access to billing information, e-bills and account management in 2019. Once made available, ENGLP will promote access and encourage enrolment. These activities will also increase customer familiarity with ENGLP and who to contact in case of an emergency or questions regarding service. ENGLP has considered customers' responses about service reliability in its Utility System Plan which will address system reliability as further described in Exhibit 2, Tab 3, Schedule 1.

118. Table 1.6-1 below summarizes how ENGLP's plan further addresses the aspects of natural gas service that customers have indicated is important.

Table 1.6-1
Most Important Aspect of Natural Gas Service to Customers

	Response	A Response %	B How Plan Addresses Response
1	Keeping rates/bills low	64.46	• Continue to educate customers on conservation measures that will help increase their energy efficiency. • Work to minimize rate increases through rigorous budgeting process and cost prudency.
2	Service Reliability	25.28	• Capital plan is proposing investments that will address system integrity concerns. • Increasing use of cross-training and implementation of updated technology including SCADA and asset management systems.
3	Safety	2.51	• Increase awareness of ENGLP as the local provider and ensure that customers know to contact ENGLP for gas services and during emergencies. • Continue to use a number of communication channels to increase customer and stakeholder awareness on the importance of safety practices.
4	Conservation	1.59	• Continue to educate customers on conservation measures that will help increase their energy efficiency.
5	Customer Service	1.59	• Continue implementation of online capability. • Continue enhancement of IT security. • Implement ongoing engagement activities, including surveys that will track customer priority and potential concerns.

119. ENGLP will continue to measure and monitor customer expectations and in regards to this and future Cost of Service applications, ENGLP has developed a customer engagement strategy to reaffirm ENGLP's investment approach and prioritize customer service priorities on an ongoing basis. The strategy will inform ENGLP of the needs and concerns of customers as it relates to ENGLP operations and will allow the utility to disseminate information about the drivers for ENGLP's planned operational activity. For specific project customer engagement, see ENGLP's Business Plan (Exhibit 1, Tab 4, Schedule 1) and ENGLP's Utility System Plan (Exhibit 2, Tab 3, Schedule 1) included in this Application. A summary of ENGLP's current and future engagement activities is provided in the table below.

Table 1.6-2
Summary of Customer Engagement Activities

	Customer Engagement Activities	A Customer needs and preferences identified through engagement activities	B Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
1	Large Customer consultation and engagement	• Reliability, Gas supply, reinforcement	Large customers participate in frequent consultation discussions regarding supply, reliability and regulatory matters. Other larger consumption customers are consulted when planned outages will occur.
2	2016 Community Information Meeting	• Review of the strategic priorities • Understand the process of rate setting • Summarize Capital Projects to date • Summary of bill impacts	Open house and presentation provided to summarize 2017 Cost of Service Rate application.* *application was placed in abeyance and NRG filed a MAAD Application.
3	MAAD Application information sessions	• Inform and provide background regarding the sale of NRG to ENGLP • Educate municipal orders of government for any questions that may arise from the sale or about ENGLP. • Inform customers about ENGLP and changes to their payment process • Reinforce and assure customers regarding operational continuity throughout and after the change in owner	Meetings were held with municipally-elected officials to address any concerns they or their citizens may have regarding the sale. Established new communication channels with municipal orders of government with the new utility ownership. Engaged customers about the new EPCOR brand, changes in banking process and assured customers no changes in rates, services or supply after the sale.
4	Office Administration – in person support	• Walk in services for new development connections • Walk in and drop off services for bill payment and bill payment arrangements • In person access for customers without access to online technology	ENGLP has significant walk in traffic to the office as some customers prefer face to face interaction or have limited access to online technology.
5	Website	• Safety education about the use of gas • Ontario OneCall information • Notices of regulatory activities • Customer notices • Services and account registration • Conservation initiatives	EPCOR's website provides a variety of customer centric information including customer information to transition to natural gas, bill samples with explanations, conservation tips and information on current government initiatives e.g. Cap and Trade calculators;
6	Changes to bill format	• Consumption graphics to compare month to month history • Easier to read (larger font) • Message center / reminders • E-billing options • Flexible payment options	2017 billing system upgrades provide an easier to read bill format for customers. Bill messaging is able to provide notices and updates to customers. 2019 planned web portal access for customers to view their accounts and add payment options (e.g. credit card payments)

	Customer Engagement Activities	A Customer needs and preferences identified through engagement activities	B Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
7	Ontario Regional Common Ground Alliance	• Line strikes from construction activities are dangerous and require continual safety reminders with industry	ENGLP published a targeted "Dig Safe" article in November 2018 ORGCA's newsletter encouraged farmers to call Ontario One Call. The messaging also emphasized safety practices and procedures should a line strike occur.
8	Customer survey	• Provide forum to enable customers to provide feedback • Determine customer priorities align with capital project planning	In its first customer survey conducted for this service territory, ENGLP received responses from 439 participants who, as a whole, were satisfied with the overall service provided. Respondents rated keeping bills/rates low and service reliability as the most important aspects of their natural gas service delivery and the areas ENGLP should put the majority of its focus. Customers also want an online account management system that they can use to pay their monthly bill and retrieve information. Of the 36% of respondents who were interested in learning more about EPCOR's Cost of Service application, 116 customers provided their contact information.
9	Conservation	• Lower bills • Access to government programs • Certified Advisors contact url links from web portal	Informs customers of rebates and programs that are available to residential consumers. The posted rebate information directs customers to Union Gas and Enbridge to enroll into the programs.
10	Safety	• Safety when smelling gas • Dig safety / Ontario OneCall familiarity • Employee safety during winters with reminders to remove snow and ice around meters	Locations of public assembly are tested on a scheduled basis. Handouts are left at premises where snow and ice are built up around meters.

1.7 Performance Measure and Scorecard

1.7.1 Scorecard

120. EPCOR is proposing a new scorecard to measure and monitor performance from January 1, 2020 to December 31, 2024. The proposed Scorecard is modeled after the electricity distributors' scorecard, the scorecard proposed by Enbridge Gas Distribution Inc. and Union Gas Limited in their application to amalgamate (EB-2017-0307), and is supported by the goals and objectives of ENGLP's business plan. This scorecard is also compliant with the GDAR as amended January 1, 2017.

121. In alignment with the Renewed Regulatory Framework as detailed in the Handbook for Utility Rate Applications dated October 13, 2016, the proposed scorecard includes measures for customer focus, operational effectiveness, public policy responsiveness and financial performance. The proposed Scorecard is provided at Exhibit 1, Tab 3, Schedule 5. The Scorecard metrics include SQR and best practice metrics; and aims to align customer and utility interests, while continuing to achieve public policy objectives and reinforcing fiscal prudence. The categories of measures included in the scorecard are as follows:

(a) Customer Focus: This performance measure is focused on service quality and customer satisfaction. The metrics included in this measure are the Board's customer care related SQRs. These include:

   (i) Reconnection response time
   (ii) Scheduled appointments met on time
   (iii) Telephone calls answered on time
   (iv) Customer complaint written response
   (v) Billing accuracy
   (vi) Abandon rate
   (vii) Time to reschedule missed appointments

(b) Operational Effectiveness: This performance measure is focused on safety, system reliability and asset management. The metrics included in this measure include the Board's operations related SQRs and damages:

(i) Meter reading performance
(ii) Percent of emergency calls responded to within one hour
(iii) Damages

(c) Public Policy Responsiveness: This performance measure includes metrics that align with the extension of natural gas distribution to new communities.

(i) Number of new communities that have access to natural gas distribution system
(ii) $/m^3 cost to deliver natural gas
(iii) Customer years
(iv) Cumulative volume

(d) Financial Performance: This performance measure includes metrics that align with the OEB Yearbook that is published annually. These include:

(i) Current ratio
(ii) Debt ratio
(iii) Debt to equity ratio
(iv) Interest coverage
(v) Financial statement return on assets
(vi) Financial statement return on equity

122. The proposed Scorecard will document the results of ENGLP's focus on providing safe and reliable service to customers.

123. ENGLP will be working to improve its Customer Focus and Operational Effectiveness SQRs including increasing cross training among employees, paying market based compensation and investment in systems such as workforce management software. The proposed investment in capital as detailed in the Utility System Plan to address system integrity concerns will allow ENGLP to expand the system to service new customers as necessary, thereby working to improve the Public Policy Responsiveness metrics.

1.7.2 Benchmarking

124. The OEB has established a set of SQR performance metrics for gas distributors through its GDAR to assess utility performance over time and to compare performance across utilities. As supported by the data in Table 1.7.2-1 below, NRG's performance was strong over time, both as an internal benchmark and external benchmark when comparing with other gas utilities. Given its strong performance historically, ENGLP is targeting to maintain its current values and continue its superior performance as compared to external utilities benchmarked. The Work Force Plan (4.3.3.1), ENGLP Business Plan and Utility System Plan highlight ENGLP's efforts to maintain these values. Activities include an ongoing focus on cross training employees and paying market based compensation as well as investment in systems such as workforce management software.

125. As detailed above, ENGLP proposes to include these SQRs in its scorecard and continue to benchmark itself internally as well as against other gas utilities. ENGLP will also initiate internal and external benchmarking against other utilities for the new metrics included in the proposed scorecard. These new metrics include Customer Satisfaction (Billing accuracy) and Safety, system reliability and asset management (Damages). ENGLP will track these metrics in order to establish a baseline and then establish a target for its next cost of service filing.

126. ENGLP is also proposing a system integrity internal benchmark. During periods of high demand in the winters of 2014 and 2018, the utility recorded low system pressure in a number of areas in the South of the system as well around Belmont. In order to address this reliability issue the utility has implemented, and will continue to implement, a number of capital projects. As detailed in the Utility System Plan and Business Plan, these projects include the Lakeview Reinforcement project to allow insertion of additional gas into the system. In addition, starting in 2019 ENGLP is planning the installation of a centralized supervised control and data acquisition (SCADA) system that will allow ENGLP to automatically track and react as necessary to system pressures. ENGLP is proposing that it establish a benchmark of minimum pressure of 40 psi within its system. Exhibit 2 includes additional details as to the capital projects completed and proposed that will address this system integrity concern.

127. ENGLP has also completed a market competitiveness benchmarking analysis to its employee compensation against comparable entities. It was determined that ENGLP wage rates for positions that could be benchmarked were on average approximately 19.9% below the local

rates (i.e. market). ENGLP is proposing to address this through increases in compensation over the 2019 Bridge Year and 2020 Test Year. This is further detailed in Section 4.3.3.1 of Exhibit 4, Tab 1, Schedule 1.

Table 1.7.2-1
Historical Service Quality Metrics[9]

		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
			2017			**2016**			**2015**			**2014**			**2013**	
	Service Quality Measure	**NRG %**	**ENB %**	**Union %**	**NRG %**	**ENB %**	**Union %**	**NRG %**	**ENB %**	**Union %**	**NRG %**	**ENB %**	**Union %**	**NRG %**	**ENB %**	**Union %**
1	Call Answering Service Level (OEB Minimum Standard: 75%)	98.80	82.50	79.20	98.50	82.40	80.10	98.50	79.70	79.10	99.10	79.00	73.50	99.30	75.90	78.40
2	Call Abandon Rate (OEB Standard: Not to Exceed 10%)	1.20	1.80	3.40	1.50	1.80	3.60	1.50	2.30	4.00	0.90	1.90	4.60	0.70	2.80	3.80
3	Meter Reading Performance (OEB Standard: Not exceed 0.5%)	0.00	0.50	0.10	0.00	0.40	0.10	0.00	0.50	0.20	0.00	0.70	0.40	0.00	0.50	0.20
4	Appointments Met (OEB Minimum Standard: 85%)	99.10	94.30	99.00	99.30	94.80	98.90	99.60	95.20	98.80	99.00	95.10	97.70	99.20	94.20	97.80
5	Reschedule Missed Appointments (OEB Standard: 100%)	100.00	96.80	99.90	100.0	94.20	99.80	96.60	94.80	99.80	100.00	95.51	99.86	100.00	94.96	99.90
6	Emergency Call Response (OEB Minimum Standard: 90%)	92.30	96.80	99.00	93.20	96.10	98.80	94.80	96.70	98.60	93.10	96.90	97.80	100.00	96.10	97.90
7	Days to Provide Written Response (OEB Minimum Standard: 80%)	100.00	100.00	100.00	100.00	95.50	100.00	100.00	100.00	100.00	N/A	93.30	100.00	0.00	94.50	100.00
8	Days to Reconnect (OEB Minimum Standard: 85%)	100.00	96.20	90.50	91.70	93.70	86.20	100.00	94.60	90.10	95.20	94.00	91.90	94.40	92.60	92.20

[9] Ontario Energy Board, Year Book of Natural Gas Distributors, Service Quality Requirements, 2017-2013.

1.8 Financial Information

128. ENGLP has provided the audited financial statements for the two months, November 1, 2017 to December 31, 2017, for which ENGLP owned the assets in 2017 in Exhibit 1, Tab 2, Schedule 2. In addition, ENGLP has provided NRG's audited financial statements for the utility for the three most recent full financial years (2015, 2016 and 2017) in Exhibit 1, Tab 2, Schedule 3, Exhibit 1, Tab 2, Schedule 4, and Exhibit 1, Tab 2, Schedule 5, respectively. ENGLP does not have financial information for the month of October 2017 which represents the last month in which the system was owned by NRG. As a result ENGLP is unable to provide this information.

129. Pro forma financial statements for the 2018 Forecast, 2019 Bridge Year and 2020 Test year are provided in Exhibit 1, Tab 2 Schedule 6. The reconciliation between the audited 2017 financial statements and the 2017 regulatory financial statements are provided in Exhibit 1, Tab 2, Schedule 7. ENGLP has also provided reconciliations between NRG's financial statements and the regulatory financial information for the years 2015, 2016, 2017 in Exhibit 1, Tab 2, Schedule 8, Exhibit 1, Tab 2, Schedule 9 and Exhibit 1, Tab 2, Schedule 10, respectively. These reconciliations rely on the balances from the audited financial statements and the information provided by NRG as being filed for its annual RRR reporting.

130. ENGLP does not have any public debt and therefore has not been rated by any agency. As detailed in Exhibit 5, EPCOR's parent company, EPCOR Utilities Inc. ("EPCOR") will be providing the capital necessary to fund ENGLP. EPCOR is rated by DBRS (A low) stable and Standard & Poor's (A-).

131. The following Account Orders for ENGLP have been approved. ENGLP has not departed from these orders.

(a) Accounting Entries for Greenhouse Gas Emissions Impact Deferral Account;
(b) Accounting Entries for Greenhouse Gas Emissions Compliance Obligation – Customer-Related;
(c) Accounting Entries for Greenhouse Gas Emissions Compliance Obligation – Facility-Related;
(d) Deferral Account to Record Rebalancing Recovery from Rates 1-5;
(e) Deferral Account to Record Regulatory Expense Deferral Account;

(f) Deferral Account to Record Purchased Gas Commodity Variance Account;
(g) Deferral Account to Record Accounting Entries for the Gas Purchase Rebalancing Account;
(h) Deferral Account to Record Revenues Recovered Through the Transportation Service Charges;
(i) Deferral Account to Record the Costs Incurred to Convert to the International Financial Reporting Standard;
(j) Deferral Account to Record Accounting Entries for the Purchased Gas Transportation Variance Account (Rates 1 – 5); and
(k) Deferral Account to Record Accounting Entries for the Purchased Gas Transportation Variance Account (Rate 6).

132. Copies of ENGLP's Accounting Orders are included in Exhibit 1, Tab 2, Schedule 11.

133. ENGLP has incorporated the main categories of accounts as stated in the Uniform System of Accounts for Class A Gas Utilities in the preparation of this Application.

134. The tax status of the utility changed on November 1, 2017 when the system assets were acquired by ENGLP. NRG, the previous owner of the assets was a corporation incorporated under the laws of Ontario. ENGLP is an Ontario limited partnership. ENGLP is a wholly owned indirect subsidiary of EPCOR. The general partner of ENGLP is EPCOR Ontario Utilities Inc. and the sole limited partner is EPCOR Power Development Corporation, which are both subsidiaries of EPCOR. ENGLP was formed pursuant to a limited partnership agreement which provides that EPCOR Ontario Utilities Inc., as general partner, will control and have the full and exclusive power, authority and responsibility for the management and day-to-day operations of ENGLP. In accordance with the limited partnership agreement, EPCOR Power Development Corporation, as limited partner, has an economic interest in the partnership but will not control or otherwise play a role in the day-to-day operations and management of ENGLP. Figure 1.3.18-1 above includes a simplified EPCOR organizational chart.

135. ENGLP is aware that NRG operated a non-utility business in the form of a water heater rental and sales business. In previous rate applications the Board had not required NRG to segregate this business. ENGLP understands that this business was sold by NRG on July 1, 2015 with the sale effective June 30, 2015. In its financial reporting NRG did not separate the natural gas business from this ancillary business. ENGLP is not aware of any non-utility businesses that

were operated by NRG after June 30, 2015; however, ENGLP is unable to confirm that understanding. As a result, ENGLP is providing historical financial information as reported by NRG up to November 1, 2017.

EPCOR

Table 1
Historical and Projected Fixed Assets Including Contribution
($ thousands)

	Asset Group	A 2011 OEB Approved	B 2011 A	C 2012 A	D 2013 A	E 2014 A	F 2015 A	G 2016 A	H 2017 A	I 2017 Stub	J 2018 F	K 2019 Bridge	L 2020 Test
1	**Gross Asset Value**												
2	Opening Balance	23,872.2	23,206.4	23,922.9	24,323.6	25,198.2	25,889.1	23,815.2	26,184.3	27,144.2	27,441.2	29,726.6	33,734.4
3	Addition	810.0	815.2	963.7	1,133.8	942.7	794.1	2,792.8	1,113.6	325.1	2,366.2	4,007.8	1,412.0
4	Disposal	0.0	(98.7)	(563.0)	(259.2)	(251.8)	(2,868.0)	(423.7)	(153.7)	(28.1)	(80.8)	0.0	(1,128.2)
5	Closing Balance	24,536.3	23,922.9	24,323.6	25,198.2	25,889.1	23,815.2	26,184.3	27,144.2	27,441.2	29,726.6	33,734.4	34,018.2
6	**Accumulated Depreciation**												
7	Opening Balance	(10,039.8)	(9,506.0)	(10,525.9)	(11,068.1)	(11,939.2)	(12,844.1)	(12,410.7)	(13,036.8)	(14,096.2)	(14,362.7)	(15,414.6)	(16,705.2)
8	Depreciation	(1,200.1)	(1,111.9)	(1,070.0)	(1,093.1)	(1,097.6)	(1,062.7)	(1,049.8)	(1,201.9)	(280.8)	(1,154.4)	(1,290.6)	(1,151.8)
9	Disposal	0.0	91.9	527.9	221.9	192.7	1,496.1	423.7	142.5	14.4	102.5	0.0	965.7
10	Closing Balance	(11,239.9)	(10,525.9)	(11,068.1)	(11,939.3)	(12,844.1)	(12,410.7)	(13,036.8)	(14,096.2)	(14,362.7)	(15,414.6)	(16,705.2)	(16,891.3)
11	Mid-year Net Asset Value	13,564.4	13,548.7	13,326.2	13,257.2	13,152.0	12,224.7	12,276.0	13,097.7	13,063.2	13,695.2	15,670.6	17,078.1
12	Closing Net Asset Value	13,296.4	13,396.9	13,255.5	13,258.9	13,045.0	11,404.5	13,147.4	13,048.0	13,078.5	14,312.0	17,029.2	17,126.9

*net of grant funded assets in years prior to 2017 Stub

Table 2
Property Taxes Payable
($)

		A	B	C	D	E	F	G	H	I	J	K	L
	Expense Category	**2011 OEB Approved**	**2011 A**	**2012 A**	**2013 A**	**2014 A**	**2015 A**	**2016 A**	**2017 A**	**2017 Stub**	**2018 F**	**2019 Bridge**	**2020 Test**
1	Property Taxes	400,776	415,184	414,606	471,816	506,712	533,094	540,380	492,809	92,826	573,251	605,000	632,000

Table 3
Operating, Maintenance and Administrative Costs
($)

	Expense Category	A 2011 OEB Approved	B 2011 A	C 2012 A	D 2013 A	E 2014 A	F 2015 A	G 2016 A	H 2017 A	I 2017 Nov & Dec	J 2018 F	K 2019 Bridge	L 2020 Test
1	Salaries and Benefits	1,219,057	995,870	1,343,213	1,335,700	1,376,847	1,441,024	1,561,365	1,336,675	216,378	1,217,748	1,255,343	1,432,123
2	Insurance	259,345	277,066	285,902	274,243	164,744	174,538	179,774	169,301	14,853	79,707	82,895	86,211
3	Utilities	18,061	11,199	9,832	11,043	9,825	10,765	11,900	9,525	1,883	10,478	16,573	17,443
4	Advertising	56,500	43,906	65,336	56,243	47,948	54,432	65,529	35,082	505	34,455	60,936	34,240
5	Telephone	65,159	39,565	30,017	28,282	26,839	28,444	29,900	27,596	6,134	41,646	27,600	36,000
6	Office & Postage	127,928	99,383	101,115	107,600	115,485	130,398	133,000	118,430	22,529	156,645	126,074	127,394
7	Repair & Maintenance	226,054	143,067	158,552	163,360	155,983	186,338	219,780	106,204	17,662	185,831	199,943	198,122
8	Automotive	71,000	53,463	68,809	61,378	81,090	65,516	72,000	57,628	4,589	50,927	44,807	45,748
9	Dues & Fees	41,705	29,418	61,976	47,912	34,255	34,835	35,880	18,007	18,106	29,740	29,922	31,185
10	Mapping Expense	919	0	0	0	0	0	0	0	0	0	0	0
11	Regulatory	111,000	278,576	246,479	400,906	1,036,973	225,356	213,500	63,010	20	887,337	206,920	211,852
12	Bad Debts	60,000	32,400	200	29,689	32,034	37,166	40,000	24,594	5,718	30,486	34,200	34,200
13	Interest - Security Deposits	6,432	1,879	2,778	1,099	2,298	(4,831)	2,000	865	0	0	0	0
14	Bank Charges	17,749	48,840	26,202	18,764	20,319	14,908	18,500	34,419	2,938	14,629	6,003	6,019
15	Collection Expense	20,000	8,008	8,352	7,017	11,408	7,942	8,800	4,847	0	0	0	0
16	Travel & Ent.	4,150	3,328	3,800	3,207	6,146	8,210	9,000	3,525	900	13,493	12,788	15,145
17	Legal	54,432	25,165	2,304	14,465	15,945	205,339	295,000	985,130	4,739	30,456	33,759	34,468
18	Audit	20,000	15,975	26,772	18,000	19,750	18,000	33,000	24,000	0	57,750	30,690	31,334
19	Consulting Fees	64,560	37,675	46,216	44,684	53,441	40,181	100,000	3,490	148,661	389,445	200,398	116,913
20	Management Fees	235,157	457,020	457,020	457,020	457,020	457,020	457,020	457,020	0	0	0	0
21	Correction on CCA issue	(75,000)	0	0	0	0	0	0	0	0	0	0	0
22	Miscellaneous	25,000	0	0	508,585	146,741	1,214,101	0	0	97	1,053	0	0
23	**Total**	**2,629,208**	**2,601,803**	**2,944,875**	**3,589,197**	**3,815,091**	**4,349,682**	**3,485,948**	**3,479,349**	**465,712**	**3,231,826**	**2,368,850**	**2,458,397**

Table 4
Affiliate and Corporate Shared Services Costs
($)

	Expense Category	A 2017 A Stub	B 2018 F	C 2019 F	D 2020 F
1	Affiliate Services	44,794	477,608	441,152	453,505
2	Corporate Shared Services	75,243	405,984	427,572	439,217
3	**Total Shared Services and Corporate Costs**	**120,037**	**883,592**	**868,724**	**892,722**

Financial Statements of

EPCOR Natural Gas Limited Partnership

Year ended December 31, 2017

BDO

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
EPCOR Ontario Utilities Inc.

We have audited the accompanying financial statements of EPCOR Natural Gas Limited Partnership, which comprise the statement of financial position as at December 31, 2017, and the statement of comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of EPCOR Natural Gas Limited Partnership as at December 31, 2017, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

BDO Canada LLP

Chartered Professional Accountants, Licensed Public Accountants

London, Ontario
April 23, 2018

EPCOR Natural Gas Limited Partnership

Statement of Comprehensive Income
(In thousands of Canadian dollars)

For the year ended December 31,		2017		2016
(With comparative amounts for the 2 months ended December 31, 2016)				
Revenue:				
Commercial services	$	1,809	$	-
Natural gas sales		1,408		-
		3,217		-
Operating expenses:				
Energy purchases		1,377		-
Staff costs and employee benefits expenses		218		-
Depreciation and amortization (note 5)		190		-
Other raw materials and operating charges		174		-
Finance expenses (net)		24		-
Franchise fees and property taxes		100		-
Other administrative expenses		1,566		-
		3,649		-
Comprehensive loss for the year - all attributable to the Partners	$	(432)	$	-

The accompanying notes are an integral part of these financial statements

EPCOR Natural Gas Limited Partnership

Statement of Financial Position
(In thousands of Canadian dollars)

	December 31, 2017	December 31, 2016	November 4, 2016
ASSETS			
Current assets:			
Cash	$ 2,408	$ -	$ -
Trade and other receivables (note 6)	2,221	1	1
Prepaid expenses	358	-	-
Inventories (note 7)	82	-	-
	5,069	-	-
Non-current assets:			
Property, plant and equipment (note 8)	17,857	-	-
Intangible assets (note 9)	1,207	-	-
Goodwill (note 9)	1,886	-	-
	20,950	1	1
TOTAL ASSETS	$ 26,019	$ 1	$ 1
LIABILITIES AND EQUITY			
Current liabilities:			
Loans and borrowings (note 11)	$ 3,153	$ -	$ -
Trade and other payables (note 10)	1,143	-	-
Customer deposits	103	-	-
Provisions (note 13)	19	-	-
	4,418	-	-
Non-current liabilities:			
Loans and borrowings (note 11)	8,660	-	-
Deferred revenue (note 12)	13	-	-
	8,673	-	-
Total liabilities	13,091	-	-
Equity attributable to the Partners:			
Partnership units (note 14)	13,360	1	1
Deficit	(432)	-	-
Total equity	12,928	1	1
TOTAL LIABILITIES AND EQUITY	$ 26,019	$ 1	$ 1

Approved on behalf of the EPCOR Ontario Utilities Inc. Board of Directors,

Stuart Lee
Director, EPCOR Ontario Utilities Inc

Tony Scozzafava
Director, EPCOR Ontario Utilities Inc

The accompanying notes are an integral part of these financial statements

EPCOR Natural Gas Limited Partnership

Statement of Changes in Equity
(In thousands of Canadian dollars)

For the year ended December 31, 2017

	Partnership units (note 14)	Retained earnings (deficit)	Equity attributable to the Partners
Equity at November 4, 2016	$ 1	$	$ 1
Comprehensive income for the period	-	-	-
Equity at December 31, 2016	$ 1	$ -	$ 1
Equity contribution from the Partners	$ 13,359	$ -	$ 13,359
Comprehensive loss for the year	-	(432)	(432)
Equity at December 31, 2017	$ 13,360	$ (432)	$ 12,928

The accompanying notes are an integral part of these financial statements

EPCOR Natural Gas Limited Partnership

Statement of Cash Flows
(In thousands of Canadian dollars)

For the year ended December 31,	2017	2016
(With comparative amounts for the 2 months ended December 31, 2016)		
Cash flows from (used in) operating activities:		
Comprehensive loss for the year	$ (432)	$ -
Reconciliation of comprehensive loss for the year to cash from (used in) operating activities:		
Depreciation and amortization (note 5)	190	-
Finance expenses (net)	24	-
Interest paid (net)	(24)	-
Change in employee benefits provisions (note 13)	16	-
Funds used in operations	(226)	-
Non-cash operating working capital (note 15)	54	(1)
Net cash flows used in operating activities	(172)	(1)
Cash flows used in investing activities:		
Acquisition or construction of property, plant and equipment (note 8)	(546)	-
Acquisition of intangible assets (note 9)	(41)	-
Business acquisition (note 22)	(22,019)	-
Net cash flows used in investing activities	(22,606)	-
Cash flows from financing activities:		
Cash contributions received (note 12)	13	-
Net proceeds from short-term loans and borrowings (note 16)	3,153	-
Issuance of long-term loans and borrowings (note 16)	8,660	-
Equity contributions from the partners (note 14)	13,360	1
Net cash flows from financing activities	25,186	1
Increase in cash	2,408	-
Cash, beginning of year	-	-
Cash, end of year	$ 2,408	$ -

The accompanying notes are an integral part of these financial statements

1. Description of business

(a) Nature of operations

EPCOR Natural Gas Limited Partnership (the Partnership or ENGLP) provides natural gas distribution service through its general partner EPCOR Ontario Utilities Inc. (the General Partner or EOUI) and operates within Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The Limited Partnership was formed on November 4, 2016 pursuant to a Certificate of Limited Partnership and a limited partnership agreement entered into between the General Partner and EPCOR Power Development Corporation (the "Limited Partner") dated as of November 4, 2016 and operates in Ontario with its registered head office located at 77 King Street West, Suite 400, Toronto, Ontario M5K 0A1.

ENGLP is a limited partnership registered in Canada and is managed by the General Partner. Although the General Partner holds legal title to the assets, the Partnership is the beneficial owner and assumes all the risks and rewards of the assets.

The Partnership is indirectly 100% owned by EPCOR Utilities Inc. (EPCOR).

(b) Rate regulation

The Partnership’s operations are regulated by the OEB pursuant to The Ontario Energy Board Act (Ontario), The Energy Act (Ontario) and regulations made under those statutes. The OEB administers these acts and regulations regarding tariffs, rates, construction, financing, operations, accounting and service area. Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Partnership on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the natural gas distribution business from achieving an acceptable rate of return that permits financial substainability of its operations including the recovery of expenses incurred for the benefit of other market participants in the natural gas industry such as transition costs and other regulatory assets. All requests for change in natural gas distribution charges require the approval of the OEB.

Regulatory developments in Ontario’s natural gas industry, including current and possible future consultations between the OEB and interest stakeholders, may affect distribution rates and other permitted recoveries in the future. EPCOR is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

2. Basis of presentation

(a) Statement of compliance

These financial statements have been prepared by management in accordance with IFRS as issued by the International Accounting Standards Board (IASB). These financial statements were approved and authorized for issue by the EPCOR Ontario Utilities Inc. Board of Directors on April 23, 2018.

(b) First time adoption of IFRS

Effective January 1, 2017, the Partnership adopted IFRS. These are the Partnership’s first financial statements prepared in accordance with IFRS. First-time adoption of IFRS had no impact on the Partnership’s comprehensive income for the year ended December 31, 2016 or on retained earnings as at November 4, 2016, the date of transition

(c) Basis of measurement

The Partnership's financial statements are prepared on the historical cost basis.

(d) Functional and presentation currency

These financial statements are presented in Canadian dollars and all rounded to the nearest thousand dollars, except where otherwise stated.

3. Significant accounting policies

The accounting policies set out below have been applied consistently during the period presented in these financial statements unless otherwise indicated.

(a) Business combinations and goodwill

Acquisitions of businesses are accounted for using the acquisition method. The determination of whether or not an acquisition meets the definition of business combination under IFRS requires judgment and is assessed on a case by case basis. The consideration for an acquisition is measured at the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of acquisition in exchange for control of the acquired business. The consideration transferred does not include amounts related to the settlement of pre-existing relationships. Such amounts are recognized in comprehensive income. Transaction costs that the Partnership incurs in connection with a business combination, other than those associated with the issue of debt or equity securities, are expensed as incurred.

Identifiable assets acquired and liabilities assumed in a business combination are measured initially at their fair values at the date of acquisition. Any contingent consideration payable is measured at fair value at the acquisition date. If the contingent consideration is classified as equity then it is not re-measured and settlement is accounted for within equity. Subsequent changes in the fair value of contingent consideration that is not classified as equity are recognized in comprehensive income.

Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. Subsequently, goodwill is measured at cost less accumulated impairment losses, if any. Goodwill is reviewed for impairment annually or more frequently, if events or changes in circumstances indicate the carrying amount may be impaired. Impairment is determined by assessing the recoverable amount of the cash-generating unit to which goodwill relates. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognized.

(b) Revenue recognition

Revenue is recognized to the extent that it is probable that economic benefits will flow to the Partnership for the provision of services and where the revenue can be reliably measured. Revenues are measured at the fair value of the consideration received or to be received, excluding discounts, rebates and sales taxes or duty.

Revenues from sales of natural gas are recognized upon delivery to the customer. These revenues include an estimate of the value of goods and services consumed by customers by the end of the reporting period and billed subsequent to the reporting period.

Revenues from the provision of natural gas distribution service are recognized over the period in which the service is performed and collectability is probable. These revenues include an estimate of the value of natural gas delivered to residential and commercial customers and billed subsequent to the reporting period. The Partnership has determined that they are acting as the principal for the commodity distribution and, therefore, have presented the commodity revenues on a gross basis

(c) Income taxes

As a limited partnership, ENGLP is not taxed at the entity level under the Canadian Income Tax Act. All income tax consequences are borne by its partners on a pro rata basis in proportion to their interest in the partnership.

(d) Inventories

Small parts and other consumables, the majority of which are consumed by the Partnership in the provision of its services, are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstances.

(e) Property, plant and equipment

Property, plant and equipment (PP&E) are recorded at cost, net of accumulated depreciation and accumulated impairment losses, if any.

Cost includes contracted services, materials and direct labor costs on qualifying assets. Where parts of an item of PP&E have different estimated economic useful lives, they are accounted for as separate items (major components) of PP&E.

The cost of major inspections and maintenance is recognized in the carrying amount of the item if the asset recognition criteria are satisfied. The carrying amount of a replaced part is derecognized. The costs of day-to-day servicing are expensed as incurred.

Depreciation of cost less residual value is charged on a straight-line basis over the estimated economic useful lives of items of each depreciable component of PP&E, from the date they are available for use, as this most closely reflects the expected usage of the assets. Land and construction work in progress are not depreciated. Estimating the appropriate economic useful lives of assets requires significant judgment and is generally based on estimates of life characteristics of similar assets. The estimated economic useful lives, methods of depreciation and residual values are reviewed annually with any changes adopted on a prospective basis.

The ranges of estimated economic useful lives for PP&E assets used are as follows:

Information systems & other	4 – 45 years
Machinery & equipment	8 – 15 years
Natural Gas distribution	20 – 55 years

Gains or losses on the disposal of PP&E are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. The gains or losses are included within depreciation and amortization.

(f) Intangible assets

Intangible assets with finite lives are stated at cost, net of accumulated amortization and impairment losses, if any. The cost of a group of intangible assets acquired in a transaction, including those acquired in a business combination that meet the specified criteria for recognition apart from goodwill, is allocated to the individual assets acquired based on their relative fair value.

The cost of intangible software includes the cost of license acquisitions, contracted services, materials, and direct labor costs on qualifying assets.

Amortization of the cost of finite life intangible assets is recognized on a straight-line basis over the estimated economic useful lives of the assets, from the date they are available for use, as this most closely reflects the expected usage of the asset. Work in progress is not amortized. The estimated economic useful lives and methods of amortization are reviewed annually with any changes adopted on a prospective basis.

The estimated economic useful lives for intangible assets with finite lives are as follows:

Software	10 years
Other rights	20 years

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. The gains or losses are included within depreciation and amortization.

(g) Deferred revenue

Certain assets may be acquired or constructed using contributions from developers or customers. Non-refundable contributions received towards construction or acquisition of an item of PP&E which are used to provide ongoing service to a customer are recorded as deferred revenue and are amortized on a straight-line basis over the estimated economic useful lives of the assets to which they relate.

(h) Provisions

A provision is recognized if, as a result of a past event, the Partnership has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation.

(i) Non-derivative financial instruments

Financial assets are identified and classified as loans and receivables. Financial liabilities are classified as other financial liabilities.

Financial assets and financial liabilities are presented on a net basis when the Partnership has a legally enforceable right to set off the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

Loans and receivables

Cash and cash equivalents and trade and other receivables are classified as loans and receivables.

The Partnership’s loans and receivables are recognized initially at fair value plus directly attributable transaction costs, if any. After initial recognition, they are measured at amortized cost using the effective interest method less any impairment as described in note 3(j). The effective interest method calculates the amortized cost of a financial asset or liability and allocates the finance income or expense over the term of the financial asset or liability using an effective interest rate. The effective interest rate is the rate that exactly discounts estimated future cash payments or receipts through the expected life of the financial instrument or a shorter period when appropriate, to the net carrying amount of the financial asset or financial liability.

Other financial liabilities

The Partnership’s trade and other payables, customer deposits and loans and borrowings are recognized on the date at which the Partnership becomes a party to the contractual arrangement. Other financial liabilities are derecognized when the contractual obligations are discharged, cancelled or expire.

Other financial liabilities are initially recognized at fair value plus directly attributable transaction costs, if any. Subsequently, these liabilities are measured at amortized cost using the effective interest rate method.

(j) Impairment of financial assets

The Partnership's financial assets held as loans and receivables are assessed for indicators of impairment at each reporting date. An impairment loss for financial assets is recorded when it is identified that there is objective evidence that one or more events has occurred, after the initial recognition of the asset, that has had a negative impact on the estimated future cash flows of the asset and that can be reliably estimated. Trade receivables and other assets that are not assessed for impairment individually are assessed for impairment on a collective basis. Objective evidence of impairment includes the Partnership's past experience of collecting payments as well as observable changes in national or local economic conditions.

For financial assets carried at amortized cost, the amount of the impairment loss recognized is the difference between the asset's carrying amount and the present value of estimated future cash flows discounted at the asset's original effective interest rate. If, in a subsequent period, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed or adjusted within comprehensive income. An impairment loss is reversed only to the extent that the financial asset’s carrying amount does not exceed the carrying amount that would have been determined if no impairment loss had been recognized.

(k) Impairment of non-financial assets

The carrying amounts of the Partnership's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. Non-financial assets include PP&E and intangible assets and goodwill. For goodwill and intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated at least once each year.

The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the cash-generating unit or CGU). For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income. Impairment losses recognized in respect of CGUs are allocated to the carrying amount of the assets in the unit (group of units) on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other non-financial assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a fundamental change, since the date of impairment, which may improve the financial performance of the non-financial asset. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(l) Standards and interpretations not yet applied

A number of new standards, amendments to standards and interpretations have been issued by the IASB and the International Financial Reporting Interpretations Committee, the application of which is effective for periods beginning on or after January 1, 2018. Those, which may be relevant to the Partnership and may impact the accounting policies of the Partnership, are set out below. The Partnership does not plan to adopt these standards early.

IFRS 9 – *Financial Instruments* (IFRS 9) which replaces IAS 39 – *Financial Instruments: Recognition and Measurement*, includes a new classification and measurement approach for financial assets that reflects the business model in which they are held and the characteristics of their contractual cash flows. IFRS 9 contains three principal classification categories for financial assets including (i) measured at amortized cost, (ii) fair value through other comprehensive income, and (iii) fair value through profit or loss. IFRS 9 also replaces the "incurred loss" model under IAS 39 with a forward looking "expected credit loss" (ECL) model for recognition of impairment on financial instruments. The effective date for implementation of IFRS 9 has been set for annual periods beginning on or after January 1, 2018.

Based on the assessment of the Partnership's existing financial instruments, the Partnership does not expect any material impact on the accounting for its financial instruments as a result of the adoption of IFRS 9. The Partnership expects to record an adjustment to the provision of allowance of doubtful accounts on its trade receivables resulting from the application of the methodology of the calculation prescribed by the new standard. As per the Partnership's existing policy, the allowance for doubtful accounts is calculated on the overdue balances of trade receivables only, whereas the new impairment model requires the Partnership to calculate the lifetime ECL on the initial recognition of trade receivables, instead of on the overdue balances only. Accordingly, the Partnership will be required to recognize the lifetime ECL on all outstanding trade receivables. As the Partnership has very short credit periods for trade receivables, the Partnership does not expect any material impact due to implementation of the new requirements in IFRS 9.

IFRS 15 - *Revenue from Contracts with Customers* (IFRS 15), which replaces IAS 11 - *Construction Contracts* and IAS 18 - *Revenue* and related interpretations, is effective for annual periods commencing on or after January 1, 2018. IFRS 15 introduces a new single revenue recognition model for contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized.

There are two methods by which the new standard can be adopted: (1) a full retrospective approach with a restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment recognized in retained earnings as of the date of adoption. The Partnership will adopt IFRS 15 using the modified retrospective approach with the cumulative effect of the adjustment, if any, recognized as of January 1, 2018, subject to allowable and elected practical expedients.

The Partnership has performed detailed analysis on each revenue stream that is within the scope of the new standard through review of the underlying contracts with customers to determine the impact of IFRS 15 on these financial statements. A significant portion of the Partnership's revenue is generated from the provision of utility services. The Partnership will continue to recognize utility revenue over time as the Partnership's customers simultaneously receive and consume the services they are provided.

The Partnership is finalizing its review and quantification of IFRS 15 application to contributions from customers and developers. Contributions, which may be in the form of physical assets or financial contributions, help fund infrastructure that will be used by the utility to provide ongoing services to customers. Such contributions are currently recorded as deferred revenue when received and are amortized and recognized as revenue on a straight-line basis over the estimated economic useful lives of the assets to which they relate. The Partnership is finalizing its review of all contributions recognized as deferred revenue to identify the contributions which will fall under the scope of IFRS 15, which includes the quantification of the impact of any change in the accounting treatment to contributions that fall within the scope of the new standard. Preliminary analysis suggests that contributions received where the utility will have an ongoing performance obligation with the contributor will fall under the scope of IFRS 15, with the fair value of the contributed assets recognized as revenue over the period which the related services will be provided. However, contributions where the utility has no ongoing performance obligation with the contributor will likely fall outside the scope of IFRS 15, and as a result, the Partnership is assessing whether a change in accounting treatment is required for these contributions.

As a result of the adoption of the new standard, the Partnership will be required to include significant disclosures in the financial statements based on prescribed requirements. These new disclosures will include information regarding the significant judgments used in evaluating how and when revenues are recognized and information related to contract assets and deferred revenues. In addition, IFRS 15 requires that the Partnership's revenue recognition policy disclosure includes additional detail regarding the various performance obligations and the nature, amount, timing, and estimates of revenues and cash flows generated from contracts with customers. The Partnership is in the process of preparing its draft disclosures, which will be required for the December 31, 2018 financial statements.

4. Use of judgments and estimates

The preparation of the Partnership's financial statements in accordance with IFRS requires management to make judgment in the application of account policies, and estimates and assumptions that affect the reported amounts of income, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the financial statements.

(a) Judgment

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in these statements are included in notes:
Note 3(a) - Business acquisitions
Note 3(b) - Revenue recognition
Note 3(h) - Provisions

(b) Estimates

The Partnership reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgment in making these estimates and assumptions. Adjustments to previous estimates, which may be material, are recorded in the period in which they become known. Actual results may differ from these estimates.

(In thousands of Canadian dollars unless otherwise indicated)

Assumptions and uncertainties that have a significant risk of resulting in a material adjustment within the next financial year include:

Revenues

Accounting estimates were made in determining revenue recognized for unbilled customer consumption which estimates usage using volumes of natural gas entering into the the distribution system.

Property plant and equipment and Intangbile assets

Estimating the appropriate economic useful lives of assets requires significant judgment and is generally based on estimates of life characteristics of similar assets.

Fair value measurement

The Partnership is required to estimate fair value for determination of asset impairments and the purchase price allocation for the business combination. Estimates of fair value may be based on readily determinable market values or depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate. Specific discussion on the recoverability of Goodwill has been considered and discussed in note 9.

5. Depreciation and amortization

		2017
Depreciation of property, plant and equipment	$	174
Amortization of intangible assets		16
	$	190

6. Trade and other receivables

		2017		2016
Trade receivables	$	1,343	$	1
Accrued revenues		980		-
Gross accounts receivables		2,323		-
Allowance for doubtful accounts		(102)		-
	$	2,221	$	1

Details of the aging of accounts receivables and analysis of the changes in the allowance for doubtful accounts are provided in note 19.

7. Inventories

		2017
Work-in-progress	$	48
General stock		34
	$	82

During the year ended December 31, 2017, inventory of $6 was expensed to other raw materials and operating charges.

No inventory write-downs were recognized in the year ended December 31, 2017. At December 31, 2017, no inventories were pledged as security for liabilities.

(In thousands of Canadian dollars unless otherwise indicated)

8. Property, plant and equipment

	Land	Information systems & other	Construction work in progress	Machinery & equipment	Natural gas distribution	Total
Cost						
Additions through business acquisition	$ 42	$ 353	$ -	$ 101	$ 16,989	$ 17,485
Additions	-	176	345	-	25	546
Balance, end of 2017	42	529	345	101	17,014	18,031
Accumulated depreciation						
Depreciation	-	24	-	2	148	174
Balance, end of 2017	-	24	-	2	148	174
Net book value, end of 2017	$ 42	$ 505	$ 345	$ 99	$ 16,866	$ 17,857

There are no security charges over the Partnership 's property, plant and equipment.

9. Intangible assets and goodwill

	Goodwill	Software	Other rights	Total
Cost				
Additions through business acquisition	$ 1,886	$ 1	$ 1,181	$ 3,068
Investment in intangible assets	-	41	-	41
Balance, end of 2017	1,886	42	1,181	3,109
Accumulated amortization				
Amortization	-	2	14	16
Balance, end of 2017	-	2	14	16
Net book value, end of 2017	$ 1,886	$ 40	$ 1,167	$ 3,093

There are no security charges over the Partnership's intangible assets.

For purposes of impairment testing, goodwill acquired through business combinations has been allocated to a single cash generating unit. The most recent review of goodwill was performed in the fourth quarter.

The recoverable amount of the cash generating unit was determined using a discounted cash flow analysis. Forecasted cash flows reflect revenues consistent with Ontario Energy Board (OEB) methodology of allowing a fair return on prudently placed capital that is recoverable through customer rates. Operating costs reflect historical costs of running the business, adjusted for inflation, and capital spending forecasts reflect system integrity and capacity needs of utility infrastructure. The pre-tax discount rate applied to cash flow projections was 5.1%

Key assumptions used in value-in-use calculations

The future cash flows of the underlying businesses are relatively stable since they relate primarily to ongoing natural gas supply in a rate-regulated environment. In the case of cash generating units operating under a rate-regulated environment, revenues are set by the regulators to cover operating costs and to earn a return on the rate base, which is set at the regulator’s approved weighted average cost of capital for the underlying utility.

The calculation of value in use for the cash generating units is most sensitive to the following assumptions:

(In thousands of Canadian dollars unless otherwise indicated)

Discount rates

The discount rates used were estimated based on the weighted average cost of capital for the cash generating unit, which, in the case of rate-regulated businesses, are the approved rate of return on capital allowed by the regulator. These rates were further adjusted to reflect the market assessment of any risk specific to the cash generating unit for which future estimates of cash flows have not been adjusted.

Timing of future rate increases

Revenue growth is forecast to continue in concordance with rate base growth. Prudent capital investment in utility infrastructure, to meet customer demand and system integrity needs, may be included in rate base and allowed to earn a fair return by the regulator. Such return on rate base is recovered through customer rates which drive revenue. In the case of rate-regulated businesses, if future rate filings are delayed then rate increases and increased cash flows from revenues would be affected

Sensitivity to changes in assumptions

Assumptions have been tested using reasonably possible alternative scenarios. For all scenarios considered, the recoverable value remained above the carrying amount of the cash generating unit.

10. Trade and other payables

		2017
Trade payables	$	260
Accrued liabilities		853
Accrued interest		30
	$	1,143

11. Loans and borrowings

		2017
Short-term note payable to EPCOR		
At the external prime interest rate	$	3,153
Long-term note payable to EPCOR		
At 3.83%, due in 2047		8,660
Total loans and borrowings		11,813
Less: current portion		3,153
	$	8,660

Short-term note payable to EPCOR is unsecured and due on demand. Interest is payable semi-annually.

The long-term notes payable to EPCOR are unsecured. Interest is payable semi-annually while principal is due at the end of the term.

12. Deferred revenue

Customer cash contributions of $13 were received in the year.

(In thousands of Canadian dollars unless otherwise indicated)

13. Provisions

Provisions consist of employee benefits obligations for benefits provided under employee incentive plans.

		2017
Provisions through business acquisition	$	3
Provisions made during the year		16
Balance, end of year	$	19

All employee benefit provision balances are expected to be utilized within one year.

14. Partnership units

The Partnership is authorized to issue unlimited number of Class A common units without nominal or par value. The units are voting and participate equally in profits, losses and capital distributions of the Partnership.

On November 4, 2016, 1,000 partnership units were issued. The General Partner was issued 1 unit and the Limited Partner 999 units.

On November 1, 2017, 13,358,556 additional units were issued. The General Partner was allocated an additional 13,359 units and the Limited Partner an additional 13,345,197 units.

The General Partner holds 13,360 Class A common units having capital contribution of $14 in the Partnership. It manages the operations of the Partnership and has a 0.10% interest in the profits, losses and capital distributions of the Partnership.

The Limited Partner holds 13,346,196 Class A common units representing a net capital contribution of $13,346 in the Partnership. The Limited Partner has 99.90% interest in the profits, losses and capital distribution of the Partnership.

15. Non-cash working capital

		2017		2016
Trade and other receivables (note 6)	$	(2,221)	$	(1)
Inventories (note 7)		(82)		-
Prepaid expenses		(358)		-
Trade and other payables (note 10)		1,143		-
Customer deposits		103		-
	$	(1,415)	$	(1)
Included in specific items on consolidated statements of cash flows:				
Business acquisitions		1,469		-
Non-cash operating working capital	$	54	$	(1)

16. Changes in liabilities arising from financing activities:

		Short-term loans and borrowings		Long-term loans and borrowings
Issued during the year ended December 31, 2017	$	44,845	$	8,660
Redemptions or repayments		(41,692)		-
Balance at December 31, 2017	$	3,153	$	$8,660

(In thousands of Canadian dollars unless otherwise indicated)

17. Related party balances and transactions

The Partnership is indirectly 100% owned by EPCOR. The Partnership purchases services from EPCOR and its subsidiaries relating to operational and inventory management, administration, maintenance, repair, utilities, facilities, general plant use, employee costs, executive oversight, legal, finance, treasury, audit, human resources, procurement, and information technology services pursuant to service agreements. Transactions between the Partnership and its related parties are in the normal course of operations, and are generally based on normal commercial rates, as agreed to by the parties.

The key management personnel of the Partnership have been defined as members of its board of directors. No payments were made to key personnel in the current or comparative period.

The following summarizes the Partnership's related party transactions with EPCOR and its subsidiaries:

	2017	2016
Statements of Comprehensive Income		
Other administrative expenses (a)	$ 1,124	$ -
Finance expenses (b)	$ 22	$ -

(a) Relates to expenditures for support and integration costs and administrative services.

(b) Relates to interest expense on short-term and long-term notes payable to EPCOR.

The following summarizes the Partnership's related party balances with EPCOR and its subsidiaries:

	2017	2016
Statements of Financial Position		
Trade and other receivables (c)	$ -	$ 1
Trade and other payables (d)	$ 30	$ -
Loans and borrowings (e)	$ 11,813	$ -
Provisions (f)	$ 8	$ -

(c) Relates to receivable balance pertaining to issuance of Partnership units.

(d) Relates to accrued interest on long-term notes payable to EPCOR.

(e) Relates to short-term and long-term notes payable to EPCOR.

(f) Relates to provisions for employee benefits.

18. Financial instruments

Classification

The classification of the Partnership’s financial instruments at December 31, 2017, is summarized as follows:

	Classification		
	Loans and receivables	Other financial liabilities	Fair value hierarchy
Measured at amortized cost			
Cash and cash equivalents	X		Level 1
Trade and other receivables (note 6)	X		Level 3
Customer deposits		X	Level 3
Trade and other payables (note 10)		X	Level 3
Loans and borrowings (note 11)		X	Level 2

Fair value

The carrying amounts of cash and cash equivalents, trade and other receivables, customer deposits and trade and other payables approximate their fair values due to the short-term nature of these financial instruments.

Fair value hierarchy

The financial instruments of the Partnership that are recorded at fair value have been classified into levels using a fair value hierarchy. A Level 1 valuation is determined by unadjusted quoted prices in active markets for identical assets or liabilities. A Level 2 valuation is based upon inputs other than quoted prices included in Level 1 that are observable for the instruments either directly or indirectly. A Level 3 valuation for the assets and liabilities are not based on observable market data.

Loans and borrowings

Short-term debt is measured at amortized cost and its fair value is not materially different from its carrying amount due to its short-term nature.

The carrying value of long-term loans and borrowings approximate their fair values as of December 31, 2017 due to the fact that the loans were issued in November 2017. Between November 1, 2017 and December 31, 2017 there has not been a material change between the carrying value and fair value of loans and borrowing.

19. Financial risk management

Overview

The Partnership is exposed to a number of different financial risks, arising from business activities and its use of financial instruments, including market risk, credit risk, and liquidity risk. The Partnership's overall risk management process is designed to identify, assess, measure, manage, mitigate and report on business risk which includes financial risk. Enterprise risk management is overseen by EPCOR's Board of Directors and senior management is responsible for fulfilling objectives, targets, and policies approved by the Board of Directors of EPCOR. EPCOR's Director, Audit and Risk Management provide the Board of Directors of EPCOR with an enterprise risk assessment quarterly. Risk management strategies, policies, and limits are designed to help ensure the risk exposures are managed within the EPCOR's business objectives and risk tolerance. The Partnership's financial risk management objective is to protect and minimize volatility in earnings and cash flow.

Financial risk management including interest rate risk, liquidity risk and the associated credit risk management is carried out by the centralized Treasury function of EPCOR in accordance with applicable policies. The Audit Committee of the Board of Directors of EPCOR, in its oversight role, performs regular and ad-hoc reviews of risk management controls and procedures to help ensure compliance.

Market risk

Market risk is the risk of loss that results from changes in market factors such as energy prices and interest rates. The level of market risk to which the Partnership is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Partnership's financial assets and liabilities held. EPCOR's financial exposure management policy is approved by the Board of Directors of EPCOR and the associated procedures and practices are designed to manage the interest rate risk throughout the Partnership.

Interest rate risk

The Partnership is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. Interest rate risk associated with short-term debt is immaterial due to its short-term maturity. At December 31, 2017, all long-term debt was fixed rate.

(In thousands of Canadian dollars unless otherwise indicated)

Credit risk

Credit risk is the possible financial loss associated with the ability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. EPCOR's counterparty credit risk management policy is approved by the Board of Directors of EPCOR and the associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the Company. Credit and counterparty risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into a transaction with the counterparty. Exposures and concentrations are subsequently monitored and are regularly reported to senior management. Creditworthiness continues to be evaluated after transactions have been initiated, at a minimum, on an annual basis. To manage and mitigate credit risk, the Partnership employs various credit mitigation practices such as master netting agreements, pre-payment arrangements and other forms of credit enhancements including cash deposits, parent Partnership guarantees, and bank letters of credit.

Maximum credit risk exposure

The Partnership's maximum credit exposure is represented by the carrying amount of the trade and other receivables balance of $2,221. These carrying amounts do not take into account collateral held. At December 31, 2017, the Partnership held cash deposits and a letter of credit of $336 as security for certain counterparty accounts receivable.

Credit quality and concentrations

The Partnership is exposed to credit risk on outstanding trade receivables associated with natural gas services to customers.

The Partnership's trade receivables are unrated, unsecured and not of investment grade.

Rate-regulated customer credit risk

Credit risk exposure is generally limited to amounts due from residential and commercial customers for natural gas consumed but not yet paid for. The Partnership mitigates credit risk from counterparties by performing credit checks and on higher risk retailers, by taking pre-payments or cash deposits.

Trade and other receivables and allowance for doubtful accounts

Trade and other receivables consist primarily of amounts due from residential and commercial customers. The Partnership mitigates these exposures by dealing with creditworthy counterparties and, when appropriate and contractually allowed, obtaining appropriate security from customers.

Credit losses are generally low and the Partnership provides an allowance for doubtful accounts on estimated credit losses.

The aging of accounts receivables was as follows:

December 31, 2017	Gross accounts Receivables	Allowance for doubtful accounts	Net accounts receivables
Current [a]	$ 2,169	$ -	$ 2,169
Outstanding 31 to 60 days	57	-	57
Outstanding 61 to 90 days	(5)	-	(5)
Outstanding more than 90 days	102	(102)	-
	$ 2,323	$ (102)	$ 2,221

(a) Current amounts represent trade and other receivables as well as accrued revenues outstanding up to 30 days. Amounts outstanding for more than 30 days are considered past due.

(In thousands of Canadian dollars unless otherwise indicated)

Bad debt expense of $6 recognized in the year relates to changes in customer amounts that the Partnership determined may not be fully collectable. Allowances for doubtful accounts are determined by considering the unique factors of different customer types. Allowances and write-offs are determined either by applying specific risk factors to customer groups' aged balances in trade and other receivables or by reviewing material accounts on a case-by-case basis. Reductions in trade and other receivables and the related allowance for doubtful accounts are recorded when the Partnership has determined that recovery is not possible.

The changes in the allowance for doubtful accounts were as follows:

		2017
Allowance acquired through business acquisition	$	96
Additional allowances created		6
Receivables written off		-
Balance, end of year	$	102

At December 31, 2017, the Partnership held $336 of customer deposits and a letter of credit for the purpose of mitigating the credit risk associated with trade and other receivables from customers.

Liquidity risk

Liquidity risk is the risk that the Partnership will not be able to meet its financial obligations as they become due. The Partnership's liquidity is managed centrally by EPCOR’s Treasury function. EPCOR manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements of the Partnership are addressed through operating cash flows, and if necessary, intercompany financing from EPCOR.

The undiscounted cash flow requirements and contractual maturities of the Partnership's financial liabilities, including interest payments, are as follows:

At December 31, 2017	2018	2019	2020	2021	2022	2023 and thereafter	Total contractual cash flows
Trade and other payables[(a)]	$ 1,113	$ -	$ -	$ -	$ -	$ -	$ 1,113
Customer Deposits	103	-	-	-	-	-	103
Loans and borrowings	3,153	-	-	-	-	8,660	11,813
Interest payments on loans and borrowings	332	332	332	332	332	8,290	9,950
	$ 4,701	$ 332	$ 332	$ 332	$ 332	$ 16,950	$ 22,979

(a) Excluding accrued interest on loans and borrowings of $30.

The Partnership’s undiscounted cash flow requirements and contractual maturities in the next twelve months of $4,701 will be funded from operating cash flows and additional loans and borrowings.

(In thousands of Canadian dollars unless otherwise indicated)

20. Capital management

The Partnership's primary objectives when managing capital is to safeguard the Partnership's ability to continue as a going concern and pay cash distributions to its unit holders. The Partnership manages its capital structure in a manner consistent with the risk characteristics of the underlying assets and in accordance with OEB regulatory decisions.

The Partnership manages capital through regular monitoring of cash requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Partnership matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity

The Partnership considers its capital structure to consist of loans and borrowings (including current portion) and unit holder's equity. The following table represents the Partnership's total capital:

		2017
Loans and borrowings (including current portion) (note 11)	$	11,813
Cash and cash equivalents		(2,408)
Net debt		9,405
Total equity		12,928
Total capital	$	22,333

To manage or adjust its capital structure, the Partnership can issue new debt, repay existing debt or issue or redeem common units.

21. Commitments and contingencies

The following are the Partnership's commitments and contingencies not otherwise disclosed in these financial statements as at December 31, 2017:

(a) Commitments for the minimum cost of the monthly demand charge from Union Gas regardless of the total volume of gas delivered into the distribution system estimated at $900 annually.

(b) Commitments for the purchase of general administrative and operation services from EPCOR and its subsidiaries are estimated at $320 annually. These estimates are subject to change based on actual activity levels.

22. Business acquisition

Effective November 1, 2017, the Partnership assumed operations and acquired substantially all of the net natural gas distribution assets of Natural Resource Gas Limited ("NRG") for cash consideration of $22,019. NRG provides services to approximately 8,700 customers located in several Southern Ontario municipalities. Prior to the acquisition of NRG net assets, there was no operating activity in the Partnership.

The fair values of net assets acquired in the acquisition of NRG are as follows:

		2017
Fair value of net assets acquired:		
Trade and other receivables	$	1,022
Inventories		112
Prepaid expenses		478
Property, plant and equipment		17,485
Intangible assets		1,182
Goodwill		1,886
Other liabilities		(146)
Net assets	$	22,019

The property, plant and equipment primarily consist of natural gas distribution assets.

The intangible assets consist of the right to distribute natural gas within the franchise area of southern Ontario for a period of 20 years.

The goodwill recognized at fair value of $1,886 includes the value of the expected benefits to the Partnership by providing entry into the Ontario natural gas and utility market, along with the potential for expanded operations in the Ontario region.

The Partnership incurred integration costs of $1,000 to complete the acquisition. Integration costs are included on the 'Other administration expenses' financial statement caption in the current period.

NATURAL RESOURCE GAS LIMITED

Financial Statements

Year Ended September 30, 2015

NATURAL RESOURCE GAS LIMITED
Index to Financial Statements
Year Ended September 30, 2015

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BDO Canada LLP
633 Colborne Street
Unit 300
London Ontario N6B 2V3 Canada

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Natural Resource Gas Limited

We have audited the accompanying financial statements of Natural Resource Gas Limited, which comprise the balance sheet as at September 30, 2015 and the statements of deficit and cash flow for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our qualified audit opinion.

(continues)

Basis for Qualified Opinion

The Company has issued and outstanding Class C shares with a redemption value of $13,461,418. Canadian accounting standards for private enterprises require that the company present and classify shares that are retractable at the option of the shareholder as a liability on the balance sheet unless the shares were issued under certain income tax planning arrangements. The Company has presented these shares as part of shareholders' equity. If the shares were classified as liabilities, then the total liabilities as at September 30, 2015 would increase by $13,461,418 and share capital would decrease by $13,461,418.

Qualified Opinion

In our opinion, except that the Class C shares of the Company have been presented as part of shareholders' equity rather than as a liability, these financial statements present fairly, in all material respects, the financial position of the Company as at September 30, 2015 and the results of its operations and its cash flows for then ended in accordance with Canadian Accounting standards for private enterprises.

Other Matter

The financial statements for the year ended September 30, 2014 were audited by the firm of NPT LLP, whose practice now operates under BDO Canada LLP.

BDO Canada LLP

London, Ontario
March 14, 2016

Chartered Professional Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Balance Sheet

September 30, 2015

	2015	2014
ASSETS		
CURRENT		
Cash	$ -	$ 668,348
Accounts receivable *(Notes 9, 13, 16)*	910,360	2,335,798
Taxes other than income taxes recoverable	9,123	-
Inventory	42,991	92,222
Prepaid expenses	205,113	73,970
Assets related to discontinued operations *(Note 4)*	13,397	1,353,263
	1,180,984	4,523,601
Property, plant and equipment *(Note 5)*	10,952,124	11,258,663
Franchises and consents *(Note 6)*	452,378	446,661
Deferred charges *(Note 7)*	1,046,859	1,183,395
Future income taxes	332,500	-
	$ 13,964,845	$ 17,412,320

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Balance Sheet
September 30, 2015

	2015	2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT		
Bank indebtedness *(Note 8)*	**$ 301,383**	$ -
Accounts payable and accrued liabilities *(Notes 9, 12)*	**3,029,478**	3,216,094
Taxes other than income taxes payable	**-**	271
Income taxes payable	**101,933**	99,463
Customer deposits	**134,340**	135,369
Deferred revenue	**121,402**	118,667
Future income taxes	**216,000**	128,700
Term notes payable *(Note 10)*	**5,372,191**	5,717,995
	9,276,727	9,416,559
Future income taxes	**-**	152,000
Accounts payable due beyond one year *(Note 13)*	**1,006,017**	501,438
	10,282,744	10,069,997
SHAREHOLDERS' EQUITY		
Share capital *(Note 11)*	**13,461,439**	13,461,439
Deficit	**(9,779,338)**	(6,119,116)
	3,682,101	7,342,323
	$ 13,964,845	$ 17,412,320

ON BEHALF OF THE BOARD

__________________________________ *Director*

__________________________________ *Director*

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Statement of Deficit
Year Ended September 30, 2015

		2015		2014
DEFICIT - BEGINNING OF YEAR	**$**	**(6,119,116)**	$	(6,804,011)
Net income (loss) for the year		**(160,222)**		684,895
		(6,279,338)		(6,119,116)
Dividends paid		**(3,500,000)**		-
DEFICIT - END OF YEAR	**$**	**(9,779,338)**	$	(6,119,116)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Income

Year Ended September 30, 2015

	2015	2014
Gas commodity revenue	$ 5,830,818	$ 5,634,874
Gas commodity cost	(5,821,334)	(5,625,327)
Gross margin on commodity	9,484	9,547
Distribution revenue	6,697,276	6,592,877
Distribution costs	(1,044,521)	(1,023,941)
Gross margin on distribution	5,652,755	5,568,936
Other sales	30,772	42,120
Labour and materials costs related to other sales	(16,526)	(109,873)
	14,246	(67,753)
TOTAL GROSS MARGIN	5,676,485	5,510,730
OPERATING EXPENSES (Schedule 1)	6,042,879	5,491,396
INCOME FROM OPERATIONS	(366,394)	19,334
OTHER INCOME (EXPENSES)		
Other revenue	$ 142,557	$ 148,393
Interest income on investments	31,038	-
Losses on disposal of investments	(2,622,625)	-
	(2,449,030)	148,393
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES	(2,815,424)	167,727
INCOME TAXES (RECOVERY)		
Current income taxes	14,000	152,000
Future income taxes	(397,200)	(160,300)
	(383,200)	(8,300)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(2,432,224)	176,027
Gain on disposal of discontinued operations (net of income tax)*(Note 4)*	1,869,582	-
Income related to discontinued operations (net of income tax) *(Note 4)*	402,420	508,867
TOTAL INCOME FROM DISCONTINUED OPERATIONS	2,272,002	508,867
NET INCOME FOR THE YEAR	$ (160,222)	$ 684,894

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Cash Flow

Year Ended September 30, 2015

	2015	2014
OPERATING ACTIVITIES		
Net income for the year	$ (160,222)	$ 684,895
Items not affecting cash:		
Amortization of property, plant and equipment	1,029,382	1,070,970
Gain on disposal of assets related to discontinued operations	(1,869,582)	-
Loss on disposal of investments	2,622,625	-
Amortization of franchises and consents, and deferred charges	103,304	95,565
Amortization of regulatory charges	141,500	276,245
Future income taxes	(397,200)	(160,300)
	1,469,807	1,967,375
Changes in non-cash working capital *(Note 15)*	1,667,187	(324,054)
Cash flow from operating activities	3,136,994	1,643,321
INVESTING ACTIVITIES		
Additions to property, plant and equipment	(755,044)	(809,937)
Proceeds on disposal of property, plant and equipment	55,110	42,180
Proceeds on disposal of assets related to discontinued operations	3,175,287	-
Additions to deferred charges	(74,601)	(1,044,663)
Additions to franchise and consents	(39,047)	(115,157)
Proceeds from sale of investments	8,073,730	-
Purchases of investments	(10,696,356)	-
Cash flow used by investing activities	(260,921)	(1,927,577)
FINANCING ACTIVITIES		
Dividends paid	(3,500,000)	-
Repayments of term notes payable	(345,804)	(345,804)
Cash flow used by financing activities	(3,845,804)	(345,804)
DECREASE IN CASH	(969,731)	(630,060)
Cash - beginning of year	668,348	1,298,408
CASH (BANK INDEBTEDNESS) - END OF YEAR	$ (301,383)	$ 668,348

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Notes to Financial Statements

Year Ended September 30, 2015

1. NATURE OF BUSINESS

The Company operates as a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

2. BASIS OF PRESENTATION

The financial statements were prepared in accordance with Canadian accounting standards for private enterprises (ASPE). ASPE are part of Canadian generally accepted accounting principles (GAAP).

Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the OEB renders their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under ASPE for non-regulated entities.

In addition to defining certain accounting requirements, the OEB has jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Revenue recognition

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet (included in accounts receivable or accounts payable and accrued liabilities) pending disposition by a decision of the OEB.

Rental revenue is recognized as income in the month earned. Revenue on other sales not subject to rate regulations are recognized when goods have been delivered or services have been performed.

Investment revenue is recognized as income when the dividends and interest is received. Gains or losses are recorded upon disposal of investments.

Cash

Cash consists of cash on hand and bank account balances, with adjustments for outstanding cheques or deposits at year-end.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Inventory

Inventory consists of materials used for the service of existing gas pipelines and the addition of new gas pipelines. Inventory is valued at the lower of cost and net realizable value with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Franchises and consents

Costs associated with acquiring municipal franchises and other consents are capitalized when incurred, if the franchise application is successful. These costs are amortized on a straight line basis over the term of the franchise.

These assets are tested for an impairment in value when events or circumstances indicate that an asset might be impaired. The assets are tested for impairment by comparing their carrying value to estimates of their fair value. Fair value is based on estimates of discounted future cash flows or other valuation methods. When the fair value is determined to be less than carrying value, the resulting impairment is reported in the income statement.

Deferred charges

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals has been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

Property, plant and equipment

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment that is subject to rate regulation, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization.

For disposals of major property, plant and equipment and for those assets not subject to rate regulation, gains or losses are included in current earnings.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2015.

(continues)

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2015

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Amortization

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis. Property, plant and equipment are amortized at the following rates and methods listed below:

Buildings	2%	straight-line method
Machinery and equipment	6% to 9%	declining balance method
Automotive equipment	17%	straight-line method
Computer equipment	33%	declining balance method
Furniture and fixtures	7%	straight-line method
Meters and regulators	3% to 4%	straight-line method
Pipeline installations	3% to 5%	straight-line method

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. The last change was made at the start of the fiscal 2005 year, and the rates were reaffirmed as part of the 2011 Cost of Service Rate filing. Any such changes in estimate are applied on a prospective basis.

Future income taxes

Income taxes are reported using the future income taxes method, as follows: current income tax expense is the estimated income taxes payable for the current year after any refunds or the use of losses incurred in previous years, and future income taxes reflect:

- the temporary differences between the carrying amounts of assets and liabilities for accounting purposes and the amounts used for tax purposes;
- the benefit of unutilized tax losses that will more likely than not be realized and carried forward to future years to reduce income taxes.

Future income taxes are estimated using the rates enacted by tax law and those substantively enacted for the years in which future income taxes assets are likely to be realized, or future income tax liabilities settled. The effect of a change in tax rates on future income tax assets and liabilities is included in earnings in the period when the change is substantively enacted.

Gas commodity costs and gas transportation costs

Gas commodity costs and gas transportation costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for consideration in future rate adjustments or disposition subject to the approval of the OEB. In a non-regulated environment periodic variances between gas commodity sales rates and costs or gas transportation costs would be reported through the income statement annually without the use of deferral accounts.

(continues)

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2015

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Financial instruments policy

Financial instruments are recorded at fair value when acquired or issued. In subsequent periods, financial assets with actively traded markets are reported at fair value, with any unrealized gains and losses reported in income. All other financial instruments are reported at amortized cost, and tested for impairment at each reporting date.

Transaction costs on the acquisition, sale, or issue of financial instruments are expensed when incurred. However, financial instruments that will not be subsequently measured at fair value are adjusted by the transaction costs that are directly attributable to their original issuance or assumption.

Measurement uncertainty

The preparation of financial statements in conformity with Canadian ASPE requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. Such estimates are periodically reviewed and any adjustments necessary are reported in earnings in the period in which they become known. Actual results could differ from these estimates.

4. DISCONTINUED OPERATIONS

The Company has sold its water heater sales and rental division. The water heater sales and rental division was sold as an operating unit on July 1, 2015 with operations ceased on June 30, 2015. The Company completed the sale prior to the year end for the majority of assets related to this division. The following assets and liabilities of the water heater sales and rentals division have been reported as assets of discontinued operations:

	2015	2014
Assets of discontinued operations:		
Inventory	**$ 13,397**	$ 13,585
Property and equipment	**-**	1,339,678
Total assets of discontinued operations	**$ 13,397**	$ 1,353,263

The income from discontinued operations in the statement of operations is reported net of related income tax expense of $446,000 (2014 - $183,000).

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2015

5. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated amortization	**2015 Net book value**	2014 Net book value
Land	$ 71,700	$ -	**$ 71,700**	$ 71,700
Buildings	687,374	228,434	**458,940**	474,199
Machinery and equipment	773,753	603,727	**170,026**	147,773
Automotive equipment	322,234	324,662	**(2,428)**	81,876
Computer equipment	445,444	383,707	**61,737**	55,131
Furniture and fixtures	110,072	74,889	**35,183**	36,399
Meters and regulators	4,180,944	2,328,135	**1,852,809**	1,714,324
Pipeline installations	16,545,123	8,240,966	**8,304,157**	8,677,261
	$ 23,136,644	$ 12,184,520	**$ 10,952,124**	$ 11,258,663

6. FRANCHISES AND CONSENTS

	2015	2014
Franchises and consents	**$ 678,567**	$ 639,520
Accumulated amortization	**(226,189)**	(192,859)
	$ 452,378	$ 446,661

7. DEFERRED CHARGES

	2015	2014
Deferred charges (see note below)	**$ 1,044,663**	$ 1,044,663
Rates application costs	**282,977**	672,990
Less: Accumulated amortization	**(280,781)**	(534,258)
	$ 1,046,859	$ 1,183,395

Deferred charges consist of amounts ordered by the OEB to be paid to a customer. Deferred charges are amortized over 15 years on a straight line basis.

Rates applications costs are deferred and amortized on a straight line basis over the time period for which the application applies.

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2015

8. OPERATING LINE OF CREDIT

The Company has credit facilities in the amount of $3,000,000 which it obtained in conjunction with the term note, consisting of:

a) Operating line of credit in the amount of $1,000,000 with interest at the Bank's Prime Rate on any advances, and

b) Non-revolving line of credit in the amount of $2,000,000 to be used for financing capital expenditures with interest at the Bank's Prime Rate plus 0.25% on any advances.

The continuation of the above credit facilities is subject to annual review by the Bank. These credit facilities are secured by the security agreement in place as disclosed in note 10.

9. RELATED PARTY TRANSACTIONS

Included in accounts receivable are amounts receivable from related companies of $7,710 (2014 - $4,195).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $50,040 (2014 - $72,859).

During the year, management fees of $457,020 (2014 - $457,020) were paid to a related company.

During the year, the Company purchased gas in the amount of $643,573 (2014 - $773,617) from a related company.

During the year, maintenance charges of $6,000 (2014 - $6,000) were charged to a related company.

During the year, the Company paid project management fees of $nil (2014 - $17,653) to a related company.

During the year, the Company agreed to provide credit facilities to a related party up to a maximum of $2,000,000 with interest charged at 1% per annum on the outstanding balance. The credit facility was utilized during the year, however no balance is outstanding on the facility at September 30, 2015. Interest earned on advances made under the credit facility amount to $18,628.

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2015

10. TERM NOTES PAYABLE

		2015		2014
Bank of Nova Scotia term note payable, maturing on June 30, 2016 (matured on June 30, 2015 and extended with identical terms), interest at bank prime plus 0.25%, repayable in monthly payments of $12,386, due on demand.	**$**	**2,316,132**	$	2,464,764
Bank of Nova Scotia term note payable, maturing on November 30, 2016 (matured on April 17, 2015 and extended with identical terms), interest at bank prime, repayable in monthly payments of $16,431 plus interest, due on demand.		**3,056,059**		3,253,231
	$	**5,372,191**	$	5,717,995

The company has pledged the following as security against the term notes payable, the operating line of credit, and the revolving line of credit (note 8):

a) General assignment of book debts

b) General Security Agreement over all of the present and future personal property and undertaking of the company

c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank

d) Postponement of dividends and share redemption payments by the Class C shareholders

e) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss if any, payable to the Bank as mortgagee.

The term notes payable, the operating line of credit, and the revolving line of credit include the following covenants that the company must meet:

1. maintain a debt service coverage ratio of 1.25:1 or better; and

2. maintain a ratio of debt to tangible net worth of 3.0 or less; and

3. annual capital expenditures of $1.3 million or less; and

At September 30, 2015, the company was not in compliance with covenant #2. The bank acknowledges and waives this breach, subject to it's correction on or before June 30, 2016.

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2015

11. SHARE CAPITAL

Authorized:

Unlimited	Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends
Unlimited	Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution
Unlimited	Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share
Unlimited	Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement
Unlimited	Unlimited number of common shares

		2015	2014
Issued:			
50,000	Class A shares	$ **1**	$ 1
10	Class B shares	**10**	10
134,614	Class C shares	**13,461,418**	13,461,418
10	Class Z shares	**10**	10
		$ 13,461,439	$ 13,461,439

12. GAS IMBALANCES

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas consumed and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $138,891 (2014 - $137,117) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

NATURAL RESOURCE GAS LIMITED

Notes to Financial Statements

Year Ended September 30, 2015

13. REGULATORY MATTERS

The Company's distribution rates are approved by the OEB. The Company's commodity rates are approved by the OEB and adjusted on a quarterly basis based on commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB.

During the prior year, Union Gas charged the Company $2,007,250 for the shortfall of the winter checkpoint. This was later reduced from a Decision and Order made by the OEB to $1,287,548. Subsequent to year-end, the OEB issued a Decision and Order on this matter which confirmed the amount of the allowable charge by Union Gas. The Decision and Order allowed $181,531 of this to be recoverable through the commodity variance account, while the remaining $1,106,016 was not to be recovered through rates. The Decision and Order sets out the terms of payment of the charge to Union Gas, which will be repayable over multiple years based on operating results of the Company. Therefore, a portion of this liability has been classified as long term.

The Company has a matter before the OEB relating to the allowable natural gas price it can recover from natural gas purchased from a related party. The OEB is currently seeking additional information prior to making a ruling on this matter.

During the year, the OEB issued Decision and Orders which approved a new franchise agreement with a municipality for a period of 20 years, retroactive to the expiry date of the previous interim orders.

Accounting principles differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under ASPE for non-regulated entities. The following balances are a direct result of rate regulatory matters:

Included in accounts payable is $1,212,200 (2014 - $1,157,309 included in accounts receivable) resulting from the regulated ratemaking process that may not be recorded under ASPE in the absence of rate regulation. The Company estimates that this amount will be settled in the upcoming year.

In the absence of rate-regulation, some of the above balances would be recognized in the income statement of the organization. As a result, net income from operations would be increased by $668,300 (2014 - decreased by $1,804,000).

In the absence of rate-regulation, the Company's current future income tax liability would be lower by $216,000 (2014 - $128,700) as a result of the elimination of the regulatory amounts included in accounts payable and accounts receivable.

14. CAPITAL LOSSES FOR INCOME TAX CARRIED FORWARD

During the year, the company incurred a capital loss of $2,622,625 which is available for application against future years' capital gains, with no expiry date. This amount has been included in the calculation of future tax assets and liabilities.

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2015

15. CHANGES IN NON-CASH WORKING CAPITAL

	2015	2014
Accounts receivable	**$ 1,425,438**	$ (1,726,275)
Taxes other than income taxes payable/recoverable	**(9,394)**	27,577
Inventory	**49,230**	(10,227)
Prepaid expenses	**(131,143)**	(26,925)
Assets related to discontinued operations	**10,915**	7,351
Accounts payable and accrued liabilities	**(186,614)**	955,726
Income taxes payable	**2,470**	(98,784)
Customer deposits	**(1,029)**	(1,186)
Deferred revenue	**2,735**	47,251
Accounts payable due beyond one year	**504,579**	501,438
	$ 1,667,187	$ (324,054)

16. FINANCIAL INSTRUMENTS

The Company is exposed to various risks through its financial instruments. The following analysis provides information about the Company's risk exposure and concentration. There have been no significant changes to the nature or concentration of these risks from the prior year, unless otherwise stated.

Credit risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation. The Company is exposed to credit risk from customers. In order to reduce its credit risk, the Company reviews a new customer's credit history before extending credit and conducts regular reviews of its existing customers' credit performance. The Company has the ability to take security deposits if there are payment issues, and charge interest and penalties on any late payments. The Company has a significant number of customers which minimizes concentration of credit risk.

An allowance for doubtful accounts is established based upon factors surrounding the credit risk of specific accounts, historical trends and other information. The allowance for doubtful accounts was $207,016 at September 30, 2015 (2014 - $169,850).

Liquidity risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages its liquidity risk by forecasting its cash needs on a regular basis and seeking additional information based on those forecasts. The Company's objective is to generate sufficient cash from its operations to meet its financial obligations. The Company also maintains available credit facilities as described in note 8 to support the liquidity requirements of the business.

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk and other price risk.

(continues)

16. FINANCIAL INSTRUMENTS *(continued)*

Currency risk

Currency risk is the risk to the company's earnings that arise from fluctuations of foreign exchange rates. The company was exposed to currency risk on the short-term investments it held during the year. As of September 30, 2015, it does not hold financial instruments denominated in a foreign currency.

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Company is exposed to interest rate risk primarily through its term notes payable and lines of credit as they bear interest at a fluctuating bank prime rate related interest rate. Additionally, the Company earns interest or is charged interest on its regulatory amounts receivable or amounts payable at the interest rate prescribed by the OEB, which is subject to adjustment on a quarterly basis.

Included in other revenue is interest income of $64,350 (2014 - $52,683) earned on regulatory balances and charged on late payments.

Other price risk

Other price risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices (other than those arising from interest rate risk or currency risk), whether those changes are caused by factors specific to the individual financial instrument or its issuer, or factors affecting all similar financial instruments traded in the market. The Company is exposed to other price risk through its natural gas prices.

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations.

17. COMPARATIVE FIGURES

Some of the comparative figures have been reclassified to conform to the current year's presentation.

NATURAL RESOURCE GAS LIMITED

Schedule of Operating Expenses ***(Schedule 1)***

Year Ended September 30, 2015

	2015	2014
Salaries and benefits	**$ 1,459,506**	$ 1,395,988
Gas commodity costs *(Note 13)*	**1,214,101**	146,741
Amortization of property, plant and equipment	**891,475**	890,253
Property taxes	**533,094**	506,712
Management fees *(Note 9)*	**457,020**	457,020
Professional fees	**263,519**	89,135
Ontario Energy Board hearings and regulatory charges	**225,356**	1,036,973
Office	**207,167**	187,968
Insurance	**174,538**	164,744
Repairs and maintenance	**172,847**	144,595
Interest on term notes payable	**165,643**	183,250
Amortization of franchises and consents and deferred charges	**103,304**	95,565
Vehicle	**65,516**	81,090
Advertising	**62,642**	54,094
Bad debts	**37,166**	32,034
Interest expense	**28,348**	45,056
Utilities	**10,765**	9,825
	6,072,007	5,521,043
Equipment expenses capitalized to pipeline installations	**(18,482)**	(19,142)
Amortization capitalized to pipeline installations	**(10,645)**	(10,504)
	$ 6,042,880	$ 5,491,397

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Financial Statements

Year Ended September 30, 2016

NATURAL RESOURCE GAS LIMITED
Index to Financial Statements
Year Ended September 30, 2016

BDO

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BDO Canada LLP
633 Colborne Street
Unit 300
London Ontario N6B 2V3 Canada

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Natural Resource Gas Limited

We have audited the accompanying financial statements of Natural Resource Gas Limited, which comprise the balance sheet as at September 30, 2016 and the statements of deficit and cash flow for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our qualified audit opinion.

Basis for Qualified Opinion

The Company has issued and outstanding Class C shares with a redemption value of $13,461,418. Canadian accounting standards for private enterprises require that the company present and classify shares that are retractable at the option of the shareholder as a liability on the balance sheet unless the shares were issued under certain income tax planning arrangements. The Company has presented these shares as part of shareholders' equity. If the shares were classified as liabilities, then the total liabilities as at September 30, 2015 and as at September 30, 2016 would increase by $13,461,418 and share capital would decrease by $13,461,418.

(continues)

Qualified Opinion

In our opinion, except that the Class C shares of the Company have been presented as part of shareholders' equity rather than as a liability, these financial statements present fairly, in all material respects, the financial position of the Company as at September 30, 2016 and the results of its operations and its cash flows for then ended in accordance with Canadian Accounting standards for private enterprises.

BDO Canada LLP

Chartered Professional Accountants
Licensed Public Accountants

London, Ontario
November 15, 2016

NATURAL RESOURCE GAS LIMITED
Balance Sheet
September 30, 2016

	2016	2015 *Restated (Note 4)*
ASSETS		
CURRENT		
Accounts receivable *(Notes 10, 14, 17)*	**$ 798,547**	$ 910,360
Income taxes recoverable	**14,501**	-
Taxes other than income taxes recoverable	**127,634**	9,123
Inventory	**58,418**	42,991
Prepaid expenses	**11,808**	205,113
Assets related to discontinued operations *(Note 5)*	**-**	13,397
	1,010,908	1,180,984
Property, plant and equipment *(Note 6)*	**12,699,156**	10,952,124
Franchises and consents *(Note 7)*	**448,294**	452,378
Deferred charges *(Note 8)*	**723,744**	1,046,859
Future income taxes	**345,000**	332,500
	$ 15,227,102	$ 13,964,845

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Balance Sheet
September 30, 2016

		2016		2015 *Restated (Note 4)*
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT				
Bank indebtedness *(Note 9)*	$	**501,838**	$	301,383
Accounts payable and accrued liabilities *(Notes 10, 13)*		**1,948,855**		2,185,173
Income taxes payable		**-**		101,933
Customer deposits		**117,153**		134,340
Deferred revenue		**48,418**		121,402
Future income taxes		**214,000**		440,000
Term notes payable *(Note 11)*		**7,018,053**		5,372,191
		9,848,317		8,656,422
Accounts payable due beyond one year *(Note 14)*		**639,423**		1,006,017
		10,487,740		9,662,439
SHAREHOLDERS' EQUITY				
Share capital *(Note 12)*		**13,461,439**		13,461,439
Deficit		**(8,722,077)**		(9,159,033)
		4,739,362		4,302,406
	$	**15,227,102**	$	13,964,845

SUBSEQUENT EVENTS *(Note 18)*

ON BEHALF OF THE BOARD

_______________________ *Director*

_______________________ *Director*

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Statement of Deficit
Year Ended September 30, 2016

	2016	2015 *Restated (Note 4)*
DEFICIT - BEGINNING OF YEAR		
As previously reported	$ **(9,159,034)**	$ (6,119,116)
Prior period adjustment *(Note 4)*	**-**	480,448
As restated	**(9,159,034)**	(5,638,668)
Net income (loss) for the year	**436,957**	(20,365)
	(8,722,077)	(5,659,033)
Dividends paid	**-**	(3,500,000)
DEFICIT - END OF YEAR	$ **(8,722,077)**	$ (9,159,033)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Statement of Income
Year Ended September 30, 2016

	2016	2015 Restated (Note 4)
Gas commodity revenue	$ 3,841,812	$ 5,830,818
Gas commodity cost	(3,833,916)	(5,821,334)
Gross margin on commodity	7,896	9,484
Distribution revenue	6,502,192	6,697,276
Distribution costs	(824,267)	(863,229)
Gross margin on distribution	5,677,925	5,834,047
Other sales	13,363	30,772
Labour and materials costs related to other sales	(4,644)	(16,526)
	8,719	14,246
TOTAL GROSS MARGIN	5,694,540	5,857,777
OPERATING EXPENSES (Schedule 1)	5,166,129	6,033,314
INCOME (LOSS) FROM OPERATIONS	528,411	(175,537)
OTHER INCOME (EXPENSES)		
Other revenue	112,046	142,557
Interest income on investments	-	31,038
Losses on disposal of investments	-	(2,622,625)
	112,046	(2,449,030)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES	640,457	(2,624,567)
INCOME TAXES (RECOVERY)		
Current income taxes	442,000	14,000
Future income taxes	(238,500)	(346,200)
	203,500	(332,200)
INCOME (LOSS) FROM CONTINUING OPERATIONS	436,957	(2,292,367)
Gain on disposal of discontinued operations (net of income tax)*(Note 5)*	-	1,869,582
Income related to discontinued operations (net of income tax) *(Note 5)*	-	402,420
TOTAL INCOME FROM DISCONTINUED OPERATIONS	-	2,272,002
NET INCOME (LOSS) FOR THE YEAR	$ 436,957	$ (20,365)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Statement of Cash Flow
Year Ended September 30, 2016

	2016	2015 *Restated (Note 4)*
OPERATING ACTIVITIES		
Net Income (loss) for the year	$ **436,957**	$ (20,365)
Items not affecting cash:		
Amortization of property, plant and equipment	**1,015,033**	1,029,382
Gain on disposal of assets related to discontinued operations	-	(1,869,582)
Loss on disposal of investments	-	2,622,625
Amortization of franchises and consents, and deferred charges	**96,444**	103,304
Amortization of regulatory charges	**141,477**	141,500
Future income taxes	**(238,500)**	(346,200)
	1,451,411	1,660,664
Changes in non-cash working capital *(Note 16)*	**(638,339)**	1,476,330
Cash flow from operating activities	**813,072**	3,136,994
INVESTING ACTIVITIES		
Additions to property, plant and equipment	**(2,748,667)**	(755,044)
Proceeds on disposal of property, plant and equipment	-	55,110
Proceeds on disposal of assets related to discontinued operations	-	3,175,287
Additions to deferred charges	-	(74,601)
Additions to franchise and consents	**(30,722)**	(39,047)
Proceeds on franchise and consents	**120,000**	-
Proceeds from sale of investments	-	8,073,730
Purchases of investments	-	(10,696,356)
Cash flow used by investing activities	**(2,659,389)**	(260,921)
FINANCING ACTIVITIES		
Dividends paid	-	(3,500,000)
Advances from term notes payable	**2,000,000**	-
Repayments of term notes payable	**(354,138)**	(345,804)
Cash flow from (used by) financing activities	**1,645,862**	(3,845,804)
DECREASE IN CASH	**(200,455)**	(969,731)
Cash (bank indebtedness) - beginning of year	**(301,383)**	668,348
BANK INDEBTEDNESS - END OF YEAR	$ **(501,838)**	$ (301,383)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2016

1. NATURE OF BUSINESS

The Company operates as a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

2. BASIS OF PRESENTATION

The financial statements were prepared in accordance with Canadian accounting standards for private enterprises (ASPE). ASPE are part of Canadian generally accepted accounting principles (GAAP).

Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the OEB renders their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under ASPE for non-regulated entities.

In addition to defining certain accounting requirements, the OEB has jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Revenue recognition

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet (included in accounts receivable or accounts payable and accrued liabilities) pending disposition by a decision of the OEB.

Revenue on sales not subject to rate regulations are recognized when goods have been delivered or services have been performed.

Investment revenue is recognized as income when the dividends and interest is received. Gains or losses are recorded upon disposal of investments.

Cash

Cash consists of cash on hand and bank account balances, with adjustments for outstanding cheques or deposits at year-end.

(continues)

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2016

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Inventory

Inventory consists of materials used for the service of existing gas pipelines and the addition of new gas pipelines. Inventory is valued at the lower of cost and net realizable value with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Franchises and consents

Costs associated with acquiring municipal franchises and other consents are capitalized when incurred, if the franchise application is successful. These costs are amortized on a straight line basis over the term of the franchise.

These assets are tested for an impairment in value when events or circumstances indicate that an asset might be impaired. The assets are tested for impairment by comparing their carrying value to estimates of their fair value. Fair value is based on estimates of discounted future cash flows or other valuation methods. When the fair value is determined to be less than carrying value, the resulting impairment is reported in the income statement.

Deferred charges

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals has been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

Property, plant and equipment

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment that is subject to rate regulation, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization.

For disposals of major property, plant and equipment and for those assets not subject to rate regulation, gains or losses are included in current earnings.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2016.

(continues)

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2016

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Amortization

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis. Property, plant and equipment are amortized at the following rates and methods listed below:

Buildings	2%	straight-line method
Machinery and equipment	7% to 9%	declining balance method
Automotive equipment	17%	straight-line method
Computer equipment and software	20% to 33%	declining balance method
Furniture and fixtures	7%	straight-line method
Meters and regulators	3% to 17%	straight-line method
Pipeline installations	3% to 5%	straight-line method

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. Any such changes in estimate are applied on a prospective basis.

Future income taxes

Income taxes are reported using the future income taxes method, as follows: current income tax expense is the estimated income taxes payable for the current year after any refunds or the use of losses incurred in previous years, and future income taxes reflect:

- the temporary differences between the carrying amounts of assets and liabilities for accounting purposes and the amounts used for tax purposes;
- the benefit of unutilized tax losses that will more likely than not be realized and carried forward to future years to reduce income taxes.

Future income taxes are estimated using the rates enacted by tax law and those substantively enacted for the years in which future income taxes assets are likely to be realized, or future income tax liabilities settled. The effect of a change in tax rates on future income tax assets and liabilities is included in earnings in the period when the change is substantively enacted.

Gas commodity costs and gas transportation costs

Gas commodity costs and gas transportation costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for consideration in future rate adjustments or disposition subject to the approval of the OEB. In a non-regulated environment periodic variances between gas commodity sales rates and costs or gas transportation costs would be reported through the income statement annually without the use of deferral accounts.

(continues)

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2016

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Financial instruments policy

Financial instruments are recorded at fair value when acquired or issued. In subsequent periods, financial assets with actively traded markets are reported at fair value, with any unrealized gains and losses reported in income. All other financial instruments are reported at amortized cost, and tested for impairment at each reporting date.

Transaction costs on the acquisition, sale, or issue of financial instruments are expensed when incurred. However, financial instruments that will not be subsequently measured at fair value are adjusted by the transaction costs that are directly attributable to their original issuance or assumption.

Measurement uncertainty

The preparation of financial statements in conformity with Canadian ASPE requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. Such estimates are periodically reviewed and any adjustments necessary are reported in earnings in the period in which they become known. Actual results could differ from these estimates.

4. PRIOR PERIOD ADJUSTMENT

During the year, the company determined that an error had been made in the calculation of certain of its regulatory account balances between 2011 and 2015, which required adjustment retroactively. As a result of this adjustment, accounts payable decreased by $844,305 as at September 30, 2015 (2014 - accounts receivable increased by $653,448), future income tax liability increased by $224,000 (2014 - $173,000) and deficit decreased by $620,305 (2014 - $480,448). For the year ended September 30, 2015, expenses decreased by $190,857, future income tax recovery decreased by $51,000, and net income for the year increased by $139,857. This matter is currently pending approval from the OEB (Note 14).

5. DISCONTINUED OPERATIONS

The Company has sold its water heater sales and rental division during the September 30, 2015 fiscal year. The water heater sales and rental division was sold as an operating unit on July 1, 2015 with operations ceasing June 30, 2015. The Company completed the sale prior to the September 30, 2015 fiscal year end for the majority of the assets related to this division. The following assets and liabilities of the water heater sales and rentals division have been reported as assets of discontinued operations:

	2016	2015
Assets of discontinued operations:		
Inventory	$ -	$ 13,397
Total assets of discontinued operations	$ -	$ 13,397

The income from discontinued operations in the statement of operations is reported net of related income tax expense of NIL (2015 - $402,420).

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2016

6. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated amortization	**2016 Net book value**	2015 Net book value
Land	$ 71,700	$ -	$ **71,700**	$ 71,700
Buildings	687,374	243,694	**443,680**	458,940
Machinery and equipment	883,818	637,595	**246,223**	170,026
Automotive equipment	372,964	254,466	**118,498**	(2,428)
Computer equipment and software	682,343	448,430	**233,913**	61,737
Furniture and fixtures	112,536	82,485	**30,051**	35,183
Meters and regulators	3,985,707	2,227,002	**1,758,705**	1,852,809
Pipeline installations	18,678,566	8,882,180	**9,796,386**	8,304,157
	$ 25,475,008	$ 12,775,852	$ **12,699,156**	$ 10,952,124

Included in pipeline installations above is $1,425,380 of pipeline in progress at September 30, 2016 (2015 - $NIL) which is not being amortized.

7. FRANCHISES AND CONSENTS

	2016	2015
Franchises and consents	$ **709,289**	$ 678,567
Accumulated amortization	**(260,995)**	(226,189)
	$ **448,294**	$ 452,378

8. DEFERRED CHARGES

	2016	2015
Deferred charges (see note below)	$ **924,664**	$ 1,044,663
Rates application costs	**282,977**	282,977
Less: Accumulated amortization	**(483,897)**	(280,781)
	$ **723,744**	$ 1,046,859

Deferred charges consist of amounts ordered by the OEB to be paid on behalf of a customer. Deferred charges are amortized over 15 years on a straight line basis.

Rates applications costs are deferred and amortized on a straight line basis over the time period for which the application applies. These costs are fully amortized as of September 30, 2016.

9. OPERATING LINE OF CREDIT

The Company has an operating line of credit in the amount of $1,000,000 which it obtained in conjunction with the term notes, with interest at the Bank's Prime Rate on any advances.

The continuation of the above credit facilities is subject to annual review by the Bank. These credit facilities are secured by the security agreement in place as disclosed in note 11.

NATURAL RESOURCE GAS LIMITED

Notes to Financial Statements

Year Ended September 30, 2016

10. RELATED PARTY TRANSACTIONS

Included in accounts receivable are amounts receivable from related companies of $140,034 (2015 - $7,710).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $NIL (2015 - $50,040).

During the year, management fees of $457,020 (2015 - $457,020) were paid to a related company.

During the year, the Company purchased gas in the amount of $483,371 (2015 - $643,573) from a related company.

During the year, maintenance charges of $6,000 (2015 - $6,000) were charged to a related company.

During the year, the Company paid pipeline construction costs of $1,270,256 (2015 - $NIL) to a related company.

During the year, the Company agreed to provide credit facilities to a related party up to a maximum of $2,000,000 with interest charged at 1% per annum on the outstanding balance. The credit facility was utilized during the year, however no balance is outstanding on the facility at September 30, 2016. Interest earned on advances made under the credit facility amount to $2,796.

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

NATURAL RESOURCE GAS LIMITED

Notes to Financial Statements

Year Ended September 30, 2016

11. TERM NOTES PAYABLE

	2016	2015
Bank of Nova Scotia term note payable, maturing on June 30, 2017 (matured on June 30, 2016 and extended with identical terms), interest at bank prime plus 0.25%, repayable in monthly payments of $12,386 plus interest, due on demand	**$ 2,167,500**	$ 2,316,132
Bank of Nova Scotia term note payable, maturing on November 30, 2016, interest at bank prime, repayable in monthly payments of $16,431 plus interest, due on demand	**2,858,887**	3,056,059
Bank of Nova Scotia term note payable, maturing on June 30, 2017, interest at bank prime plus 0.25%, repayable in monthly payments of $8,333 plus interest, due on demand	**1,991,666**	-
	$ 7,018,053	$ 5,372,191

The company has pledged the following as security against the term notes payable, the operating line of credit, and the revolving line of credit (note 9):

a) General assignment of book debts

b) General Security Agreement over all of the present and future personal property and undertaking of the company

c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank

d) Postponement of dividends and share redemption payments by the Class C shareholders

e) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss if any, payable to the Bank as mortgagee.

The term notes payable, the operating line of credit, and the revolving line of credit include the following covenants that the company must meet:

1. maintain a debt service coverage ratio of 1.25:1 or better; and

2. maintain a ratio of debt to tangible net worth of 3.0 or less; and

3. annual capital expenditures of $3.0 million or less for the fiscal year ending September 30, 2016 and reducing to $1.5 million annually thereafter.

At September 30, 2016, the company was in compliance with these covenants.

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2016

12. SHARE CAPITAL

Authorized:

Unlimited	Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends
Unlimited	Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution
Unlimited	Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share
Unlimited	Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement
Unlimited	Unlimited number of common shares

		2016	2015
Issued:			
50,000	Class A shares	**$ 1**	$ 1
10	Class B shares	**10**	10
134,614	Class C shares	**13,461,418**	13,461,418
10	Class Z shares	**10**	10
		$ 13,461,439	$ 13,461,439

13. GAS IMBALANCES

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas consumed and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $161,897 (2015 - $138,891) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2016

14. REGULATORY MATTERS

The Company's distribution rates are approved by the OEB. The Company's commodity rates are approved by the OEB and adjusted on a quarterly basis based on commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB.

During the year, the company determined that an error had been made in the calculation of certain of its regulatory account balances between 2011 and 2015. The company has made a submission to the OEB to allow the retroactive application of the correct calculations. The matter is currently being reviewed by the OEB, with a decision expected within 12 months after year-end. The company expects to be successful in its application for retroactive adjustment, and therefore has reflected the calculation error retroactively as a prior period adjustment (note 4).

During a prior year, Union Gas charged the Company $2,007,250 for the shortfall of the winter checkpoint. This was later reduced from a Decision and Order made by the OEB to $1,287,548. During the current year, the OEB issued a Decision and Order on this matter which confirmed the amount of the allowable charge by Union Gas. The Decision and Order allowed $181,531 of this to be recoverable through the commodity variance account, while the remaining $1,106,016 was not to be recovered through rates. The Decision and Order sets out the terms of payment of the charge to Union Gas, which will be repayable over multiple years based on operating results of the Company. Therefore, a portion of this liability has been classified as long term.

The Company has a matter before the OEB relating to the allowable natural gas price it can recover from natural gas purchased from a related party. The OEB is currently seeking additional information prior to making a ruling on this matter.

During the year, the OEB issued Decision and Orders which approved a new franchise agreement with a municipality for a period of 20 years, retroactive to the expiry date of the previous interim orders.

Accounting principles differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under ASPE for non-regulated entities. The following balances are a direct result of rate regulatory matters:

Included in accounts payable is $95,250 (2015 - $368,000) resulting from the regulated ratemaking process that may not be recorded under ASPE in the absence of rate regulation. The Company estimates that this amount will be settled in the upcoming year.

In the absence of rate-regulation, some of the above balances would be recognized in the income statement of the organization. As a result, net income from operations would be decreased by $984,000 (2015 - increased by $1,774,000).

In the absence of rate-regulation, the Company's current future income tax liability would be lower by $214,000 (2015 - $216,000) as a result of the elimination of the regulatory amounts included in accounts payable and accounts receivable.

NATURAL RESOURCE GAS LIMITED

Notes to Financial Statements

Year Ended September 30, 2016

15. CAPITAL LOSSES FOR INCOME TAX CARRIED FORWARD

In the prior year, the company incurred a capital loss of $2,622,625 which is available for application against future years' capital gains, with no expiry date. This amount has been included in the calculation of future income tax assets and liabilities.

16. CHANGES IN NON-CASH WORKING CAPITAL

	2016	2015
Accounts receivable	**$ 111,813**	$ 2,078,886
Taxes other than income taxes payable/recoverable	**(118,511)**	(9,394)
Inventory	**(15,425)**	49,230
Prepaid expenses	**193,305**	(131,143)
Assets related to discontinued operations	**-**	10,915
Accounts payable and accrued liabilities	**(236,322)**	(1,030,919)
Income taxes payable	**(116,434)**	2,470
Customer deposits	**(17,187)**	(1,029)
Deferred revenue	**(72,984)**	2,735
Accounts payable due beyond one year	**(366,594)**	504,579
	$ (638,339)	$ 1,476,330

17. FINANCIAL INSTRUMENTS

The Company is exposed to various risks through its financial instruments. The following analysis provides information about the Company's risk exposure and concentration. There have been no significant changes to the nature or concentration of these risks from the prior year, unless otherwise stated.

Credit risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation. The Company is exposed to credit risk from customers. In order to reduce its credit risk, the Company reviews a new customer's credit history before extending credit and conducts regular reviews of its existing customers' credit performance. The Company has the ability to take security deposits if there are payment issues, and charge interest and penalties on any late payments. The Company has a significant number of customers which minimizes concentration of credit risk.

An allowance for doubtful accounts is established based upon factors surrounding the credit risk of specific accounts, historical trends and other information. The allowance for doubtful accounts was $212,580 at September 30, 2016 (2015 - $207,016).

Liquidity risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages its liquidity risk by forecasting its cash needs on a regular basis and seeking additional information based on those forecasts. The Company's objective is to generate sufficient cash from its operations to meet its financial obligations. The Company also maintains available credit facilities as described in note 9 to support the liquidity requirements of the business.

(continues)

17. FINANCIAL INSTRUMENTS *(continued)*

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk and other price risk.

Currency risk

Currency risk is the risk to the company's earnings that arise from fluctuations of foreign exchange rates. The company was exposed to currency risk on the short-term investments it held during the prior year. As of September 30, 2016 and throughout the fiscal year, it did not hold financial instruments denominated in a foreign currency.

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Company is exposed to interest rate risk primarily through its term notes payable and lines of credit as they bear interest at a fluctuating bank prime rate related interest rate. Additionally, the Company earns interest or is charged interest on its regulatory amounts receivable or amounts payable at the interest rate prescribed by the OEB, which is subject to adjustment on a quarterly basis.

Included in other revenue is interest income of $5,190 (2015 - $64,350) earned on regulatory balances and charged on late payments.

Other price risk

Other price risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices (other than those arising from interest rate risk or currency risk), whether those changes are caused by factors specific to the individual financial instrument or its issuer, or factors affecting all similar financial instruments traded in the market. The Company is exposed to other price risk through its natural gas prices.

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations.

18. SUBSEQUENT EVENTS

Subsequent to year-end, the company signed an Asset Purchase Agreement (the "Agreement") to sell the natural gas distribution utility assets including all franchises and consents, which constitute substantially all of the assets of the Company, along with the purchaser assuming certain liabilities related to the utility business as outlined in the Agreement. The purchase price is subject to a number of working capital and purchase price adjustments, and will be paid in full on the closing date.

The closing date for this transaction has not yet been set, since it is subject to the necessary regulatory approvals. However the transaction is expected to close prior to August 31, 2017.

NATURAL RESOURCE GAS LIMITED
Schedule of Operating Expenses *(Schedule 1)*
Year Ended September 30, 2016

		2016		2015
Salaries and benefits	$	**1,586,426**	$	1,459,506
Amortization of property, plant and equipment		**1,015,033**		891,475
Property taxes		**540,380**		533,094
Management fees *(Note 10)*		**457,020**		457,020
Professional fees		**411,548**		263,519
Office		**212,649**		207,167
Ontario Energy Board hearings and regulatory charges		**191,958**		225,356
Insurance		**169,767**		174,538
Interest on term notes payable		**151,668**		165,643
Repairs and maintenance		**117,133**		172,847
Amortization of franchises and consents and deferred charges		**96,444**		103,304
Interest expense		**52,806**		18,784
Vehicle		**49,027**		65,516
Gas commodity costs *(Note 14)*		**47,670**		1,214,101
Bad debts		**44,957**		37,166
Advertising		**43,289**		62,640
Utilities		**9,205**		10,765
		5,196,980		6,062,441
Equipment expenses capitalized to pipeline installations		**(19,637)**		(18,482)
Amortization capitalized to pipeline installations		**(11,214)**		(10,645)
	$	**5,166,129**	$	6,033,314

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Financial Statements

Year Ended September 30, 2017

NATURAL RESOURCE GAS LIMITED
Index to Financial Statements
Year Ended September 30, 2017

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INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Natural Resource Gas Limited

We have audited the accompanying financial statements of Natural Resource Gas Limited, which comprise the balance sheet as at September 30, 2017 and the statements of deficit and cash flow for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Natural Resource Gas Limited as at September 30, 2017 and the results of its operations and its cash flow for the year then ended in accordance with Canadian accounting standards for private enterprises.

BDO Canada LLP

London, Ontario
March 20, 2018

Chartered Professional Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Balance Sheet

September 30, 2017

	2017	2016
ASSETS		
CURRENT		
Accounts receivable *(Notes 3, 9, 15)*	**$ -**	$ 798,547
Income taxes recoverable	**-**	14,501
Taxes other than income taxes recoverable	**1,790**	127,634
Inventory *(Note 3)*	**-**	58,418
Prepaid expenses *(Note 3)*	**-**	11,808
Assets held for sale *(Note 3)*	**14,745,363**	-
Future income taxes	**1,200,000**	-
	15,947,153	1,010,908
Property, plant and equipment *(Notes 3, 5)*	**-**	12,699,156
Franchises and consents *(Notes 3, 6)*	**-**	448,294
Deferred charges *(Notes 3, 7)*	**-**	723,744
Future income taxes	**-**	345,000
	$ 15,947,153	$ 15,227,102

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Balance Sheet

September 30, 2017

	2017	2016
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT		
Bank indebtedness *(Note 8)*	**$ 965,248**	$ 501,838
Accounts payable and accrued liabilities *(Notes 9, 12)*	**2,226,899**	1,948,855
Income taxes payable	**187,670**	-
Customer deposits *(Note 3)*	**-**	117,153
Deferred revenue	**-**	48,418
Future income taxes	**409,000**	214,000
Term notes payable *(Note 10)*	**6,572,253**	7,018,053
Liabilities transferred with assets held for sale *(Note 3)*	**489,065**	-
	10,850,135	9,848,317
Accounts payable due beyond one year *(Note 13)*	**-**	639,423
	10,850,135	10,487,740
SHAREHOLDERS' EQUITY		
Share capital *(Note 11)*	**13,461,439**	13,461,439
Deficit	**(8,364,421)**	(8,722,077)
	5,097,018	4,739,362
	$ 15,947,153	$ 15,227,102

SUBSEQUENT EVENTS *(Note 3)*

ON BEHALF OF THE BOARD

________________________________ *Director*

________________________________ *Director*

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Statement of Deficit
Year Ended September 30, 2017

	2017	2016
DEFICIT - BEGINNING OF YEAR	**$ (8,722,077)**	$ (9,159,034)
Net income for the year	**357,656**	436,957
DEFICIT - END OF YEAR	**$ (8,364,421)**	$ (8,722,077)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Income

Year Ended September 30, 2017

	2017 *(Note 3)*	2016
Gas commodity revenue	**$ 4,085,802**	$ 3,841,812
Gas commodity cost	**(4,077,386)**	(3,833,916)
Gross margin on commodity	**8,416**	7,896
Distribution revenue	**6,855,629**	6,502,192
Distribution costs	**(850,009)**	(824,267)
Gross margin on distribution	**6,005,620**	5,677,925
Other sales	**7,620**	13,363
Labour and materials costs related to other sales	**(1,343)**	(4,644)
	6,277	8,719
TOTAL GROSS MARGIN	**6,020,313**	5,694,540
OPERATING EXPENSES (Schedule 1)	**5,719,592**	5,166,129
INCOME FROM OPERATIONS	**300,721**	528,411
OTHER INCOME (EXPENSES)		
Other revenue	**102,105**	112,046
Loss on disposal of property, plant and equipment	**(5,170)**	-
	96,935	112,046
INCOME FROM OPERATIONS BEFORE TAXES	**397,656**	640,457
INCOME TAXES (RECOVERY)		
Current income taxes	**700,000**	442,000
Future income taxes	**(660,000)**	(238,500)
	40,000	203,500
NET INCOME FOR THE YEAR	**$ 357,656**	$ 436,957

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Statement of Cash Flow
Year Ended September 30, 2017

	2017	2016
OPERATING ACTIVITIES		
Net income for the year	**$ 357,656**	$ 436,957
Items not affecting cash:		
Amortization of property, plant and equipment	**1,165,661**	1,015,033
Loss on disposal of property, plant and equipment	**5,170**	-
Amortization of franchises and consents, and deferred charges	**97,855**	96,444
Amortization of regulatory charges	**-**	141,477
Future income taxes	**(660,000)**	(238,500)
Write down of deferred charges	**286,427**	-
	1,252,769	1,451,411
Changes in non-cash working capital:		
Accounts receivable	**(105,894)**	111,813
Taxes other than income taxes payable/recoverable	**125,844**	(118,511)
Inventory	**(53,151)**	(15,427)
Prepaid expenses	**(4,179)**	193,305
Income taxes payable / recoverable	**202,171**	(116,434)
Accounts payable and accrued liabilities	**(277,944)**	(236,322)
Deferred revenue	**(48,418)**	(72,982)
Accounts payable due beyond one year	**-**	(366,594)
Customer deposits	**(1,252)**	(17,187)
	(162,823)	(638,339)
Cash flow from operating activities	**1,089,946**	813,072
INVESTING ACTIVITIES		
Additions to property, plant and equipment	**(1,084,205)**	(2,748,667)
Proceeds on disposal of property, plant and equipment	**6,000**	-
Additions to franchise and consents	**(29,351)**	(30,722)
Proceeds on franchise and consents	**-**	120,000
Cash flow used by investing activities	**(1,107,556)**	(2,659,389)
FINANCING ACTIVITIES		
Advances from term notes payable	**-**	2,000,000
Repayments of term notes payable	**(445,800)**	(354,138)
Cash flow from (used by) financing activities	**(445,800)**	1,645,862
DECREASE IN CASH	**(463,410)**	(200,455)
Bank indebtedness- beginning of year	**(501,838)**	(301,383)
BANK INDEBTEDNESS - END OF YEAR	**$ (965,248)**	$ (501,838)

See note 3 for breakdown between continuing and discontinued operations for cash flow purposes.

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Notes to Financial Statements

Year Ended September 30, 2017

1. NATURE OF BUSINESS

The Company operates as a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

2. BASIS OF PRESENTATION

The financial statements were prepared in accordance with Canadian accounting standards for private enterprises (ASPE). ASPE are part of Canadian generally accepted accounting principles (GAAP).

Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the OEB renders their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under ASPE for non-regulated entities.

In addition to defining certain accounting requirements, the OEB has jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2017

3. SUBSEQUENT EVENTS

On October 31, 2017, the Company completed an Asset Purchase Agreement (the "Agreement") to sell the natural gas distribution utility assets and operations including all franchises and consents, which constitutes substantially all of the assets of the Company, along with the purchaser assuming certain liabilities related to the utility business as outlined in the Agreement. The Company received $21,018,554, subject to adjustment based on final numbers at the closing date, for this transaction, which it used to repay the term notes in note 7 and the bank indebtedness.

The intention to sell the assets and operations of the Company was in effect during the September 30, 2017 year end and therefore the long-term assets have been recorded on the balance sheet as held for sale. No loss was required to be recorded in the income statement upon this reclassification.

Assets held for sale consists primarily of $12,606,529 of property, plant and equipment, $662,105 of deferred charges, $441,430 of franchises and consents, $111,569 of inventory and $904,441 of accounts receivable.

Liabilities transferred with assets held for sale consists primarily of $300,489 of deferred charges, $115,901 of customer deposits and $69,372 of accounts payable and accrued liabilities.

All operations represented on the income statement were transferred to the purchaser on closing.

Substantially all of the items on the cash flow statement relate to the sale of the operating assets. The allocation of operating, investing and financing activities on the cash flow statement is allocated between continuing and discontinued operations as follows: Operating activities - continuing $71,025, discontinued $1,018,921; investing - continuing $nil, discontinued ($1,107,556); financing - continuing ($445,800), discontinued $nil. Overall continuing operations resulted in a net cash outflow of $374,775 and discontinued operations resulted in a net cash outflow of $88,635.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Revenue recognition

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet (included in accounts receivable or accounts payable and accrued liabilities) pending disposition by a decision of the OEB.

Revenue on sales not subject to rate regulations are recognized when goods have been delivered or services have been performed.

Investment revenue is recognized as income when the dividends and interest is received. Gains or losses are recorded upon disposal of investments.

(continues)

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Cash

Cash consists of cash on hand and bank account balances, with adjustments for outstanding cheques or deposits at year-end.

Inventory

Inventory consists of materials used for the service of existing gas pipelines and the addition of new gas pipelines. Inventory is valued at the lower of cost and net realizable value with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Franchises and consents

Costs associated with acquiring municipal franchises and other consents are capitalized when incurred, if the franchise application is successful. These costs are amortized on a straight line basis over the term of the franchise.

These assets are tested for an impairment in value when events or circumstances indicate that an asset might be impaired. The assets are tested for impairment by comparing their carrying value to estimates of their fair value. Fair value is based on estimates of discounted future cash flows or other valuation methods. When the fair value is determined to be less than carrying value, the resulting impairment is reported in the income statement.

Deferred charges

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals has been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

Property, plant and equipment

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment that is subject to rate regulation, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization.

For disposals of major property, plant and equipment and for those assets not subject to rate regulation, gains or losses are included in current earnings.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2017.

(continues)

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2017

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Amortization

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis. Property, plant and equipment are amortized at the following rates and methods listed below:

Buildings	2%	straight-line method
Machinery and equipment	7% to 9%	declining balance method
Automotive equipment	17%	straight-line method
Computer equipment and software	20% to 33%	declining balance method
Furniture and fixtures	7%	straight-line method
Meters and regulators	3% to 17%	straight-line method
Pipeline installations	3% to 5%	straight-line method

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. Any such changes in estimate are applied on a prospective basis.

Future income taxes

Income taxes are reported using the future income taxes method, as follows: current income tax expense is the estimated income taxes payable for the current year after any refunds or the use of losses incurred in previous years, and future income taxes reflect:

- the temporary differences between the carrying amounts of assets and liabilities for accounting purposes and the amounts used for tax purposes;
- the benefit of unutilized tax losses that will more likely than not be realized and carried forward to future years to reduce income taxes.

Future income taxes are estimated using the rates enacted by tax law and those substantively enacted for the years in which future income taxes assets are likely to be realized, or future income tax liabilities settled. The effect of a change in tax rates on future income tax assets and liabilities is included in earnings in the period when the change is substantively enacted.

Gas commodity costs and gas transportation costs

Gas commodity costs and gas transportation costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for consideration in future rate adjustments or disposition subject to the approval of the OEB. In a non-regulated environment periodic variances between gas commodity sales rates and costs or gas transportation costs would be reported through the income statement annually without the use of deferral accounts.

(continues)

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2017

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Financial instruments policy

Financial instruments are recorded at fair value when acquired or issued. In subsequent periods, financial assets with actively traded markets are reported at fair value, with any unrealized gains and losses reported in income. All other financial instruments are reported at amortized cost, and tested for impairment at each reporting date.

Transaction costs on the acquisition, sale, or issue of financial instruments are expensed when incurred. However, financial instruments that will not be subsequently measured at fair value are adjusted by the transaction costs that are directly attributable to their original issuance or assumption.

Measurement uncertainty

The preparation of financial statements in conformity with Canadian ASPE requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. Such estimates are periodically reviewed and any adjustments necessary are reported in earnings in the period in which they become known. Actual results could differ from these estimates.

5. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated amortization	**2017 Net book value**	2016 Net book value
Land	$ -	$ -	**$ -**	$ 71,700
Buildings	-	-	**-**	443,680
Machinery and equipment	-	-	**-**	246,223
Automotive equipment	-	-	**-**	118,498
Computer equipment and software	-	-	**-**	233,913
Furniture and fixtures	-	-	**-**	30,051
Meters and regulators	-	-	**-**	1,758,705
Pipeline installations	-	-	**-**	9,796,386
	$ -	$ -	**$ -**	$ 12,699,156

Included in pipeline installations above is $nil of pipeline in progress at September 30, 2017 (2016 - $1,425,380) which is not being amortized.

6. FRANCHISES AND CONSENTS

	2017	2016
Franchises and consents	**$ -**	$ 709,289
Accumulated amortization	**-**	(260,995)
	$ -	$ 448,294

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2017

7. DEFERRED CHARGES

	2017	2016
Deferred charges (see note below)	**$ -**	$ 924,664
Rates application costs	**-**	282,977
Less: Accumulated amortization	**-**	(483,897)
	$ -	$ 723,744

Deferred charges consist of amounts ordered by the OEB to be paid on behalf of a customer. Deferred charges are amortized over 15 years on a straight line basis. The deferred charges were included in assets held for sale as at September 30, 2017 in the amount of $662,105.

Rates applications costs are deferred and amortized on a straight line basis over the time period for which the application applies. These costs are fully amortized as of September 30, 2017.

8. OPERATING LINE OF CREDIT

The Company has an operating line of credit in the amount of $1,000,000 which it obtained in conjunction with the term notes, with interest at the Bank's Prime Rate on any advances.

The continuation of the above credit facilities is subject to annual review by the Bank. These credit facilities are secured by the security agreement in place as disclosed in note 10.

NATURAL RESOURCE GAS LIMITED

Notes to Financial Statements

Year Ended September 30, 2017

9. RELATED PARTY TRANSACTIONS

Included in accounts receivable (part of Assests held for sale for 2017) are amounts receivable from related companies of $565 (2016 - $140,034).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $727,044 (2016 - $NIL).

During the year, management fees of $457,020 (2016 - $457,020) were paid to a related company.

During the year, the Company purchased gas in the amount of $506,907 (2016 - $483,371) from a related company.

During the year, maintenance charges of $6,000 (2016 - $6,000) were charged to a related company.

During the year, the Company paid pipeline construction costs of $355,173 (2016 - $1,270,256) to a related company.

During the year, the Company agreed to provide credit facilities to a related party up to a maximum of $2,000,000 with interest charged at 1% per annum on the outstanding balance. The credit facility was utilized during the year, however no balance is outstanding on the facility at September 30, 2017. Interest earned on advances made under the credit facility amount to $1,046.

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

NATURAL RESOURCE GAS LIMITED

Notes to Financial Statements

Year Ended September 30, 2017

10. TERM NOTES PAYABLE

		2017		2016
Bank of Nova Scotia term note payable, maturing on November 3, 2017 (matured on June 30, 2017, extended with identical terms), interest at bank prime plus 0.25%, repayable in monthly payments of $12,386 plus interest, due on demand	**$**	**2,018,868**	$	2,167,500
Bank of Nova Scotia term note payable, maturing on November 3, 2017 (matured on June 30, 2017, extended with identical terms), interest at bank prime, repayable in monthly payments of $16,431 plus interest, due on demand		**2,661,715**		2,858,887
Bank of Nova Scotia term note payable, maturing on November 3, 2017 (matured on June 30, 2017, extended with identical terms), interest at bank prime plus 0.25%, repayable in monthly payments of $8,333 plus interest, due on demand		**1,891,670**		1,991,666
	$	**6,572,253**	$	7,018,053

The Company has pledged the following as security against the term notes payable, the operating line of credit, and the revolving line of credit (note 5):

a) General assignment of book debts

b) General Security Agreement over all of the present and future personal property and undertaking of the company

c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank

d) Postponement of dividends and share redemption payments by the Class C shareholders

e) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss if any, payable to the Bank as mortgagee.

The term notes payable, the operating line of credit, and the revolving line of credit include the following covenants that the company must meet:

1. maintain a debt service coverage ratio of 1.25:1 or better; and

2. maintain a ratio of debt to tangible net worth of 3.0 or less; and

3. annual capital expenditures of $3.0 million or less for the fiscal year ending September 30, 2016 and reducing to $1.5 million annually thereafter.

At September 30, 2017, the Company was not in compliance with the first covenant due to the debt being listed as short term as it was settled after year end. Otherwise the Company was in compliance with all covenants. Subsequent to year-end the term notes payable and the operating line of credit were repaid (note 3).

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2017

11. SHARE CAPITAL

Authorized:

Unlimited	Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends
Unlimited	Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution
Unlimited	Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share
Unlimited	Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement
Unlimited	Unlimited number of common shares

		2017	2016
Issued:			
50,000	Class A shares	**$ 1**	$ 1
10	Class B shares	**10**	10
134,614	Class C shares	**13,461,418**	13,461,418
10	Class Z shares	**10**	10
		$ 13,461,439	$ 13,461,439

12. GAS IMBALANCES

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas consumed and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $nil (2016 - $161,897) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2017

13. REGULATORY MATTERS

The Company's distribution rates are approved by the OEB. The Company's commodity rates are approved by the OEB and adjusted on a quarterly basis based on commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB.

During a prior year, Union Gas charged the Company $2,007,250 for the shortfall of the winter checkpoint. This was later reduced from a Decision and Order made by the OEB to $1,287,548. The OEB issued a Decision and Order on this matter which confirmed the amount of the allowable charge by Union Gas. The Decision and Order allowed $181,531 of this to be recoverable through the commodity variance account, while the remaining $1,106,016 was not to be recovered through rates. The Decision and Order sets out the terms of payment of the charge to Union Gas, which will be repayable over multiple years based on operating results of the Company. Subsequent to year-end the remaining amount owing was repaid in full upon the sale of its net operating assets. Therefore, entire balance is accrued for as a current amount.

The Company has a matter before the OEB relating to the allowable natural gas price it can recover from natural gas purchased from a related party. The OEB is currently seeking additional information prior to making a ruling on this matter.

Accounting principles differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses. As a result the Company records assets and liabilities that would not have been recorded under ASPE for non-regulated entities, which would include deferred charges and other regulatory assets and liabilities. The following balances are a direct result of rate regulatory matters:

Included in accounts payable is $nil (2016 - $95,250) resulting from the regulated ratemaking process that may not be recorded under ASPE in the absence of rate regulation.

Included in liabilities transferred with assets held for sale is $300,489 in liabilities related to the regulated ratemaking process that would not be recorded as a liability under ASPE in the absence of rate regulation. The balance of deferred charges in the amount $286,427 were charged to the statement of operations due to the sale of the rate regulated operations subsequent to year end, as per note 3.

In the absence of rate-regulation, some of the above balances would be recognized in the income statement of the organization. As a result, net income from operations would decrease by $79,559 (2016 - decrease by $1,149,584).

In the absence of rate-regulation, the Company's current future income tax liability would be lower by $190,000 (2016 - lower by $214,000) as a result of the elimination of the regulatory amounts included in accounts payable and accounts receivable.

14. CAPITAL LOSSES FOR INCOME TAX CARRIED FORWARD

In the prior year, the company incurred a capital loss of $2,622,625 which is available for application against future years' capital gains, with no expiry date. This amount has been included in the calculation of future income tax assets and liabilities.

15. FINANCIAL INSTRUMENTS

The Company is exposed to various risks through its financial instruments. The following analysis provides information about the Company's risk exposure and concentration. There have been no significant changes to the nature or concentration of these risks from the prior year, unless otherwise stated.

Credit risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation. The Company is exposed to credit risk from customers. In order to reduce its credit risk, the Company reviews a new customer's credit history before extending credit and conducts regular reviews of its existing customers' credit performance. The Company has the ability to take security deposits if there are payment issues, and charge interest and penalties on any late payments. The Company has a significant number of customers which minimizes concentration of credit risk.

An allowance for doubtful accounts is established based upon factors surrounding the credit risk of specific accounts, historical trends and other information. The allowance for doubtful accounts was $66,258 at September 30, 2017 (2016 - $212,580).

Liquidity risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages its liquidity risk by forecasting its cash needs on a regular basis and seeking additional information based on those forecasts. The Company's objective is to generate sufficient cash from its operations to meet its financial obligations. The Company also maintains available credit facilities as described in note 5 to support the liquidity requirements of the business.

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk and other price risk.

Currency risk

Currency risk is the risk to the company's earnings that arise from fluctuations of foreign exchange rates. The company was exposed to currency risk on the short-term investments it held during the prior year. As of September 30, 2017 and throughout the fiscal year, it did not hold financial instruments denominated in a foreign currency.

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Company is exposed to interest rate risk primarily through its term notes payable and lines of credit as they bear interest at a fluctuating bank prime rate related interest rate. Additionally, the Company earns interest or is charged interest on its regulatory amounts receivable or amounts payable at the interest rate prescribed by the OEB, which is subject to adjustment on a quarterly basis.

Included in other revenue is interest income of $4,444 (2016 - $5,190) earned on regulatory balances and charged on late payments.

(continues)

NATURAL RESOURCE GAS LIMITED
Notes to Financial Statements
Year Ended September 30, 2017

15. FINANCIAL INSTRUMENTS *(continued)*

Other price risk

Other price risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices (other than those arising from interest rate risk or currency risk), whether those changes are caused by factors specific to the individual financial instrument or its issuer, or factors affecting all similar financial instruments traded in the market. The Company is exposed to other price risk through its natural gas prices.

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations. The remaining balances on these contracts were transferred to the purchaser on closing (note 3).

NATURAL RESOURCE GAS LIMITED

Schedule of Operating Expenses ***(Schedule 1)***

Year Ended September 30, 2017

	2017	2016
Salaries and benefits	**$ 1,411,675**	$ 1,586,426
Amortization of property, plant and equipment	**1,165,661**	1,015,033
Professional fees	**1,012,620**	411,548
Property taxes	**492,809**	540,380
Management fees *(Note 9)*	**457,020**	457,020
Gas commodity costs *(Note 13)*	**209,996**	47,670
Interest on term notes payable	**197,688**	151,668
Office	**187,022**	212,649
Insurance	**169,301**	169,767
Repairs and maintenance	**104,602**	117,133
Amortization of franchises and consents and deferred charges	**97,855**	96,444
Ontario Energy Board hearings and regulatory charges	**63,010**	191,958
Vehicle	**57,628**	49,027
Interest expense	**52,420**	52,806
Advertising	**38,608**	43,291
Bad debts	**24,591**	44,955
Utilities	**9,525**	9,205
	5,752,031	5,196,980
Equipment expenses capitalized to pipeline installations	**(21,385)**	(19,637)
Amortization capitalized to pipeline installations	**(11,054)**	(11,214)
	$ 5,719,592	$ 5,166,129

See accompanying notes to the financial statements.

Pro Forma Financial Statements ($ thousands)

	2018	2019	2020
Income Statement			
Commodity Revenue	4,298	4,665	4,750
Commodity Cost	-4,299	-4,666	-4,750
Commodity Margin	-1	-2	0
Distribution Revenue	7,235	7,079	6,653
Other Revenue	120	113	113
Distribution OM&A	-5,092	-3,919	-4,035
Property Taxes	-573	-605	-632
EBITDA	1,688	2,666	2,099
Net Depreciation and Amortization	-1,152	-1,271	-1,136
Interest Expense	-380	-384	-408
Current Income Tax	0	-170	-5
Future Income Tax	-47	-98	-99
Gain / Loss on Disposal	22	0	-162
Net Income	131	743	288

Balance Sheet

	2018	2019	2020
Cash	-475	0	0
Other Current Assets	2,544	2,544	2,544
CWIP	176	0	0
PP&E and Intangibles	14,312	17,029	17,127
Goodwill	7,838	7,838	7,838
Total Assets	24,395	27,411	27,508
ST Debt	1,055	2,651	1,306
Other Current Liabilities	1,265	1,265	1,265
LT Debt	8,660	8,660	9,658
Contributions	115	694	750
Deferred Tax Liability	47	145	245
Total Liabilities	11,142	13,415	13,224

Share Capital	13,360	13,360	13,360
Retained Earnings	-107	636	925
Total Equities	13,253	13,996	14,284

Statement of Cash Flows

EBITDA	1,688	2,666	2,099
Interest Expense	-380	-384	-408
Current Income Tax	0	-170	-5
less: Increase in Other Current Assets	0	0	0
add: Increase in Other Current Liabilities	0	0	0
Cash from Operating Activities	1,308	2,113	1,686
Capital Expenditure	-2,092	-3,234	-1,340
Cash from Investing Activities	-2,092	-3,234	-1,340
Borrowing	0	1,596	998
Repayment	-2,098	0	-1,345
Dividend Paid	0	0	0
Cash from Financing Activities	-2,098	1,596	-346
Net Change in Cash	-2,883	475	0

Reconciliation between ENGLP's Ending 2017 Stub Period Audited Financial Statements to Regulatory Financial Statements ($ thousands)

	Audited	Adjustments	Regulatory
Income Statement			
Energy Sales	1,408	-31	1,377
Commercial Services	1,809	-157	1,652
Revenues	3,217	-188	3,029
Energy Purchases and System Access Fees	-1,377	0	-1,377
Other Raw Materials and Operating Charges	-174	0	-174
Staff Costs and Employee Benefits Expense	-218	0	-218
Depreciation and Amortization Expense	-190	11	-179
Other Administrative Expenses	-1,566	371	-1,194
Franchise Fees & Property Taxes	-100	0	-100
Expenses	-3,625	382	-3,242
Operating income	-408	194	-213
Net Finance Expense	-24	0	-24
(Loss)/income before tax	-432	194	-237
Current Income Tax	0	0	0
Deferred Income Tax	0	0	0
(Loss)/profit for the year	-432	194	-237
Balance Sheet			
ASSETS			
Current assets			
Cash and cash equivalents	2,408	0	2,408
Trade and other receivables	2,221	-116	2,104
Prepaid expenses	358	0	358
Inventories	82	0	82

Total current assets	5,069	-116	4,952
Non-current assets			
Intangible assets	1,207	-362	845
Property, plant and equipment	17,857	-5,279	12,578
Goodwill	1,886	5,952	7,838
Total non-current assets	20,950	311	21,261
TOTAL ASSETS	26,019	195	26,213
LIABILITIES AND EQUITY			
Trade and other payables	1,143	0	1,143
Loans and borrowings	3,153	0	3,153
Provision	19	0	19
Other current liabilities/Customer Deposits	103	0	103
Total current liabilities	4,418	0	4,418
Loans and borrowings	8,660	0	8,660
Deferred revenues	13	0	13
Total non-current liabilities	8,673	0	8,673
Total liabilities	13,091	0	13,091
Share capital	13,360	0	13,360
Retained earnings	-432	194	-238
Total equity	12,928	194	13,122
TOTAL LIABILITIES AND EQUITY	26,019	194	26,213

Statement of Cash Flows

Comprehensive Income	-432	0	-432
Interest paid (net)	24	0	24
Interest expense (net)	-24	0	-24
Depreciation and amoritization	190	0	190
Deferred revenue recognized	0	0	0
Current income tax expense	0	0	0
Deferred income tax expense	0	0	0

Change in employee benefits provisions	16	0	16
Changes in non-cash working capital balances	54	0	54
Net cash (used in) generated from operating activities	-172	0	-172
Purchase of property, plant and equipment	-546	0	-546
Purchase of intangible assets	-41	0	-41
Business Combination	-22,019	0	-22,019
Net cash used in investing activities	-22,606	0	-22,606
Cash Contributions received	13	0	13
Net proceeds from (repayment of) short-term loans and borrowings	3,153	0	3,153
Proceeds from long term loans and borrowings	8,660	0	8,660
Equity contributions from the partners	13,360	0	13,360
Net cash used in financing activities	25,186	0	25,186
Net change in cash and cash equivalents	2,408	0	2,408

Reconciliation between ENGLP's Year Ending September 30 2017 Period Audited Financial Statements to Regulatory Financial Statements
($ thousands)

Income Statement	Audited	Adjustments	Regulatory
Gas commodity revenue	4,086	0	4,086
Gas commodity cost	4,077	0	4,077
Gross margin on commodity	8	0	8
Distribution revenue	6,856	0	6,856
Distribution costs	850	0	850
Gross margin on distribution	6,006	0	6,006
Other sales	8	0	8
Labour and Materials costs related to other sales	1	0	1
Gross margin on other sales	6	0	6
TOTAL GROSS MARGIN	6,020	0	6,020
OPERATING EXPENSES	5,720	0	5,720
INCOME FROM OPERATIONS	301	0	301
OTHER INCOME (EXPENSES)			
Other revenue	102	0	102
Losses on disposal of property, plant and equipment	($5)	0	($5)
	97	0	97
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES	398	0	398
INCOME TAX RECOVERY			
Current income taxes	700	0	700
Future income taxes	($660)	0	($660)
	40	0	40

INCOME (LOSS) FROM CONTINUING OPERATIONS	358	0	358
NET INCOME FOR THE YEAR	358	0	358

Balance Sheet

ASSETS			
CURRENT			
Accounts receivable	0	852	852
Inventory	0	112	112
Income taxes recoverable	2	0	2
Future Income taxes	1,200	0	1,200
Prepaid expenses		26	26
Assets held for sale	14,745	($14,745)	0
	15,947	($13,756)	2,191
Property, plant and equipment	0	12,607	12,607
Other assets:			
Franchises and consents	0	441	441
Deferred Charges	0	662	662
Future Income taxes	0	0	0
	0	1,104	1,104
	15,947	($46)	15,901
LIABILITIES AND SHAREHOLDERS' DEFICIENCY			
CURRENT			
Bank indebtedness	965	0	965
Accounts payable and accrued liabilities	2,227	327	2,554
Income taxes payable	188	0	188
Future income taxes payable	409	0	409
Deferred revenue	0	0	0
Customer deposits	0	116	116
Liabilities transferred with assets held for sale	489	($489)	0
Term note payable	6,572	0	6,572

	10,850	($46)	10,804
Accounts payable due beyond one year	0	0	0
	10,850	($46)	10,804
SHAREHOLDERS' EQUITY			
Share capital	13,461		13,461
Deficit	($8,364)		($8,364)
	5,097	0	5,097
	15,947	($46)	15,901

Reconciliation between ENGLP's Year Ending September 30 2016 Period Audited Financial Statements to Regulatory Financial Statements
($ thousands)

	Audited	Adjustments	Regulatory
Income Statement			
Gas commodity revenue	3,842	0	3,842
Gas commodity cost	3,834	0	3,834
Gross margin on commodity	8	0	8
Distribution revenue	6,502	0	6,502
Distribution costs	824	0	824
Gross margin on distribution	5,678	0	5,678
Other sales	13	0	13
Labour and Materials costs related to other sales	5	0	5
Gross margin on other sales	9	0	9
TOTAL GROSS MARGIN	5,695	0	5,695
OPERATING EXPENSES	5,166	0	5,166
INCOME FROM OPERATIONS	528	0	528
OTHER INCOME (EXPENSES)			
Other revenue	112	0	112
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES	640	0	640
INCOME TAX RECOVERY			
Current income taxes	442	0	442
Future income taxes	($239)	0	($239)
	204	0	204
INCOME (LOSS) FROM CONTINUING OPERATIONS	437	0	437

NET INCOME FOR THE YEAR	437	0	437

Balance Sheet

ASSETS			
CURRENT			
Accounts receivable	799	0	799
Inventory	58	0	58
Income taxes recoverable	128	0	128
Prepaid expenses	12	0	12
Assets held for sale	0	0	0
	996	0	996
Property, plant and equipment	12,699	0	12,699
Other assets:			
Franchises and consents	448	0	448
Deferred Charges	724	0	724
Future Income taxes	345	0	345
	1,517	0	1,517
	15,213	0	15,213
LIABILITIES AND SHAREHOLDERS' DEFICIENCY			
CURRENT			
Bank indebtedness	502	0	502
Accounts payable and accrued liabilities	1,949	0	1,949
Income taxes payable	($15)	0	($15)
Future income taxes payable	214	0	214
Deferred revenue	48	0	48
Customer deposits	117	0	117
Term note payable	7,018	0	7,018
	9,834	0	9,834

Accounts payable due beyond one year	639	0	639
	10,473	0	10,473
SHAREHOLDERS' EQUITY			
Share capital	13,461		13,461
Deficit	($8,722)		($8,722)
	4,739	0	4,739
	15,213	0	15,213

Reconciliation between ENGLP's Year Ending September 30 2015 Period Audited Financial Statements to Regulatory Financial Statements
($ thousands)

Income Statement	Audited	Adjustments	Regulatory
Gas commodity revenue	5,831	0	5,831
Gas commodity cost	5,821	0	5,821
Gross margin on commodity	9	0	9
Distribution revenue	6,697	0	6,697
Distribution costs	1,045	0	1,045
Gross margin on distribution	5,653	0	5,653
Other sales	31	0	31
Labour and Materials costs related to other sales	17	0	17
Gross margin on other sales	14	0	14
TOTAL GROSS MARGIN	5,676	0	5,676
OPERATING EXPENSES	6,043	0	6,043
INCOME FROM OPERATIONS	($366)	0	($366)
OTHER INCOME (EXPENSES)			
Other revenue	143	0	143
Interest income on investments	31	0	31
Losses on disposal of investments	($2,623)	0	($2,623)
	($2,449)	0	($2,449)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES	($2,815)	0	($2,815)
INCOME TAX RECOVERY			
Current income taxes	14	136	150
Future income taxes	($397)	0	($397)
	($383)	136	($247)

INCOME (LOSS) FROM CONTINUING OPERATIONS	($2,432)	($136)	($2,568)
Gain on Disposal of discontinued operations	1,870	0	1,870
Income related to discontinued operations	402	161	563
TOTAL INCOME FROM DISCONTINUED OPERATIONS	2,272	161	2,433
NET INCOME FOR THE YEAR	($160)	25	($135)

Balance Sheet

ASSETS			
CURRENT			
Accounts receivable	910		910
Inventory	43		43
Income taxes recoverable	9		9
Future Income taxes	0		0
Prepaid expenses	205		205
Assets held for sale	0		0
Assets relating to discontinued operations	13	0	13
	1,181	0	1,181
Property, plant and equipment	10,952	0	10,952
Other assets:			
Franchises and consents	452		452
Deferred Charges	1,047	1,683	2,730
Future Income taxes	333		333
	1,832	1,683	3,514
	13,965	1,683	15,647
LIABILITIES AND SHAREHOLDERS' DEFICIENCY			
CURRENT			
Bank indebtedness	301	0	301

Accounts payable and accrued liabilities	3,029	1,804	4,834
Income taxes payable	102	($25)	77
Future income taxes payable	216	0	216
Deferred revenue	121	($121)	0
Customer deposits	134	0	134
Liabilities transferred with assets held for sale	0	0	0
Term note payable	5,372	0	5,372
	9,277	1,658	10,934
Accounts payable due beyond one year	1,006	0	1,006
	10,283	1,658	11,940
SHAREHOLDERS' EQUITY			
Share capital	13,461	0	13,461
Deficit	($9,779)	25	($9,754)
	3,682	25	3,707
	13,965	1,683	15,647

Reconciliation between Natural Resource Gas Limited's 2015 Audited Financial Statements to Regulatory Financial Statements

Income Statement

	Audited	Adjustments	Regulatory
Gas commodity revenue	$ 5,830,818	$ -	$ 5,830,818
Gas commodity cost	5,821,334	-	5,821,334
Gross margin on commodity	9,484	-	9,484
Distribution revenue	6,697,276	-	6,697,276
Distribution costs	1,044,521	-	1,044,521
Gross margin on distribution	5,652,755	-	5,652,755
Other sales	30,772	-	30,772
Labour and Materials costs related to other sales	16,526	-	16,526
Gross margin on other sales	14,246	-	14,246
TOTAL GROSS MARGIN	5,676,485	-	5,676,485
OPERATING EXPENSES	6,042,879	-	6,042,879
INCOME FROM OPERATIONS	(366,394)	-	(366,394)
OTHER INCOME (EXPENSES)			
Other revenue	142,557	-	142,557
Interest income on investments	31,038	-	31,038
Losses on disposal of investments	(2,622,625)	-	(2,622,625)
	(2,449,030)	-	(2,449,030)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES	(2,815,424)	-	(2,815,424)
INCOME TAX RECOVERY			
Current income taxes	14,000	136,000	150,000
Future income taxes	(397,200)	-	(397,200)
	(383,200)	136,000	(247,200)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(2,432,224)	(136,000)	(2,568,224)
Gain on Disposal of discontinued operations	1,869,582	-	1,869,582
Income related to discontinued operations	402,420	161,000	563,420
TOTAL INCOME FROM DISCONTINUED OPERATIONS	2,272,002	161,000	2,433,002
NET INCOME FOR THE YEAR	$ (160,222)	$ 25,000	$ (135,222)

Balance Sheet

	Audited	Adjustments	Regulatory
ASSETS			
CURRENT			
Accounts receivable	$ 910,360		$ 910,360

Inventory	42,991		42,991
Income taxes recoverable	9,123		9,123
Future Income taxes	-		-
Prepaid expenses	205,113		205,113
Assets held for sale	-		-
Assets relating to discontinued operations	13,397	-	13,397
	1,180,984	-	1,180,984
Property, plant and equipment	10,952,124	-	10,952,124
Other assets:			
Franchises and consents	452,378		452,378
Deferred Charges	1,046,859	1,682,643	2,729,502
Future Income taxes	332,500		332,500
	1,831,737	1,682,643	3,514,380
	$ 13,964,845	$ 1,682,643	$ 15,647,488
LIABILITIES AND SHAREHOLDERS' DEFICIENCY			
CURRENT			
Bank indebtedness	$ 301,383	$ -	$ 301,383
Accounts payable and accrued liabilities	3,029,478	1,804,045	4,833,523
Income taxes payable	101,933	(25,000)	76,933
Future income taxes payable	216,000	-	216,000
Deferred revenue	121,402	(121,402)	-
Customer deposits	134,340	-	134,340
Liabilities transferred with assets held for sale	-	-	-
Term note payable	5,372,191	-	5,372,191
	9,276,727	1,657,643	10,934,370
Accounts payable due beyond one year	1,006,017	-	1,006,017
	10,282,744	1,657,643	11,940,387
SHAREHOLDERS' EQUITY			
Share capital	13,461,439	-	13,461,439
Deficit	(9,779,338)	25,000	(9,754,338)
	3,682,101	25,000	3,707,101
	$ 13,964,845	$ 1,682,643	$ 15,647,488

Reconciliation between Natural Resource Gas Limited's 2016 Audited Financial Statements to Regulatory Financial Statements

Income Statement

	Audited	Adjustments	Regulatory
Gas commodity revenue	$ 3,841,812	$ -	$ 3,841,812
Gas commodity cost	3,833,916	-	3,833,916
Gross margin on commodity	7,896	-	7,896
Distribution revenue	6,502,192	-	6,502,192
Distribution costs	824,267	-	824,267
Gross margin on distribution	5,677,925	-	5,677,925
Other sales	13,363	-	13,363
Labour and Materials costs related to other sales	4,644	-	4,644
Gross margin on other sales	8,719	-	8,719
TOTAL GROSS MARGIN	5,694,540	-	5,694,540
OPERATING EXPENSES	5,166,129	-	5,166,129
INCOME FROM OPERATIONS	528,411	-	528,411
OTHER INCOME (EXPENSES)			
Other revenue	112,046	-	112,046
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFOR	640,457	-	640,457
INCOME TAX RECOVERY			
Current income taxes	442,000	-	442,000
Future income taxes	(238,500)	-	(238,500)
	203,500	-	203,500
INCOME (LOSS) FROM CONTINUING OPERATIONS	436,957	-	436,957
NET INCOME FOR THE YEAR	$ 436,957	$ -	$ 436,957

Balance Sheet

	Audited	Adjustments	Regulatory
ASSETS			
CURRENT			
Accounts receivable	$ 798,548	$ -	$ 798,548
Inventory	58,418	-	58,418

Income taxes recoverable	127,634	-	127,634
Prepaid expenses	11,808	-	11,808
Assets held for sale	-	-	0
	996,408	-	996,408
Property, plant and equipment	12,699,155	-	12,699,155
Other assets:			
Franchises and consents	448,294	-	448,294
Deferred Charges	723,744	-	723,744
Future Income taxes	345,000	-	345,000
	1,517,038	-	1,517,038
	$ 15,212,601	$ -	$ 15,212,601
LIABILITIES AND SHAREHOLDERS' DEFICIENCY			
CURRENT			
Bank indebtedness	$ 501,838	$ -	$ 501,838
Accounts payable and accrued liabilities	1,948,855	-	1,948,855
Income taxes payable	-14,501	-	-14,501
Future income taxes payable	214,000	-	214,000
Deferred revenue	48,418	-	48,418
Customer deposits	117,153	-	117,153
Term note payable	7,018,053	-	7,018,053
	9,833,816	-	9,833,816
Accounts payable due beyond one year	639,423	-	639,423
	10,473,239	-	10,473,239
SHAREHOLDERS' EQUITY			
Share capital	13,461,439		13,461,439
Deficit	-8,722,077		-8,722,077
	4,739,362	-	4,739,362
	$ 15,212,601	$ -	$ 15,212,601

Reconciliation between Natural Resource Gas Limited's 2017 Audited Financial Statements to Regulatory Financial Statements

Income Statement

	Audited	Adjustments	Regulatory
Gas commodity revenue	$ 4,085,802	$ -	$ 4,085,802
Gas commodity cost	4,077,386	-	4,077,386
Gross margin on commodity	8,416	-	8,416
Distribution revenue	6,855,629	-	6,855,629
Distribution costs	850,009	-	850,009
Gross margin on distribution	6,005,620	-	6,005,620
Other sales	7,620	-	7,620
Labour and Materials costs related to other sales	1,343	-	1,343
Gross margin on other sales	6,277	-	6,277
TOTAL GROSS MARGIN	6,020,313	-	6,020,313
OPERATING EXPENSES	5,719,592	-	5,719,592
INCOME FROM OPERATIONS	300,721	-	300,721
OTHER INCOME (EXPENSES)			
Other revenue	102,105	-	102,105
Losses on disposal of property, plant and equipment	(5,170)	-	(5,170)
	96,935	-	96,935
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES	397,656	-	397,656
INCOME TAX RECOVERY			
Current income taxes	700,000	-	700,000
Future income taxes	(660,000)	-	(660,000)
	40,000	-	40,000
INCOME (LOSS) FROM CONTINUING OPERATIONS	357,656	-	357,656
NET INCOME FOR THE YEAR	$ 357,656	$ -	$ 357,656

Balance Sheet

	Audited	Adjustments	Regulatory
ASSETS			
CURRENT			
Accounts receivable	$ -	$ 852,229	$ 852,229
Inventory	-	111,569	111,569
Income taxes recoverable	1,790	-	1,790
Future Income taxes	1,200,000	-	1,200,000
Prepaid expenses		25,546	25,546
Assets held for sale	14,745,363	(14,745,363)	-

	15,947,153	-13,756,019	2,191,134
Property, plant and equipment	-	12,606,528	12,606,528
Other assets:			
Franchises and consents	-	441,430	441,430
Deferred Charges	-	662,105	662,105
Future Income taxes	-	-	-
	-	1,103,535	1,103,535
	$ 15,947,153	$ (45,956)	$ 15,901,197
LIABILITIES AND SHAREHOLDERS' DEFICIENCY			
CURRENT			
Bank indebtedness	$ 965,248	$ -	$ 965,248
Accounts payable and accrued liabilities	2,226,899	327,208	2,554,107
Income taxes payable	187,670	-	187,670
Future income taxes payable	409,000	-	409,000
Deferred revenue	-	-	-
Customer deposits	-	115,901	115,901
Liabilities transferred with assets held for sale	489,065	(489,065)	-
Term note payable	6,572,253	-	6,572,253
	10,850,135	-45,956	10,804,179
Accounts payable due beyond one year	-	-	-
	10,850,135	(45,956)	10,804,179
SHAREHOLDERS' EQUITY			
Share capital	13,461,439		13,461,439
Deficit	(8,364,421)		(8,364,421)
	5,097,018	-	5,097,018
	$ 15,947,153	$ (45,956)	$ 15,901,197

NATURAL RESOURCE GAS LIMITED

Accounting Entries for
Greenhouse Gas Emissions Impact Deferral Account
Deferral Account No. 179-49

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit/Credit	-	Account No.179-49 Other Deferred Charges - Greenhouse Gas Emissions Impact Deferral Account
Credit/Debit	-	Account No. 728 General Expense

To record, as a debit (credit) in Deferral Account No. 179-49, the administrative costs associated with the impacts of provincial and federal regulations related to greenhouse gas emission requirements.

Debit/Credit	-	Account No.179-49 Other Deferred Charges - Greenhouse Gas Emissions Impact Deferral Account
Credit/Debit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-49, interest on the balance in Deferral Account No. 179-152. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

NATURAL RESOURCE GAS LIMITED

Accounting Entries for
Greenhouse Gas Emissions Compliance Obligation – Customer-Related
Deferral Account No. 179-50

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit/Credit	-	Account No.179-50 Other Deferred Charges - Greenhouse Gas Emissions Compliance Obligation - Customer-Related
Credit/Debit	-	Account No. 520; Account No. 521; Account No. 522 Gas Sales Residential; Gas Sales Commercial; Gas Sales Industrial

To record, as a debit (credit) in Deferral Account No. 179-50, the variance between actual customer-related obligation costs and customer-related obligation costs recovered in rates as approved by the Board.

Debit/Credit	-	Account No.179-50 Other Deferred Charges - Greenhouse Gas Emissions Compliance Obligation - Customer-Related
Credit/Debit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-50, interest on the balance in Deferral Account No. 179-154. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

NATURAL RESOURCE GAS LIMITED

Accounting Entries for
Greenhouse Gas Emissions Compliance Obligation – Facility-Related
Deferral Account No. 179-51

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit/Credit	-	Account No.179-51 Other Deferred Charges - Greenhouse Gas Emissions Compliance Obligation - Facility-Related
Credit/Debit	-	Account No. 520; Account No. 521; Account No. 522 Gas Sales Residential; Gas Sales Commercial; Gas Sales Industrial

To record, as a debit (credit) in Deferral Account No. 179-51, the variance between actual facility-related obligation costs and facility-related obligation costs recovered in rates as approved by the Board.

Debit/Credit	-	Account No.179-51 Other Deferred Charges - Greenhouse Gas Emissions Compliance Obligation - Facility-Related
Credit/Debit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-51, interest on the balance in Deferral Account No. 179-155. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Accounting Order

Deferral Account to Record Rebalancing Recovery from Rates 1-5

Note: Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

EPCOR Natural Gas Limited Partnership ("ENGLP") shall establish a new "2019 Rebalancing Deferral Account" to record $210,000 for the recovery of revenue from Rates 1 through 5 associated with rebalancing of the utility's 2019 revenue as between Rate 1 through 5 with Rate 6 as a result of changes in rate base for the respective groups as outlined in the Settlement Proposal for EB-2018-0235. The account will be established as Account 179 Other Deferred Charges, Sub-Account 100 Rebalancing Deferral Account until such time as the amounts have been disposed of.

ENGLP will not record interest on any balance in this sub-account.

This amount will be disposed of using fixed monthly rate rider for the period of 12 months commencing January 1, 2019 as outlined in the Settlement Proposal for EB-2018-0235

Accounting Entries for Rebalancing Deferral Account

To record the $210,000 of revenue to be recovered from Rates 1-5 for 2019 rate base rebalancing with Rate 6 in Deferral Account No. 179-100 Rebalancing Deferral Account and recognize the associated revenue.

Debit - Account No. 179-100 2019 Rebalancing Deferral Account

Credit - Account No. 529 – Gas Sales

Accounting Order

Deferral Account to Record

Regulatory Expense Deferral Account

Note: Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

Accounting Entries for Regulatory Expense Deferral Account (REDA)

To record monthly as a debit (credit) in Deferral Account No. 179-21 (REDA) the cost for participating in generic proceedings and Union Gas proceedings, including a main rates case.

Debit/Credit Account No. 179-21 Regulatory Expense Deferral Account (REDA)

Credit/Debit - Account No. 251 Accounts Payable

To record, as a debit (credit) in Deferral Account No. 179-22, interest on the balance in Deferral Account

Debit/Credit - Account No.179-22 Regulatory Expense Deferral Account (REDA)

Credit/Debit - Account No. 323 Other Interest Expense

Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

To record the collection of the balance recorded in the account as of September 30, 2009 from REDA Rate Rider:

Credit Account No. 179-21 Regulatory Expense Deferral Account (REDA) by REDA Rate Rider to collect $172,801

Debit Account No. 140 Accounts Receivable - Customers

To record the collection of the balance of associated carrying charges as of September 30, 2009 from REDA Rate Rider:

Credit Account No. 179-22 Other Interest Expense by REDA Rate Rider to collect $1,106

Debit Account No. 140 Accounts Receivable – Customers

Accounting Order

Deferral Account to Record

Purchased Gas Commodity Variance Account

Note: Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

Accounting Entries for Purchased Gas Commodity Variance Account (PGCVA)

To record monthly as a debit (credit) in Deferral Account No. 179-27 (PGCVA) the decrease (increase) to reflect the projected changes in gas costs and prospective recovery of the balances of the gas supply deferral accounts approved by the Board for rate making purposes.

Debit/Credit Account No. 179-27 Purchased Gas Commodity Variance Account (PGCVA)

Credit/Debit Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-28, interest on the balance in Deferral Account

Debit/Credit Account No. 179-28 Purchased Gas Commodity Variance Account (PGCVA)

Credit/Debit - Account No. 323 Other Interest Expense

Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Order

Deferral Account to Record

Accounting Entries for the Gas Purchase Rebalancing Account

Note: Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, ClassA, prescribed under the Ontario Energy Board Act.

<u>Accounting Entries for Gas Purchase Rebalancing Account (GPRA)</u>

To record monthly as a debit (credit) in Deferral Account No. 179-35 (GPRA) the decrease (increase) in the value of gas inventory available for sale to sales service customers due to changes in NRG's PGCVA reference price approved by the Board for rate making purposes.

Debit/Credit - Account No. 179-35 Gas Purchase Rebalancing Account ("GPRA")

Credit/Debit - Account No. 623 Gas Purchases

To record monthly as a debit (credit) in Deferral Account No. 179-36 (GPRA), interest on the balance in Deferral Account

Debit/Credit - Account No. 179-36 Interest on GPRA

Credit/Debit - Account No. 323 Other Interest Expense

Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Order

Deferral Account to Record

Revenues Recovered Through the Transportation Service Charges

Note: Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

As indicated in its Decision dated December 6, 2010, the Board authorized NRG to establish a deferral account to record the revenues recovered through the Board authorized Transportation service Charges.

Accounting Entries for Transportation Service Charges Revenues

Deferral Account No. 179 Other Deferred Revenues – Transportation Service Charge Revenues

To record, as a debit (credit) in Deferral Account No. 179-39 the actual revenues recovered through the operation of the Board authorized Transportation Service Charge and the Transportation Service Administration Fee.

> Debit/Credit - Account No. 179-39 Other Deferred Revenues- Transportation Service Revenues
>
> Credit/Debit - Account No. 579 Miscellaneous Operating Revenues

To record, as a debit (credit) in Deferral Account No. 179-40, interest on the balance in Deferral Account

> Debit/Credit - Account No.179-40 Other Deferred Revenues- Transportation Service Revenues
>
> Credit/Debit - Account No. 323 Other Interest Expense

Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Order

Deferral Account to Record the Costs Incurred to Convert to the International Financial Reporting Standard

Note: Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

As indicated in its Decision dated December 6, 2010, the Board authorized NRG to establish a deferral account to record the costs incurred to convert to the International Financial Reporting Standard ("IFRS").

Accounting Entries for IFRS Conversion Costs

To record, as a debit (credit) in Deferral Account No. 179-41 the actual costs incurred to convert accounting policies and processes from their current compliance with Canadian Generally Accepted Accounting Principles to their future compliance with International Financial Reporting Standards (IFRS).

Debit/Credit - Account No. 179-41 Other Deferred Charges- IFRS Conversion Costs

Credit/Debit - Account No. 251 Accounts Payable

To record, as a debit (credit) in Deferral Account No. 179-42, interest on the balance in Deferral Account

Debit/Credit - Account No.179-42 Other Deferred Charges- IFRS Conversion Costs

Credit/Debit - Account No. 323 Other Interest Expense

Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Order

Deferral Account to Record

Accounting Entries for the Purchased Gas Transportation Variance Account

Note: Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the *Ontario Energy Board Act, 1998.*

Accounting Entries for Purchased Gas Transportation Variance Account - Rates 1-5 (PGTVA 1-5)

Effective October 1, 2010 NRG is authorized to reset the reference price for the PGTVA Fiscal 2011. Whereas formerly a single reference price was used effective October 1, 2010, two references prices will be relied on:

A reference price of $0.018339/m^3 applicable to all customers in rate classes 1 through 5:

Debit/ Credit	-	Account No. 179-45 Purchased Gas Transportation Variance Account - Rates 1-5 (PGTVA 1-5)
Credit/ Debit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-46, interest on the balance in the above Deferral Account:

Debit/ Credit	-	Account No. 179-46 Interest on PGTVA 1-5
Credit/ Debit	-	Account No. 323 Other Interest Expense

Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Order

Deferral Account to Record

Accounting Entries for the Purchased Gas Transportation Variance Account

Note: Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the *Ontario Energy Board Act, 1998*.

<u>Accounting Entries for Purchased Gas Transportation Variance Account - Rate 6 (PGTVA 6)</u>

Effective October 1, 2010 NRG is authorized to reset the reference price for the PGTVA Fiscal 2011. Whereas formerly a single reference price was used effective October 1, 2010, two references prices will be relied on:

A reference price of $\$0.009885/m^3$ applicable to all customers in rate class 6:

Debit/ Credit	-	Account No. 179-47 Purchased Gas Transportation Variance Account - Rate 6 (PGTVA 6)
Credit/ Debit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-48, interest on the balance in the above Deferral Account:

Debit/ Credit	-	Account No. 179-48 Interest on PGTVA 6
Credit/ Debit	-	Account No. 323 Other Interest Expense

Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

CERTIFICATION OF EVIDENCE

The undersigned, being EPCOR Ontario Utilities Inc.'s Senior Vice-President, Commercial Services, Steve Stanley hereby certifies for and on behalf of EPCOR Natural Gas Limited Partnership (ENGLP), as general partner of ENGLP that:

1. I am a senior officer of EPCOR Ontario Utilities Inc., which is the general partner of ENGLP;

2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's (the "**Board**")

   Filing Requirements for Natural Gas Rate Applications dated February 16, 2017; and

3. The evidence submitted in support of ENGLP's Application for rates effective on January 1, 2020 filed with the Board is accurate, consistent and complete to the best of my knowledge.

DATED this ____ day of January, 2019.

[original signed by]

Stephen Stanley

Senior Vice-President, Commercial Services
EPCOR Ontario Utilities Inc.

Natural Resource Gas Limited
39 Beech St. E., Aylmer On N5H 2S1

Via Courier

July 28, 2015

Ontario Energy Board
Board Secretary
2300 Yonge St, 27th Floor
Toronto, ON M4P 1E4

Dear Kirsten Walli,

Re: Competitive Market Study
Pursuant to OEB Decision and Order EB-2010-0018, and an extension granted by the Board on December 23, 2010, Natural Resource Gas Limited ("NRG") is providing the attached Competitive Market Study ("Study").

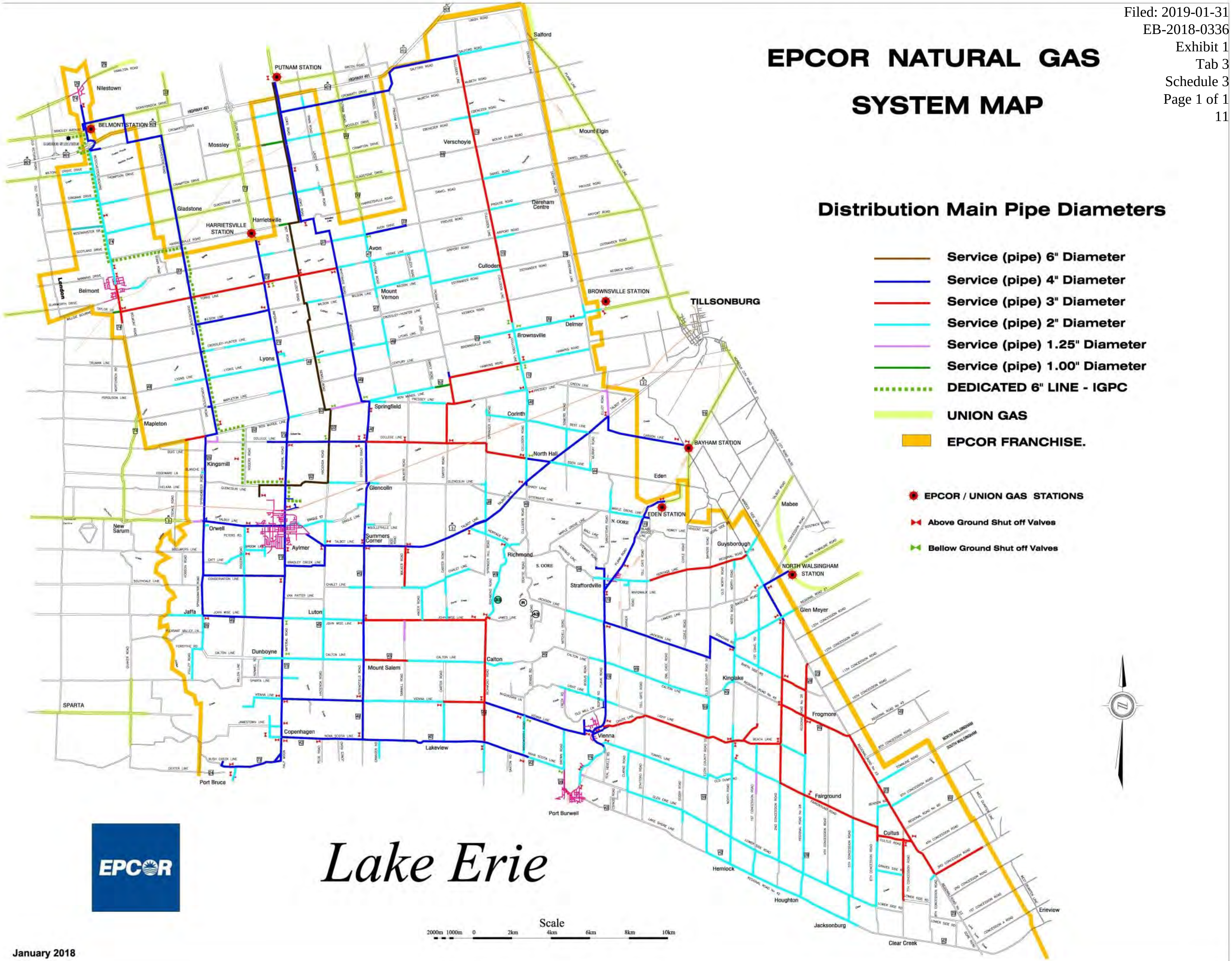
A meeting was held with the eligible candidate identified in the Study and a Request for Qualification was given to them.

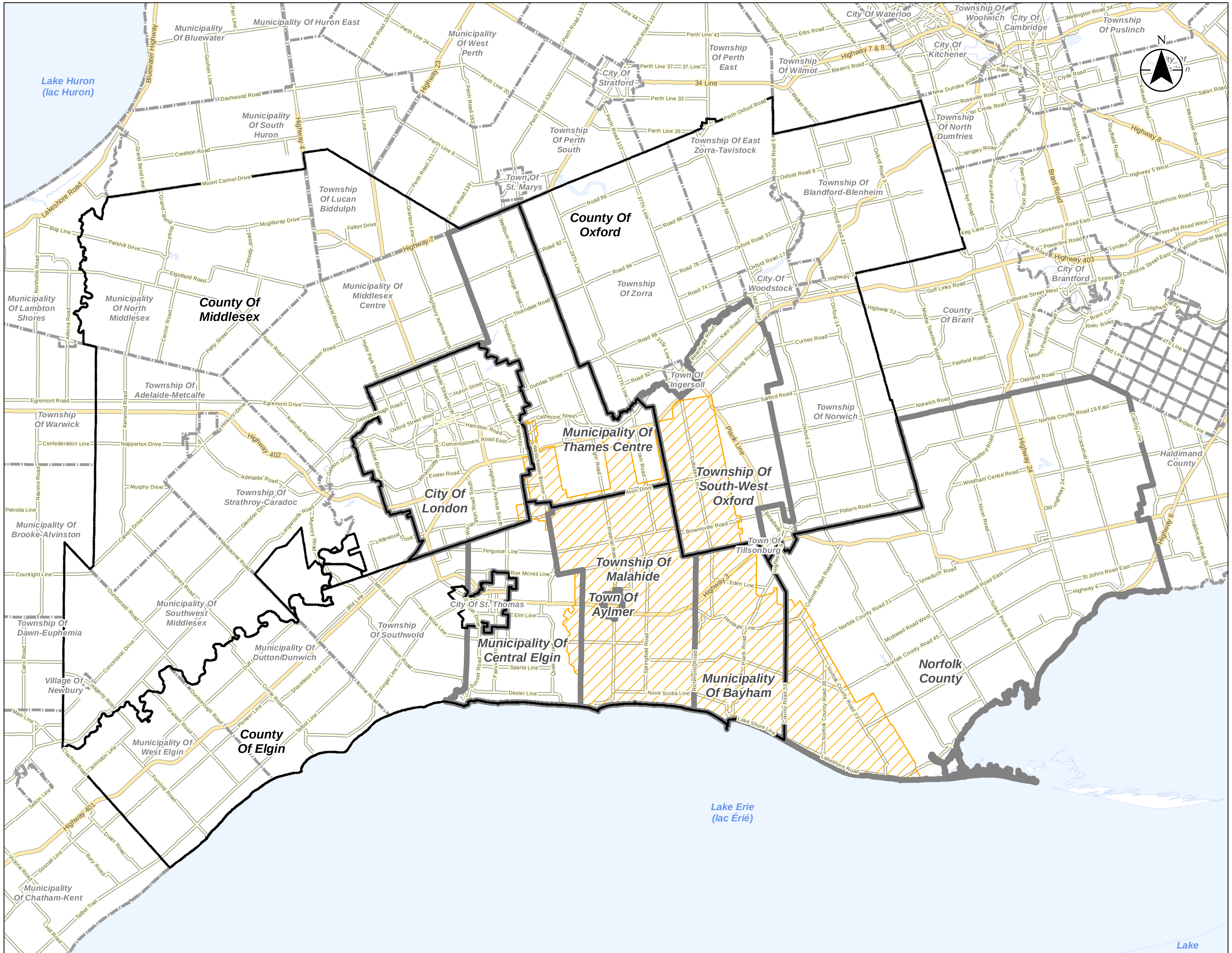
NRG followed that up with an email on May 11, 2015 and a letter on June 18, 2015 – no response has been received to date.

Kind regards,

Natural Resource Gas Limited

Anthony H. Graat,
President


EPCOR NATURAL GAS
SYSTEM MAP
Distribution Main Pipe Diameters
Service (pipe) 6" Diameter
Service (pipe) 4" Diameter
Service (pipe) 3" Diameter
Service (pipe) 2" Diameter
Service (pipe) 1.25" Diameter
Service (pipe) 1.00" Diameter
DEDICATED 6" LINE - IGPC
UNION GAS
EPCOR FRANCHISE.
EPCOR / UNION GAS STATIONS
Above Ground Shut off Valves
Bellow Ground Shut off Valves
PUTNAM STATION
BELMONT STATION
HARRIETSVILLE STATION
BROWNSVILLE STATION
BAYHAM STATION
EDEN STATION
NORTH WALSINGHAM STATION
TILLSONBURG
Salford
Nilestown
Mossley
Verschoyle
Mount Elgin
Dereham Centre
Gladstone
Harrietsville
Avon
Culloden
Belmont
London
Mount Vernon
Delmer
Brownsville
Lyons
Springfield
Mapleton
Corinth
North Hall
Eden
Kingsmill
Glencolin
Mabee
New Sarum
Orwell
Aylmer
Summers Corner
Richmond
S. OORE
N. GORE
Guysborough
Straffordville
Glen Meyer
Jaffa
Luton
Dunboyne
Mount Salem
Calton
Kinglake
SPARTA
Frogmore
Copenhagen
Vienna
Lakeview
Port Bruce
Port Burwell
Fairground
Cultus
Hemlock
Houghton
Jacksonburg
Clear Creek
Erieview
Lake Erie
EPCOR
Scale
2000m 1000m 0 2km 4km 6km 8km 10km
January 2018



Disclaimer: Stantec assumes no responsibility for data supplied in electronic format. The recipient accepts full responsibility for verifying the accuracy and completeness of the data. The recipient releases Stantec, its officers, employees, consultants and agents, from any and all claims arising in any way from the content or provision of the data.

Stantec

Legend

- EPCOR Franchise
- Expressway / Highway
- Major Road
- Municipal Boundary - Upper Tier
- Municipal Boundary - Lower Tier
- Waterbody

0 10,000 20,000 metres

1:500,000 (At original document size of 11x17)

Notes

1. Coordinate System: NAD 1983 UTM Zone 17N
2. Base features produced under license with the Ontario Ministry of Natural Resources and Forestry © Queen's Printer for Ontario, 2016.

Project Location

160950916-0001 REVA
Prepared by SE on 2016-07-25

Client/Project
EPCOR

Figure No.
1

Title
EPCOR Franchise and Lower Tier Municipalities

Exhibit 1, Tab 3, Schedule 5
Proposed Scorecard

Performance Outcomes	Performance Categories	Measures	
Customer Focus	Service Quality	Reconnection response time (# of days to reconnect a customer)	*# of reconnections completed within 2 business days/# of reconnections completed*
		Scheduled appointments met on time (appointments met within designated time period)	*# of appointments met within 4hrs of the scheduled date / # of appointments scheduled in the month*
		Telephone calls answered on time (call answering service level)	*# of calls answered within 30 seconds / # of calls received*
	Customer Satisfaction	Customer Complaint Written Response (# of days to provide a written response)	*# of complaints requiring response within 10 days / # of complaints requiring a written response*
		Billing accuracy	*Number of manual checks done as per quality assurance program, for excessively high or low usage.*
		Abandon Rate (# of calls abandon rate)	*# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent*
		Time to reschedule missed appointments	*% of rescheduled work within 2 hours of the end of the original appointment time*
Operational Effectiveness	Safety, system reliability and asset management	Meter Reading Performance	*# of meters with no read for 4 consecutive months / # of active meters to be read*
		% of Emergency Calls Responded within One Hour	*# of emergency calls responded within 60 minutes / # of emergency calls*
		Damages	*Third party line breaks per 1,000 locate requests*

Performance Outcomes	Performance Categories	Measures	
Public Policy Responsiveness	Extending natural gas distribution to new communities	New communities that have access to natural gas distribution system	*(# of communities serviced by system/# of communities committed to in CIP)*
		$/m3 cost to deliver natural gas	*Average $/m3 determined in CIP (as adjusted) – Actual average $/m3*
		Customer years	*Average customer years / Customer years as determined in CIP*
		Cumulative volume	*Actual cumulative volume / Cumulative volume as determined in CIP*
Financial Performance	Financial Ratios	Current Ratio	
		Debt Ratio	
		Debt to Equity Ratio	
		Interest Coverage	
		Financial Statement Return on Assets	
		Financial Statement Return on Equity	

Filed: 2019-01-31
EB-2018-0336
Exhibit 1
Tab 3
Schedule 6
Page 1 of 1

Presentation to:

Southwest Oxford Council

Presentation by:

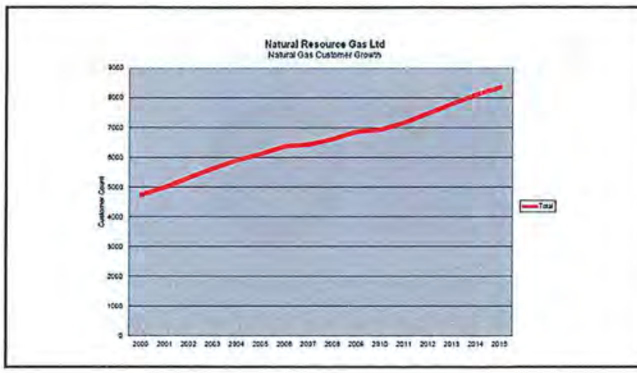
Brian Lippold, General Manager

NATURAL RESOURCE GAS Ltd.

Date: November 3, 2015

About NRG Ltd

- Nearly 100 years old, NRG was first know as Dominion Gas. It later became the Medina Gas Co. Medina was rescued from bankruptcy in the mid 70s by a prominent local businessman, Anthony Graat.
- NRG has 8500 Customers. You can find our customers in Aylmer-Malahide, Bayham, Norfolk, Thames Centre (North Dorchester), London/Middlesex, Central Elgin, Elgin County and of course. . . South-West Oxford.
- NRG operates in an area defined by renewable Franchise Agreements. Each agreement term is typically 20 years. The agreements are approved by the Ontario Energy Board in conjunction with local governments. We recently renewed our agreements with each of our municipal partners.
- Within NRG's franchise area, there is enough line underground that if linked end-to-end it would connect the PEI to Victoria Island, BC.
- Rates
  - Regulated by the Ontario Energy Board
  - Rates comparison to Union based on Economy of scales. Comparable to Union Gas' Northern Ontario rates
  - Storage is the differentiator
  - Fracking = 400 years worth of NG = price stability. A positive outlook
  - Don't believe the competition.



NRG's Plans to Serve South-west Oxford

Moving into Southwest Oxford

- Our plan is aggressive (Pipeline Options -refer to slide 6)
- The introduction of much needed reinforcement gas supply will aid us in our efforts to supply Natural Gas in this area (refer to slide X).

Currently we have Supplier Constraints (Union Gas Map - see slide 7)

- Involves a fight, your support

What is encouraging?

- Government has made a commitment to allow gas utilities to get creative in their applications to expand into rural or what was considered to be "remote" communities (Refer to Ontario Letter - Slide 8).

Filed: 2019-01-31
EB-2018-0336
Exhibit 1
Tab 3
Schedule 6
Page 1 of 1

Dependent on Union Gas System

Distribution	
Retail Customers:	1.4 million
Annual Throughput:	537 PJ
Distribution Pipe:	107,000+ km
Transmission	
Annual Throughput:	867 PJ
Transmission Pipe:	4,743 km
Markets Served:	Ontario, Quebec, US Northeast
Dawn Storage	
Storage:	173 PJ
Underground Facilities:	23
Markets Served:	Ontario, Quebec, Marketers, US

Refer to Handout

BY EMAIL AND WEB POSTING

HOW CAN WE MAKE THIS HAPPEN TOGETHER?

1. Communicate with each other throughout the process;
2. Encourage multiple residents to plan conversion together
3. Apply sustained pressure to MPP's office and the Energy Minister

Refer to handout

Refer to handout

TOWNSHIP OF SOUTH - WEST OXFORD

Thank you for your invitation and your time.

Contact us at :

WWW.NRGAS.CA

(519) 773-5321

Brian Lippold at Ext. # 205

Brian@nrgas.on.ca

2017 Cost of Service Rate Application

Brian Lippold
October 13, 2016

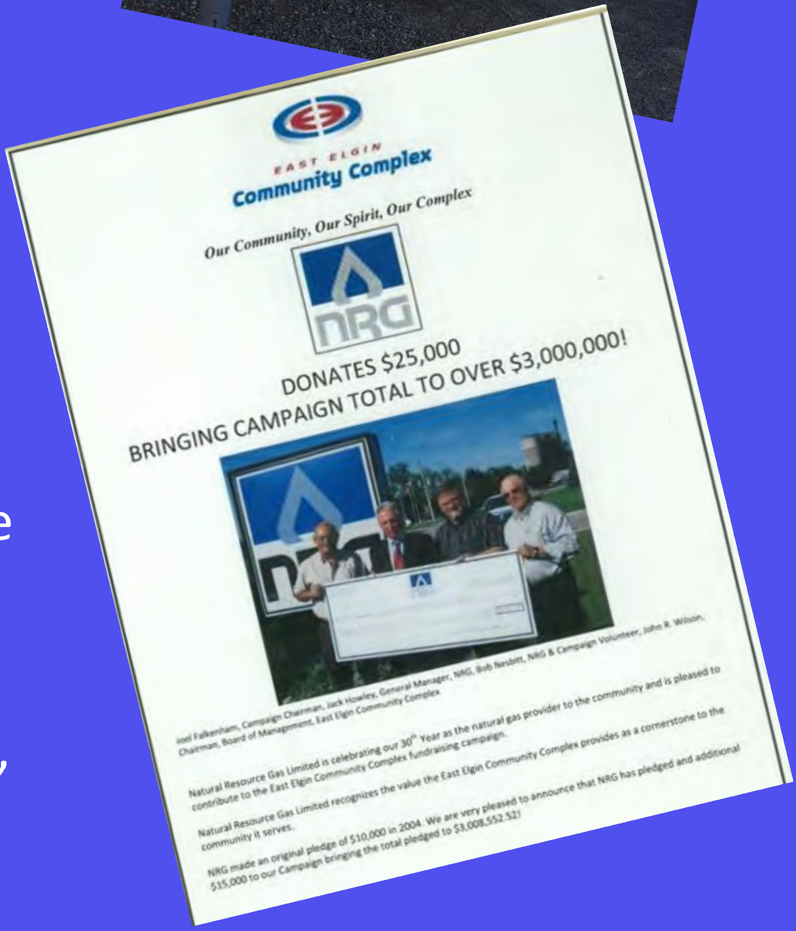
NATURAL RESOURCE GAS LIMITED

AGENDA

- About NRG
- Rates Process
- Strategic Priorities
- Capital
- O.M. & A.
- Questions/Answers

ABOUT NATURAL RESOURCE GAS:

- Locally and privately owned utility.
- Employs approximately 25 full-time staff
- NRG supports local suppliers, contractors service providers
- 8500 customers in Middlesex, Oxford, Norfolk & Elgin Counties
- NRG is 1 of 3 regulated Gas Utilities in the Province of Ontario
- NRG supports the community with sponsorship of local sports associations, teams, events and charities


EAST ELGIN Community Complex

Our Community, Our Spirit, Our Complex

DONATES $25,000
BRINGING CAMPAIGN TOTAL TO OVER $3,000,000!

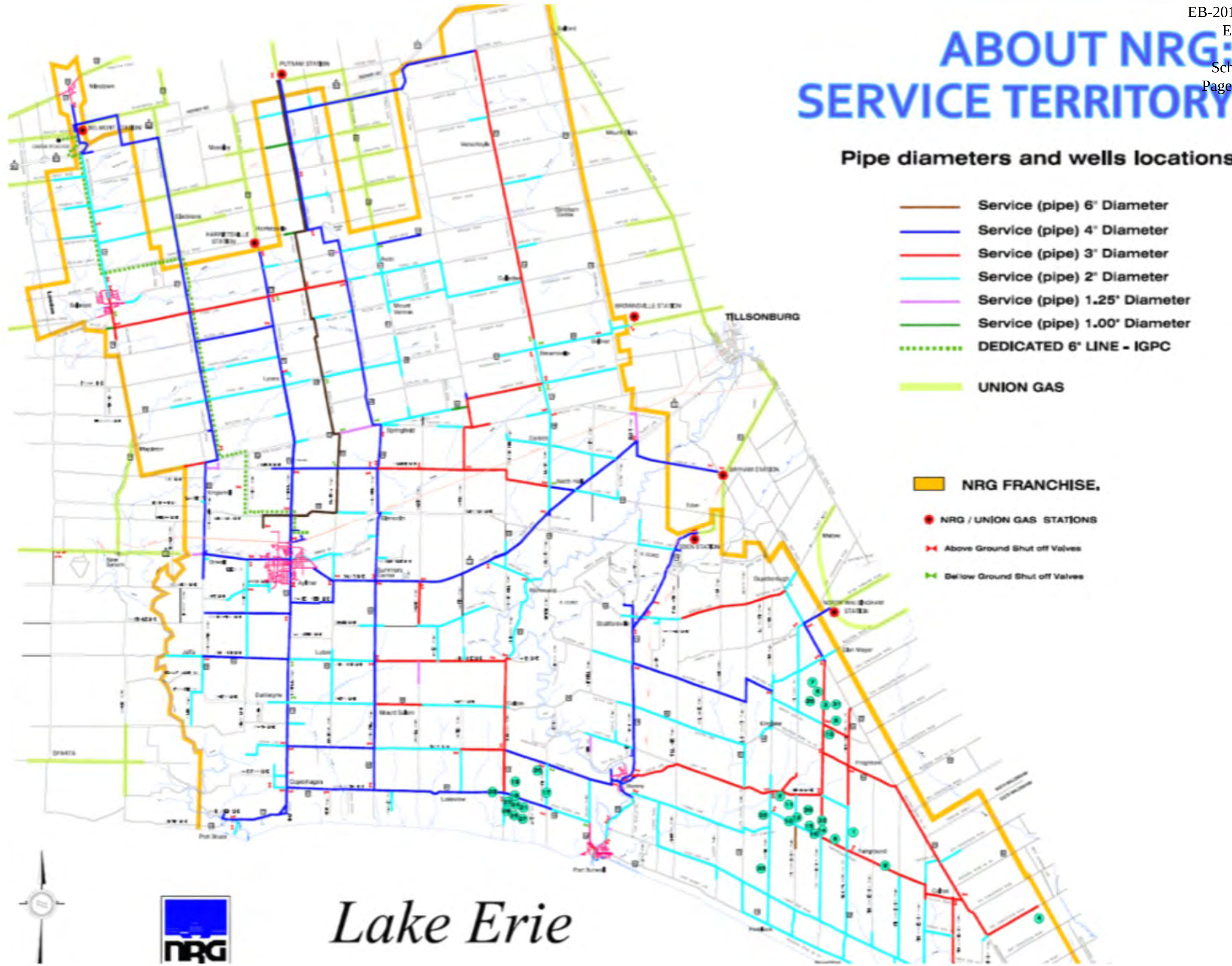
Joel Falkenham, Campaign Chairman, Jack Howley, General Manager, NRG, Bob Nesbitt, NRG & Campaign Volunteer, John R. Wilson, Chairman, Board of Management, East Elgin Community Complex

Natural Resource Gas Limited is celebrating our 30th Year as the natural gas provider to the community and is pleased to contribute to the East Elgin Community Complex fundraising campaign.

Natural Resource Gas Limited recognizes the value the East Elgin Community Complex provides as a cornerstone to the community it serves.

NRG made an original pledge of $10,000 in 2004. We are very pleased to announce that NRG has pledged and additional $15,000 to our Campaign bringing the total pledged to $3,008,552.52!

ABOUT NRG: SERVICE TERRITORY

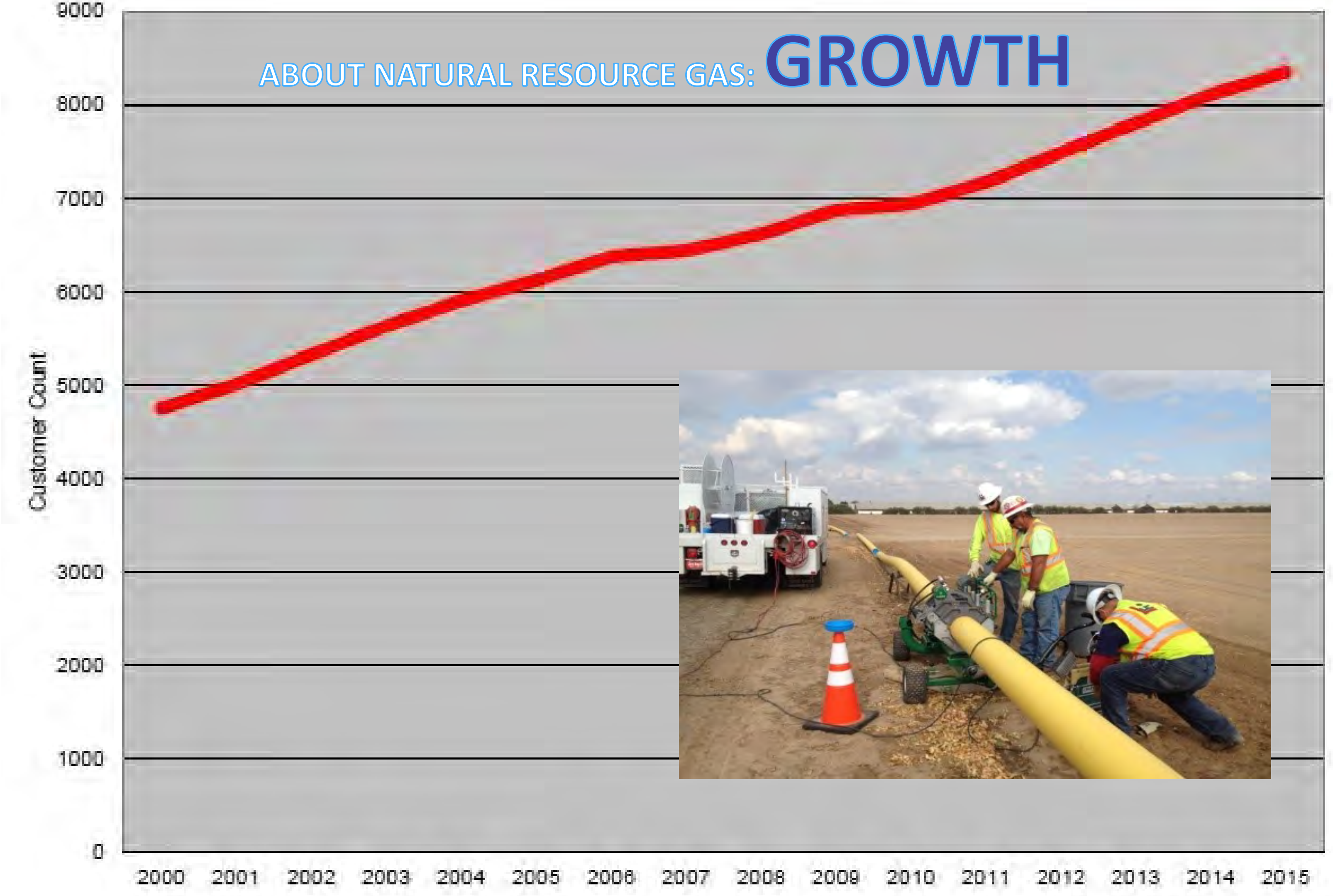


About Natural Resource Gas:

SCORECARD

- Service Quality – Exceeds all industry targets
- Safety Response– Maintained 100% Compliance
- Asset Management – On Schedule
- 100% on-time service connections
- Financial Ratios – Maintain profitability within allowed band

ABOUT NATURAL RESOURCE GAS: GROWTH



- Steady growth rate of 2.5-4.5% /year (36.5% over last 10 years)
- Growth and stability is positive for ratepayers

RATE-SETTING PROCESS

- THE CURRENT COST OF SERVICE (C.O.S.) APPLICATION RESULTED IN INTERIM RATES EFFECTIVE OCTOBER 1, 2016
- THROUGH THE C.O.S. PROCESS, RATES ARE ADJUSTED TO CONSIDER PRUDENT COSTS REQUIRED TO OPERATE, GROW AND MAINTAIN A SAFE DISTRIBUTION SYSTEM
- APPLICATIONS ARE REVIEWED BY THE OEB AND REGULARLY UNDERTAKE A SETTLEMENT PROCESS WITH INTERVENORS.
- RATE IMPACT IS FORECASTED TO BE GREATEST IN THE FIRST YEARS (2016/17) AND LESS IN SUBSEQUEST YEARS
- **IMPORTANT:** RATE PAYERS ARE REPRESENTED BY INTERVENORS LIKE **V.E.C.C**. (VULNERABLE ENERGY CONSUMERS COALITION). THEY PROTECT THE VULNERABLE & BY EXTENSTION, THEIR WORK BENEFITS THE RESIDENTIAL RATE PAYER OF NRG.

ACHIEVING JUST AND REASONABLE RATES

- Customer Focus
  - Provide value for customers
  - Better ways to gauge household consumption and understand bills
  - Greater Payment Options
  - Improved communication tools through robust billing messages
- Operational Effectiveness
  - System reinforcement projects aimed at bolstering system reliability and ensuring property protection and public safety
  - Asset Management Plans address prioritization of asset replacement
- Public Policy Responsiveness
  - Distribution System Growth ensures ability to connect to affordable, safe and abundant natural gas in predominantly rural areas
- Financial Performance
  - Prudent 5 year capital plan and OM&A strategy

Union Gas Limited (southern)	10.8927 ¢/m^3
Enbridge Gas Distribution Inc.	10.6439 ¢/m^3
Natural Resource Gas Limited	16.6850 ¢/m^3

The rate for NRG includes storage and transportation charges.

Step 1: Enter your monthly gas usage
Select month for usage estimate: Jan
Enter your monthly natural gas usage: 377 m^3

Step 2: Click to view results
Calculate

Optional: See how your bill might look on a contr

Monthly Bill Statement
NRG - All

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Natural Gas Charges	
Customer Charge (what is this charge?)	$13.50
Delivery (what is this charge?)	$61.19
Gas Supply Charge (what is this charge?)	$62.90
Total Natural Gas Charges	**$137.59**
HST	$17.89
Total Amount	**$155.48**

Step 1: Enter your monthly gas usage
Select month for usage estimate: Jan
Enter your monthly natural gas usage: 377 m^3

ep 2: Click to view results
Calculate

ptional: See how your bill might look on a con

Monthly Bill Statement
Union - Southern

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Natural Gas Charges	
Customer Charge (what is this charge?)	$21.00
Delivery (what is this charge?)	$14.24
Delivery Charge Price Adjustment	$3.52
Gas Supply Charge (what is this charge?)	$43.62
Cost Adjustment (what is this charge?)	($2.56)
Transportation Charges (what is this charge?)	$15.85
Transportation Price Adjustment	$0.00
Storage Charges (what is this charge?)	$2.65
Total Natural Gas Charges	**$98.32**
HST	$12.78
Total Amount	**$111.1**

Step 1: Enter your monthly gas usage
Select month for usage estimate: Jan
Enter your monthly natural gas usage: 377 m^3

Step 2: Click to view results
Calculate

Optional: See how your bill might look on a contr

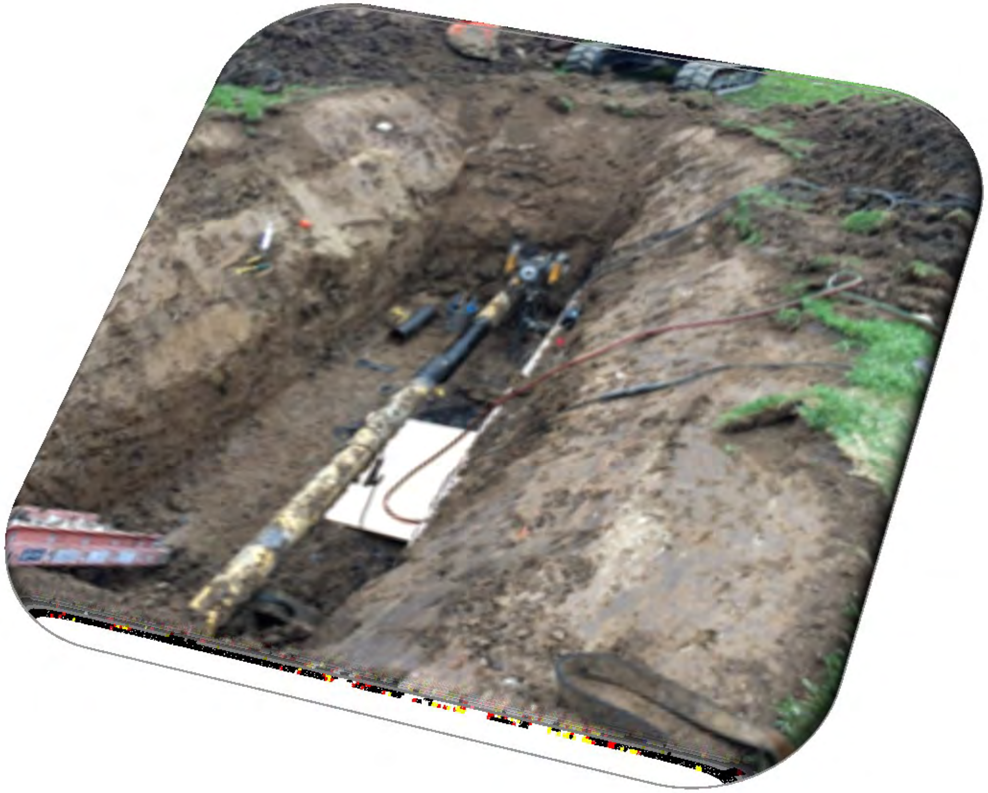
Monthly Bill Statement
Union - Northern

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Natural Gas Charges	
Customer Charge (what is this charge?)	$21.00
Delivery (what is this charge?)	$32.69
Delivery Charge Price Adjustment	$4.93
Gas Supply Charge (what is this charge?)	$43.28
Cost Adjustment (what is this charge?)	($6.37)
Transportation Charges (what is this charge?)	$24.47
Transportation Price Adjustment	$1.48
Storage Charges (what is this charge?)	$14.88
Total Natural Gas Charges	**$136.35**
HST	$17.73
Total Amount	**$154.08**

NRG'S STRATEGIC PRIORITIES



- Safety
- Reliability
- Rates
- Conservation
- Community Focus
- Agribusiness Support

Explanation of Prudent Capital Additions

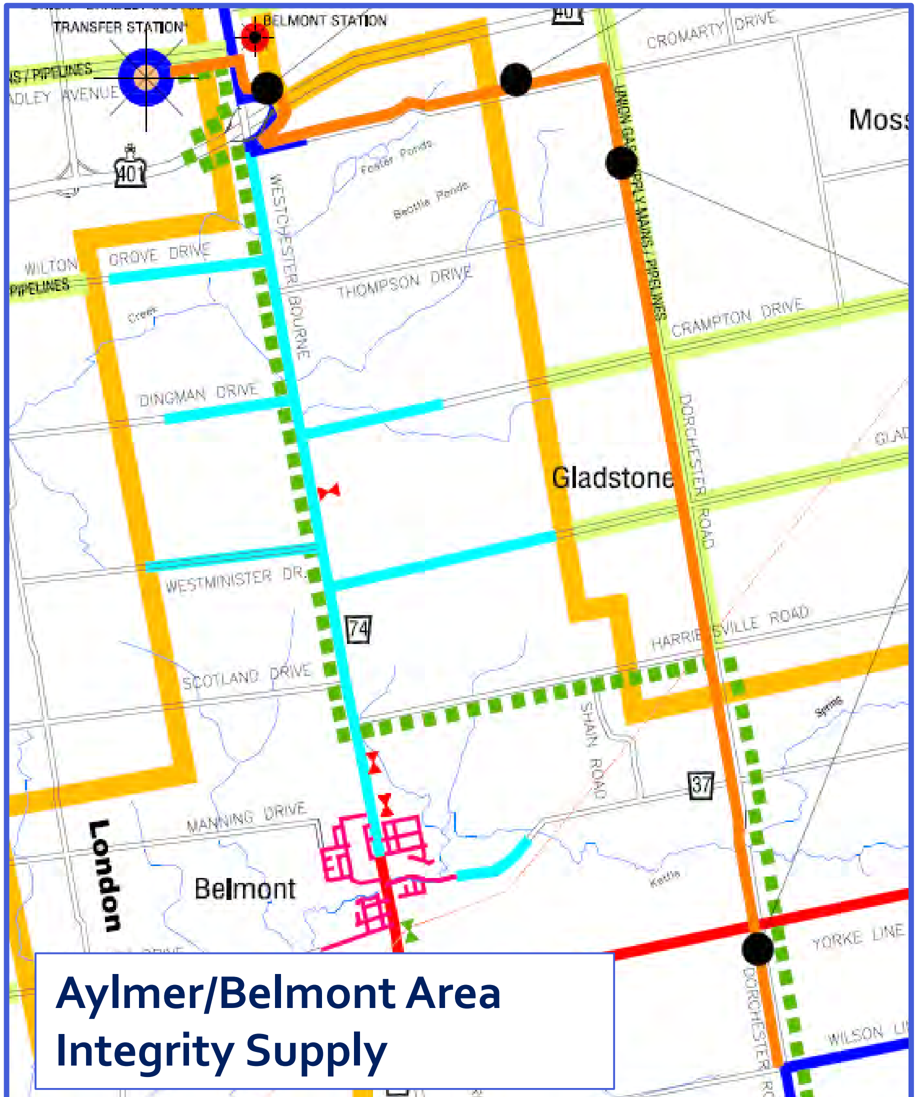
	Test 2017	Bridge 2016	Actual 2015	Actual 2014	Actual 2013	Actual 2012	Actual 2011	Actual 2010
Mains - Additions	425,000	2,046,520	56,544	55,483	49,023	350,150	422,291	117,826
- Replacements	150,000	6,500	0	0	0	0	0	2,160
Services - Additions	212,096	135,000	188,548	100,574	199,720	199,126	100,085	86,842
- Replacements	0	0	0	0	0	0	0	1,490
Ethanol Pipeline	200,000	0	0	0	0	0	0	0
New Steel Mains	0	0	0	0	0	0	0	0
Meters	131,189	125,026	276,027	260,412	176,570	73,713	22,920	103,219
Meter - IGPC	0	0	14,512	0	0	0	0	0
Regulators	63,500	62,250	14,512	22,302	71,354	42,387	17,105	16,139
Franchises	0	30,000	39,047	115,157	373,270	0	1,450	6,197
Land	0	15,000	0	0	0	0	0	0
Buildings	60,000	12,000	0	3,285	1,758	0	0	0
Furniture & Fixtures	4,200	2,000	6,214	21,653	2,946	10,083	0	0
Computer Equipment	20,000	9,000	15,638	6,076	6,972	3,640	1,159	5,214
Computer Software	89,500	200,000	10,977	9,327	7,504	3,952	16,800	21,115
Machinery & Equipment	17,700	98,100	47,243	40,158	38,373	5,328	3,741	4,347
Communication Equipment	7,500	12,000	0	15,889	4,730	0	10,196	6,500
Automotive	84,600	79,200	15,632	126,257	54,384	55,064	65,571	14,075
Rental Water Heaters	0	0	123,708	166,120	147,245	220,239	153,853	192,902
Total Capital Expenditures	1,465,285	2,832,596	808,603	942,693	1,133,848	963,682	815,171	578,027

	Reasons for major variance
Red	Pipeline Installations
Green	Accounting Change -Regs
Purple	MCAN Changes to policy
Yellow	20-year renewal
Orange	Required for reporting and CR
Blue	Safety policy and CNG
Light green	Ancilliary sales removed

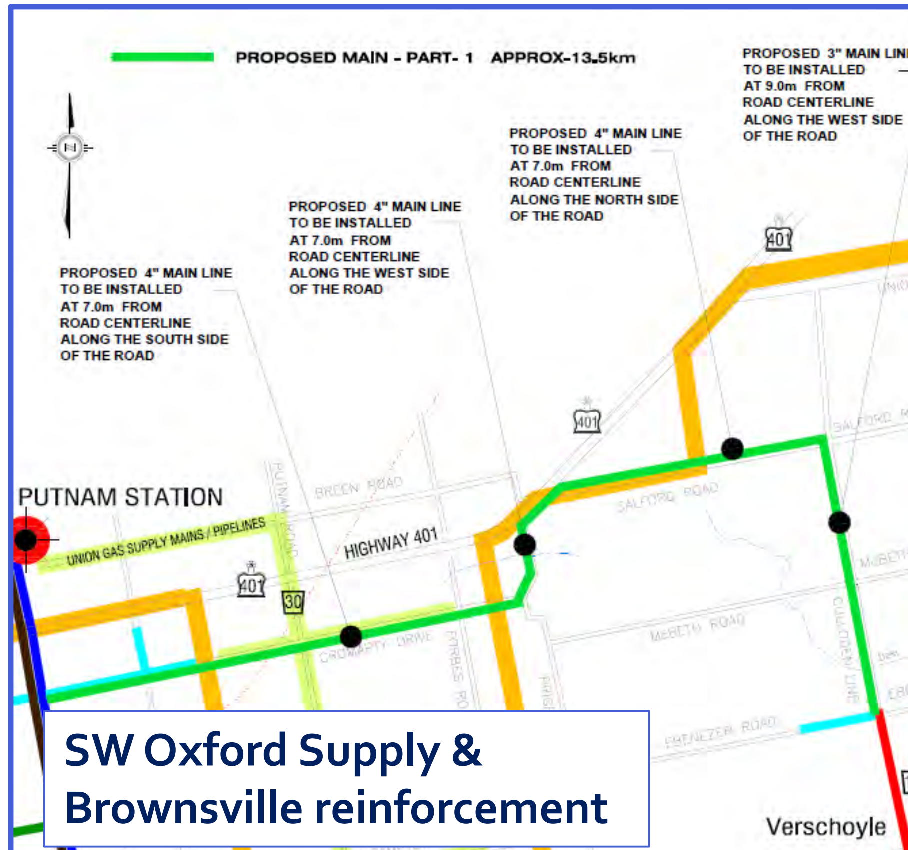
CAPITAL:
INVESTMENTS THAT SAVE OPERATIONAL DOLLARS OVER TIME

CAPITAL: REINFORCEMENT PROJECTS

2016 Major Capital Projects completed YTD



Aylmer/Belmont Area Integrity Supply



SW Oxford Supply & Brownsville reinforcement

OPERATIONS, MAINTENANCE & ADMINISTRATION

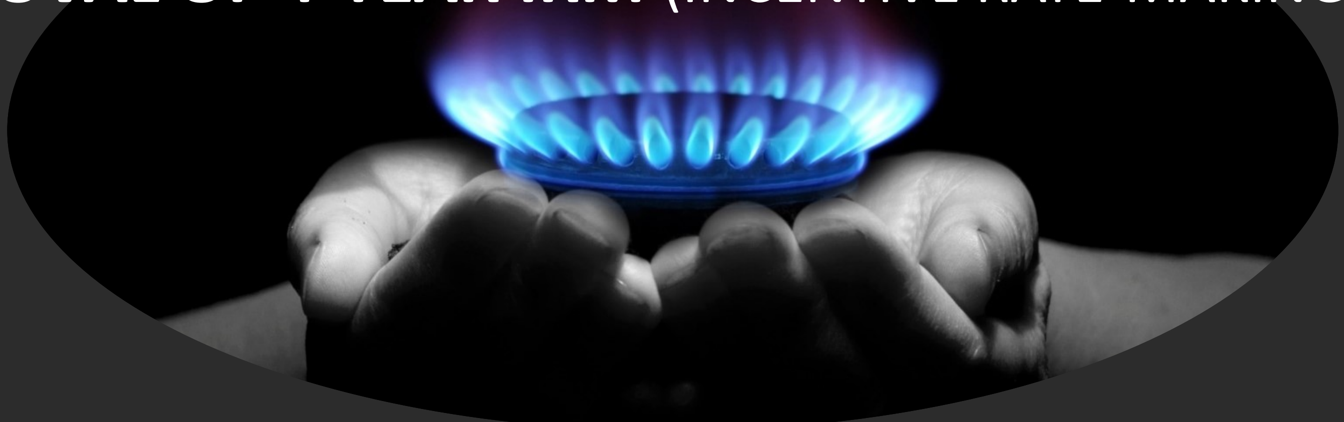
O.M. & A:

2017 Application for 3.866 M costs vs 2.629 M approved in 2011. Key drivers for increase:

- 22% Growth in customer since 2011
- Inflation, increased legal cost
- Growing contractor and consulting costs in response to regulatory & environmental policy changes
- Acquisition of talent & additional consulting
- Recruitment costs, succession planning and training cost that come with replacement of experienced staff
- Process and field safety improvements

SUMMARY OF ITEMS IN COS APPLICATION

- ✓ **SEEKING APPROVAL FOR ADDITION TO CAPITAL**
- ✓ **INCREASE OF 1.2 MILLION IN OPERATING, MAINTENANCE & ADMINISTRATION COSTS**
- ✓ **ADDITIONAL 500,000 m3 LOCAL WELL GAS @ $8.43/**MCF
- ✓ **CUST CHARGE $13.50 TO $18.50 then 50¢/yr** (UNION AT $21)
- ✓ **APPROVAL OF 4-YEAR IRM** (INCENTIVE RATE-MAKING PLAN)



BILL IMPACT

Year	Distribution Portion of Bill	Total $ Change	Annual % Change
2006	445.37		
2009	468.76	23.39	1.3%
2010	470.09	1.33	0.2%
2011	472.38	2.29	0.5%
2013	475.29	2.91	0.6%
2014	479.67	4.38	0.9%
2015	488.08	8.42	1.8%
2016	588.35	100.27	20.5%
2017	593.06	4.71	0.8%
2018	597.80	4.74	0.8%
2019	602.58	4.78	0.8%
2020	607.40	4.82	0.8%
OCT 2016 through 2020 AVERAGES.			
	597.84	**23.86**	**4.0%**

= 23.86/

Notes: 1) This assumes 0 change to Commodity - Without Union System Gas
2) Above are **Pre-Settlement** figures

REASONS FOR 2016 VARIANCE?

- ✓ 2 Pipeline Projects
  - Engineering
  - Legal/Land Acquisition
  - TSSA Variances
- ✓ 5Yr Rate-case
  - Consulting costs
  - Legal Fees
- ✓ System Integrity Study
  - OEB Directed
- ✓ Increases to staff level, labour & contract costs
- ✓ Software system Upgrade
  - Cap and Trade
  - Payment Options
- ✓ Challenges with UG for increased volumes
- ✓ TSSA Audit Year
- ✓ USD impact on services

LOOK FOR IN NOVEMBER

Outfitting your home with energy-smart upgrades can help you save 3 ways:

1 **SAVE MONEY NOW.**
Improve the energy efficiency of your home and get up to **$5,000** of your renovation costs back.

2 **SAVE MONEY LATER.**
Increased energy efficiency will decrease your energy bill by up to **20% every year.**

3 **INCREASE THE VALUE OF YOUR HOME.**
An energy-efficient home is more attractive to future buyers.

How to take advantage of the Home Reno Rebate:

1 **Call** a participating certified energy advisor before starting your renovations. For a complete list, go to **uniongas.com/homereno**.

2 **Complete** your pre-renovation energy assessment.

3 **Review** your assessment and renovation options with your energy advisor.

4 **Complete** at least two of the eligible renovations with a reputable contractor.*

5 **Call** your advisor to complete your post-renovation assessment.

Your advisor will collect and submit all the necessary paperwork to Union Gas. You will get your rebate cheque within 90 days of submission.
*We recommend that you get quotes from at least three reputable contractors.

QUESTIONS

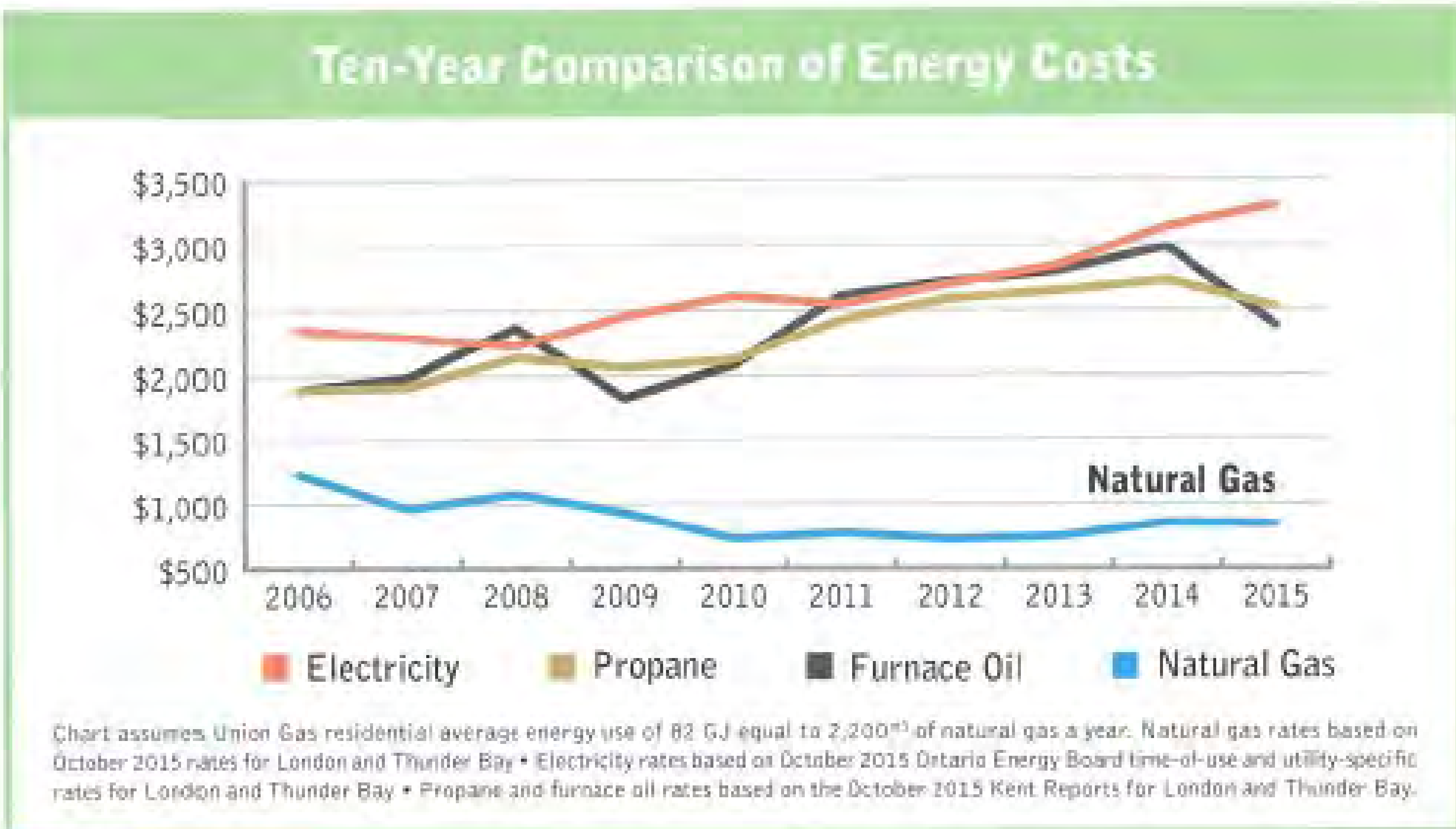
THANK YOU TO OUR CUSTOMERS!

We promise to continue to deliver safe, affordable & abundant natural gas to your home or business

REFERENCES FOR Q AND A:

TRENDS IN GAS PRICING

COURTESY OF UNION GAS



REFERENCES FOR Q AND A:
OMB COMAPARBLES IN GAS PRICING

Utilities Kingston

Gas Rate Structure (effective May 1 2016)

These rates apply to all customers <u>except</u>, Interruptible Customers and Direct Purchase Customers (Retailer)

monthly		per m^3
Block #1	1st 1500 m^3	$0.3302
Block #2	Next 3500 m^3	$0.2956
Block #3	Next 70000 m^3	$0.2738
Block #4	All over 75000 m^3	$0.2613

Residential Service Charge (Monthly)	**$21.00**
Commercial Service Charge (Monthly)	**$70.00**

<u>Components that make up the m^3 rate</u>

per m^3 (cubic meter)	Commodity	Transportation & Storage	Local Distribution Costs	Total
Block #1	0.1285	0.1156	**0.0861**	$ 0.3302
Block #2	0.1285	0.1156	**0.0515**	$ 0.2956
Block #3	0.1285	0.1156	**0.0297**	$ 0.2738
Block #4	0.1285	0.1156	**0.0172**	$ 0.2613

REFERENCES FOR Q AND A:
OMB COMAPARBLES IN GAS PRICING

All volume - m^3	10.5	4.0	7.1543	21.6543	73 ¢/day
Previous Rate for first 100 m^3	19.0	3.0	7.4042	29.4042	73 ¢/day x 31 = 22.63

m3=cubic meters

The above fees are also subject to an additional 13% HST

Current rates for general service M2 customers

General service M2 - annual consumption greater than 50,000 m^3

Amount of Natural Gas Used Per Month	Supply Rate ¢/m^3	Transportation Rate ¢/m^3	Variable Delivery rate ¢/m^3	Net Rate ¢/m^3	Daily Fixed Charge
First 1,000 m^3	10.5	4.0	6.6466	21.1466	$2.30/day
Next 6,000 m^3	10.5	4.0	6.5677	21.0677	$2.30/day
Next 13,000 m^3	10.5	4.0	6.3326	20.8326	$2.30/day
All over 20,000 m^3	10.5	4.0	6.0505	20.5505	$2.30/day
Previous Rate for first 1,000 m^3	19.0	3.0	6.6466	28.6466	$2.30/day

The above fees are also subject to an additional 13% HST

Contact Name
Contact Address
Contact Address line 2

NEW NAME,
SAME GREAT TEAM AND SERVICE!

Dear

Natural Resource Gas Limited assets transition to EPCOR.

We are pleased to announce that ownership of the assets of Natural Resource Gas Limited (NRG), your local natural gas distribution company, is expected to transfer to EPCOR on October 1, 2017 as the sale has been approved by the Ontario Energy Board.

The team from NRG is still committed to providing the great service you've been accustomed to and will soon transition to the EPCOR brand.

As a result, your monthly NRG natural gas bill will be replaced with an EPCOR natural gas bill. Your billing account number, our phone numbers, employees and service will not change.

If you pay by Automatic Payment Withdrawal, no action is required from you. Going forward, the payee on your bank statement will read: EPCOR Natural Gas L.P.

If you pay by cheque, starting on October 1st, 2017 address it to: EPCOR Natural Gas L.P. You will also be able to pay as you have before - through your bank, in person at the EPCOR office or by phone. EPCOR will maintain the same address and phone number to make the transition smooth. See below for details on how you can reach us.

If you have any questions or concerns about your natural gas bill or account, please contact the office at 519-773-5321. An advisor will be happy to help you.

We are proud to serve in the communities in which we live. Our priority is to ensure continued quality customer service and safe and reliable delivery of natural gas to NRG customers.

How to contact us:

For Emergency: 519-773-5321 (24 hours)

Regular Office Hours: Monday to Friday 8 am to 4 pm 519-773-5321

EPCOR office location: 39 Beech St. E, in Aylmer Ontario

PROVIDING MORE EPCOR

Questions you may have

Who is EPCOR?

EPCOR is a Canadian-based company and a trusted provider of utility services to over one million consumers in North America for over 125 years. We're a recognized leader in our commitment and service to our customers and the communities where we work and live.

What do I do with my current NRG bill?

Pay this as you normally do, and of course, if you have questions about your bill or service, please call the office during regular business hours at 519-773-5321.

Will my natural gas rates change?

Regulated natural gas rates will continue to be approved by the Ontario Energy Board (OEB). If you buy gas directly from a gas marketer, your negotiated rates will continue.

Your bill will continue to provide you with consumption history, payment history and the same payment options.

What if I am on Budget Billing?

The monthly budget bill will continue as was previously set by NRG. There is no action required by you to set this up.

What if I have a credit balance?

Your balance on your account will transfer with your next bill.

Have more questions?

We're here to help. Please email us with questions at **gas@epcor.com** or call the office at 519-773-5321.

Where can you get more information?

Information on the transition and any action you need to take will be provided with your bill and available on our website.

We look forward to being your natural gas distributor and becoming part of your community. For information about EPCOR please visit **epcor.com**.

EPCOR Natural Gas L.P.
39 Beech St E,
Aylmer ON, N5H 3J6
519-773-5321
www.epcor.com
email: gas@epcor.com

August 29, 2018

Dear Valued Customer,

We completed emergency service work in your area and there was a temporary interruption to your natural gas service. To turn your gas service back on, it requires a technician to enter the premises and relight any gas appliances you may have, and we did not find anyone available when we were there today.

We apologize for any inconveniences this may cause but please contact our office and we will schedule an appointment to have your gas turned back on.

Please call our service department at 519-773-5321 to arrange a follow-up time for us to return. If you are calling after 4pm, choose option 1 to be connected to our after hours service and they will be passing along the messages to the on call Technician.

Please ensure that you provide a contact phone number for us to make access arrangements.

Thank you for your co-operation.

Service Department
EPCOR Natural Gas L.P.

Farmers: maximize yields by digging safe

Each year, EPCOR Natural Gas responds to several emergency hits on natural gas lines on local farms. These incidents can result in significant property damage or injury.

As a landowner, you have the right to dig on your property but just sinking a shovel into the ground could cause a disruption for which you could be held liable. While natural gas lines are typically buried at a minimum 18 inches, excavating even just 12 inches below the surface can result in a line being struck.

As you harvest this month and prepare your fields for the season ahead, remember: before you dig, you must have all buried utilities located. This process begins by calling Ontario One Call.

Why you need to Dig Safe

Any work that disturbs the ground could result in serious injury, widespread service disruption and costly repairs. These significant consequences could be avoided.

- **Prevent injury or death:** injuries affect the physical and emotional wellbeing of you, your family and your employees. They can also result in delays to production or have legal ramifications.
- **Save money:** under Ontario regulations, you are responsible for the cost of repairs if you hit a natural gas line. You may also be required to pay a fine or costs associated with an investigation. These costs could add up to thousands of dollars.
- **Avoid disruption:** your operations could be halted as the gas line is repaired, preventing you from maximizing your productivity. The disruptions can also affect neighbouring homes and businesses.

Signs you may have struck a line

Knowing when you've hit a natural gas line can help reduce the risks to both people and property. Look for the following signs:

- **Smell it:** in its pure state, natural gas has no smell or taste. As a safety precaution, a scent called methyl mercaptan is added to natural gas before it is delivered to your home. This odour smells like rotten eggs or sulphur so that natural gas can be detected.
- **See it**: natural gas is odourless and colourless but it can leave behind visible signs including patches of dead vegetation, blowing dust from holes in the ground, bubbles in wet or flooded areas or even flames. In some cases, spotting vapours or ground frosting can suggest a line has been hit.
- **Hear it:** a hissing or roaring noise coming from the ground could also indicate you've hit a line.

What to do if you hit a line

If you suspect you've struck a line, call your natural gas provider or 911 right away. This requires immediate attention. Be sure to keep clear of the area, turn off any machinery or motor vehicles, don't smoke or use anything that could spark a flame.

Who to call before you dig

Striking a natural gas line is preventable. Before starting any type of excavation, you must contact Ontario One Call to have the underground utilities located. At no cost to you, they will notify EPCOR or your local provider. The utility will provide locates for all areas in advance of the meter without charge. If the area where you are excavating is after the meter, you may be required to contract a private locating contractor.

Your natural gas provider is a great resource for information. They can provide you with helpful contact cards or educational brochures or conduct an on-site inspection. As part of our service, EPCOR conducts annual visits to customers who have large factored meters that provide higher pressure to dryers, kilns or poultry operations.

At EPCOR, safety is our top priority—for our employees and our customers. Whether you're beginning your harvest, planting crops or doing repairs, be sure to phone Ontario One Call at 1-800-400-2255 or visit www.digsafe.ca before you dig to keep everyone safe and the farm running at full production.

EPCOR is a Canadian-based company that provides clean water, wastewater and drainage services and safe, reliable electricity and natural gas to more than one million residential and commercial customers in North America.

EPCOR

EPCOR Natural Gas LP
39 Beech Street East
Aylmer, ON N5H 3J6
www.epcor.com
email: gas@epcor.com

PLEASE RETURN THIS PORTION WITH PAYMENT

BILLING DATE	DUE DATE	ACCOUNT NUMBER
06/30/2017	07/24/2017	

AMOUNT DUE	AMOUNT PAID
$28.37	

BILL TO

SERVICE ADDRESS

PAYABLE AT MOST CHARTERED BANK AND FINANICAL INSTITUTIONS

A04551d900A 96

EPCOR Natural Gas LP
39 Beech Street East
Aylmer, ON N5H 3J6
epcor.com
email: gas@epcor.com

Contact Us:
519-773-5321
Service: Extension 215
Billing: Extension 212
Sales: Extension 200

SERVICE ADDRESS			ACCOUNT NUMBER	LOCATION NUMBER	BILLING DATE
					06/30/2017
SERVICE	SERVICE PERIOD & METER READINGS		METER USE MCF's · FACTOR * · CONVERSION FACTOR · USAGE m³		DUE DATE
Gas Commodity	PREVIOUS 135.80	PRESENT 136.90	1.1 X 0.99649 X 28.17399 = 30.9		07/24/2017
Type of Reading	FROM	TO	BILLS ARE DUE WHEN RENDERED A LATE CHARGE OF 1.5% PER MONTH (19.56% PER ANNUM) WILL APPLY. *Volume corrections account for barometric pressure.		Number of Service Days
Actual Read	05/24/2017	06/25/2017			32

FEES AND CHARGES

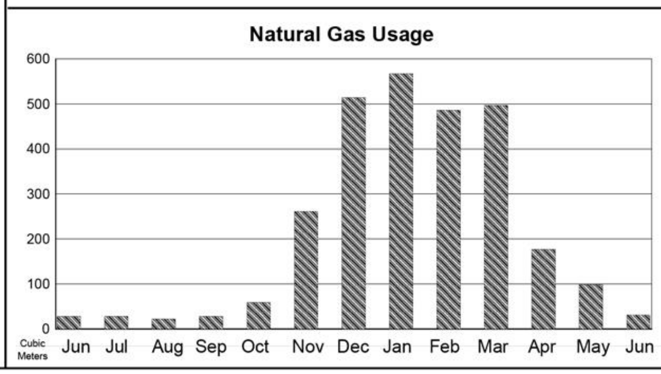
DESCRIPTION					AMOUNT
Previous Balance					56.99
Payments					-56.99
Delivery To You	30.9	M3 @	0.19626	PER M3 =	6.06
Gas Commodity	30.9	M3 @	0.17947	PER M3 =	5.55
Monthly Charge					13.50
HST #R103839106					3.26
	Total Due				**$28.37**

TOTAL AMOUNT DUE BY 07/24/2017

$28.37

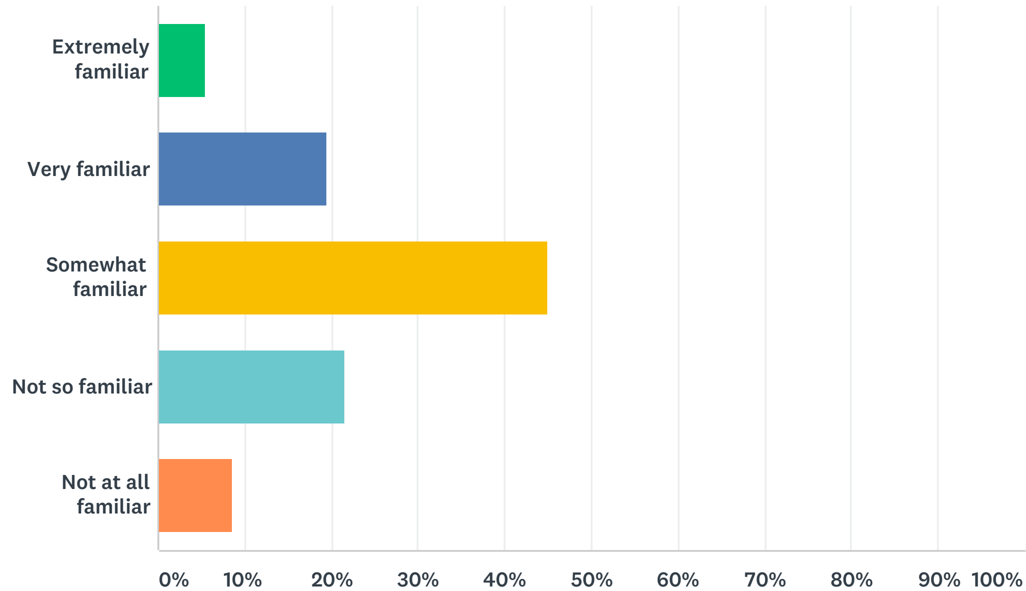
TOTAL AMOUNT DUE AFTER 07/24/2017

$29.37



As you may know, EPCOR delivers natural gas to more than 8,000 residential, commercial and industrial customers throughout Elgin, Middlesex, Norfolk and Oxford counties. How familiar are you with EPCOR, which operates in your community?

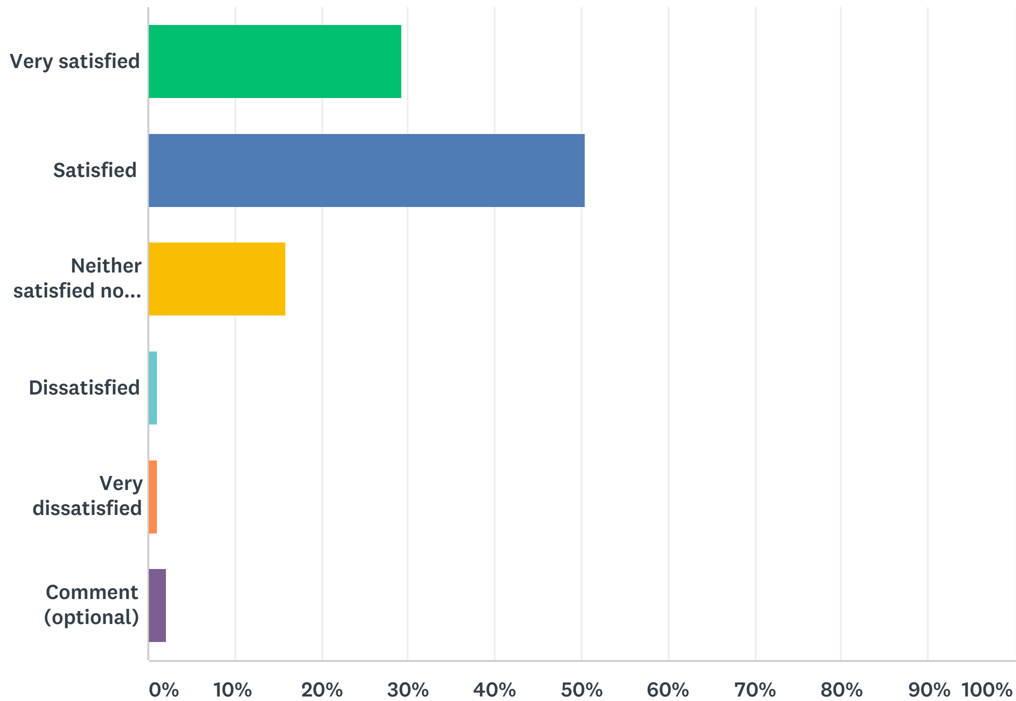
Answered: 439 Skipped: 2



ANSWER CHOICES	RESPONSES	
Extremely familiar	5.47%	24
Very familiar	19.36%	85
Somewhat familiar	44.87%	197
Not so familiar	21.64%	95
Not at all familiar	8.66%	38
TOTAL		439

Overall, how satisfied are you with the service you receive from EPCOR?

Answered: 439 Skipped: 2



ANSWER CHOICES	RESPONSES	
Very satisfied	29.38%	129
Satisfied	50.34%	221
Neither satisfied nor dissatisfied	15.95%	70
Dissatisfied	1.14%	5
Very dissatisfied	1.14%	5
Comment (optional)	2.05%	9
TOTAL		439

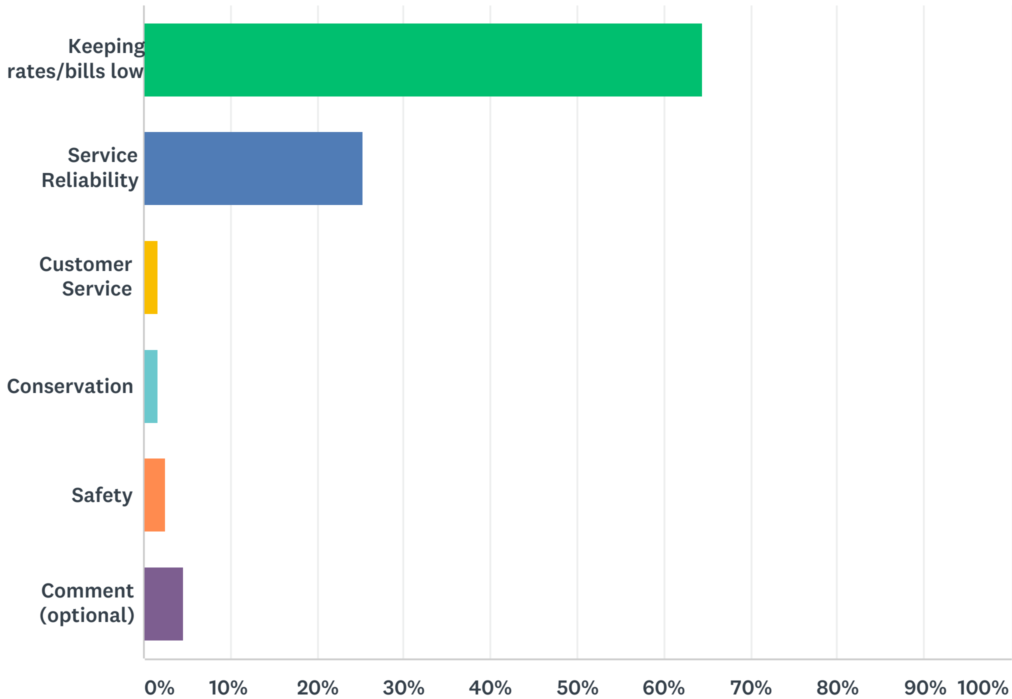
#	COMMENT (OPTIONAL)	DATE
1	My hook up date was not lived up to. I disconnected everything and the house was 53 degrees . Connection I understood would be Monday and I believe some office person came on that day and no installations could be done as a result . I only received an email of the change of schedule . This not only affected me but also my electrician and the furnace installer. I was very displeased with this. In my opinion it was very disrespectful to the other two professionals who then had to change their schedules for the week. This was really disrespectful to everyone.some employees were great on the job and some laughed at the change of date . (those individuals obvious have never had to operate their own business and make ends meet. You truck broke down at the end of my driveway and leaked antifreeze or transmission fluid. For this particular installation I was in another province and flew in on Saturday for the change over on Monday only to receive an email that it wasn't going to happen after I had everyone lined up for the change over. .	12/2/2018 6:41 PM
2	Very Satisfied this far - we are just moving into new house - never had gas before	11/27/2018 8:51 AM

Natural Gas Customer Survey

3	lower price; no minimum	11/25/2018 7:57 AM
4	I just moved here.	11/22/2018 4:40 PM
5	Mainly because we don’t qualify for the same rebates offered by a Union Gas	11/22/2018 11:12 AM
6	Currently building so we are not receiving gas at this time.	11/22/2018 10:15 AM
7	I haven't gotten my first bill yet. I haven't had epcors services for a month yet.	11/19/2018 6:29 PM
8	First new account	11/16/2018 9:59 PM
9	it is not available for us, because you will not provide your service to our house	11/15/2018 7:13 PM

What is the most important aspect of your natural gas services?

Answered: 439 Skipped: 2



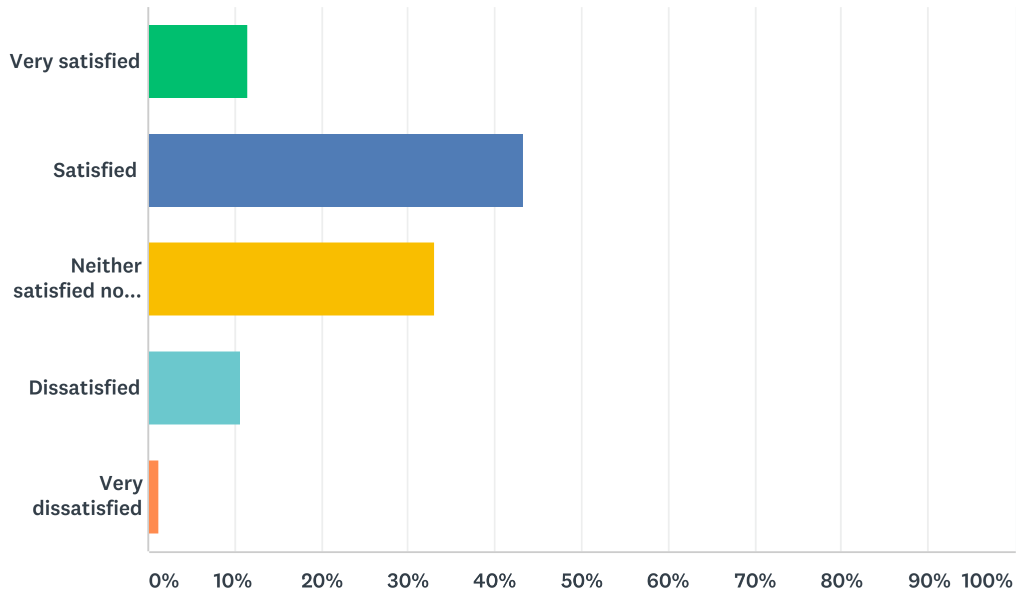
ANSWER CHOICES	RESPONSES	
Keeping rates/bills low	64.46%	283
Service Reliability	25.28%	111
Customer Service	1.59%	7
Conservation	1.59%	7
Safety	2.51%	11
Comment (optional)	4.56%	20
TOTAL		439

#	COMMENT (OPTIONAL)	DATE
1	I wasn't even considering Natural Gas and was encouraged that this was the way to go when replacing my oil furnace. On that Monday night bi wasn't definitely wasn't sure I had made the right decision in a 53 degree house ! All of your above options are important to me .	12/2/2018 6:41 PM
2	na	11/27/2018 5:52 PM
3	But customer service is also high priority	11/26/2018 5:43 PM
4	need to change website - tried to go on e-billing but couldn't get any link to open	11/24/2018 1:07 PM
5	All of them	11/23/2018 7:38 PM
6	All of the above	11/22/2018 12:55 PM
7	reliablitiy for my family as well as keeping it affordable so we can afford to be warm, safe, clean etc.	11/22/2018 12:14 PM
8	All of the above	11/22/2018 11:54 AM

9	Keeping rates/bills low, service reliability, safety	11/22/2018 11:42 AM
10	All the above are important to me.	11/20/2018 11:24 AM
11	All of the above	11/19/2018 6:29 PM
12	All of the above are very important, but with tlady's high cost of living I would have to say that keeping rates low is the most important to me.	11/18/2018 6:53 PM
13	All of the above	11/16/2018 1:01 PM
14	availability	11/15/2018 7:13 PM
15	Expanded service area	11/15/2018 1:06 PM
16	All of the above	11/15/2018 12:10 PM
17	All of the above are important but costs are always a driving factor.	11/15/2018 11:53 AM
18	Rates and bills low also service	11/15/2018 11:04 AM
19	all of the above	11/15/2018 11:00 AM
20	Setting up of Construction heating	11/15/2018 10:33 AM

If you chose "keeping rates/bills low" as most important, how satisfied are you that your monthly bill is fair?

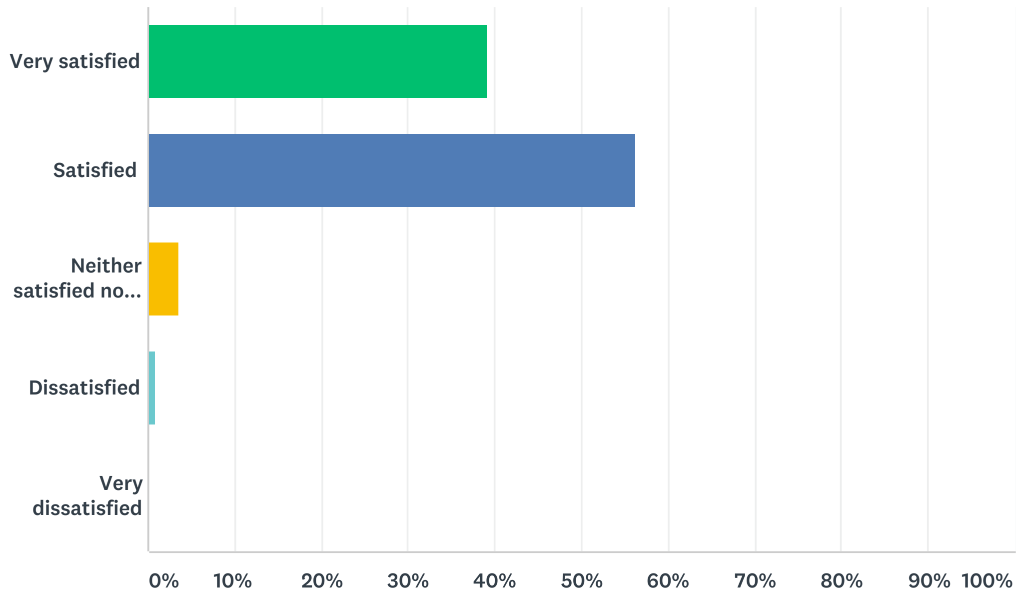
Answered: 302 Skipped: 139



ANSWER CHOICES	RESPONSES	
Very satisfied	11.59%	35
Satisfied	43.38%	131
Neither satisfied nor dissatisfied	33.11%	100
Dissatisfied	10.60%	32
Very dissatisfied	1.32%	4
TOTAL		302

If you chose "service reliability" as most important, how satisfied are you with your current delivery of natural gas?

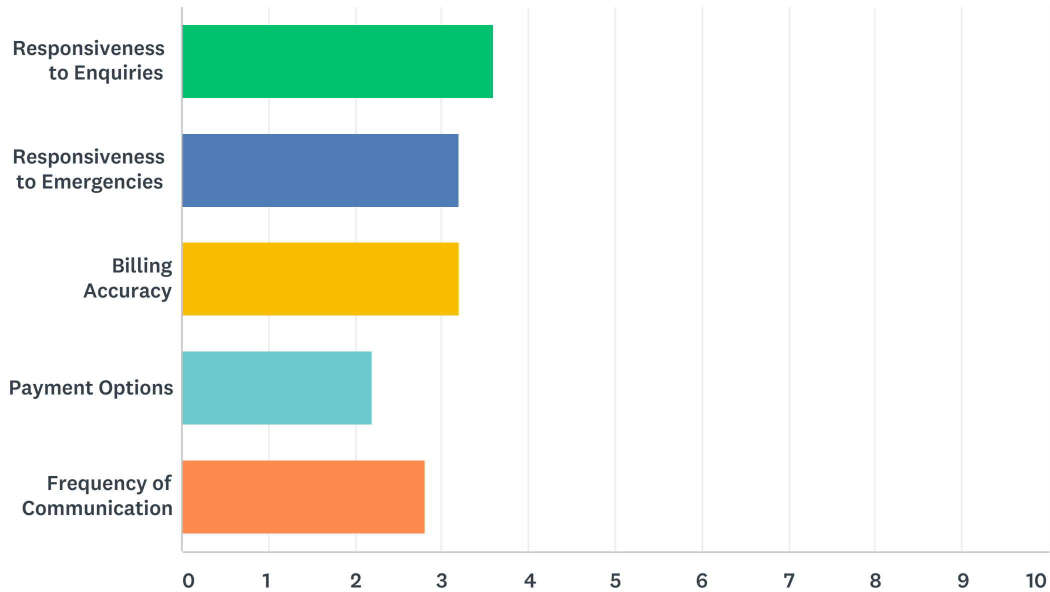
Answered: 110 Skipped: 331



ANSWER CHOICES	RESPONSES	
Very satisfied	39.09%	43
Satisfied	56.36%	62
Neither satisfied nor dissatisfied	3.64%	4
Dissatisfied	0.91%	1
Very dissatisfied	0.00%	0
TOTAL		110

If you chose "customer service" as most important, rank the following services in importance.

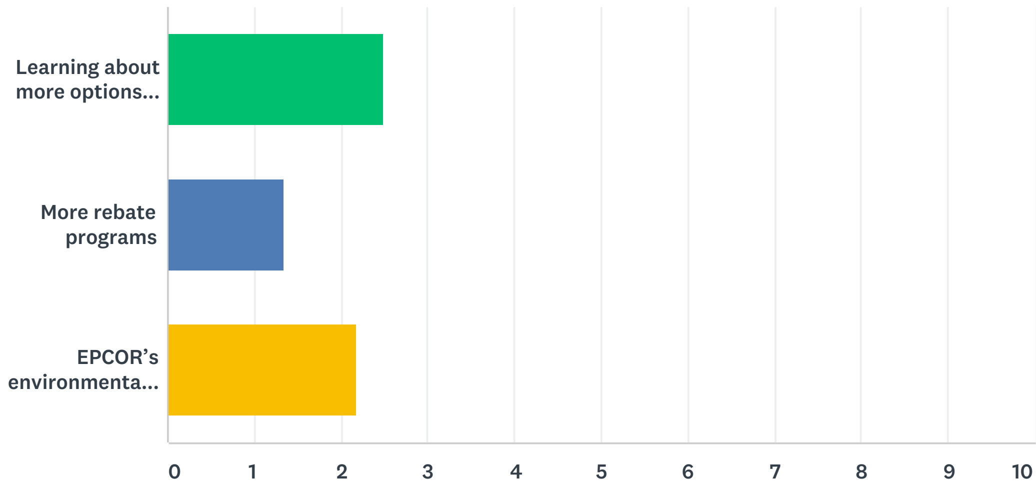
Answered: 5 Skipped: 436



	1	2	3	4	5	TOTAL	SCORE
Responsiveness to Enquiries	20.00% 1	40.00% 2	20.00% 1	20.00% 1	0.00% 0	5	3.60
Responsiveness to Emergencies	40.00% 2	20.00% 1	0.00% 0	0.00% 0	40.00% 2	5	3.20
Billing Accuracy	20.00% 1	0.00% 0	60.00% 3	20.00% 1	0.00% 0	5	3.20
Payment Options	0.00% 0	40.00% 2	0.00% 0	0.00% 0	60.00% 3	5	2.20
Frequency of Communication	20.00% 1	0.00% 0	20.00% 1	60.00% 3	0.00% 0	5	2.80

If you chose "conservation" as most important, rank the following in importance.

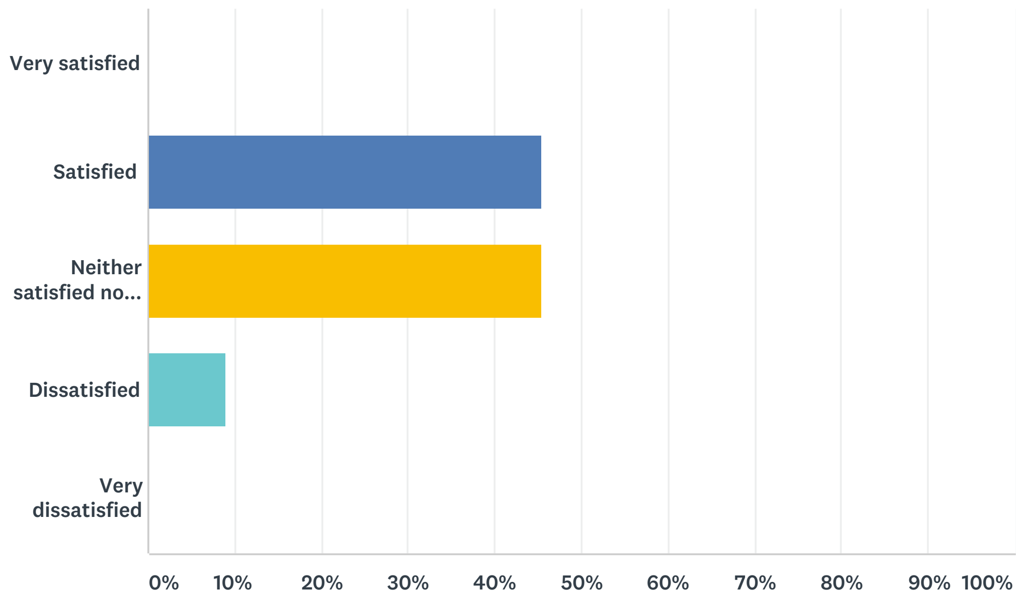
Answered: 6 Skipped: 435



	1	2	3	TOTAL	SCORE
Learning about more options to conserve	50.00% 3	50.00% 3	0.00% 0	6	2.50
More rebate programs	16.67% 1	0.00% 0	83.33% 5	6	1.33
EPCOR's environmental initiatives	33.33% 2	50.00% 3	16.67% 1	6	2.17

If you chose "safety" as most important, how satisfied are you with EPCOR's communications of safety information (e.g. gas leaks, carbon monoxide, etc.)?

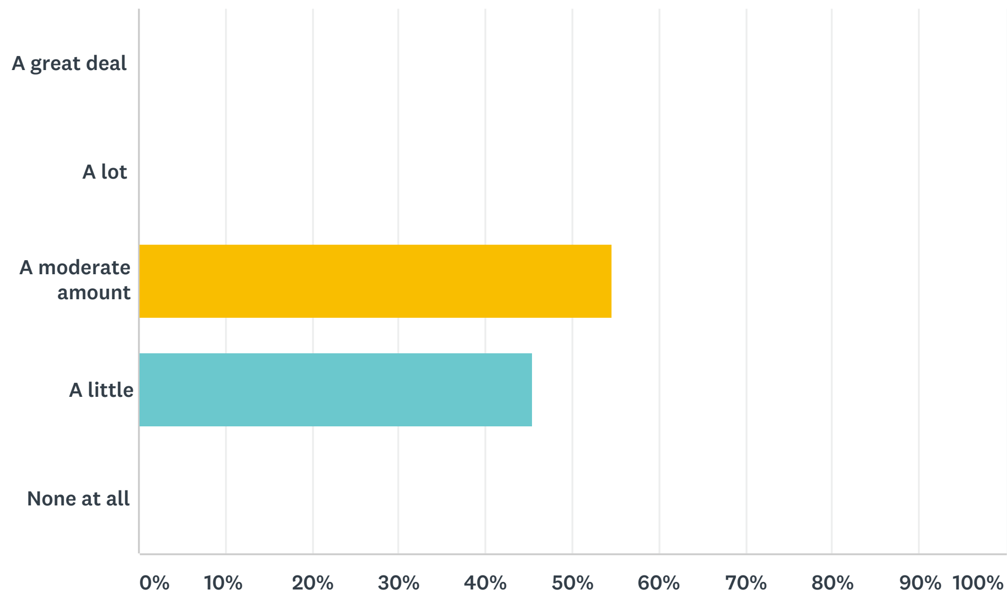
Answered: 11   Skipped: 430



ANSWER CHOICES	RESPONSES	
Very satisfied	0.00%	0
Satisfied	45.45%	5
Neither satisfied nor dissatisfied	45.45%	5
Dissatisfied	9.09%	1
Very dissatisfied	0.00%	0
TOTAL		11

If you chose "safety" as most important, how often do you think about a natural gas incident occurring (e.g. gas leaks, carbon monoxide,etc.?

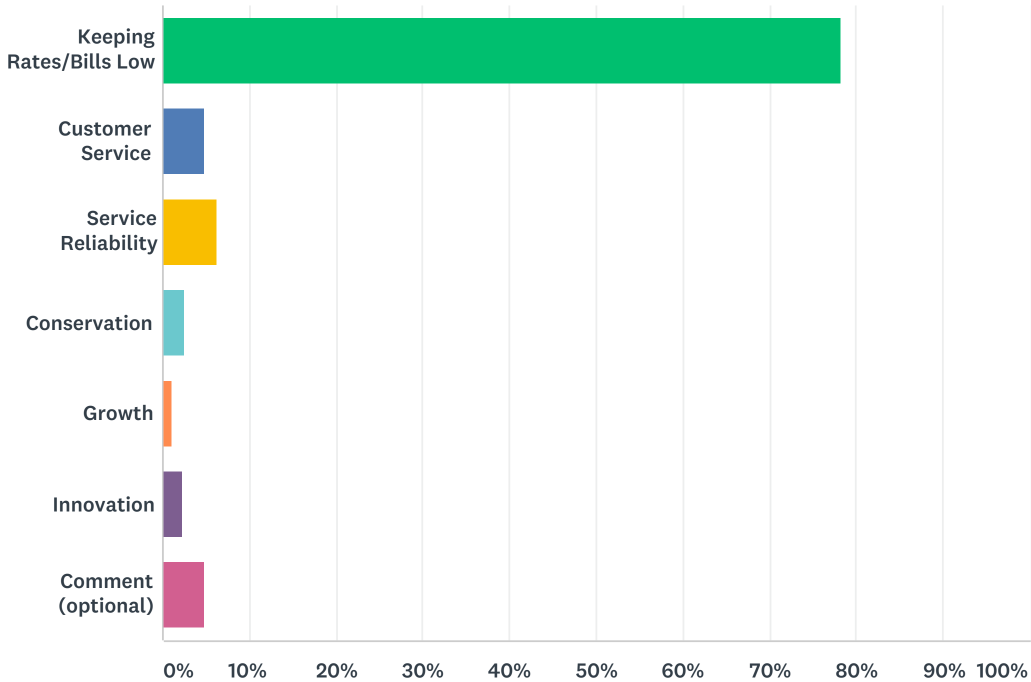
Answered: 11   Skipped: 430



ANSWER CHOICES	RESPONSES	
A great deal	0.00%	0
A lot	0.00%	0
A moderate amount	54.55%	6
A little	45.45%	5
None at all	0.00%	0
TOTAL		11

What should EPCOR focus on to improve our service to you?

Answered: 424   Skipped: 17



ANSWER CHOICES	RESPONSES	
Keeping Rates/Bills Low	78.30%	332
Customer Service	4.72%	20
Service Reliability	6.37%	27
Conservation	2.59%	11
Growth	0.94%	4
Innovation	2.36%	10
Comment (optional)	4.72%	20
TOTAL		424

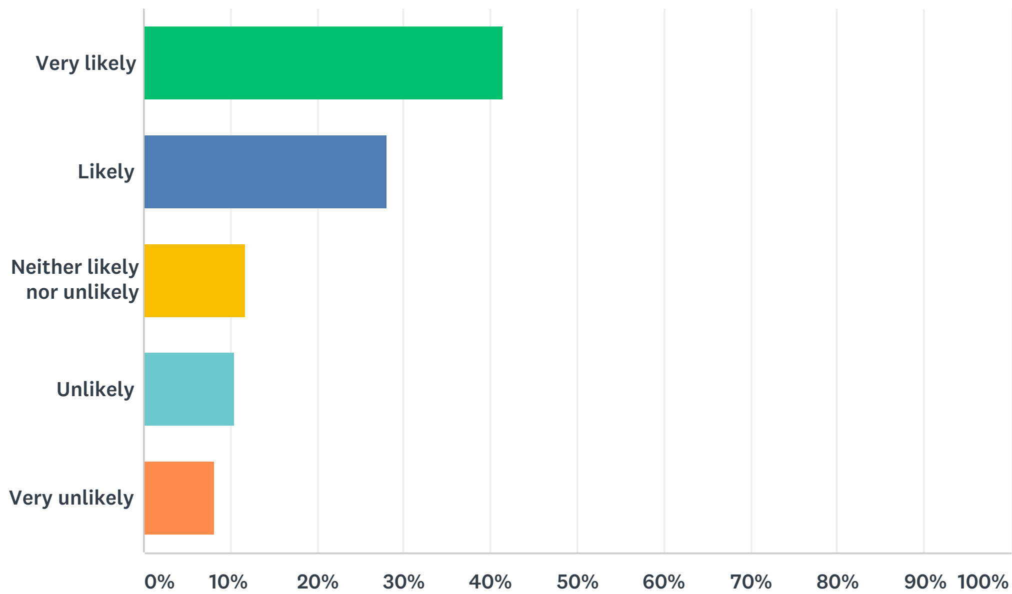
#	COMMENT (OPTIONAL)	DATE
1	My transition from oil to Natural Gas was not very smooth! I believe it should not take 3 days to do your installation with the same people coming back for short periods of time. In my opinion there is a great deal of road time of back and forth that is not very time and cost effective. This covers several categories of keeping price down and customer service .	12/2/2018 6:50 PM
2	see comment about website	11/24/2018 1:11 PM
3	Keeping service reliable with an affordable rate.	11/23/2018 7:54 AM
4	The first 4 choices are equally important	11/23/2018 5:56 AM
5	All of the above	11/22/2018 11:56 AM
6	Should improve on same access to rebates offered to customers of Hydro aone	11/22/2018 11:16 AM
7	Can't comment since we aren't receiving the service at this time	11/22/2018 10:16 AM

Natural Gas Customer Survey

8	I think they are doing fine	11/20/2018 11:25 AM
9	Keep doing what you are doing .We have no problems.Keep educating your client's	11/19/2018 12:21 PM
10	All of the above	11/16/2018 1:04 PM
11	I do not want to receive my monthly bill by mail. This is a huge waste of paper, along with the cost of postage. It is long overdue for your company to be able to provide the option to receive our monthly bill on-line	11/16/2018 7:52 AM
12	provide the opportunity to have your service, if it went by our home, we may be interested in it.	11/15/2018 7:16 PM
13	Your rates are so much higher than Union Gas rates. We have friends just a couple of concessions away from us who pay so much less because they are with Union Gas.	11/15/2018 3:25 PM
14	Hooking up gas should not require a trip to your office. Every other utility and service can be set up by phone or online	11/15/2018 12:20 PM
15	Offering incentive to switch electric furnace to natural gas.	11/15/2018 11:58 AM
16	Perhaps when Epcor turns up to "locate" their underground pipes they should be more sensitive existing gardens and not trample over growth	11/15/2018 11:44 AM
17	We are new costomers, just put on line.	11/15/2018 11:31 AM
18	Online access to your account	11/15/2018 11:15 AM
19	all of the above	11/15/2018 11:03 AM
20	Possibly more experience with construction heating	11/15/2018 10:36 AM

We are currently implementing an e-billing system. This will allow customers to go paperless and manage their account online, 24/7. How likely are you to use the system when ready?

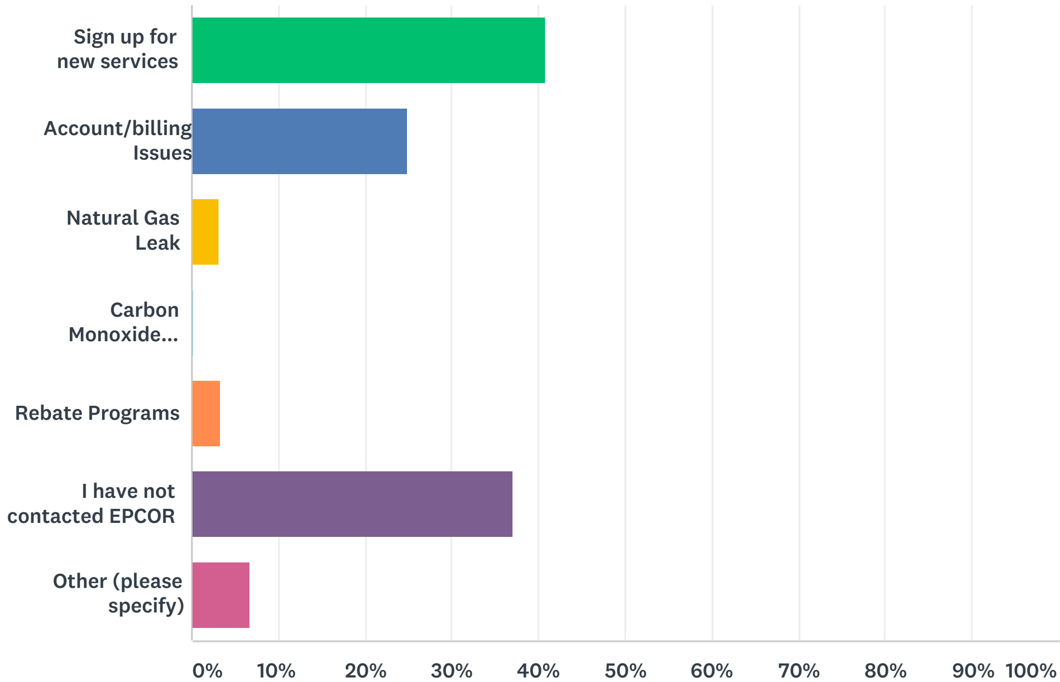
Answered: 424 Skipped: 17



ANSWER CHOICES	RESPONSES	
Very likely	41.51%	176
Likely	28.07%	119
Neither likely nor unlikely	11.79%	50
Unlikely	10.38%	44
Very unlikely	8.25%	35
TOTAL		424

Check the following services that you have contacted EPCOR about in the past year:

Answered: 424 Skipped: 17



ANSWER CHOICES	RESPONSES	
Sign up for new services	40.80%	173
Account/billing Issues	25.00%	106
Natural Gas Leak	3.07%	13
Carbon Monoxide Testing	0.24%	1
Rebate Programs	3.30%	14
I have not contacted EPCOR	37.03%	157
Other (please specify)	6.60%	28
Total Respondents: 424		

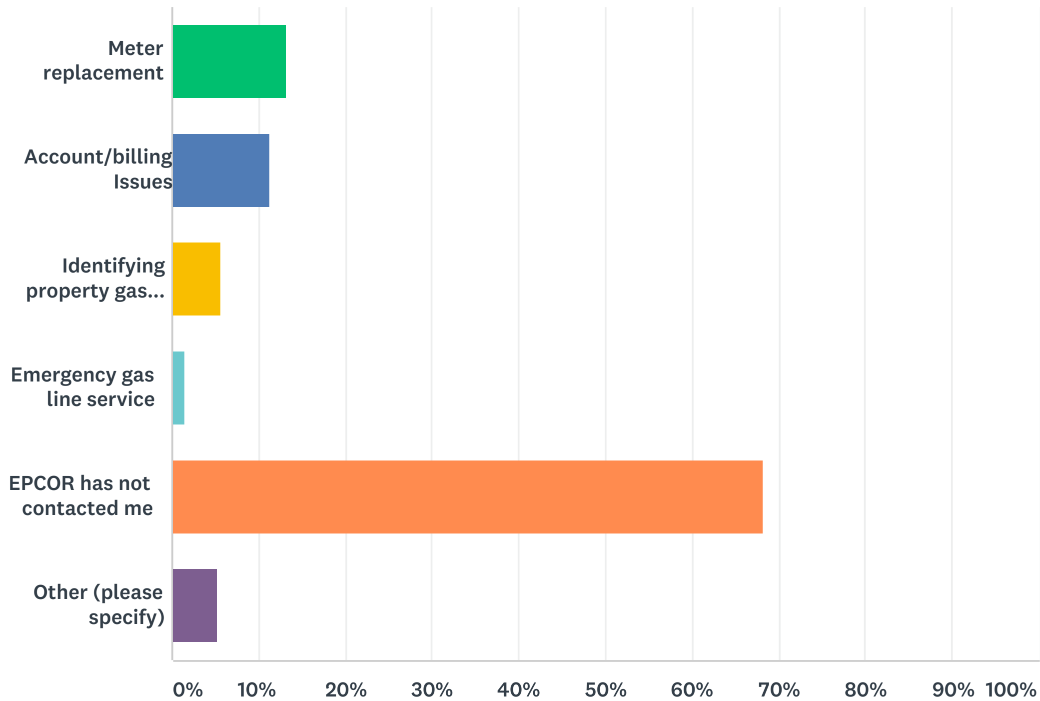
#	OTHER (PLEASE SPECIFY)	DATE
1	Are there rebates available?	12/2/2018 6:50 PM
2	just new to your service	11/27/2018 8:57 AM
3	Check where the lines were for digging	11/26/2018 7:55 PM
4	getting line locate	11/24/2018 1:11 PM
5	Simply to get my bill amount, because sometimes the mail here is slow and I don't want to miss payment of a bill.	11/24/2018 9:52 AM
6	Checking that our meter is functioning properly	11/22/2018 3:46 PM
7	main hydro connector on the outside of my home old and failing	11/22/2018 10:15 AM

Natural Gas Customer Survey

8	Replacement of meter	11/19/2018 7:02 AM
9	Asked if could sign up for on-line billing	11/18/2018 11:38 AM
10	how to read the bill	11/17/2018 7:27 AM
11	location service	11/16/2018 7:28 AM
12	Flood damage, new meter	11/16/2018 5:37 AM
13	call before you dig	11/16/2018 4:20 AM
14	Called to inquire about on-line account access.	11/15/2018 10:29 PM
15	service to our home	11/15/2018 7:16 PM
16	Meter replacement	11/15/2018 3:45 PM
17	line locates	11/15/2018 3:04 PM
18	about to have the ebilling that we wanted a year ago already	11/15/2018 1:43 PM
19	I went there for information about e- billing, but it was not available at that time.	11/15/2018 12:47 PM
20	call before you dig	11/15/2018 12:13 PM
21	Would have liked to know about rebates before I did work	11/15/2018 12:01 PM
22	Location services	11/15/2018 11:44 AM
23	Moving	11/15/2018 11:25 AM
24	Renew previous service	11/15/2018 11:08 AM
25	Budgetting	11/15/2018 11:06 AM
26	adding my spouse's name to the account	11/15/2018 10:45 AM
27	Flood consequences (Spring 2018)	11/15/2018 10:44 AM
28	Contacted to find out where to get new furnace and water heater	11/15/2018 10:42 AM

Check the following services that EPCOR has contacted you about in the past year:

Answered: 424 Skipped: 17



ANSWER CHOICES	RESPONSES	
Meter replacement	13.21%	56
Account/billing Issues	11.32%	48
Identifying property gas line	5.66%	24
Emergency gas line service	1.42%	6
EPCOR has not contacted me	68.16%	289
Other (please specify)	5.19%	22
Total Respondents: 424		

#	OTHER (PLEASE SPECIFY)	DATE
1	I'm a new customer	12/2/2018 6:50 PM
2	None. I am a new customer.	11/24/2018 11:45 AM
3	I just moved here last week.	11/22/2018 4:42 PM
4	Up selling on other features available	11/22/2018 12:08 PM
5	this survey	11/22/2018 10:35 AM
6	Not sure	11/22/2018 10:16 AM
7	New services	11/19/2018 1:31 PM
8	Locate	11/19/2018 7:02 AM

Natural Gas Customer Survey

9	to complete this survey	11/16/2018 12:49 PM
10	Setting up account as new owner of home	11/16/2018 10:10 AM
11	Installing new service	11/16/2018 8:55 AM
12	Reducing costs	11/16/2018 7:15 AM
13	I don't recall being contacted by them in the past year.	11/16/2018 6:34 AM
14	Nothing	11/15/2018 6:57 PM
15	We are new customers so no contact yet	11/15/2018 4:28 PM
16	Survey	11/15/2018 3:06 PM
17	As a new customer, the only contact was to set up a new service.	11/15/2018 11:57 AM
18	New customer gas hook up	11/15/2018 11:25 AM
19	Connecting gas line	11/15/2018 11:18 AM
20	Nothing yet	11/15/2018 11:05 AM
21	Response to my request to add spouse's name to account	11/15/2018 10:45 AM
22	Building a fence you came and gave me my property gas line layout	11/15/2018 10:42 AM

In regards to your natural gas service, what would you like to know more about?

Answered: 266 Skipped: 175

#	RESPONSES	DATE
1	What rebates are available. I had an oil furnace and now have converted to natural gas .	12/2/2018 6:50 PM
2	No comment at this time.	11/30/2018 8:57 AM
3	We are good!	11/29/2018 6:17 PM
4	Online billing	11/28/2018 2:11 PM
5	can't think of anything	11/28/2018 8:51 AM
6	Cant think of anything at the moment.	11/28/2018 8:00 AM
7	Nothing as of now	11/28/2018 5:43 AM
8	na	11/27/2018 5:54 PM
9	e billing	11/27/2018 10:46 AM
10	Budget Plan	11/27/2018 9:27 AM
11	not sure of anything right now	11/27/2018 8:57 AM
12	I'm not sure!	11/26/2018 7:55 PM
13	Rates and reliability	11/26/2018 5:45 PM
14	,	11/26/2018 1:23 PM
15	none	11/26/2018 8:01 AM
16	Using combination heating sources like natural gas and solar power.	11/26/2018 7:28 AM
17	Any interuptions should be notified early	11/26/2018 4:58 AM
18	I would like to know about EPCOR	11/25/2018 6:46 PM
19	Nothing	11/25/2018 5:08 PM
20	Nothing at the moment	11/25/2018 1:09 PM
21	What are the billing periods	11/25/2018 9:46 AM
22	nothingh	11/25/2018 7:59 AM
23	Satisfied	11/24/2018 7:20 PM
24	I am not aware of anything that I would like to know more about at present. However, I would not hesitate to ask if there was something that I would like to have more information about	11/24/2018 5:20 PM
25	Nothing	11/24/2018 11:45 AM
26	Not applicable	11/24/2018 11:23 AM
27	I'm completely satisfied with EPCOR, including their customer service, which is amazing. I also like that the bills are kept low, because as seniors, budget is always a concern. We haven't been with them long, but love the company already.	11/24/2018 9:52 AM
28	nothing	11/24/2018 8:21 AM
29	nothing really	11/24/2018 4:59 AM
30	where to perches new furnace/billing	11/24/2018 2:57 AM
31	Nothing	11/23/2018 7:39 PM
32	Nothing	11/23/2018 5:13 PM

33	How hard it would be to relocate a gas fireplace	11/23/2018 10:01 AM
34	Nothing at this time.	11/23/2018 7:54 AM
35	Nothing. Satisfied with the service.	11/23/2018 7:00 AM
36	I know everything	11/23/2018 5:05 AM
37	Nothing in particular	11/23/2018 3:17 AM
38	Nothing at this time	11/22/2018 9:21 PM
39	Not applicable	11/22/2018 8:47 PM
40	Nothing	11/22/2018 7:49 PM
41	nothing	11/22/2018 7:25 PM
42	constant communication such as this information survey	11/22/2018 6:06 PM
43	Nothing at this time	11/22/2018 5:31 PM
44	About the company	11/22/2018 4:59 PM
45	any new changes in service, price, developments	11/22/2018 4:43 PM
46	How to save on my gas bill.	11/22/2018 4:42 PM
47	Nothings	11/22/2018 4:40 PM
48	Have too many other things I'm dealing with. Just expect reliable, safe service.	11/22/2018 4:07 PM
49	Nothing right now	11/22/2018 3:52 PM
50	nothing at this time	11/22/2018 3:42 PM
51	Rates	11/22/2018 3:36 PM
52	If I can go on a budget	11/22/2018 3:31 PM
53	Nothing	11/22/2018 3:21 PM
54	Na	11/22/2018 3:20 PM
55	Rebates that apply to my situation	11/22/2018 3:10 PM
56	Nothing, all is good □	11/22/2018 3:06 PM
57	Government use of funds	11/22/2018 2:56 PM
58	Everything is good.	11/22/2018 2:48 PM
59	Nothing I can think of	11/22/2018 2:41 PM
60	Nothing at the moment	11/22/2018 2:30 PM
61	nothing	11/22/2018 2:25 PM
62	Nothing	11/22/2018 2:21 PM
63	Just keeping bills low and easy to afford.	11/22/2018 1:54 PM
64	Nothing really	11/22/2018 1:04 PM
65	Cheaper bills	11/22/2018 12:54 PM
66	how does epcor plan for the long term, we eventually need to reduce our carbon consumption, are they thinking about some sort of solar energy system that they can sell instead?	11/22/2018 12:43 PM
67	I am satisfied with service as is	11/22/2018 12:21 PM
68	Nothing at the moment.	11/22/2018 12:12 PM
69	Nothing	11/22/2018 12:08 PM
70	We are OK	11/22/2018 11:49 AM
71	How can we decrease delivery charges?	11/22/2018 11:42 AM
72	online billing	11/22/2018 11:41 AM

Natural Gas Customer Survey

73	NIL, the service is great!	11/22/2018 11:39 AM
74	Na	11/22/2018 11:33 AM
75	safety assurances and if my heating system is uptodate re technology/efficency wise	11/22/2018 11:25 AM
76	Nothing	11/22/2018 11:24 AM
77	x	11/22/2018 11:12 AM
78	Nothing	11/22/2018 11:11 AM
79	New to using gas ... really happy so far !	11/22/2018 11:11 AM
80	Cost	11/22/2018 11:10 AM
81	Nothing	11/22/2018 11:07 AM
82	Future installation of new lines	11/22/2018 11:05 AM
83	We are okay.	11/22/2018 11:05 AM
84	nothing, I think I'm good	11/22/2018 11:04 AM
85	Ways to conserve	11/22/2018 11:03 AM
86	Maybe	11/22/2018 10:53 AM
87	Nothing	11/22/2018 10:51 AM
88	rebate programs	11/22/2018 10:47 AM
89	Rebates	11/22/2018 10:44 AM
90	Where does the gas I use originate?	11/22/2018 10:43 AM
91	Nothing	11/22/2018 10:40 AM
92	Nothing	11/22/2018 10:37 AM
93	rates and how much is being used prior to getting the bill	11/22/2018 10:33 AM
94	Nothing at this point.	11/22/2018 10:31 AM
95	There isn't anything	11/22/2018 10:31 AM
96	Nothing	11/22/2018 10:30 AM
97	Rebates and lower prices	11/22/2018 10:30 AM
98	How to keep bills low	11/22/2018 10:23 AM
99	I would like to know. why your employees are so rude and disrespectful	11/22/2018 10:22 AM
100	Nothing	11/22/2018 10:20 AM
101	Nothing	11/22/2018 10:19 AM
102	Nothing	11/22/2018 10:16 AM
103	all good	11/22/2018 10:15 AM
104	N/A	11/22/2018 10:13 AM
105	Rebates	11/21/2018 3:52 PM
106	Nothing	11/20/2018 5:22 PM
107	Reducing rates	11/20/2018 2:24 PM
108	I can't think of anything right now.	11/20/2018 11:25 AM
109	Nothing	11/20/2018 6:57 AM
110	I don't know because I haven't gotten my first bill yet	11/19/2018 6:31 PM
111	Rebate programs for low income families	11/19/2018 3:24 PM
112	Nothing at this time	11/19/2018 1:31 PM
113	When power goes out is it still safe to use my gas stove and bq	11/19/2018 12:21 PM

114	Nothing in particular.	11/19/2018 12:14 PM
115	Quite happy, please don't change anything. If it works then it doesn't need mending !	11/19/2018 7:59 AM
116	Nothing	11/19/2018 7:22 AM
117	Increasing the size of the gas meter. Would like to install 2 more appliances which require natural gas	11/19/2018 7:02 AM
118	Nothing	11/19/2018 6:50 AM
119	ways to save on energy and usage in my home	11/19/2018 6:09 AM
120	Nothing at this time.	11/18/2018 6:55 PM
121	Nothing	11/18/2018 6:06 PM
122	Just switched to gas last year.	11/18/2018 4:36 PM
123	n/a	11/18/2018 11:38 AM
124	the rebate program	11/18/2018 9:02 AM
125	Where the investments are for natural gas	11/17/2018 7:50 PM
126	How to save money	11/17/2018 6:01 PM
127	extreme costs	11/17/2018 2:35 PM
128	I'm satisfied with what I know.	11/17/2018 2:05 PM
129	how can you. keep bill from increasing	11/17/2018 10:51 AM
130	How to keep my usage lower	11/17/2018 10:26 AM
131	Nothing	11/17/2018 7:50 AM
132	nothing	11/17/2018 7:27 AM
133	Why delivery charges are so expensive	11/17/2018 5:58 AM
134	no answer	11/16/2018 10:59 PM
135	Not sure I’m a new customer	11/16/2018 10:00 PM
136	paperless or credit card payment	11/16/2018 9:23 PM
137	Nothing	11/16/2018 8:19 PM
138	Online access to bills	11/16/2018 4:08 PM
139	Rates and conservation programs and rebates	11/16/2018 3:14 PM
140	WOULD LIKE TO GET ON EQUAL BILLING	11/16/2018 2:09 PM
141	where is the gas coming from (location).	11/16/2018 12:49 PM
142	I am content with service as it e	11/16/2018 12:37 PM
143	I have no questions at this time	11/16/2018 11:16 AM
144	Safety	11/16/2018 10:25 AM
145	Rates and billing options	11/16/2018 10:10 AM
146	nothing	11/16/2018 8:26 AM
147	Nothing	11/16/2018 8:15 AM
148	Contact from EPCOR on how to improve efficiency on gas consumption	11/16/2018 7:52 AM
149	Just being informed of any changes or rate increases in advance and WHY the gov't has to take so much $$$	11/16/2018 7:29 AM
150	nothing	11/16/2018 7:21 AM
151	Services offered by epcor.	11/16/2018 7:15 AM
152	Nothing	11/16/2018 6:39 AM

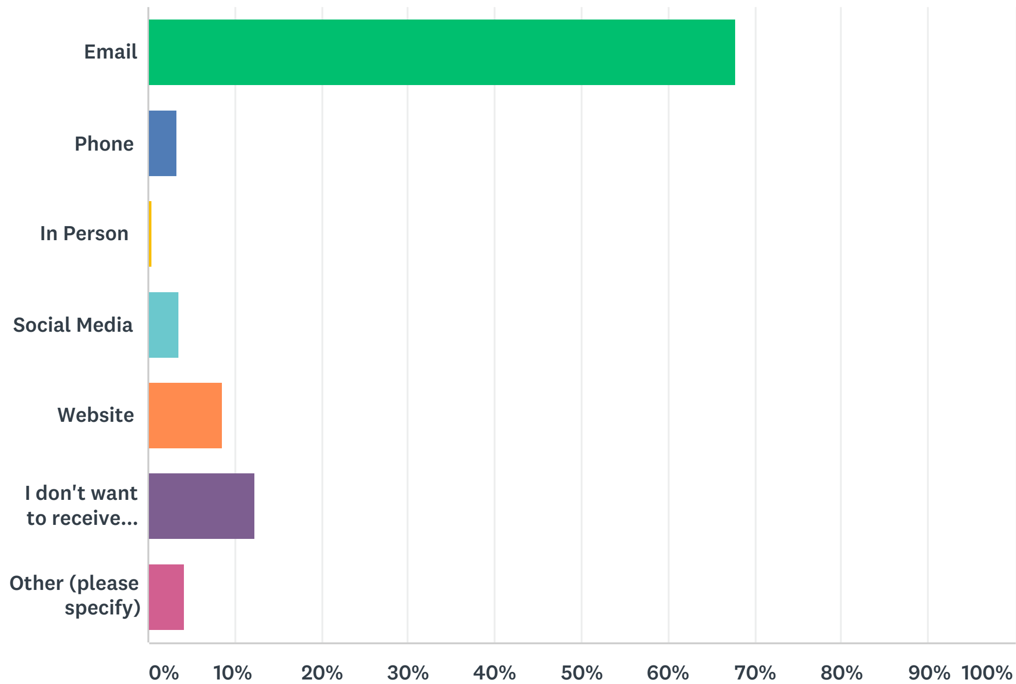
153	nothing	11/16/2018 6:34 AM
154	Nothing	11/16/2018 6:13 AM
155	Will you be expanding your service area	11/16/2018 5:23 AM
156	Nothing	11/16/2018 3:36 AM
157	Norhing	11/16/2018 2:36 AM
158	I haven't been a customer very long, so I don't know much about Epcor.	11/16/2018 1:41 AM
159	Please include degree day statistics as part of monthly bill.	11/15/2018 10:29 PM
160	Nothing at this time	11/15/2018 10:20 PM
161	Eveything	11/15/2018 8:28 PM
162	Nothing, I'm satisfied	11/15/2018 7:51 PM
163	Nothing at the moment	11/15/2018 7:49 PM
164	service to our home	11/15/2018 7:16 PM
165	Nothing	11/15/2018 6:44 PM
166	I would like to know more about the percentage of gas that each natural gas operated part of my house uses.	11/15/2018 6:39 PM
167	Nothing	11/15/2018 6:39 PM
168	where does the home owner's responsibility start.At the road or at the meter? If at the meter, then why should the home owners have to pay the trenching charge from the road?	11/15/2018 6:32 PM
169	Nothing at this time , Thankyou .	11/15/2018 6:13 PM
170	Nothing.	11/15/2018 6:09 PM
171	Decreasing usage in home	11/15/2018 6:02 PM
172	Other services available to me.	11/15/2018 5:54 PM
173	Nothing	11/15/2018 5:51 PM
174	Nothing	11/15/2018 5:51 PM
175	Nothing	11/15/2018 5:49 PM
176	nothing	11/15/2018 5:45 PM
177	nothing at this time	11/15/2018 5:35 PM
178	Nothing	11/15/2018 5:27 PM
179	Nothing	11/15/2018 5:08 PM
180	How to get my bills low as possible	11/15/2018 5:07 PM
181	nothing that I can think of	11/15/2018 5:03 PM
182	Programs for rebates	11/15/2018 4:35 PM
183	I'd like to know where the pipe enters my house, and who to contact to run other appliances on natural gas	11/15/2018 4:28 PM
184	Nothing else	11/15/2018 4:28 PM
185	None	11/15/2018 4:17 PM
186	Nothing- all is well! ☺	11/15/2018 4:15 PM
187	How efficient it is run?	11/15/2018 3:54 PM
188	What proportion each appliance/service uses of my gas bill Eg. fireplace...stove etc.	11/15/2018 3:42 PM
189	na	11/15/2018 3:37 PM
190	N/a	11/15/2018 3:31 PM
191	any reason the prices rise	11/15/2018 3:29 PM

192	How Epcor's rates can be more in line with Union Gas rates.	11/15/2018 3:25 PM
193	How to reduce my heating costs.	11/15/2018 3:08 PM
194	Nothing	11/15/2018 3:06 PM
195	How the government makes their decisions as to how much to charge from their end? How you arrive at your cost? Why do you include this crazy page all the time that says the price of gas is going up or down .000471 percent on your next bill. I think for this low amount it is not worth putting in a whole sheet of paper. Just include a paper that lets the customer opt out of this crazy page !	11/15/2018 3:04 PM
196	Nothing	11/15/2018 2:43 PM
197	Can’t really think Of anything	11/15/2018 2:29 PM
198	n/a	11/15/2018 2:16 PM
199	Nothing special	11/15/2018 2:02 PM
200	N/A	11/15/2018 1:59 PM
201	No further information is needed.	11/15/2018 1:46 PM
202	just the ebilling	11/15/2018 1:43 PM
203	How it compares competitively in the market.	11/15/2018 1:36 PM
204	nothing	11/15/2018 1:31 PM
205	When paperless billing will be available?	11/15/2018 1:30 PM
206	Promotions or incentive programs	11/15/2018 1:10 PM
207	Nothing	11/15/2018 1:04 PM
208	nothing at the moment	11/15/2018 12:57 PM
209	If on average bills are $76 a mth I imagine those are for houses. Why is mine that much in a 2 bedroom apt.	11/15/2018 12:52 PM
210	I’m positive with what you have. Thank you.	11/15/2018 12:47 PM
211	N/A	11/15/2018 12:27 PM
212	Nothing	11/15/2018 12:20 PM
213	Paperless billing	11/15/2018 12:16 PM
214	Rebates	11/15/2018 12:15 PM
215	overall I'm happy	11/15/2018 12:13 PM
216	Nothing	11/15/2018 12:11 PM
217	Why the delivery charge is so much	11/15/2018 12:08 PM
218	Rebates	11/15/2018 12:01 PM
219	Incentives for switching from electric furnace to gas	11/15/2018 11:58 AM
220	Cost	11/15/2018 11:54 AM
221	N/A	11/15/2018 11:44 AM
222	Nothing	11/15/2018 11:38 AM
223	N/A	11/15/2018 11:38 AM
224	Nothing	11/15/2018 11:34 AM
225	Didn t realize the Govt was taking part of my payment. Why ???	11/15/2018 11:32 AM
226	None	11/15/2018 11:25 AM
227	Integrity of reporting costs	11/15/2018 11:20 AM
228	how much will this ill advised Carbon Tax affect me and my bill	11/15/2018 11:19 AM

229	Im a new customer and I am not to familiar with it yet.	11/15/2018 11:19 AM
230	nothing	11/15/2018 11:17 AM
231	Nothing	11/15/2018 11:13 AM
232	Billing	11/15/2018 11:12 AM
233	rebate programs - insulation, doors and windows envelope sealing	11/15/2018 11:10 AM
234	?	11/15/2018 11:09 AM
235	When will the online services become available?	11/15/2018 11:07 AM
236	nothing I can think of	11/15/2018 11:07 AM
237	Nothing	11/15/2018 11:07 AM
238	Ability to move the meter or ability to read the meter elsewhere. We want to build a deck which would be over the current meter	11/15/2018 11:06 AM
239	Devices that can be run by Natural Gas.	11/15/2018 11:01 AM
240	If all lines in my home are in good usable condition. Just bought a home recently in aylmer and noticing a lot of terribly done renovations	11/15/2018 11:00 AM
241	I'm good. Nothing needed.	11/15/2018 10:56 AM
242	Pre-paid on line billing	11/15/2018 10:56 AM
243	Rebates to get money back	11/15/2018 10:54 AM
244	Innovation	11/15/2018 10:51 AM
245	not sure	11/15/2018 10:50 AM
246	Not much maybe if I should update my furance	11/15/2018 10:48 AM
247	How to keep bills low	11/15/2018 10:47 AM
248	Everything is ok	11/15/2018 10:47 AM
249	Very interested in internet services for billings etc.	11/15/2018 10:46 AM
250	Nothing	11/15/2018 10:45 AM
251	Rebate programs, cost savings	11/15/2018 10:44 AM
252	N/A	11/15/2018 10:43 AM
253	Why are the distribution costs so high when compared to the other service areas in Ontario	11/15/2018 10:42 AM
254	Nothing.	11/15/2018 10:42 AM
255	Nothing at the moment	11/15/2018 10:42 AM
256	Yes	11/15/2018 10:42 AM
257	Nothing	11/15/2018 10:39 AM
258	O	11/15/2018 10:36 AM
259	I am not sure.	11/15/2018 10:36 AM
260	Nancy in the area of customer set-up was fantastic to work with.	11/15/2018 10:36 AM
261	n/a	11/15/2018 10:35 AM
262	I'm content with the service provided	11/15/2018 10:35 AM
263	N/a	11/15/2018 10:35 AM
264	Rate increases	11/15/2018 10:34 AM
265	Future rates	11/15/2018 10:34 AM
266	Very little, I don't particularly care to know the details I just want them to continue to be reliable and convenient - which they currently are.	11/15/2018 10:34 AM

How would you prefer to receive information from EPCOR about conservation and safety?

Answered: 424 Skipped: 17



ANSWER CHOICES	RESPONSES	
Email	67.69%	287
Phone	3.30%	14
In Person	0.47%	2
Social Media	3.54%	15
Website	8.49%	36
I don't want to receive information about safety or conservation	12.26%	52
Other (please specify)	4.25%	18
TOTAL		424

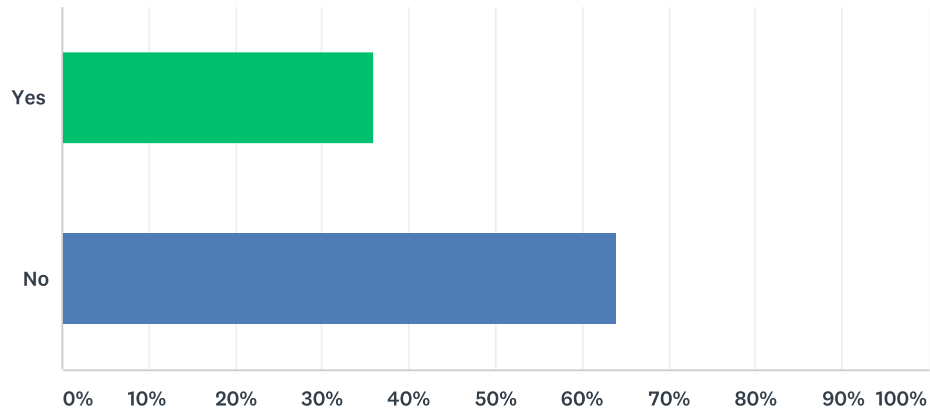
#	OTHER (PLEASE SPECIFY)	DATE
1	mail	11/25/2018 6:03 AM
2	Mail	11/24/2018 11:45 AM
3	mail	11/24/2018 2:57 AM
4	Inserted with billing invoice	11/23/2018 7:54 AM
5	mail	11/22/2018 3:38 PM
6	Letter	11/22/2018 12:02 PM
7	Mail	11/22/2018 10:24 AM
8	News flyer	11/20/2018 2:24 PM

Natural Gas Customer Survey

9	Mail	11/19/2018 6:31 PM
10	Mail	11/19/2018 1:31 PM
11	Mail	11/16/2018 1:04 PM
12	By mail.	11/16/2018 1:41 AM
13	Mail	11/15/2018 5:27 PM
14	Email	11/15/2018 3:30 PM
15	Mail	11/15/2018 3:06 PM
16	snail mail	11/15/2018 3:04 PM
17	mail	11/15/2018 1:41 PM
18	Mail	11/15/2018 10:41 AM

Are you interested in receiving more information about EPCOR's Cost of Service application?

Answered: 424 Skipped: 17



ANSWER CHOICES	RESPONSES	
Yes	36.08%	153
No	63.92%	271
TOTAL		424

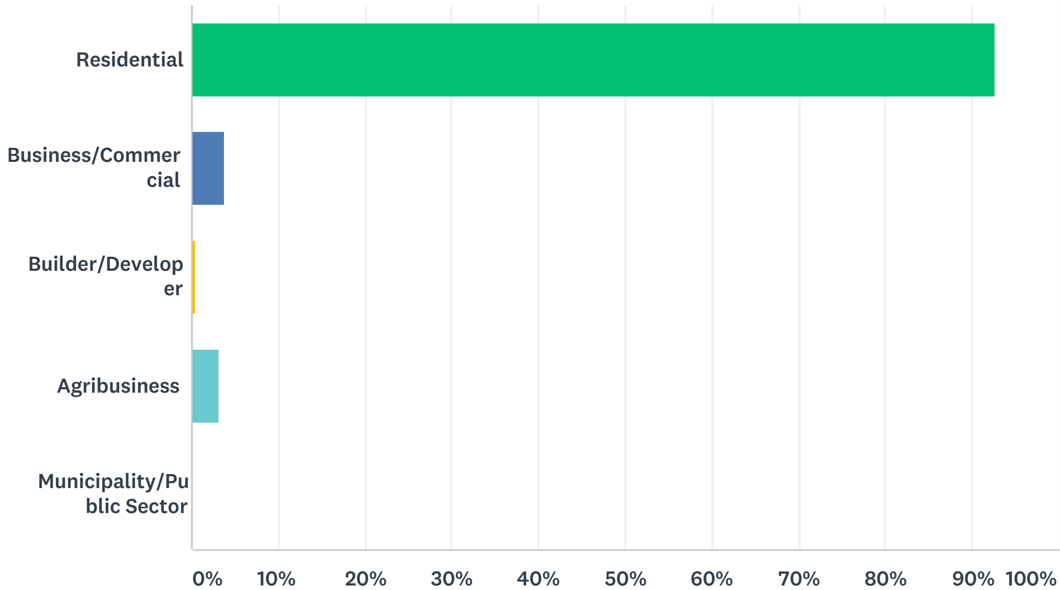
If you are interested in receiving more information about EPCOR's Cost of Service application, please provide your contact information.

Answered: 118 Skipped: 323

ANSWER CHOICES	RESPONSES	
Name	98.31%	116
Company	0.00%	0
Address	97.46%	115
Address 2	20.34%	24
City/Town	98.31%	116
State/Province	97.46%	115
ZIP/Postal Code	96.61%	114
Country	96.61%	114
Email Address	96.61%	114
Phone Number	86.44%	102

What type of customer are you?

Answered: 408 Skipped: 33

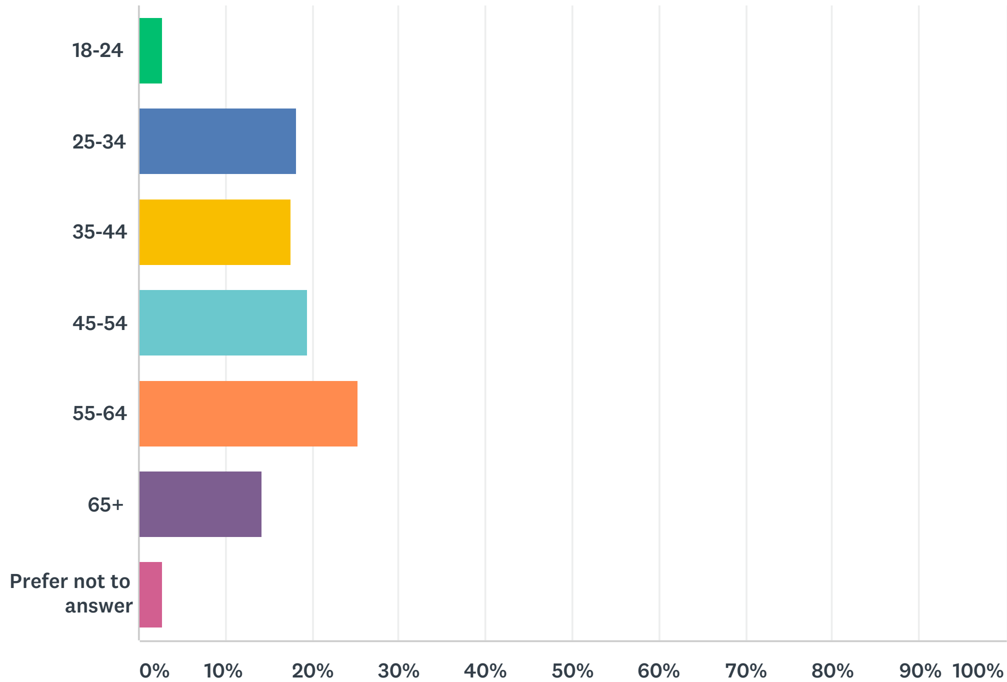


ANSWER CHOICES	RESPONSES	
Residential	92.65%	378
Business/Commercial	3.68%	15
Builder/Developer	0.49%	2
Agribusiness	3.19%	13
Municipality/Public Sector	0.00%	0
TOTAL		408

#	COMMENT (OPTIONAL)	DATE
1	Own farm which was changed to gas in 2017	11/18/2018 4:43 PM
2	We have a farm as well as a home in town	11/15/2018 6:35 PM
3	We are these items 1,2 and 4 but this answer would not let me put in all three	11/15/2018 3:08 PM
4	No longer an Epcor customer	11/15/2018 11:46 AM
5	and commercial	11/15/2018 11:17 AM
6	And business	11/15/2018 10:57 AM

What is your age?

Answered: 408 Skipped: 33



ANSWER CHOICES	RESPONSES	
18-24	2.70%	11
25-34	18.14%	74
35-44	17.65%	72
45-54	19.36%	79
55-64	25.25%	103
65+	14.22%	58
Prefer not to answer	2.70%	11
TOTAL		408

To be entered into a draw to win one of three $50 gift cards, please provide the following contact information:

Answered: 375 Skipped: 66

ANSWER CHOICES	RESPONSES	
Name	100.00%	375
Company	0.00%	0
Address	98.93%	371
Address 2	17.33%	65
City/Town	98.93%	371
State/Province	98.40%	369
ZIP/Postal Code	98.40%	369
Country	0.00%	0
Email Address	95.20%	357
Phone Number	90.93%	341

ENGLP (Aylmer) BUSINESS PLAN (2019-2022)

Table of Contents

1.0 Executive Summary

EPCOR Natural Gas LP ("ENGLP") distributes natural gas to over 9,000 customers in and around Aylmer, Ontario, with its service area stretching from south of Highway 401 to the shores of Lake Erie, from Port Bruce in the west to Clear Creek in the east. It provides natural gas service to customers in Townships of Malahide and South-West Oxford; Municipalities of Bayham, Thames Centre and Central Elgin; and Norfolk County. The system serves the individual communities of Aylmer, Belmont, Brownsville, Port Burwell, Springfield, Straffordville, and Vienna. The gas demands in the ENGLP System are mainly for residential and commercial heating, small industrial users, and grain drying. In addition, the system provides service to IGPC Ethanol Inc. ("IGPC"), a large industrial customer that is served using a standalone distribution system.

The following 2019 – 2022 business plan details how ENGLP (Aylmer) will create shareholder value by delivering safe, reliable, and cost effective distribution services to its customers in a fair and transparent manner.

Key trends and issues identified through the business plan in ENGLP's operating environment have been considered:

- Providing its customers, employees and third party contractors with a safe and injury-free environment by delivering services that meet and exceed those expectations on a daily basis;
- Focus on high level of service reliability through system-wide investments by ensuring initiatives are targeted that provide increased customer satisfaction levels;
- Seeking cost efficiencies through growth, process improvement and implementation of new technologies where appropriate to ensure customer satisfaction levels are met and exceeded;
- Creating enduring shareholder value through excellence in customer service, reliability and cost efficiency across its operations.

ENGLP (Aylmer) plans to achieve these strategic goals through the following directives and objectives:

- Improve reliability and internal processes to promote an efficient and sustainable environment;
- Improve marketing and communications to better serve our customers;
- Reduce operational costs and ensure efficient long term capital planning;
- Build and maintain regulatory relationships with the Ontario Energy Board ("OEB") and municipal entities to promote efficient provision of utility services.

Keeping the strategic objectives in mind, ENGLP plans to focus its programs and activities in a range of areas, with particular importance on customer engagement, service reliability, conservation, safety and community involvement. The Utility is confident that it has the appropriate financial resources as well as strong staff and an experienced Board of Directors to make significant contributions in undertaking these programs and activities.

ENGLP has also developed a risk appetite objective framework to assist with capital and resource allocation as well as a basis for more strategic direction making regarding risk. This will help foster a more risk-intelligent culture by promoting accountability and transparency within the organization. The most important and relevant risk appetite objectives identified include Identifiable, Understandable & Manageable Operational Risks, Compliance and Reputation.

1.1 Background

ENGLP's acquisition of the natural gas distribution assets of Natural Resource Gas Limited (NRG) received regulatory approval from the Ontario Energy Board in August 2017 and the assets were acquired from NRG on November 1st, 2017.

ENGLP's parent company, EPCOR Utilities Inc. ("EPCOR"), owns and operates electrical transmission and distribution networks, and natural gas distribution networks, water and wastewater treatment facilities, sanitary and storm water systems and networks in Canada and the United States. EPCOR manages over $6.0 billion in assets and an annual capital program of approximately $530 million. In fiscal 2017, EPCOR's consolidated revenue was $2.035 billion and its consolidated operating income was $309 million. EPCOR is an issuer of public debt and is raised by DBRS (A low) stable and Standard & Poor's (A-).

ENGLP's Aylmer business unit ("ENGLP (Aylmer)") or the ("Utility") is a fully licensed distributor of natural gas by the Ontario Energy Board (the "OEB" or the "Board") under the Ontario Energy Board Act, 1998 (the "Act").

ENGLP (Aylmer) is a local distribution company (LDC) that distributes natural gas in Southern Ontario to approximately nine thousand customers in the Town of Aylmer and surrounding areas. The service territory extends south from Highway 401 to the shores of Lake Erie. In addition to the Town of Aylmer, ENGLP (Aylmer) system also serves the municipalities of Thames Centre and Central Elgin, the townships of Bayham, Malahide and South West Oxford. The ENGLP (Aylmer) distribution system consists of approximately 800 kilometers of gas distribution mains being fed by seven custody transfer stations from Enbridge Gas' Union South system, and 38 gas wells owned by an arm's length third party.

1.1 Mission, Vision and Values

ENGLP (Aylmer's) Mission, Vision and Values extend from those of its parent company, EPCOR, which is committed to providing clean water and safe, reliable energy to its customers. EPCOR is committed to be a premier North American essential services company, providing clean drinking water, safe reliable electricity and natural gas.

To achieve this mission, EPCOR focuses heavily on operational excellence, its people, customers and stakeholders, health, safety and the environment, as well as growth.

The successful execution of EPCOR's business strategy is supported by what's important to ENGLP (Aylmer):

i. **Safety and Wellness:** We put safety in everything we do and promote wellness at work, at home and in the communities we serve;
ii. **Accountability:** We act with integrity and are accountable for doing what we say we will do;
iii. **Customer Focused:** We are trusted by customers and are dedicated to providing excellent customer service and solutions for our customers;
iv. **Teamwork and Collaboration:** We proudly work as a team and support each other's contributions;
v. **Shareholder Value:** We strive to create and enhance shareholder value;
vi. **Environmental Stewardship:** We are environmental leaders and are responsible users of all resources.

1.2 Utility Description

ENGLP (Aylmer) is a natural gas utility located south-east of London and includes the towns of Aylmer, Belmont, Port Burwell, Brownsville, Springfield, Straffordville, and Vienna. The area is embedded within the service area of Enbridge Gas Limited. It carries on the business of selling, distributing and transmitting natural gas within the province of Ontario. ENGLP will operate separate business units, one for the former Natural Resource Gas Limited gas distribution system in the Aylmer region described as ENGLP (Aylmer) and the future gas distribution system in the Southern Bruce area[1]. These two gas distribution systems will operate under separate rate schedules and tariffs while sharing certain management and functions so as to increase the efficiencies.

Gas is supplied into the ENGLP (Aylmer) system from Enbridge Gas Limited at seven different locations: Belmont Station, Harrietsville Station, Putnam Station, Brownsville Station, Bayham Station, Eden Station, and North Walsingham Station. Gas is also supplied from gas wells located within the ENGLP (Aylmer) franchise area. These wells are owned by ON-ENERGY Corp.

The gas demands in the ENGLP (Aylmer) system are mainly driven by a single large industrial customer, residential heating, small industrial customers, and agricultural (grain drying) customers. The single large industrial customer has a process load that is reasonably independent of the heating season, residential heating demand peaks during the winter months, the small industrial customers include heating which means that they peak in the winter, while the grain drying demand usually occurs in autumn or winter, but can occur at any time during the year. The figure below depicts ENGLP (Aylmer's) service area franchise municipalities:

[1] On November 29, 2018 the OEB approved an application (EB-2017-0247) to transfer certain Certificates of Public Convenience and Necessity required providing natural gas distribution service to the Southern Bruce region to ENGLP.


Lake Huron
(lac Huron)
County Of
Middlesex
County Of
Oxford
Township Of
Zorra
City Of
London
Municipality Of
Thames Centre
Township Of
South-West
Oxford
Town Of
Ingersoll
City Of
Woodstock
Township Of
Norwich
Town Of
Tillsonburg
Township Of
Malahide
Town Of
Aylmer
Municipality Of
Central Elgin
City Of St. Thomas
Township
Of Southwold
Municipality
Of Bayham
Norfolk
County
County
Of Elgin
Township Of
Strathroy-Caradoc
Township Of
Adelaide-Metcalfe
Municipality Of
Middlesex
Centre
Township Of
Blandford-Blenheim
Township Of East
Zorra-Tavistock
Town Of
St. Marys
Lake Erie
(lac Érié)
Haldimand
County
Municipality
Of Chatham-Kent
N

1.3 Strategic Priorities and Risk Appetite

ENGLP has identified key areas of focus that support the Utility's mission. ENGLP (Aylmer) will follow a similar structure to support its mission:

i. To provide safe, efficient and reliable delivery of natural gas to its customers;
ii. To deliver stable cash flow, achieve regulated returns on existing assets and maintain costs at a reasonable level on behalf of its customers;
iii. To provide a safe and engaging workplace for its employees; and,
iv. To continue to build reputation as a trusted developer and operator of utility assets.

ENGLP plans on achieving its strategic goals through the following objectives:

i. Improve reliability and internal processes to promote an efficient and sustainable environment;
ii. Improve marketing and communications to better serve our customers;
iii. Reduce operational costs and ensure efficient long term capital planning; and,
iv. Build and maintain regulatory relationships with the OEB and municipal entities to promote efficient provision of utility services.

In order to meet these priorities, ENGLP follows EPCOR's risk appetite objective framework to assist with capital and resource allocation as well as a basis for more strategic direction making regarding risk. This also fosters a more risk-intelligent culture by promoting accountability and transparency within the organization. Below is a table that summarizes the objectives of the risk appetite EPCOR is willing to take in order to meet its strategic priorities

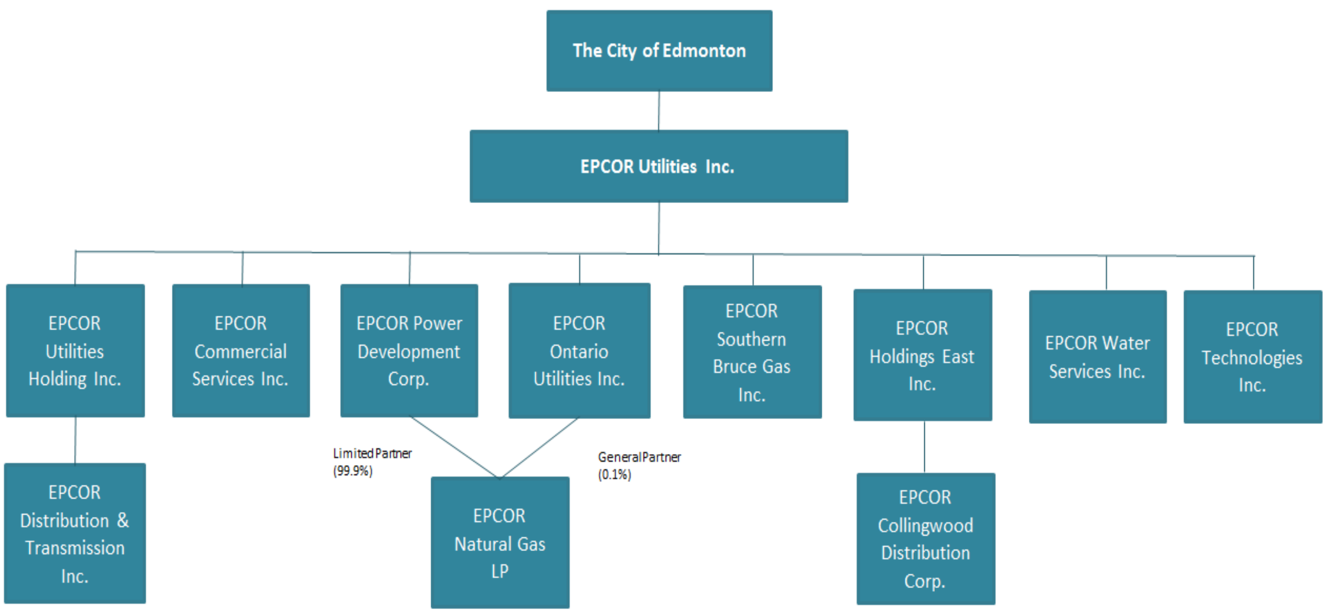
Risk Appetite Objectives	
Credit Rating	We will maintain a credit rating that ensures access to debt at reasonable rates.
Counterparty Credit Risk	We will assess and monitor all current and potential counterparties to ensure that any financial exposure remains within acceptable limits and any projected losses are appropriately provided for.
Compliance	We will have no appetite for illegal or unethical actions by EPCOR's employees, suppliers or other parties EPCOR associates with.
Identifiable, Understandable & Manageable Operational Risks	We will only engage in business activities (service offerings and geographies) where we have (or can acquire) the capacity to identify, understand and appropriately manage attendant development and operational risks. We have no appetite for activities that threaten the safety of our people. We will not put existing operations at risk because of a new growth opportunity.
Cyber	We rely on computer information and industrial control systems to operate and in addition, our operations require, generate and store vast amounts of confidential and private data. Our reputation is dependent on reliable systems and the protection of private customer and employee data. We have no appetite for cyber incidents that could impair our reputation as a trusted provider of utility services. Also, we will adopt the OEB proposed cyber security protocol.
Reputation	We understand that our success as a provider of utility services is highly reliant on our reputation as a competent and trusted operator of utility infrastructure. We have no appetite for significant operational mishaps that could impair our reputation as a trusted provider of utility services.

1.4 EPCOR Ownership

1.4.1 Ownership Overview

On November 7th, 2016, NRG and ENGLP entered into an Asset Purchase Agreement whereby NRG agreed to sell and ENGLP agreed to purchase NRG's natural gas distribution system. The Asset Purchase Agreement transferred to ENGLP all of the property and assets needed to operate the gas distribution system then owned and operated by NRG. ENGLP's acquisition of the natural gas distribution assets of NRG received regulatory approval from the Board in August 2017 and the transaction closed on November 1st, 2017.

ENGLP is an Ontario limited partnership and is a wholly owned indirect subsidiary of EPCOR. The general partner of ENGLP is EPCOR Ontario Utilities Inc. ("EOUI") and the sole limited partner is EPCOR Power Development Corporation, which are both subsidiaries of EPCOR. ENGLP was formed pursuant to a limited partnership agreement which provides that EOUI, as general partner, will control and have the full and exclusive power, authority and responsibility for the management and day-to-day operations of ENGLP. In accordance with the limited partnership agreement, EPCOR Power Development Corporation, as limited partner, has an economic interest in the partnership but will not control or otherwise play a role in the day-to-day operations and management of ENGLP. The chart below is a simplified EPCOR Organizational Chart.



1.4.2 EOUI Board of Directors

Following are the names of EOUI’s Board of Directors and their responsibilities:

Stuart Lee, President and Chief Executive Officer of EPCOR (Alberta, Canada)

Stuart Lee has been EPCOR’s President & CEO since 2015. Stuart is a seasoned business executive with extensive financial and commercial expertise. Before joining EPCOR, Stuart was an executive with Capital Power Corporation for six years, overseeing various business functions as Senior Vice President and as its former Chief Financial Officer. From 2009 to 2011, Stuart was President and Director of Capital Power Income LP, a publicly traded subsidiary of Capital Power Corporation. This was a $2 billion enterprise value business with 20 plants across North America.

Stuart holds a Bachelor of Commerce from the University of Alberta and is a chartered accountant. He serves on the Board of STARS (Shock Trauma Air Rescue Service), the Audit Committee for the University of Alberta and recently completed a term with the Board of Directors of Edmonton's Citadel Theatre.

Stephen Stanley, Senior Vice President, Commercial Services of EPCOR (Alberta, Canada)

Steve Stanley is EPCOR’s Senior Vice President, Commercial Services, responsible for EPCOR's business development activities and EPCOR’s Ontario operations including those of ENGLP. Prior to this, Steve served as Senior Vice President of EPCOR Water Canada, responsible for providing water and wastewater treatment services to more than 85 communities. Under his leadership, the company expanded its operations across Alberta, and into British Columbia and Saskatchewan.

Steve holds a B.Sc. in Civil Engineering, a M.Sc. in Water Resources Engineering, and a Ph.D. in Environmental Engineering, all from the University of Alberta. He is also a graduate of the Executive Program at Queen's University.

Steve is one of Canada's leading experts in water treatment and associated infrastructure. Prior to joining EPCOR, he was a professor at the University of Alberta's Department of Civil and Environmental Engineering. He currently serves on a number of boards, including the Board of Directors of the Alberta Chamber of Resources and the University of Alberta's External Advisory Council for the School of Public Health.

Frank Ross, Senior Advisor Aecon Group Inc. (Independent Board Member)

Frank Ross supports infrastructure projects across Aecon Group Inc. as a Senior Advisor. Mr. Ross was previously President of Aecon Buildings Group, and has also led Aecon Atlantic Group and Aecon Fabco in Halifax, N.S., both divisions of Aecon.

An active member of the construction community for over 40 years, Mr. Ross has served on the Board of Directors of the Canadian Construction Association, the Ontario General Contractors Association, and the Board of Directors for the Toronto Construction Association. He also served as a Trustee of the Labourers' International Union of North America – Local 615 Health and Welfare Program, and as a Board of Directors member for the NS Construction Labour Relations Association.

1.4.3 Role of the Board and ENGLP Management

The Directors of EOUI have the power and duty to manage the business and affairs of the EOUI and as the general partner of ENGLP, the business and affairs of ENGLP. The EOUI Board of Directors ("EOUI Board")is elected by EUI as the voting shareholder of EOUI (the "Shareholder") to oversee management and to ensure that the long-term interests of the business are being served. The size of the EOUI Board is determined by the Shareholder from time to time as appropriate and the Shareholder determines appropriate terms for Directors. The composition of the EOUI Board is in accordance with applicable laws and regulatory requirements.

ENGLP management is responsible for the day-to-day leadership and management of the business and formulates strategies and plans consistent with the overall strategic plan established for the EPCOR group of companies and present these to the EOUI Board for review and approval. From time to time, the Shareholder may suggest or provide guidance regarding goals, plans, objectives and policies, which the EOUI Board shall review and consider. The EOUI Board approves the goals of the business, the objectives, plans and policies within which it is managed and evaluates management performance. Management keeps the EOUI Board fully informed of the business' progress towards the achievement of goals, objectives and policies in a timely and candid manner.

The EOUI Board generally has a minimum of two scheduled meetings each year during which it reviews and discusses the performance of the business, its plans and prospects, as well as immediate issues facing the business. It may also be necessary for the EOUI Board to meet at other times to consider business which arises between regularly scheduled meetings.

1.4.4 Functions of the Board

In addition to its general oversight of management, the EOUI Board performs a number of specific functions, including:

- managing the affairs of the EOUI Board, including evaluating the performance of the EOUI Board;
- adopting, reviewing, monitoring and directing the implementation of fundamental strategies, plans and policies;
- adopting, reviewing and monitoring annual capital and operating budgets;

- selection and appointment of the Vice President, Ontario Region;
- monitoring and reviewing management's performance, and providing advice and counsel to management;
- business and risk management, including monitoring corporate performance against strategic, operating and capital plans;
- approving material acquisitions and dispositions;
- approving dividend transactions and equity issuances as well as any issuance, refinancing or prepayment of long-term debt;
- appointment of the auditors of the annual financial statements (subject to consultation with the Audit Committee of EPCOR Board of Directors);
- approval of financial statements;
- ensuring that EOUI has effective communication processes with the Shareholder and other stakeholders; and
- monitoring compliance with applicable legal requirements and significant policies and procedures to ensure that EOUI (and ENGLP) operates to meet all applicable laws and regulations and to the highest ethical standards.

1.4.5 EOUI Board Responsibilities

The basic responsibilities of the members of the EOUI Board are to fulfill their fiduciary duties of loyalty, good faith and due care so as to exercise their business judgment on an informed basis in what they reasonably and honestly believe to be in the best interests of the EOUI (and therefore ENGLP).

The EOUI Board represents and is accountable to EOUI. The EOUI Board's responsibilities are active, not passive, and include the responsibility to regularly evaluate the strategic direction of the business, management policies and the effectiveness with which management implements its policies.

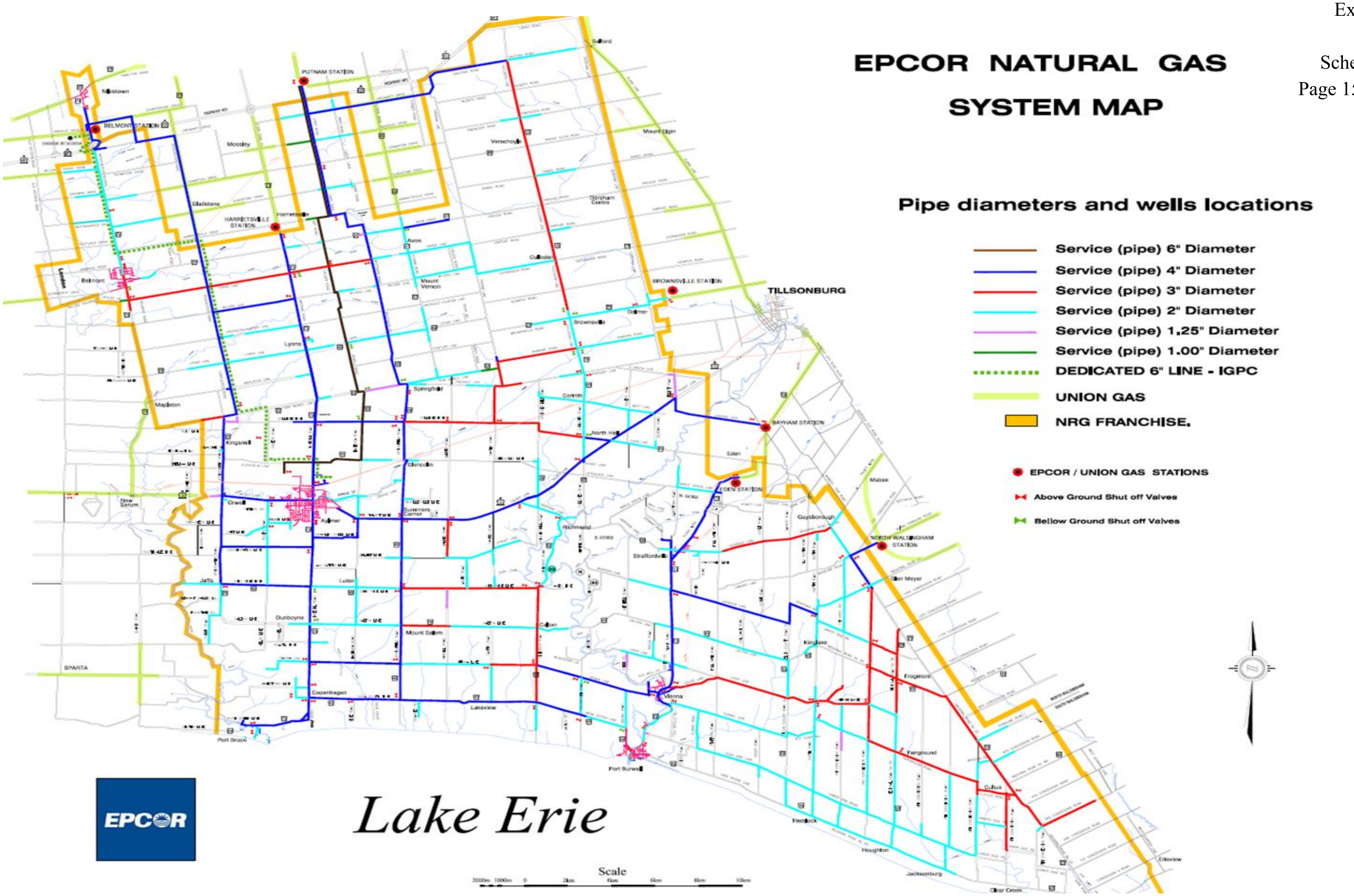
2.0 Customer and System Overview

ENGLP (Aylmer) is a utility located south-east of London and includes the towns of Aylmer, Belmont, Port Burwell, Brownsville, Springfield, Straffordville, and Vienna. The area is embedded within the service territory of Enbridge Gas Limited. ENGLP (Aylmer) does not host, nor have any embedded utilities within its service area.

ENGLP (Aylmer) serves approximately 9,000 customers under six established rates classes and four categories (Residential, Commercial, Seasonal and Industrial). The annual average consumption of its customers is approximately 63,500,000 m^3. The largest customer consumes approximately 34,000,000 m^3 annually and growing due to a recently completed expansion. The six rate classes include Rate 1 (General Service Rate), Rate 2 (Seasonal Service), Rate 3 (Special Large Volume Contract Rate), Rate 4 (General Service Peaking), Rate 5 (Interruptible Peaking Contract Rate) and Rate 6 (Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility).

The ENGLP (Aylmer) system consists of approximately 800 kilometers of gas distribution mains being fed by seven custody transfer stations from Enbridge Gas' Union South system, and 38 gas wells owned by third party natural gas producers within ENGLP's service territory. Gas is supplied into the ENGLP (Aylmer) system from Enbridge Gas Limited at seven different locations: Belmont Station, Harrietsville Station, Putnam Station, Brownsville Station, Bayham Station, Eden Station, and North Walsingham Station. Gas is also supplied from gas wells located in the ENGLP (Aylmer) franchise area. These wells are owned and operated by ON-ENERGY Corp, an arm's length third party. Further, the distribution system has a 30 kilometer High-pressure steel pipeline that is dedicated to its largest industrial customer and 88 regulator and control stations that include manual monitoring systems. The figure below shows an overall ENGLP (Aylmer) system map.

ENGLP (Aylmer) expects to continue to focus on incorporating customer feedback into operational and capital plans, addressing concerns regarding system pressure in the south part of the system and expanding services within its existing franchise areas over the next five-year period of operations. In particular, this expansion is likely to occur south of Aylmer within the north shore Lake Erie region and also in the southwest Oxford area. Further growth in residential customers can also be anticipated in Belmont, which serves as a bedroom community for London, Ontario. All of the above initiatives may benefit the existing rate payers through economies of scale in current operations.


EPCOR NATURAL GAS
SYSTEM MAP
Pipe diameters and wells locations
Service (pipe) 6" Diameter
Service (pipe) 4" Diameter
Service (pipe) 3" Diameter
Service (pipe) 2" Diameter
Service (pipe) 1.25" Diameter
Service (pipe) 1.00" Diameter
DEDICATED 6" LINE - IGPC
UNION GAS
NRG FRANCHISE.
EPCOR / UNION GAS STATIONS
Above Ground Shut off Valves
Bellow Ground Shut off Valves
TILLSONBURG
PUTNAM STATION
BELMONT STATION
HARRIETSVILLE STATION
BROWNSVILLE STATION
BAYHAM STATION
EDEN STATION
NORTH WALSINGHAM STATION
Lake Erie
EPCOR
Scale

3.0 Customer Engagement

3.1 Overview of Customer Engagement

As part of ENGLP (Aylmer's) commitment to providing customers with a safe and reliable supply of natural gas and excellent customer service, ENGLP (Aylmer) seeks opportunities to communicate and engage with our customers. Since ENGLP acquired the assets of NRG in November 2017, ENGLP (Aylmer) has worked to strengthen the Utility's relationship with the approximately 9,000 customers in our distribution area to ensure that its operations are well aligned with community interests and priorities. ENGLP (Aylmer) has reviewed the practices of customer engagement of the previous owner of the distribution assets and ENGLP (Aylmer) intends to improve upon historical customer engagement activities.

In November 2018, ENGLP (Aylmer) conducted a customer engagement survey to gather insight into communication preferences, customer priorities and service satisfaction. The results also provided data to assist in developing ENGLP (Aylmer's) 2019 communications plans, as well as feedback regarding investment in the distribution system and services.

ENGLP (Aylmer) engages customers and the community through various means including:

- Bill inserts
- Bill notices
- Print advertisements
- News media
- Regular web content updates
- LEAP Program and support
- Charitable investments
- Community events
- Safety-focused partnerships
- Employee engagement in the community
- Customer face-to-face meetings
- Local access at the administration office
    - In-person service at local office
    - Inbound and outbound phone calls
    - Email correspondence
- Meeting with municipal and regional orders of government

The following reflects recent and planned activity to communicate about customer service, reliability, conservation and safety.

3.2 Customer Service and Local Presence

High levels of customer service are of prime importance to ENGLP (Aylmer). During business hours, ENGLP (Aylmer's) customer services personnel engage with customers by phone, email, facsimile, or in person at the administration office located in the center of ENGLP (Aylmer's) distribution territory at 39 Beech Street East, Aylmer, Ontario. The representatives will also make outbound calls to customers in regards to coordinating service arrangements, such as meter replacements or identifying property gas lines. During non-business hours, inbound phone calls are managed by a third-party call center so customers can report an emergency or enquire about account services.

In November 2018, ENGLP (Aylmer) undertook a customer engagement survey to gather feedback from customers regarding investment in the distribution system and services. The survey was distributed by email to 1,776 customers and was promoted on bill notices, the ENGLP website and at the ENGLP (Aylmer) administration office for those who visited our customer service representatives in person. The primary audience included residential homeowners, commercial customers and municipalities in ENGLP (Aylmer's) service territory and secondary audience included customers in ENGLP (Aylmer's) service territory who rent or are temporary residents.

The survey was issued as a non-blind survey (ENGLP (Aylmer's) name was transparent to the respondent) and open to all customer rate classes. The survey was intended to give ENGLP (Aylmer) insight into customer preferences, customer priorities and service satisfaction. The results of the survey fit under the following categories:

- Familiarity and awareness of EPCOR operating in the community;
- Importance of service reliability and customer satisfaction with current delivery of natural gas;
- Importance of conservation, lower rates and rebate programs;
- Importance of safety measurements;
- Importance of community involvement and charitable investments.

Each of the results from the customer engagement survey is discussed in more detail below.

3.2.1 Customer Awareness

The results of the customer survey showed that 80% of respondents were satisfied or very satisfied with the level of service they receive, it noted that 75% were not familiar or only somewhat familiar with ENGLP (Aylmer) as the service provider. The results from the survey supports ENGLP (Aylmer's) assumptions that an awareness campaign is needed in ENGLP (Aylmer's) service territory as the transition from NRG to ENGLP (Aylmer) occurred just over a year ago.

To increase awareness and ensure that customers know to contact ENGLP (Aylmer) for natural gas services and during emergencies, ENGLP (Aylmer) will work to increase the frequency of its communication initiatives. In 2019, ENGLP (Aylmer) will reach customers through various means, including postings at the ENGLP (Aylmer) administration office, email, industry partnerships and community events. ENGLP (Aylmer) currently supports a number of local events and charitable organizations and will endeavor to leverage these relationships to include ENGLP (Aylmer) staff activation to engage with customers and build awareness.

3.2.2 Service Reliability

The results of the customer engagement survey also showed that service reliability was rated second by respondents as the most important aspect of their natural gas service (25%). Of those who rated it as most important, 95% of respondents were satisfied or very satisfied with their current service delivery. With this in mind, ENGLP (Aylmer) will continue to contact customers by phone to inform them of planned service disruptions and in person of unplanned service interruptions. Further, ENGLP (Aylmer) has undertaken a Utility System Plan and System Integrity Study reaffirming that system reliability, gas supply and reinforcement continue to be appropriate investment in its distribution system. The Utility continues to focus on reducing its costs to demonstrate to customers that they are delivering as much value per dollar as possible to them.

ENGLP (Aylmer) responds immediately to customer concerns of carbon monoxide or other natural gas leaks. When leaks are identified, Field Technicians will work with customers to inform and educate them on safety and service interruptions by speaking with them in person and providing educational material, while remediating the situation. Customers can also find educational material on the ENGLP website, which has content from both ENGLP and the Ontario Regional Common Ground Alliance's (”ORCGA”)Dig Safe program.

As part of ENGLP (Aylmer's) 2019 communication plans, various channels will be used to continue educating customers on service reliability. In addition to contact from ENGLP (Aylmer)

Field Technicians and Customer Service Representatives for planned and unplanned service disruptions, we plan to use customer newsletters, email blasts and the EPCOR website to share information on service reliability.

3.2.3 Conservation

The customer survey results showed that the majority of respondents (78%) want ENGLP (Aylmer) to focus on keeping customers' rates/bills low. ENGLP (Aylmer) will continue to educate customers on conservation measures that will help customers increase their energy efficiency. When asked how customers would like to receive information about conservation and safety measures, 68% of respondents would prefer to receive it through email, followed by the EPCOR website and then mail. In addition to these tools, ENGLP (Aylmer) plans to produce educational collateral to distribute at community and sponsored events. Cost efficiency and increased reliability measures are further discussed in Section 6.2.2.

3.3 Safety

ENGLP (Aylmer) adheres to strict safety measurements making safety to our customers and community our number one priority. Responding to emergency services is a critical part of our role with customers. ENGLP (Aylmer) responds immediately to customer concerns of carbon monoxide or other natural gas leaks and performs annual leak testing in areas of public assembly.

ENGLP (Aylmer) works with local industry and agricultural associations, as well as with municipalities, to discuss safety and construction practices while working in proximity to natural gas distribution lines. In 2018, ENGLP partnered with the ORCGA to provide newsletter content for its Trouble Zone publication. In November 2018, ORCGA published an ENGLP (Aylmer) article directed to the agricultural community to address the increase in natural gas line strikes that occurred that year. ENGLP (Aylmer) also posted an ORCGA Dig Safe video on the EPCOR website to highlight the importance of working safely around natural gas lines. ENGLP will continue to use a number of communication channels to increase customer and stakeholder awareness on the importance of safety practices.

ENGLP (Aylmer) will continue to strengthen its health, safety and environment management system, in keeping with EPCOR's values and accepted industry practice. This includes better documenting practices and procedures, building upon the successes of the Utility to date and addressing any gaps found.

3.4 Charitable Investments and Community Involvement

The programs ENGLP (Aylmer) supports provide education essentials to young minds to inspire an employment path towards a poverty-free tomorrow. ENGLP (Aylmer) and its employees participate and volunteer in the community and contribute to not-for-profit and charitable organizations. For example, ENGLP (Aylmer) sponsors local hockey associations and provides a scholarship for East Elgin Secondary School. Employees also donate to the United Way Campaign with EPCOR matching employee contributions.

ENGLP (Aylmer) supports sponsorships in the community to increase awareness of natural gas safety, the organization and understanding of who to contact for natural gas services. In 2018, ENGLP (Aylmer) supported the East Elgin Community Complex, Aylmer Spitfires Hockey Club and Kinsmen Club Santa Clause Parade.

3.5 Customer Engagement Future Plans

The customer engagement tactics, measurement and communication activities laid out below are designed to reflect insights from the customer survey and ENGLP (Aylmer's) operational priorities, specifically focusing on providing safe, efficient and reliable delivery of services, as well as building brand reputation.

3.5.1 Customer Engagement Tactics

The following Table provides a list and description of each tactic ENGLP (Aylmer) plans to utilize to educate its customers.

Tactic	Description
Website content	EPCOR's website is a great source of information for customers and is updated regularly. Content related to conservation and provincial rebate programs is posted and promoted on the website, as is safety messaging, regulatory notices and service updates.
Email blasts	The customer survey was the first time an email blast was distributed to the 1,776 customers who had provided ENGLP (Aylmer) with their email address. The survey results show that customers would like to be contacted about conservation and

Tactic	Description
	safety information through email so in 2019 we will endeavor to send emails on a quarterly basis.
Print advertisements	Print advertisements will be used to notify customers in regards to the Cost of Service application. Quarter page, black and white advertisements are expected to be placed in the Aylmer Express to reach customers in our service territory.
Customer newsletter	As a way to strengthen relationships with our customers while providing them with relevant information on our service delivery, we will produce a biannual newsletter that will be distributed with customer bills and posted on the EPCOR website. As ENGLP transitions away from paper bills to electronic services, we will also transition the newsletter from hard copy to soft copy distribution.
Industry partnerships	ENGLP (Aylmer) will continue to work with industry and agricultural associations, as well as municipalities, as a way to reach more of our service territory on a more frequent basis. This will primarily be a way to share educational material on safety practices.
Administration Office notice board	To keep customers who visit the office informed, a notice board will be displayed that has conservation and safety information, as well as updates on the 2020 Cost of Service application.
Bill notices	ENGLP (Aylmer's) billing software has the capability to print messaging at the bottom of the monthly statement. ENGLP has used this to convey messaging about rebate programs, such as cap and trade, promotion of safety-related content, including carbon monoxide testing, and the 2020 Cost of Service application. We will continue to use this tool as it reaches all ENGLP (Aylmer) customers on a monthly basis.

The following Table provides a list and description of each tactic ENGLP (Aylmer) plans to utilize to build brand recognition with its customers.

Tactic	Description
Customer survey	ENGLP (Aylmer) first conducted a customer engagement survey as part of the 2020 Cost of Service application to provide insight into communication preferences, customer priorities and service satisfaction. ENGLP (Aylmer) will begin to conduct a customer engagement survey on an annual basis to measure customer satisfaction, brand awareness and effectiveness of educational campaigns.
Community events	EPCOR supports the communities where we live and work. In the past year, ENGLP (Aylmer) engaged in sponsorships as a way to build our brand and trust in the community. This activity was to help increase awareness of our organization and understanding of the services we provide. ENGLP (Aylmer) will continue to partner with local associations as opportunities arise.
Charitable investments	The programs EPCOR supports provide education essentials to young minds today to inspire an employment path towards a poverty-free tomorrow. EPCOR's charitable donation program focuses on engaging in partnerships with local charities that set socially vulnerable young people up for success along their educational journey in three key areas: K-Gr. 3, high school transition, and post-secondary pursuits. ENGLP (Aylmer) and its employees participate and volunteer in the community and contribute to not-for-profit and charitable organizations. ENGLP (Aylmer) will continue to support organizations in our service territory, including Thames Valley Education Foundation. Employees will also continue to donate to the United Way Campaign with EPCOR matching employee contributions.

3.5.2 Customer Engagement Measurement

ENGLP (Aylmer) will measure the effectiveness of its stakeholder engagement plan in the following ways:

Measurement	Description
Website traffic	ENGLP (Aylmer) will analyze previous monthly website visitation compared to the specific months when we are encouraging customers to visit the site to learn more about the 2020 Cost of Service application. We will also be able to measure the number of visits to those dedicated webpages. Customers will be directed to the website through signage at the administration office, print advertisements, bill notices and the open house.
Website bounce rate	In addition to measuring how many visitors we receive to the website, we will also measure how long they remain on the website and how many other webpages they view.
Channels	Based on the number of communication channels used to reach ENGLP (Aylmer) customers during the 2020 Cost of Service application process.
Engagement	Based on the number of completed customer surveys we receive, number of customers from the survey who express interest in learning more about the application, number of attendees at the open house and number of feedback forms submitted in the administration office comment box.

4.0 Public Policy Responsiveness

ENGLP (Aylmer) extends their natural gas distribution to new roads and customers every year. ENGLP (Aylmer) reaches out to its potential customer base through its website, as messages on bill statements and in advertisements in newspapers and magazines. ENGLP (Aylmer) educates the public regarding the properties of natural gas and how it smells, clearing snow and ice from meters and ensuring that they call before they dig for locates.

5.0 Performance Measurement and Scorecard

5.1 Performance Scorecard Proposal

ENGLP (Aylmer) is proposing a new scorecard to measure and monitor performance from January 2020 to December 2024. The proposed Scorecard is modeled after the electricity distributors' scorecard, and a similar scorecard proposed by Enbridge Gas Distribution Inc. and Union Gas Limited in their application to amalgamate (EB-2017-0307), and is supported by the goals and objectives of ENGLP's business plan. This scorecard is also compliant with the Board's Gas Distribution Access Rule as amended January 1, 2017.

In alignment with the Renewed Regulatory Framework as detailed in the Handbook for Utility Rate Applications dated October 13, 2016, the proposed scorecard includes measures for customer focus, operational effectiveness, and financial performance. The Scorecard metrics include service quality requirements ("SQR") and best practice metrics; and aims to align customer and utility interests, while continuing to achieve public policy objectives and reinforcing fiscal prudence. A copy of the existing scorecard metrics provided to the OEB as well as the new proposed Scorecard is provided below. The categories of measures included in the proposed scorecard are as follows:

i. **Customer Focus:** This performance measure is focused on service quality and customer satisfaction. The metrics included in this measure are the Board's customer care related SQRs. These include:

   a. Reconnection response time
   b. Scheduled appointments met on time
   c. Telephone calls answered on time
   d. Customer complaint written response
   e. Billing accuracy
   f. Abandon rate

g. Time to reschedule missed appointments

ii. **Operational Effectiveness:** This performance measure is focused on safety, system reliability and asset management. The metrics included in this measure include the Board's operations related SQRs and damages:

a. Meter reading performance
b. Percent of emergency calls responded to within an hour
c. Damages

iii. **Public Policy Responsiveness:** This performance measure includes metrics that align with the extension of natural gas distribution to new communities.

a. Number of new communities that have access to natural gas distribution system
b. \$/m3 cost to deliver natural gas
c. Customer years
d. Cumulative volume

iv. **Financial Performance:** This performance measure includes metrics that align with the OEB Yearbook that is published annually. These include:

e. Current Ratio
f. Debt Ratio
g. Debt to equity ratio
h. Interest coverage
i. Financial statement return on assets
j. Financial statement return on equity

5.1.1 Existing ENGLP (Aylmer) OEB Scorecard Sample – 2017[2]

The following Tables provides a summary of ENGLP (Aylmer) OEB scorecard results for service quality and financial performance for 2017.

2017 Service Quality Measures
(%)

	Service Quality Requirements	A OEB Standard	B Enbridge Gas	C Union Gas	D NRG
1	Call Answering	minimum 75%	82.50	79.20	98.80
2	Call Abandon Rate	not exceed 10%	1.80	3.40	1.20
3	Meter Reading	not exceed 0.5%	0.50	0.10	0.00
4	Appointments Met	minimum 85%	94.30	99.00	99.10
5	Reschedule Appointments	100%	96.80	99.90	100.00
6	Emergency Call Response	minimum 90%	96.80	99.00	92.30
7	Days to Provide Written Response	minimum 80%	100.00	100.00	100.00
8	Days to Reconnect	minimum 85%	96.20	90.50	100.00

2017 Financial Ratios

	Financial Ratios	A Enbridge Gas	B Union Gas	C NRG	D Industry
1	Liquidity Ratio – Current Ratio	0.84	0.47	0.62	0.64
2	Leverage Ratios – Debt Ratio	0.47	0.49	0.47	0.48
3	Debt to Equity Ratio	1.54	2.08	1.48	1.74
4	Interest Coverage	1.96	2.42	3.88	2.15
5	Profitability – Return on Assets	2.27%	2.71%	2.21%	2.47%
6	Profitability – Return on Equity	7.39%	11.43%	7.02%	8.93%

[2] https://www.oeb.ca/oeb/_Documents/RRR/2017_Yearbook_of_Natural_Gas_Distributors.pdf

5.1.2 ENGLP (Aylmer) Proposed Scorecard

Performance Outcomes	Performance Categories	Measures	
Customer Focus	Service Quality	Reconnection response time (# of days to reconnect a customer)	*# of reconnections completed within 2 business days/# of reconnections completed*
		Scheduled appointments met on time (appointments met within designated time period)	*# of appointments met within 4hrs of the scheduled date / # of appointments scheduled in the month*
		Telephone calls answered on time (call answering service level)	*# of calls answered within 30 seconds / # of calls received*
	Customer Satisfaction	Customer Complaint Written Response (# of days to provide a written response)	*# of complaints requiring response within 10 days / # of complaints requiring a written response*
		Billing accuracy	*Number of manual checks done as per quality assurance program, for excessively high or low usage.*
		Abandon Rate (# of calls abandon rate)	*# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent*
		Time to reschedule missed appointments	*% of rescheduled work within 2 hours of the end of the original appointment time*
Operational Effectiveness	Safety, system reliability and asset management	Meter Reading Performance	*# of meters with no read for 4 consecutive months / # of active meters to be read*
		% of Emergency Calls Responded within One Hour	*# of emergency calls responded within 60 minutes / # of emergency calls*
		Damages	*Third party line breaks per 1,000 locate requests*
Public Policy Responsiveness	Extending natural gas distribution to new communities	New communities that have access to natural gas distribution system	*(# of communities serviced by system/# of communities committed to in CIP)*
		$/m3 cost to deliver natural gas	*Average $/m3 determined in CIP (as adjusted) – Actual average $/m3*
		Customer years	*Average customer years / Customer years as determined in CIP*
		Cumulative volume	*Actual cumulative volume / Cumulative volume as determined in CIP*

Performance Outcomes	Performance Categories	Measures
Financial Performance	**Financial Ratios**	Current Ratio
		Debt Ratio
		Debt to Equity Ratio
		Interest Coverage
		Financial Statement Return on Assets
		Financial Statement Return on Equity

6.0 Performance Metrics

6.1 Capital Expenditure Plan

6.1.1 Capital Expenditure Plan Overview

ENGLP (Aylmer) is focused on maintaining high-performance levels in all aspects of its capital investments and planning activities to comply with the regulatory obligations of the OEB. The table below summarizes the capital budget planned for the period 2019 through 2024.

Summary of Capital Budget (Net of Contributions)
($ thousands)

	Project or Program	A 2019 Bridge Year	B 2020 Test Year	C 2021 Forecast	D 2022 Forecast	E 2023 Forecast	F 2024 Forecast
1	Belmont Reinforcement	439					
2	Lakeview Reinforcement	357					
3	IGPC Pipeline Realignment at Highway 401 Interchange	699					
4	SCADA Upgrade	283	128	42	43	44	45
5	Aylmer Office 2nd Floor Development	31	31				
6	UMS and Workforce Management Software	110	26				
7	Telephone System Replacement	129					
8	ARC GIS Mapping			106			
9	CNG Vehicle Fueling Station Recertification			53			
10	Main Additions	555	564	578	589	601	613
11	Service Additions	89	100	92	95	95	98
12	Meters	255	260	265	271	276	282
13	Regulating Stations	73	75	76	78	79	81
14	Regulators	71	73	74	76	77	79
15	Pipeline Markers	10	10	11	11	11	11
16	Fleet	108	47	133	49	50	51
17	Small Tools and Equipment	15	16	16	16	17	17
18	Computers and Office Equipment	10	10	11	11	11	11
19	Additions from CWIP going into service	176					
20	**Total**	**3,410**	**1,340**	**1,457**	**1,239**	**1,261**	**1,288**

6.1.2 Total Annual Expenditures by Category

Capital investments can be broadly can be broadly grouped into the following categories based on the driver triggering the expenditure:

i. ***System access:*** investments are modifications to the distribution system to provide a new customer or group of customers with access to natural gas service. This includes the relocation of distribution assets to accommodate infrastructure development or modifications by a municipal or provincial authority, or other third-party (e.g. modifications to a highway interchange).

ii. ***System renewal:*** investments are the lifecycle replacement distribution assets, or refurbishment to extend the original service life, ensuring system integrity and safe operation.

iii. ***System service:*** investments are modifications to the distribution system to improve reliability, mitigate risk or introduce efficiencies and ensure that performance goals and objectives are met.

iv. ***General plant:*** investments are additions, modification or replacements of assets used to support business, operations and maintenance activities but not part of the distribution system, such as fleet, tools and equipment, buildings and computers and software.

Planned capital expenditures, by investment category, for the period 2019 through 2024, as identified in the 2020 cost of service application are summarized in the tables below. The forecasted expenditures for 2018 are included for comparison.

Planned Capital Expenditures by Category
($ thousands)

		A	B	C	D	E	F	G
	GCategory	**2018 Forecast**	**2019 Bridge Year**	**2020 Test Year**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**
1	System Access	1,433	1,181	451	451	461	468	479
2	System Renewal	510	502	490	501	512	520	532
3	System Service	149	1,275	269	187	190	194	198
4	General Plant	168	453	130	319	76	78	79
5	**Total**	**2,261**	**3,410**	**1,340**	**1,457**	**1,239**	**1,261**	**1,288**

Planned Capital Expenditure by Category
(%)

		A	B	C	D	E	F	G
	Category	**2018**	**2019 Bridge Year**	**2020 Test Year**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**
1	System Access	63%	35%	34%	31%	37%	37%	37%
2	System Renewal	23%	15%	37%	34%	41%	41%	41%
3	System Service	7%	37%	20%	13%	15%	15%	15%
4	General Plant	7%	13%	10%	22%	6%	6%	6%
5	**Total**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

6.1.3 5-Year Outlook

The Town of Aylmer is a vibrant community located in Southwestern Ontario close to the city of London. The community is strategically located with ready access to the 400 series highways, Buffalo and Detroit borders, and the major airports in London and Toronto. The town is home to a busy commercial district and diverse industrial area, serving approximately 7,500 residents and a trade area of approximately 18,000 people.

The Town of Aylmer is home to many different businesses and industries primarily including green technology such as Ethanol production, food processing, composites and advanced manufacturing. The Ontario Police College is also located within the service area. The unemployment rate as of November 2017 was 9.1% which saw an average rate of decline of 3.9% from 2011 to 2016. Declines in unemployment rates reflect positive economic conditions in the community, as more people are finding jobs and businesses are likely thriving.

The key long term economic and planning assumption informing this Business Plan is customer growth. Over the period covered by this plan, customer growth is expected to be consistent with the average growth experienced in the service area in historic years. As ENGLP (Aylmer's) historic customer growth has been relatively stable over a number of years, expectations on future natural gas prices do not seen to be a factor for customer growth for this utility and have not influenced the growth assumption of this plan.

ENGLP (Aylmer) expects to continue expanding services within its existing franchise areas over the next five-year period of operations. In particular, this expansion is likely to occur south of Aylmer within the north shore Lake Erie region and also in the southwest Oxford area. Further growth in residential customers can also be anticipated in Belmont, which serves as a bedroom community for London, Ontario.

6.1.3.1 Main Additions Annual Program (2019-2024)

This program accounts for the installation of new pipeline mains or the replacement of existing mains for the purposes of serving new customers, replacement of pipe assessed to be at the end of the useful service life, or reinforcement of the system to improve reliability. The estimated annual capital spend is estimated based on management judgments and average historical spending.

The following Table provides the forecasted annual spend of Main Additions from 2019 to 2024.

Main Additions 2019-2024
($ dollars)

	A **2019 Bridge Year**	B **2020 Test Year**	C **2021 Forecast**	D **2022 Forecast**	E **2023 Forecast**	F **2024 Forecast**
1 Main Additions	$555,000	$564,000	$578,000	$589,000	$601,000	$613,000

Individual projects under the program are evaluated, planned and prioritized based on customer need and risk. Annual program costs are partially contingent on growth and the number of new customer connections were estimated based on the utility's experience in recent years.

Individual projects to install new mains with the primary purpose of serving new customers (system access) are subject to an economic test as required by the OEB, the calculation of a profitability index (PI) value. If the PI value is less than 1, a contribution in aid of construction is calculated.

Individual projects under the program will typically be completed in a single construction season and the asset put in service by December 31 of the program year.

6.1.3.2 Service Additions Annual Program (2019-2024)

This program accounts for the installation of new services including the service line, punch tee, excess flow valve, riser, and service valve. The estimated annual capital cost is based on estimated new service connections and historic costs. Individual new service installations are subject to customer contributions.

The following Table provides the forecasted annual spend net of contributions.

Service Additions 2019-2024
($ dollars)

		A	B	C	D	E	F
		2019 Bridge Year	**2020 Test Year**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**
1	Service Additions	$151,000	$172,000	$157,000	$161,000	$163,000	$167,000
2	Contributions	($62,000)	($72,000)	($65,000)	($66,000)	($68,000)	($69,000)
3	Service Additions Net of Contributions	**$89,000**	**$100,000**	**$92,000**	**$95,000**	**$95,000**	**$98,000**

Annual program costs are contingent on growth and the number of new customer connections were estimated based on the utility's experience in recent years.

6.1.3.3 Meters Annual Program (2019 – 2024)

This program accounts for the purchase and replacement of natural gas meters for new customer connections and the lifecycle replacement of meters on existing services. It also includes the refurbishment and reverification of existing meters to extend the useful service life, when economical.

The following Table provides the forecasted annual spend of Meters from 2019 to 2024.

Meters Annual Program 2019-2024
($ dollars)

		A **2019 Bridge Year**	B **2020 Test Year**	C **2021 Forecast**	D **2022 Forecast**	E **2023 Forecast**	F **2024 Forecast**
1	Meters	$255,000	$260,000	$265,000	$271,000	$276,000	$282,000

ENGLP (Aylmer) is required to ensure that meters are removed from service or recertified and sealed upon expiry of the approved verification period, as per the requirements of Measurement Canada, and comply with meter accuracy obligations prescribed under the Electricity and Gas Inspection Act.

Annual program costs are partially contingent on growth and the number of new customer connections were estimated based on the utility's experience in recent years.

6.1.3.4 Regulating Stations Annual Program (2019 – 2024)

This program accounts for the replacement of regulating stations. The forecast annual capital spend is based on management judgement and historical spend based on the replacement of one regulating station per year.

The following Table provides the forecasted annual spend of Regulating Stations from 2019 to 2024.

Regulating Stations Annual Program 2019-2024
($ dollars)

		A **2019 Bridge Year**	B **2020 Test Year**	C **2021 Forecast**	D **2022 Forecast**	E **2023 Forecast**	F **2024 Forecast**
1	Regulating Stations	$73,000	$75,000	$76,000	$78,000	$79,000	$81,000

6.1.3.5 Regulators Annual Program (2019 – 2024)

This project accounts for the purchase and replacement of natural gas regulators for new customer connections and the lifecycle replacement of regulators on existing services. The forecasted annual capital spend is estimated based on management judgement and average historical spending.

The following Table provides the forecasted annual spend on Regulators from 2019 to 2024

Regulators Annual Program 2019-2024
($ dollars)

		A	B	C	D	E	F
		2019 Bridge Year	**2020 Test Year**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**
1	Regulators	$71,000	$73,000	$74,000	$76,000	$77,000	$79,000

6.1.3.6 Pipeline Markers Annual Program (2019 – 2024)

This program accounts for the purchase and replacement of pipeline markers for existing pipelines and new installations. The forecasted annual capital spend is estimated based on management judgement and average historical spending.

The following Table provides the forecasted annual spend on Pipeline Markers from 2019 to 2024.

Pipeline Markers Annual Program 2019-2024
($ dollars)

		A	B	C	D	E	F
		2019 Bridge Year	**2020 Test Year**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**
1	Pipeline Markers	$10,000	$10,000	$11,000	$11,000	$11,000	$11,000

Pipeline markers must be installed and maintained in keeping with the requirements of the Technical Standards and Safety Act and CSA Z662 Standard for Oil and Gas Pipeline Systems.

6.1.3.7 Fleet Annual Program (2019 – 2024)

This program accounts for the replacement of fleet, including light trucks and vans, medium-duty trucks and construction equipment. The estimated timing and annual capital spend is based on the age, anticipated odometer readings and historical or pending maintenance costs.

The following Table provides the forecasted annual spend on Fleet from 2019 to 2024.

Fleet Annual Program 2019-2024
($ dollars)

		A	B	C	D	E	F
		2019 Bridge Year	**2020 Test Year**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**
1	Fleet	$108,000	$47,000	$133,000	$49,000	$50,000	$51,000

ENGLP (Aylmer) plans to replace a medium-duty construction truck and fork truck in 2019, and a trailer used for hauling construction equipment in 2021. The remaining planned replacements are light service trucks and vans.

6.1.3.8 Small Tools and Equipment Annual Program (2019 – 2024)

This program accounts for the purchase and replacement of small tools and equipment, as required, including pipe fusion and pinch off tools, pipeline locate equipment, and gas monitors. The forecasted annual capital spend is estimated based on management judgement and average historical spending.

The following Table provides the forecasted annual spend on Small Tools and Equipment from 2019 to 2024.

Small Tools and Equipment Annual Program 2019-2024
($ dollars)

		A	B	C	D	E	F
		2019 Bridge Year	**2020 Test Year**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**
1	Small Tools and Equipment	$15,000	$16,000	$16,000	$16,000	$17,000	$17,000

6.1.3.9 Computers and Office Equipment Annual Program (2019 – 2024)

This program accounts for the purchase and replacement of computers, peripherals and office equipment. The forecasted annual capital spend is estimated based on management judgement and average historical spending.

The following Table provides the forecasted annual spend on Computers and Office Equipment from 2019 to 2024.

Computers and Office Equipment Annual Program 2019-2024
($ dollars)

		A	B	C	D	E	F
		2019 Bridge Year	**2020 Test Year**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**
1	Computers and Office Equipment	$10,000	$11,000	$11,000	$11,000	$11,000	$11,000

6.2 Operational Excellence

ENGLP (Aylmer's) key to success lies in building the value of its brand and reputation as a trusted and safe operator. Safe, reliable and consistent operational performance puts ENGLP (Aylmer) in good stead with its customers, regulators and new business clients. ENGLP (Aylmer) seeks cost efficiencies through growth, process improvement and the implementation of new technologies where appropriate. By doing so, ENGLP (Aylmer) is also able to remain cost competitive in an evolving market, where customers are now being presented with alternatives to traditional utility services. ENGLP (Aylmer's) operational priorities are summarized below:

6.2.1 Safety, Environment and Public Health

ENGLP (Aylmer) is committed to providing its employees and third party contractors with a safe and injury-free workplace by delivering its services in a manner that ensures both customer and public safety. Our customers have high expectations of safety and reliability and ENGLP (Aylmer) strives to meet and exceed those expectations on a daily basis. Public health, employee, contractor and public safety, and environmental stewardship are the foundation of everything the Utility does. The security of supply, treatment and delivery of natural gas in the communities we serve is primarily a public health role.

Further, commitment to workplace safety is an important part of the culture at ENGLP (Aylmer) and ENGLP (Aylmer) continues to work towards the goal of having a Total Recordable Injury Frequency Rate (a metric companies use to assess their safety performance)[3] below 1.0. To achieve this, ENGLP (Aylmer) is committed to delivering on a number of key initiatives, including completing the implementation of the musculoskeletal injury reduction program ("EPCOR Athletes") and mental health programs to support employee wellness. In addition, work will commence in 2019 to enhance worker competency training to support safe work practice compliance and understanding across ENGLP (Aylmer).

ENGLP (Aylmer) also provides engagement through industry and agricultural association memberships with respect to safety and construction practices while working in close proximity to gas distribution lines. In November 2018, ENGLP (Aylmer) published line strike educational article in the ORCGA directed to the Agriculture community in direct response to the increase in line strikes in 2018.

6.2.2 Cost Efficiency, Customer Service and Reliability

ENGLP (Aylmer) creates value for its customers through excellence in customer service, reliability and cost efficiency across its operations. Operational excellence includes achieving allowed returns on ENGLP (Aylmer's) rate regulated businesses through prudent cost control. In order to remain competitive and in good standing with regulators, continuous improvement of shared service costs which is a key costs in our various businesses is necessary. The Utility is focused on improving the efficiency of its operations while maintaining service quality. Management continually plays a key role in balancing costs to grow, improve and maintain the system against the impacts of these plans on customer rates.

ENGLP (Aylmer) focuses on high level of reliability through system-wide investments by ensuring that initiatives are targeted that would provide increased customer satisfaction levels. ENGLP (Aylmer) continues to focus on reducing its costs to demonstrate to customers that they are delivering as much value per dollar as possible to them. This includes striking the right balance in delivering initiatives, such as upgrades to the distribution system, all while improving customer engagement programs.

High levels of customer service are of prime importance to ENGLP (Aylmer). During business hours, the Utility's customer services personnel engage with customers by phone, email, facsimile,

[3] The Total Recordable Injury Frequency Rate is calculated by multiplying the number of recordable cases by 200,000, and then dividing that number by the number of labor hours at the company.

or in person at the ENGLP (Aylmer) administration office during non-business hours, inbound inquiries are managed by a call center for customers to report an emergency, inquire about services or billing questions.

In 2017, the ENGLP (Aylmer) billing system was modernized from the previous DOS-based billing system which was no longer supported and did not have the capabilities to adapt to market and regulatory changes. Modernizing the system was necessary to increase reliability and enhance cyber security measures to meet current security standards necessary to safely protect and retain customer data. Design options of the billing system will provide flexibility to meet future functionality for OEB programs or government initiatives such as the Green Button Initiative.

Further, the natural gas bill format was enhanced to provide additional consumption information to customers. The design now shows historical gas consumption via a bar graph intended to inform customers about their consumption patterns over a 12 month period. Also, customers have requested additional features from ENGLP (Aylmer) to access or receive bills electronically and expand on current available bill payment options to include credit card payment options. ENGLP (Aylmer) is pursuing options to provide e-billing and online web portal payment options to customers in 2019.

6.2.3 IT System

As a result of its review of NRG's existing IT systems, ENGLP implemented a number of necessary security and performance improvements in order to effectively protect utility and customer information. These included enhancements to threat detection and prevention, access control and general IT management. As a receiver of Corporate IT shared services, ENGLP will continue to have access to leading edge IT resources, with ongoing improvements to security and performance as necessary.

Enhancements to the legacy IT system include:

Area of Enhancement	Enhance Measures Include
Threat detection and prevention	Strengthening network security measures by adding additional firewalls, intrusion prevention and internet traffic scanning as well as increasing security at the desktop level.
Access control	Addressing password strength and computer configuration authorization and enrolling mobile phone devices into an enterprise mobile device management system.
General IT management	Accessing EPCOR's enterprise IT systems which are supported with disaster recovery plans.

6.2.4 Technology and Disruption

Management continues to evaluate and implement technological improvements as part of the business unit and corporate strategic planning processes. The use of technology in ENGLP (Aylmer) to improve reliability, safety and quality is continuing to evolve. The proposed capital plan includes investment in new technologies such as SCADA, GIS and workforce management that equip the utility with the tools necessary to strengthen its ability to operate its system in a safe, reliable and efficient manner.

ENGLP (Aylmer) continues to understand opportunities to exploit technology in order to drive performance improvements, leverage technological changes and adapt to and mitigate risks that emerge as a result of potential industry disruptors. Although utility technology generally has a long incubation period ENGLP (Aylmer) will position itself to adopt technology at the right time, and implement the appropriate solutions to remain competitive.

6.2.5 People

As an organization, ENGLP (Aylmer) focuses heavily on building a workforce that is engaged and skilled. The utility cares about its employees by ensuring a safe work environment, providing opportunities for personal growth and development, as well as fair wages and management practices. ENGLP (Aylmer) follows a compensation strategy and structure based on EPCOR's compensation philosophy, which targets the "mid-market" or 50th percentile of a defined peer group for total employee compensation. Moving forward, ENGLP (Aylmer) will continue to identify the key gaps between the talent in place and the talent required to drive business success.

In order to successfully have the right resources in place to execute its plan, ENGLP (Aylmer) must:

i. Be able to attract external talent by having competitive compensation, a strong employment brand and a system to retain external hires. This is particularly important as we look externally to fill specific skill gaps.
ii. Support the workforce, both existing and acquired, with tools to understand expectations, grow in their individual capacity as leaders and provide the supports required through wellness and other programs to ensure that they can function at a high level.
iii. Have a succession program in place for leaders and operational specialists and the necessary training and resources available to support their development.
iv. Constantly foster the ENGLP culture and continue to develop a highly productive and engaged workforce.

The overall ENGLP (Aylmer) people strategy can be summarized in the graphic below:

People			
Attract and retain the talent required to grow and operate our business	**Support a high performing workforce reflective of EPCOR's values**	**Develop and train employees for succession and operational needs**	**Continue to build a great culture and improve employee engagement**
Improve new employee onboarding	Integrate leadership competencies across the organization	Complete and sustain the employee assessment and development planning process	Implement the inclusion and diversity framework
Improve, integrate and promote employment brand	Support and promote employee wellness and supporting programs	Develop and implement a consistent approach for developing high potential employees	Improve employee recognition programs
	Improve the effectiveness of the EPCOR performance management program	Improve both leadership and competency training	
		Develop and support a professional growth program for front line employees	

7.0 Personnel Plan and Operational Structure

ENGLP (Aylmer) recognizes the importance of having a skilled workforce, where all employees are customer focused, engaged and proud to work for the Utility and in the community. As a result, ENGLP (Aylmer) continually reviews its operational and business goals against its workforce requirements, financial strength and impact on customers.

Currently, there are 17 employees that report directly to the General Manager. ENGLP (Aylmer) employees fit within the categories of Utility Services Manager (1), Coordinator, Sales and Emergency Field Support (1), Administrative and Field Supervisor (1), Senior Advisor (1), System Technicians (2), Service Technicians (3), Construction Crew (2), and Administration (6). Further, ENGLP (Aylmer) also relies on third party consultants and contractors for the maintenance of the distribution system and assistance with meeting regulatory requirements.

ENGLP (Aylmer) recognizes the importance of cross-training its employees as the cornerstone for running an efficient utility business. As a result, ENGLP (Aylmer) focuses on cross-training its employees to fill in gaps for others when needed. Cross-training of employees promotes teamwork, increases employee morale and provides improved customer service by allowing one team member to step in and resolve issues when another employee is either away or unavailable.

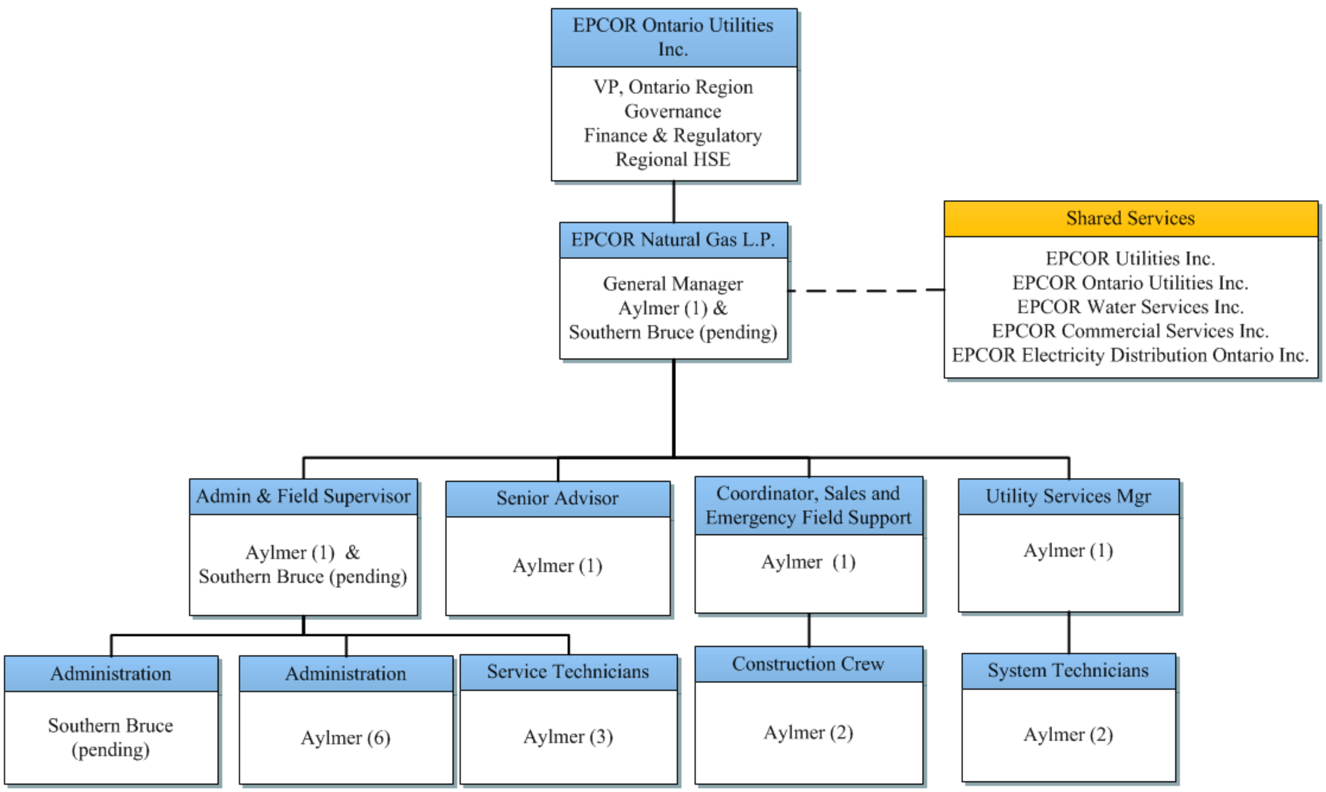
Further, ENGLP (Aylmer) plans to strengthen its regulatory skillset to increase its effectiveness with the Board. The Utility will continue ensure adequate resources and processes are in place to protect the interests of its natural gas customers and that the Utility provides energy at a reasonable cost. Strengthening the regulatory skillset will help assess different approaches used by the utility in recovering its costs and also ensures that engaging the regulatory process is handled in the most effective manner possible.

One of the advantages for ENGLP (Aylmer) is that it can leverage and access expertise across EPCOR's entities through a shared services model. As a member of the EPCOR group of corporations, ENGLP (Aylmer) has structured its business operations to reasonably and prudently take advantage of economies of scale and scope through the appropriate use of corporate and affiliate services. As such, ENGLP (Aylmer) receives certain shared services from and provides certain services to, other members of the EPCOR group.

ENGLP (Aylmer) receives shared services from its parent EPCOR (Corporate Shared Services) and EPCOR affiliates: EPCOR Water Services Inc., EPCOR Commercial Services Inc., EPCOR Electricity Distribution Ontario Inc., and EPCOR Ontario Utilities Inc. E NGLP (Aylmer) will provide services to ENGLP (Southern Bruce) when the system receives all the necessary approvals. The services that ENGLP (Aylmer) receives are governed through Service Level Agreements (SLA) between ENGLP (Aylmer) and each EPCOR entity. ENGLP (Aylmer) only receives and only pays for the services it requires to operate the utility. The delivery of these services using the shared services model approach achieves economies of scale benefits and cost efficiencies for ENGLP (Aylmer).

The chart below details the organizational chart for ENGLP (Aylmer) business unit and the shared services it will be accessing. This chart includes the sharing of two positions (General Manger and Admin & Field Supervisor) with the Southern Bruce operation. The costs detailed in this Application include the charging of these costs to the Southern Bruce utility through offsets in OM&A. The Administrative (Southern Bruce) position reporting to the Admin & Field Supervisor will be a new full time Southern Bruce employee funded by the Southern Bruce utility and is expected to be located in Kincardine.

Organizational Chart for ENGLP



8.0 Financial Information

8.1 Capital and Operational Costs Summary

ENGLP's 2018 Forecast, 2019 Bridge Year and 2020 Test Year and previous years' OM&A costs are shown in the table below. The year-over-year changes in the costs are shown and the table identifies what portion of each year-over-year change is due by expense category.

Summary of OM&A 2011-2020
($ thousands)

	Expense Category	A Board Approved	B 2011 A	C 2012 A	D 2013 A	E 2014 A	F 2015 A	G 2016 A	H 2017 A[1]	I 2018 F[2]	J 2019 Bridge Year	K 2020 Test Year
1	WFP and Employee Compensation	1,219,057	995,870	1,343,213	1,335,700	1,376,847	1,441,024	1,561,365	1,336,675	1,217,748	1,255,343	1,432,123
2	Operating Support Costs[3,4]	1,410,151	1,605,933	1,601,662	1,744,912	2,291,503	1,694,557	1,924,583	2,142,674	2,014,078	1,113,508	1,026,274
3	Shared Services and Corporate Cost Allocation	-	-	-	-	-	-	-	-	883,592	868,724	892,722
4	Low Income Program	-	-	-	-	-	-	-	-	6,582	6,582	7,983
5	**Total[5]**	**2,629,208**	**2,601,803**	**2,944,875**	**3,080,612**	**3,668,350**	**3,135,581**	**3,485,948**	**3,479,349**	**4,122,001**	**3,244,157**	**3,359,102**

[1] 2017 Actual based on a fiscal period of October 1, 2016 to September 30, 2017.
[2] 2018. 2019 and 2020 Forecast based on a fiscal period of January 1 to December 31.
[3] One Time costs are reflected within Operating Support Costs under regulatory.
[4] Non-Affiliate costs are reflected within Operating Support Costs.
[5] Excluded from the total OM&A costs for 2018, 2019 and 2020 are the amounts associated with the system gas fee as these amounts are removed from the OM&A costs for the purposes of determining the distribution revenue requirement. The costs removed are $11,012, $11,196 and $11,501 respectively.

On an overall basis, ENGLP's OM&A levels have been on a slight increasing trend since the previous owner NRG's last OEB Approved amount (EB-2010-0018). ENGLP cannot speak definitively about the costs from 2011 to 2017 as NRG was the owner at that timeframe.

8.2 Rate Base

The rate base at the end of 2020 Test Year is projected to be $16.69 million. The projected rate base is calculated as the utility's average in-service gross fixed assets and offset by the accumulated depreciation of those fixed assets. ENGLP uses the half-year rule for calculating the average in-service fixed assets for the test year.

The table below summarizes the historical, 2019 Bridge and 2020 Test Year rate base for ENGLP. The rate base is broken down by gross plant, accumulated depreciation and working capital. ENGLP notes that it is proposing to not include working capital in its rate base for 2017 to 2020.

Summary of Historical and Projected Aylmer Rate Base
($ thousands)

		A	B	C	D	E	F	G	H	I	J	K	L
		2011 OEB Approved	**2011 A**	**2012 A**	**2013 A**	**2014 A**	**2015 A**	**2016 A**	**2017 A**	**2017 Stub**	**2018 F**	**2019 B**	**2020 T**
1	Property, Plant & Equipment's*												
2	Gross Asset Value	24,204.3	23,564.6	24,123.2	24,760.9	25,543.7	24,852.2	24,999.8	26,664.2	27,292.7	28,583.9	31,730.5	33,876.3
3	Accumulated Depreciation	(10,639.9)	(10,016.0)	(10,797.0)	(11,503.7)	(12,391.7)	(12,627.4)	(12,723.8)	(13,566.5)	(14,229.5)	(14,888.7)	(16,059.9)	(16,798.2)
4	Net Book Value (Mid-year)	13,564.4	13,548.7	13,326.2	13,257.2	13,152.0	12,224.7	12,276.0	13,097.7	13,063.2	13,695.2	15,670.6	17,078.1
5													
6	less: Contributions												
7	Gross Asset Value	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(6.6)	(65.7)	(417.2)	(752.2)
8	Accumulated Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.4	12.4	29.9
9	Net Book Value (Mid-year)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(6.5)	(64.3)	(404.8)	(722.3)
10													
11	add: Allowance for Working Capital												
12	Inventory	145.1	120.2	137.7	128.2	100.4	112.8	56.4	0.0	0.0	0.0	0.0	0.0
13	Working Cash Allowance	(101.4)	53.8	79.7	70.9	39.4	59.6	81.9	0.0	0.0	0.0	0.0	0.0
14	Security Deposits	(176.1)	(160.5)	(150.8)	(137.9)	(130.1)	(139.2)	(134.3)	0.0	0.0	0.0	0.0	0.0
15	Working Cash Allowance	(132.4)	13.5	66.5	61.2	9.7	33.3	3.9	0.0	0.0	0.0	0.0	0.0
16													
17	Other Adjustment to Rate Base	253.0											
18													
19	Utility Rate Base (Mid-year)	13,685.0	13,562.1	13,392.8	13,318.4	13,161.6	12,258.0	12,279.9	13,097.7	13,056.7	13,631.0	15,265.8	16,355.8
20													
21	Change from year to year ($)			(169.4)	(74.4)	(156.8)	(903.6)	21.9	839.7	776.8	574.3	1,634.8	1,090.0
22	Change from year to year (%)			-1.25%	-0.56%	-1.18%	-6.87%	0.18%	6.85%	6.33%	4.40%	11.99%	7.14%

8.3 Pro-forma Financial Statements ($ thousands)

		A 2018	B 2019	C 2020
1	**Income Statement**			
2				
3	Commodity Revenue	4,296	4,663	4,748
4	Commodity Cost	-4,298	-4,665	-4,748
5	Commodity Margin	-1	-2	0
6				
7	Distribution Revenue	7,235	7,079	6,674
8	Other Revenue	120	113	113
9	Distribution OM&A	-5,092	-3,919	-4,056
10	Property Taxes	-573	-605	-632
11	EBITDA	1,688	2,666	2,099
12				
13	Net Depreciation and Amortization	-1,152	-1,271	-1,136
14	Interest Expense	-380	-384	-408
15	Current Income Tax	0	-170	-5
16	Future Income Tax	-47	-98	-99
17	Gain / Loss on Disposal	22	0	-162
18	Net Income	131	743	288
19				
20	**Balance Sheet**			
21				
22	Cash	-475	0	0
23	Other Current Assets	2,544	2,544	2,544
24	CWIP	176	0	0
25	PP&E and Intangibles	14,312	17,029	17,127
26	Goodwill	7,838	7,838	7,838
27	Total Assets	24,395	27,411	27,508
28				
29	ST Debt	1,055	2,651	1,306
30	Other Current Liabilities	1,265	1,265	1,265
31	LT Debt	8,660	8,660	9,658
32	Contributions	115	694	750
33	Deferred Tax Liability	47	145	245
34	Total Liabilities	11,142	13,415	13,224
35				
36	Share Capital	13,360	13,360	13,360
37	Retained Earnings	-107	636	925
38	Total Equities	13,253	13,996	14,284
39				
40	**Statement of Cash Flows**			
41				
42	EBITDA	1,688	2,666	2,099
43	Interest Expense	-380	-384	-408
44	Current Income Tax	0	-170	-5
45	less: Increase in Other Current Assets	0	0	0
46	add: Increase in Other Current Liabilities	0	0	0
47	Cash from Operating Activities	1,308	2,113	1,686
48				
49	Capital Expenditure	-2,092	-3,234	-1,340
50	Cash from Investing Activities	-2,092	-3,234	-1,340
51				
52	Borrowing	0	1,596	998
53	Repayment	-2,098	0	-1,345
54	Dividend Paid	0	0	0
55	Cash from Financing Activities	-2,098	1,596	-346
56				
57	Net Change in Cash	-2,883	475	0

SNC·LAVALIN OIL & GAS BUSINESS UNIT	NATURAL RESOURCE GAS LIMITED Transient Simulations of the NRG Distribution System Report	Page 1 of 34 Revision No.: A
		Date: March, 2016

INSTRUCTION TO DOCUMENT CONTROL

- [ ] Entire specification revised. Reissue all pages.
- [ ] Reissue revised pages only.

STAMP THE SPECIFICATION AS FOLLOWS:

- [X] Issued for review and comments
- [ ] Issued for quotation
- [ ] Issued for purchase
- [ ] Issued for fabrication (equipment specs only)
- [ ] Issued for construction (installation specs only)
- [ ] Issued for design

TECHNICAL REPORT REVISION INDEX

Revision					Pages Revised	Remarks
No.	Prepared By/ Date	Checked By/ Date	Project Approved/ Date	Client Approved/ Date		
A	John Orr Mar. 2016	Alex Huddleston Mar, 2016	Alex Huddleston Mar, 2016			

TABLE OF CONTENTS

NOTICE

This document contains the expression of the professional opinion of SNC-Lavalin Inc. ("SNC-Lavalin") as to the matters set out herein, using its professional judgment and reasonable care. It is to be read in the context of the Services Agreement Dated May 22, 2014 (the "Agreement") between SNC-Lavalin and Natural Gas Resources Limited (the "Company"), and the methodology, procedures and techniques used, SNC-Lavalin's assumptions, and the circumstances and constraints under which its mandate was performed. This document is written solely for the purpose stated in the Agreement, and for the sole and exclusive benefit of the Company, whose remedies are limited to those set out in the Agreement. This document is meant to be read as a whole, and sections or parts thereof should thus not be read or relied upon out of context.

SNC-Lavalin has, in preparing this report, followed methodology and procedures, and exercised due care consistent with the intended level of accuracy, using its professional judgment and reasonable care. Unless expressly stated otherwise, assumptions, data and information supplied by, or gathered from other sources (including the Company, other contractors, testing laboratories and equipment suppliers, etc.) upon which SNC-Lavalin's opinion as set out herein is based has not been verified by SNC-Lavalin; SNC-Lavalin makes no representation as to its accuracy and disclaims all liability with respect thereto.

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1. INTRODUCTION

Natural Resource Gas Limited (NRG) own and operate a gas distribution system (NRG System) in Ontario. NRG's franchise area is located south-east of London and includes the towns of Aylmer, Belmont, Brownsville, Port Burwell, Springfield, Straffordville, and Vienna. A map showing the NRG System and the NRG franchise area is attached in Appendix A.

Gas is supplied into the NRG System from Union Gas Limited (UGL) at 7 different locations: Belmont Station, Harrietsville Station, Brownsville Station, Bayham Station, Eden Station, and North Walsingham Station. Gas is also supplied from gas wells owned by the NRG Gas Corporation (NRG Gas Corp wells), located in the NRG franchise area.

The gas demands in the NRG System are mainly for residential heating, small industrial customers, and grain drying. The residential heating demand peaks during the winter months, the small industrial customers include heating which means that they peak in the winter, while the grain drying demand usually occurs in autumn or winter, but can occur at any time during the year.

NRG are currently experiencing periods of very high gas demand, usually on cold days when grain drying is under way, where gas pressure gets very low in certain parts of the system. NRG want to determine if there are viable, cost effective alternatives to the purchase of natural gas from their current suppliers to maintain adequate system pressures and volumes required to meet this seasonal demand. Alternatives could include: looping existing pipelines in the system, adding new pipelines to the system, modifications to UGL interconnects, and connections to new gas wells.

NRG have contracted SNC-Lavalin Inc. (SNC-Lavalin) to study NRG's existing gas distribution system and recommend viable solutions to meet NRG's requirements. This report contains the results of the study.

2. OBJECTIVES AND SCOPE

SNC-Lavalin used the following steps to complete the study:

- Build a model of the NRG System in DNV-GL's transient hydraulic pipeline simulation tool, the Synergi Pipeline Simulator (SPS).
- Simulate the NRG System using actual data. Winter residential data will be used when grain drying is also underway to simulate the highest gas demand in the system.
- Benchmark the simulation to confirm that the model matches actual NRG System performance.
- Test various solutions to alleviate low pressure conditions in the NRG System.
- In concert with NRG select the optimum solution taking NRG's judgments on constructability, and cost into account

- Test the optimum scenario by increasing gas demand in the NRG System

3. INPUT DATA AND ASSUMPTIONS

A cold front moved into the NRG franchise area on November 12th, 2014 dropping temperatures by about 20°C over a short period of time and creating a large gas demand from residential customers. In conjunction with this, grain drying was occurring at various farms within the NRG franchise area. NRG noted that gas pressures in the system during this time period were very low.

NRG has provided data from November 12th, 2014 to be used as input to the SPS model to simulate the highest gas demand case. In the tables of input data below, data from November 12th, 2014 is identified as "Actual Data". Pipeline pressures at various locations in the NRG System that were used to benchmark the model are contained in section 3.6.

The data for the study was collected from the documents provided by NRG. Each document has been attached in Appendix B for reference. Appendix B contains the following:

- General Transient Analysis Data Requirements
- Pipe specification
- E-mail containing input data
- Direct Purchase Twelve Month Volume Report of November 21st, 2014
- Gas pressure at all measured locations on November 12th, 2014
- E-mail containing input data
- E-mail containing input data
- Gas flow rates on November 12th, 2014
- E-mail containing input data
- Contracted labour and material costs for SW Ontario Market
- Base Map of NRG system. Note that the CAD drawing contains additional details of customer connections
- Town Maps for Aylmer, Belmont, Brownsville, Port Burwell, Springfield, Straffordville, and Vienna

The NRG model was separated into two parts:

- Belmont — Belmont Station and the Northern portion of the town of Belmont
- Main System — The southern portion of the town of Belmont and the remainder of the NRG System

This report focuses on the main system which was affected by the November 12th, 2014 cold front while the Belmont section of the system was not significantly affected by the cold front.

SNC-Lavalin has used their previous experience and best judgement to assume typical values for any data required by the SPS model that NRG was unable to provide. This data is marked as "Assumed" below.

3.1. FLUID PROPERTIES

Typical natural gas composition for the NRG System is shown in Table 3.1-1.

Table 3.1-1 The NRG Gas Composition

Component	% Mole
C_1	94.85
C_2	3.40
C_3	0.16
C_4	0.04
C_5	0.01
C_6+	0.01
N_2	0.80
CO_2	0.69
O_2	0.01
H_2	0.03
Total	100.00

3.2. PIPELINE PHYSICAL DATA & SOIL PROPERTIES

The applicable pipeline physical data for this study were collected from the documents provided by NRG (see Appendix B). The pipes are made of Medium Density Polyethylene (MDPE). The pipe physical data and the soil properties are shown in Table 3.2-1.

Table 3.2-1 Pipeline Physical Data and Soil Properties

Description	Parameter
Maximum Allowable Operating Pressure (Winter)	80 psig
Assumed Ground Temperature (Winter)	0.0 °C
Assumed Pipe Depth of Burial	20 in
Assumed Pipe Roughness	0.005 mm
Assumed Pipe Thermal Conductivity	0.398 W/m°C
Assumed Pipe Heat Capacity	2.35 KJ/Kg°C

Description	Parameter
Pipe Density	939 Kg/m^3
Assumed Winter Soil Thermal Conductivity	0.5 W/m°C

Pipe wall thickness is different depending on the pipe size used in the gas network. The pipe nominal sizes and wall thicknesses are presented in Table 3.2-2.

Table 3.2-2 Nominal Pipe Sizes and Wall Thicknesses Used in the Model

Nominal Size (Inches)	Wall Thickness (Inches)
6	0.576
4	0.391
3	0.304
2	0.216
1 ¼	0.166
1	0.120

3.3. VALVE DATA

The valve flow coefficients (Cv) for the block valves have been summarized in Table 3.3-1. Typical valve data for the block valves were assumed based on previous experience.

Table 3.3-1 Block Valve Data

Valve Size (NPS)	Valve Type	Fully Open Valve Coefficient - Cv (USGPM/psi0.5)	Cv Opening and Closing Curve
6	Gate	2020	Linear
4	Gate	850	Linear
3	Gate	500	Linear
2	Gate	165	Linear

There are a number of valve stations in the NRG System. The locations of these valve stations are shown in Figures 3.3-1 to 3.3-6.

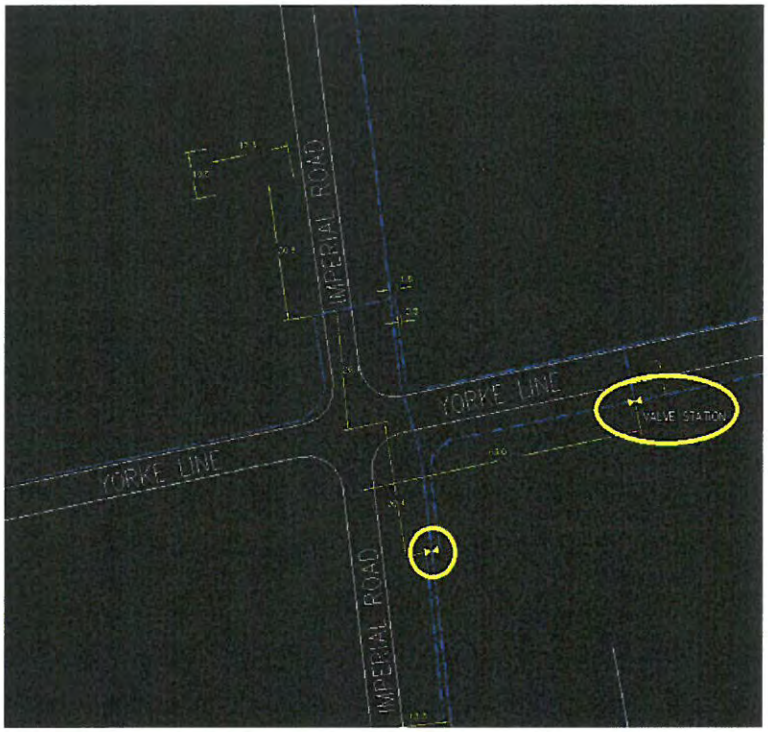


Figure 3.3-1 The Imperial Road and York Line Valve Stations

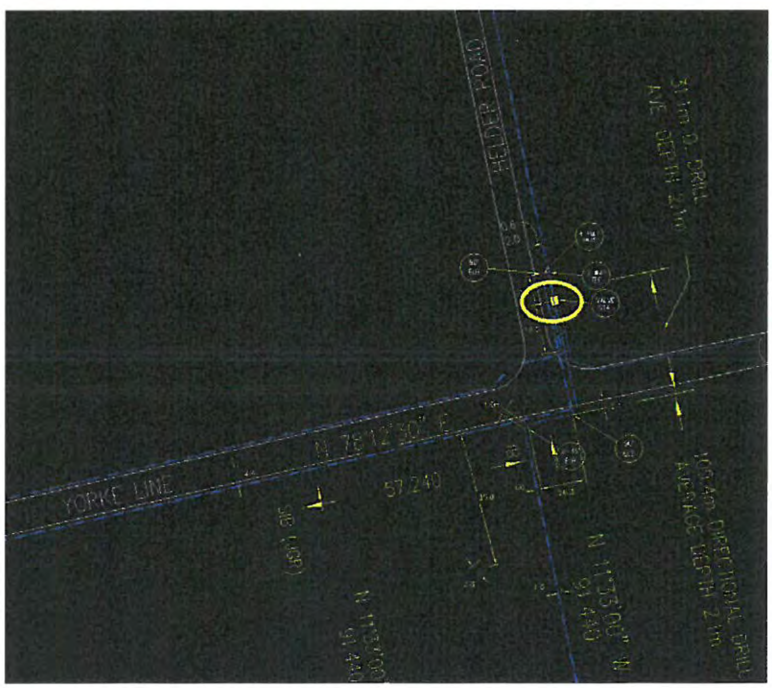


Figure 3.3-2 The Helder Road Valve Station

Figure 3.3-3 The Whittaker Road Valve Station

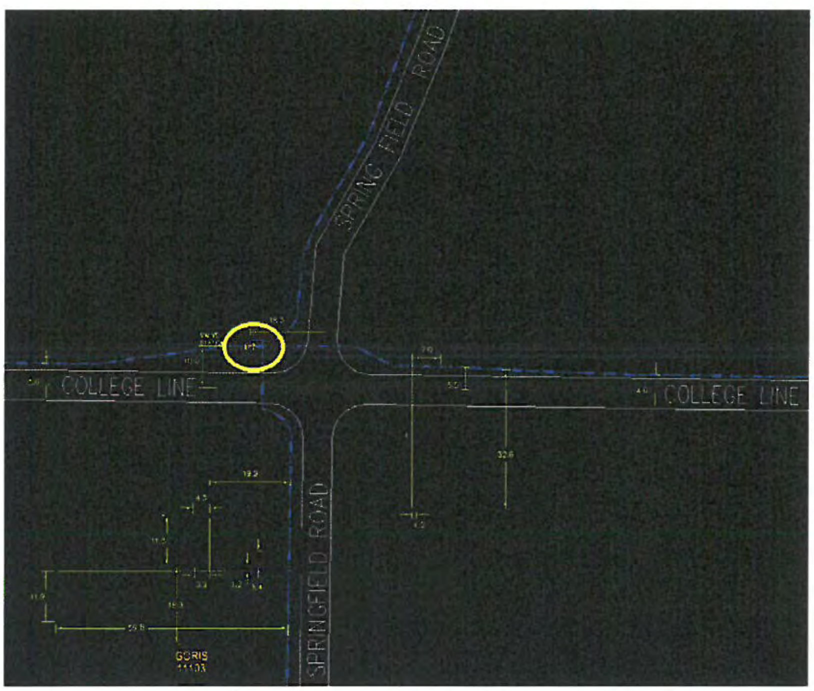


Figure 3.3-4 The Springfield Road Valve Station

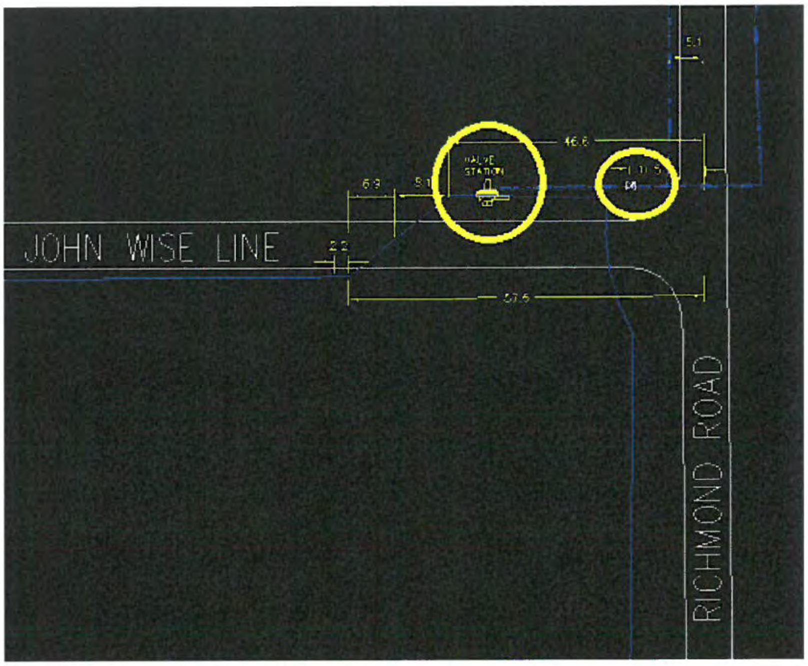


Figure 3.3-5 The Richmond Road Valve Station

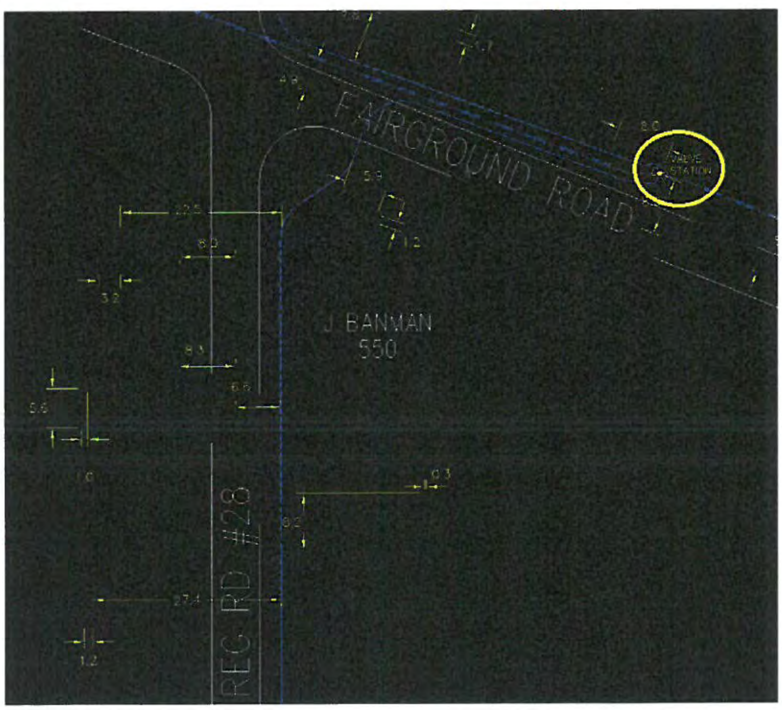


Figure 3.3-6 The Fairground Road Valve Station

3.4. GAS REGULATOR DATA

The datasheets for the gas regulators were not available; therefore, the required data is based on a typical control valve Cv for the corresponding valve size. The assumed gas regulator data is presented in Table 3.4-1.

Table 3.4-1 Gas Regulator Data

Regulator Location	Regulator Size (NPS)	Fully Open Valve Coefficient - Cv (USGPM/psi0.5)	Cv vs Stem Position Curve	Upstream Pressure Set-Point (psig)	Downstream Pressure Set-Point (psig)
Belmont North	2	30.1	Equal Percentage	33	-
Belmont South	3	40	Equal Percentage	78	-
Brown NovaScotia	4	50.1	Equal Percentage	-	30
Culloden	2	30.1	Equal Percentage	38	-
Glencolin	4	50.1	Equal Percentage	65	-
Hacienda Talbot	4	50.1	Equal Percentage	-	52
Aylmer North	4	50.1	Equal Percentage	65	
Brownsville North	2	30.1	Equal Percentage	-	30
Imperial	4	50.1	Equal Percentage	-	28
Port Bruce	4	50.1	Equal Percentage	-	30
Rogers Mushroom	2	30.1	Equal Percentage	-	30
Talbot	2	30.1	Equal Percentage	42	-
Vienna Tunnel	2	30.1	Equal Percentage	-	30

3.5. OPERATING DATA

There are seven UGL Stations that supply natural gas into the NRG System. The flow rate on November 12th, 2014, for each station is shown in Table 3.5-1.

Table 3.5-1 Supply Parameters

Supply	Supply Pressure (psig)	Flow Rate (m^3/hr)
Bayham Station	79	1207
Belmont Station	Assumed 80	521
Brownsville Station	Assumed 50	49
Eden Station	83	1167
Harrietsville Station	89	3621
North Walsingham Station	83	997
Putnam Station	81	1604

The gas wells in the NRG franchise area have been added together based on location and included in the model in 3 groups. The well group locations and flow rate on November 12th, 2014, are shown in Table 3.5-2.

Table 3.5-2 Gas Well Group Locations

Well Group	Location	Actual Flow Rate (m^3/hr)
1	On 2nd Concession Rd north of Barth Side Rd	78
2	Fairground Rd and Regional Rd #28	204
3	Nova Scotia Line Between Richmond Rd and Woodworth Rd	204

Note that the gas well groups are referred to in this report using a "group name" as shown in Table 3.5-3.

Table 3.5-3 Gas Well Group Names

Gas Well Group Location	Group Name
On 2nd Concession Rd north of Barth Side Rd	2nd Concession
Fairground Rd and Regional Rd #28	Fairground
Nova Scotia Line Between Richmond Rd and Woodworth Rd	Scotia Line

There are 9 towns in the NRG franchise area that form the major residential deliveries. In addition, there are many farms outside these towns that consume a significant portion of the gas flow. The following assumptions were made to estimate the flows to each customer:

- The average annual dwelling consumption is 2400 m^3
- The distribution of dwellings between each town was determined by a manual count of dwellings on each town map.

- The average dwelling consumption was increased to account for dwellings not counted on the map.
- Farm consumption for grain drying or other activities is determined based on the corresponding flow rate that achieves the pressure benchmark data.
- Pressure benchmark data are assumed to occur simultaneously.

The number of dwellings within each large town was estimated by NRG and is shown in Table 3.5-4.

Table 3.5-4 Number of Dwellings in each Town

Town	Number of Dwellings
Aylmer	2030
Belmont	555
Brownsville	150
Nilestown	100
Port Burwell	319
Port Bruce	150
Springfield	235
Straffordville	150
Vienna	150

3.6. BENCHMARK DATA

Actual supply pressures and locations for the high flow rate day November 12th, 2014 are shown in Table 3.6-1. Pressures provided are assumed to be gauge pressure.

Table 3.6-1 Benchmark Pressures

Location	Actual Pressure (psig)	Type
North Walsingham	83	UGL Input
New England	79	UGL Input
Putnam Station	81	UGL Input
Harrietsville Station	89	UGL Input
Ridge Rd	83	UGL Input
Rogers Rd and Talbot Ln	42	Feeding town of Aylmer
Hacienda Rd and Talbot Ln	52	Feeding town of Aylmer
John St South at Bradley Creek	51	Feeding town of Aylmer
Beech St	65	Feeding town of Aylmer
Belmont South	78	Feeding town of Belmont
Belmont North	33	Feeding town of Belmont
Port Bruce	53	Feeding town of Port Bruce
Brownsville South	38	Feeding town of Brownsville
Vanmoerkerke	63	Customer

Location	Actual Pressure (psig)	Type
YPMA	9	Customer
Sylvite Avon	55	Customer
FS Partners Straffordville	54	Customer
Klassen Farms	55	Customer
Kingsmill Grain	21	Customer
Graydon Farms	33	Customer
Isaak Bartsch	59	Customer
Best Line Farms	35	Customer
Herman	74	Check Point
Doerksen	60	Check Point
Whittaker Rd and Yorke Ln	79	Check Point

3.7. SEED FLOW RATES

The flow rates in Table 3.7-1 were input into the SPS model and used as an initial seed to help the model get to steady state conditions faster. These flow rates were the highest flow rates seen in NRG's Direct Purchase Twelve Month Volume Report of November 21st, 2014. Town flow rates were increased by the number of dwellings in that town. These flow rates were modified as required to match flow rates shown in Tables 3.5-1 and 3.5-2 and the gas pressures in Table 3.6-1 above.

Table 3.7-1 Seed Flow Rates

Location	Flow Rate (m^3/hr)
Aylmer	480
Belmont	130
Brownsville	23
Nilestown	15
Port Burwell	73
Port Bruce	34
Springfield	54
Straffordville	23
Vienna	23

3.8. ASSUMPTIONS

The following assumptions were made to complete this study.

1) All the existing valves in the system are open at all times during normal operation.
2) The consumption of residential and industrial gas take-offs is known and the delivery pressure is calculated by SPS.
3) The "Dedicated 6" Line – IGPC", shown on the NRG System Map, is not included in the NRG System.
4) There are no significant elevation differences in the NRG franchise area.
5) The benchmark pressure data occurs simultaneously.
6) The maximum discharge pressure to the system from the UGL Stations is limited to 80 psig so that it does not exceed the MAOP of the line.
7) Gas demand from dwellings not accounted for the in the town maps are included in other take-offs across the network.
8) All known grain drying farms are assumed to be operational and draw gas at a rate dictated by their corresponding inlet pressures on the high flow day of November 12th, 2014.

4. CALCULATIONS AND METHODOLOGY

The hydraulic calculations were conducted using SPS by DNV-GL, Version 10.0. SPS is a network modeling software package designed for the analysis of steady-state and transient pipeline operation.

The gas flow rates in Tables 3.5-1 and 3.5-2 and the gas pressures in Table 3.6-1 were input into the SPS model. SPS then calculated a flow rate for all gas customers in the system and resolved to a steady state.

Once a steady state for November 12th, 2014 had been achieved, SPS calculated flow rates were used as inputs to the model and gas pressures were calculated by SPS.

The working model contains a gas take-off flow rate for each customer and a gas input flow rate for each UGL station and the gas well groups.

5. BENCHMARKING RESULTS

The results of the benchmarking using data for November 12th, 2014 are shown graphically on the Benchmark Results Schematic in Appendix C. Note that the layout of the NRG System on the Benchmark Results Schematic (and all of the other schematics included in this report) is a very close approximation of the NRG System Map, but not an exact match.

Please also note that the loops and pipeline extensions that were tested during the course of this study are also shown on all of the schematics. Each of the loops or extensions has block valves that are used to isolate the pipe. In most cases, the block valves are closed and the additional pipe is not included in the simulation. When the loop or extension is in operation, the block valves are open and the loop or extension has been circled on the schematic.

Color is used to denote gas pressures calculated by SPS on the schematic. Darker colors (black, blue, and purple) denote areas of higher pressure (>= 50 psi), green denotes the mid-point pressure (>= 40 psi < 50 psi) while lighter colors (yellow and red) denote areas of lower pressure (< 40 psi).

On the schematic, lower pressure areas are noted around Brownsville and in the Southwest quadrant of the NRG franchise area. NRG reviewed these results and confirmed that they were a close match to the actual results that are seen in their franchise area during high gas demand days.

A comparison of the actual pressures from November 12th, 2014 and the pressures calculated by SPS is shown in Table 5-1. The difference between the actual and calculated pressures is also shown in the table.

Table 5-1 Actual and Calculated Pressures

Location	Actual Pressure (psig)	Calculated Pressure (psig)	Pressure Differential (psi)
North Walsingham	83	77	6
Bayham	79	79	0
Putnam Station	81	81	0
Harrietsville Station	89	83	6
Eden	83	75	8
Rogers Road and Talbot Line	42	34	8
Hacienda Road and Talbot Line	52	48	4
John St S at Bradley Creek	51	47	4
Beech St	65	64	1
Belmont South	78	78	0
Port Bruce	53	53	0
Brownsville South	38	38	0
Vanmoerkerke	63	63	0
YPMA	9	11	2
Sylvite Avon	55	55	0
FS Partners Straffordville	54	54	0
Klassen Farms	55	55	0
Kingsmill Grain	21	21	0
Graydon Farms	33	33	0
Isaak Bartsch	59	59	0
Best Line Farms	35	35	0

Location	Actual Pressure (psig)	Calculated Pressure (psig)	Pressure Differential (psi)
Herman	74	74	0
Doerksen	60	59	1
Whittaker Road and Yorke Line	79	72	7

The differences in pressure between the actual pressure and the pressure calculated by SPS are small enough that the model can be deemed to match the system during the high demand day of November 12th, 2014.

To match the gas pressures in the NRG System as shown above, SNC-Lavalin modified the "seed" flow rates as shown in Table 5-2.

Table 5-2 Modified Seed Flow Rates

Location	Modified Flow Rate (m^3/hr)	% Increase over previous estimate
Aylmer	1750	265%
Brownsville	70	200%
Port Burwell	162	120%
Port Bruce	0≠	N/A
Springfield	146	170%
Straffordville	74	220%
Vienna	47	100%

≠ Pressures at the town gate for Port Burwell are lower than the required pressure so the flow rate is listed as zero (0).

6. IMPROVING SYSTEM INTEGRITY

The model shown in the Benchmark Results Schematic was deemed the baseline model and used as the starting point for further study. This baseline model was modified to attempt to alleviate the low pressure areas in the southwest and around Brownsville. Modifications that were considered to the system configuration included:

- Looping existing pipelines in the system
- Adding new pipelines to the system
- Modifications to UGL interconnects
- Increasing flow rates from gas wells

The Benchmark Results Schematic was analysed to determine areas of high pressure that could be easily connected to lower pressure areas. Doing so would better use the existing system capacity.

6.1. LOOPS AND LINE EXTENSIONS

Loops and extensions to existing lines were added to the NRG System to attempt to move gas from the higher pressure areas into the lower pressure areas. The following loops and extensions were added to the system and will be further discussed below:

- John Wise Line Loop
- Glencolin Line Extension
- Wilson Line Extension
- Talbot Line Extension

In addition to the loops and line extensions above, the following were considered and rejected as having no benefit or less benefit than the above. These loops and extensions will not be discussed further in this report:

- Carlton line extension from Bogus Road to Richmond Road
- Elgin Country Road extension from Jackson Line to Light Line
- Hacienda Road extension from Glencolin Road to Dingle Line
- Pigram Line Extension from Avon Drive to Wilson Line
- Loop of line to high demand gas customer in Kingsmill
- Loop of pipe to YPMA
- Springwater Road extension from just north of Brouwers Line to Conservation Line
- Springwater Road extension from just north of Brouwers Line to John Wise Line
- Lyons Line/Brownsville Road extension from Lyons Line at Putnam Road to Pigram Line then along Brownsville Road

6.1.1. JOHN WISE LINE LOOP

The John Wise Line pipe was looped between Imperial Road and Springfield Road to try and move gas into the south-west quadrant of the NRG system. An NPS 3 loop was added of approximately 4070 m in length.

Adding the John Wise Line loop had negligible impact on system. Pressures were somewhat higher around Aylmer, but still low throughout the south-west quadrant. In general, the average pressure at pipeline intersections was constant and with no area having an increase of more than 2 psi. The result of this simulation is shown in Appendix D.

Looping the John Wise Line pipe had an insignificant effect on the NRG system.

6.1.2. GLENCOLIN LINE EXTENSION

The Glencolin Line pipe was extended from Glencolin Line, approximately midway between Imperial Road and Rogers Road, to Springwater Road to try and move gas into the south-west quadrant of the NRG system. An NPS 4 pipeline was added of approximately 3500 m in length.

Extending the Glencolin Line had a significant impact on the system. Higher pressures were seen in the south and south-west quadrants of the system. Pressures west of Aylmer increased by approximately 10 psig and pressure in the south-west quadrant increased significantly. The result of this simulation is shown in Appendix D.

6.1.3. WILSON LINE EXTENSION

The Wilson Line pipe was extended from Putnam Road to Whitaker Road to try and increase gas flow into the Brownsville area. An NPS 3 pipeline was added of approximately 500 m in length.

Extending the Wilson Line did not have a significant impact on the system. Gas flow into the Brownsville area is limited by the pressure regulator on Ostrander Road near Pigram Line that is set to 30 psig and the check valve on Culloden Line near Keswick Road that doesn't allow gas flow to the north. The result of this simulation is shown in Appendix D.

Increasing the set pressure of the pressure regulator to 50 psig, in addition to extending the pipe along the Wilson Line, increases pressures in the Brownsville area above 30 psig. The result of this simulation is shown in Appendix D. However, increasing the set pressure of the Ostrander Road pressure regulator will most likely require that a large number of pressure regulators be installed at individual take-offs further downstream.

Adding a loop to the Ostrander Road pipeline, in addition to extending the pipe along the Wilson Line, helps to alleviate the low pressures areas around Brownsville. The pressures in the Brownsville area increase to just less than 30 psig, with the gas pressure of the high demand gas customer on Culloden Line increasing to 27 psig. And of course, increasing the set pressure of pressure regulator as well as adding the Ostrander Road Loop increases the downstream pressures to slightly higher than 30 psig.

6.1.4. TALBOT LINE EXTENSION

The Talbot Line pipe was extended from Culloden Road to just past Springer Hill Road to try and move gas into the south-west quadrant of the NRG system. An NPS 4 pipeline was added of approximately 4500 m in length.

Extending the Talbot Line did have an impact on the eastern part of the southwest quadrant of the NRG system. System pressures in that section of the line were increased by approximately 10 psig. However, the system pressures around Alymer were not significantly affected. The result of this simulation is shown in Appendix D.

6.2. INCREASING GAS FLOW FROM UGL STATIONS

Increasing gas flow rates from the UGL stations could transport additional gas into the south and around Brownsville. Increasing the flow limits of Eden and Brownsville Stations, and increasing the pressure at the Bayham Station to 80 psig increased average system pressures by 0.8 psi with some customers experiencing delivery pressure increases of 3 psi or more, but did not have a significant impact on the south-west quadrant of the system.

Solely increasing the gas supply from UGL Stations has a small impact on the system.

6.3. NRG GAS CORP WELLS

6.3.1. NO NRG GAS CORP WELLS

When gas flow from the NRG Gas Corp Wells is shut-in, much lower pressures are seen in the south and south-west with most of the system at less than 30 psig. This indicates that the NRG Gas Corp wells have a significant impact on the NRG system. A flow schematic showing the results of this simulation is shown in Appendix E.

If the NRG Gas Corp wells were removed from the NRG system additional gas flow would be required from the UGL Stations and additional pipelines would be required to move gas from the UGL stations into the southern areas of the system.

6.3.2. HIGHER FLOW RATES FROM THE NRG GAS CORP WELLS

When gas flow rates are quadrupled from the Scotia Line group of wells, higher pressures occur in the south and south-east, but low pressures still occur in the south-west. Gas flow rates from the Scotia Line group of wells must increased by 7 times in order to increase pressure in the south-west. A flow schematic showing the results of this simulation is shown in Appendix E.

Increasing gas flow from the NRG Gas Corp wells could alleviate low pressures in the southern areas of the NRG System. However, the increase in flow rate is significant.

6.3.3. HIGHER GAS FLOW RATES AND THE JOHN WISE LINE LOOP

Increasing the gas flow rate from the NRG Gas Corp Wells as well as looping the John Wise Line helps to move gas from the central south into the south-west. A flow schematic showing the results of this simulation is shown in Appendix E. For this simulation the John Wise line was looped between Imperial Road and Springfield Road (NPS 3 approximately 4070 m).

Adding the John Wise Line loop decreases the requirement for additional gas. Quintupling the gas flow rate from the Scotia Line group of wells and looping the John Wise line is roughly equivalent to increasing gas flow from the Scotia Line group of wells 7 times.

Quintupling gas flow from the Scotia Line group of wells as well as looping the John Wise Line is an effective way of increasing gas availability in the south and moving gas into the south-west.

7. CONCLUSIONS AND RECOMMENDATIONS

The NRG gas distribution system was modelled and benchmarked to a high gas flow day on November 12th, 2014. The simulated results were deemed to be a good representation of the actual system on the high flow day. A series of modifications were made to the model to attempt to alleviate low pressure areas in the south-west and around Brownsville.

Based on the simulations completed, it appears that the NRG system integrity problem is that gas cannot move freely from the inlet locations, in the north and east, into the south-west quadrant and into the Brownsville area. It should be noted that the total flow rate into the NRG system closely matches the total flow take-off from the NRG system. Loops and extensions of existing pipes were the most effective way of moving gas into the low gas pressures areas of the system.

7.1. SOUTH-WEST QUADRANT

The simulation results showed that there were three viable alternatives to alleviate low pressure in the south-west quadrant of the system:

1. Extending the Glencolin Line pipe
2. Increasing gas flow from the Scotia Line well group by 7 times
3. Quintupling gas flow from the Scotia Line well group and looping the John Wise Line

Extending the Glencolin Line is the more attractive alternative because it appears to be much simpler and much less extensive than looping the John Wise Line and increasing gas flow from the NRG Gas Corp wells.

7.2. BROWNSVILLE AREA

The simulation results showed that there were two viable alternatives to alleviate low pressure in the Brownsville area of the system:

1. Extending the Wilson Line and increasing the set pressure on the Ostrander Road pressure regulator to 50 psi
2. Extending the Wilson Line and looping the Ostrander Road Line

Extending the Wilson Line and looping the Ostrander Road Line is the more attractive alternative as changing the Ostrander Road regulator set pressure will most likely require that a large number of pressure regulators be installed at individual take-offs further downstream.

7.3. RECOMMENDATION

The Glencolin Line extension, the Wilson Line extension, and the Ostrander Road Loop were simultaneously added to the model. A flow schematic showing the result of the high gad flow day is shown in Appendix F.

The result shows that the low pressure areas in the south-west quadrant and around Brownsville have been eliminated. The Brownsville area is still colored red on the results schematic, because the Ostrander Road pressure regulator is set to 30 psig. However, the pressures have increased substantially with the lowest pressure at 26 psig.

It is recommended that the Glencolin Line and the Wilson Line be extended and the Ostrander Loop be added to the NRG system.

8. COST ESTIMATE

An unclassified estimate was prepared for the recommended modifications above:

- Glencolin Line Extension
- Wilson Line Extension
- Ostrander Road Loop

The cost estimates are factored estimates based on data obtained from NRG on similar work and exclude NRG's costs, land costs, telecommunications, environmental assessments, legal and regulatory, third party consultation, escalation, and NRG's risk.

NRG has advised that a construction survey is not required in their franchise area.

The total cost for each pipeline segment is shown in Table 8-1. A breakdown of the costs for each pipe segment is shown in Appendix G.

Table 8.1 – Unclassified Costs estimate

Extension	Pipe Diameter	Length (m)	Cost (CAD $)
Glencolin Line Extension	NPS 4	3200	213,800
Wilson Line Extension	NPS 3	500	34,800
Ostrander Road Loop	NPS 3	4060	207,900
Total	-	-	**456,500**

9. GROWTH LIMITATIONS

The NRG system could be impacted by two different types of growth:

- Increase in population in the area
- Increase in the number of high demand gas customers

The NRG system with the Glencolin Line and Wilson Line extensions and the Ostrander Loop added into the system were investigated with the two types of growth described above.

9.1. INCREASE IN POPULATION

The Ontario Ministry of Finance (Ontario) has produced population projections for the Region and Census Divisions in Ontario. The NRG Franchise generally lies within the Elgin Census Division and Ontario predicts a population increase of 3.4% in the region by the year 2021. To simulate this increase in population we increased the demand from each customer by 3.4% and increased the gas flow rate into the NRG system from the UGL stations and from the NRG wells by 3.4%.

The result of increasing the gas demand to match a 3.4% increase in the population is shown as a flow schematic included in Appendix H.

The results schematic is very similar to the recommended results schematic from Section 7 above, except that the gas pressure in the south-west are approximately 3 psi lower.

If the population in the area increases in a uniform way throughout the franchise area, then the NRG system when the recommended modifications have been made to the system should be able to meet the demand for gas.

9.2. INCREASE IN THE NUMBER OF HIGH DEMAND GAS CUSTOMERS

High gas demands customers, such as grain dryers, have a large impact on the NRG system. It is impossible to predict where the next high gas demand customer could be introduced into the system, so high demand gas customers were simulated in various locations in the NRG system.

The high demand customer was assumed to be equivalent to the highest average monthly flow rate to Kingsmill Grains (277 m^3/hr). This flow rate was added in various locations throughout the NRG franchise area (the 277 m3/hr was added to an existing customer's gas flow rate). An equivalent flow was then added to the nearest UGL station and/or to the NRG Gas Corp group of wells to provide gas for this customer. The simulation was run and the results were observed.

In general, if a new high demand customer added in close proximity to a UGL station, an NRG Gas Corp group of wells or in the north, modifications will not be required to the NRG system, as long as gas from the nearby station and/or group of wells can be increased to satisfy the customer's gas demand.

If a new high demand customer is added in the south-east the line feeding the customer and in some instances the lines immediately upstream of the customer would need to be looped.

If a new high demand customer is added in the south-west then looping would be required.

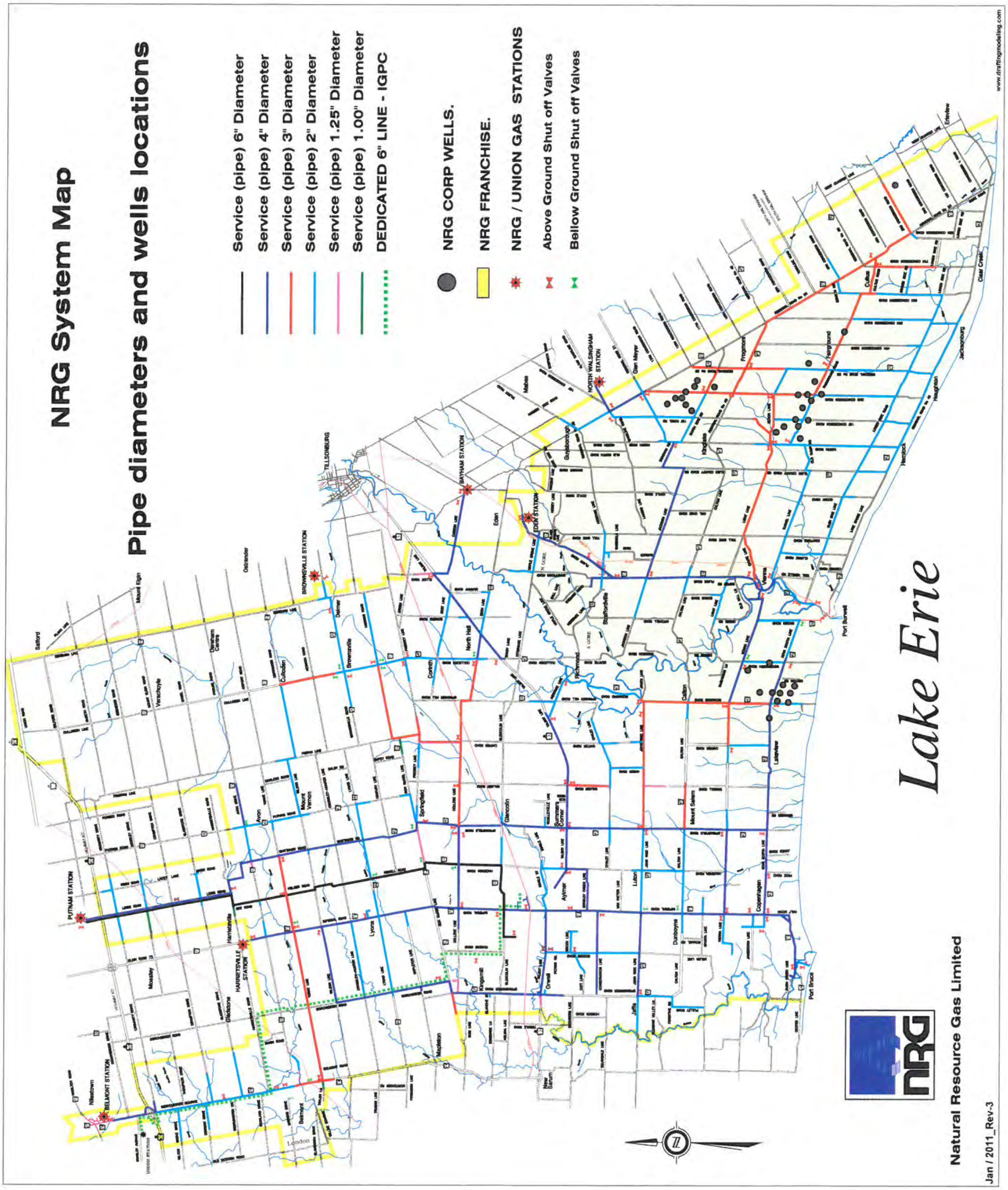
Examples of high demand customer simulations performed are as follows:

- On Avon Drive near Pigram Road
    - Gas flow must be increased from Putnam and Harrietsville Stations
    - Slight decrease in gas pressures (5 psi) along Putnam Road
- On Pressey Line near Springer Hill Road
    - Gas flow must be increased from Putnam, Bayham, and Harrietsville Stations
    - Slight decrease in gas pressures (3 psi) along Hawkins Road
- On Lyons Line near Newell Road
    - Gas flow must be increased from Harrietsville Station and a slight increase from Putnam Station

- No significant pressure drop in the system
- On Chalet Line off Springfield Road
    - Gas flow must be increased from Putnam Station and a slight increase from Bayham Station
    - Gas pressure decreases by about 10 psi in the centre of the south-west section of the system
- On Pulley Road
    - Gas flow must be increased from Putnam and Harrietsville Stations and the Scotia Line group of wells
    - Very low gas pressures (17 to 29 psi) along Pulley Road. Would need to loop Pulley Road, Forsythe Road, and lower portion of Springwater Road
- On Vienna Line and Carter Road
    - Gas flow must be increased from the Scotia Line group of wells, and Eden and North Walsingham Stations
    - A portion of the Vienna Line must be looped
- On 3rd Concession Road
    - Gas flow must be increased from the Fairground group of wells, and either the 2nd Concession group of wells or the North Walsingham Station
    - No significant pressure drop in the system
- On Clark Road and Glen Erie Line
    - Gas flow must be increased from the Fairground group of wells and Eden Station
    - Clark Road and Tunnel Line and Glen Erie Line must be looped

It is recommended that a steady state simulation be performed when a new high demand gas customer is added to the system to determine the impact that this will have on the NRG system and the modifications required, if any, to meet the new demand.

Appendix A – NRG System Map


NRG System Map
Pipe diameters and wells locations
Service (pipe) 6" Diameter
Service (pipe) 4" Diameter
Service (pipe) 3" Diameter
Service (pipe) 2" Diameter
Service (pipe) 1.25" Diameter
Service (pipe) 1.00" Diameter
DEDICATED 6" LINE - IGPC
NRG CORP WELLS.
NRG FRANCHISE.
NRG / UNION GAS STATIONS
Above Ground Shut off Valves
Bellow Ground Shut off Valves
Lake Erie
Natural Resource Gas Limited
Jan / 2011_Rev-3
www.draftingmodeling.com
PUTNAM STATION
HARRIETSVILLE STATION
BELMONT STATION
BROWNSVILLE STATION
BAYHAM STATION
EDEN STATION
NORTH WALSINGHAM STATION
TILLSONBURG
Aylmer
Port Bruce
Port Burwell
Vienna
Lakeview
Springfield
Belmont
Copenhagen
Lyons
Mount Salem
Straffordville

Appendix B – Reference Documents

GENERAL TRANSIENT ANALYSIS DATA REQUIREMENTS

1) **Elevation profile in an electronic format**
   - Not applicable. I suspect that this is only applicable to a singular high volume pipeline.

2) **Pipeline diameter, MAOP, wall thickness, design temperature, and internal roughness**
   - Pipe Diameter – See base map already provided earlier;
   - MAOP – the MAOP of our system is 80psig;
   - For wall thickness, design temp and internal roughness – See Appendix A; specifications of the pipe currently being purchased and installed. We would have to assume that all pipe previously installed has the similar properties to achieve CSA approval.

3) **Gas composition in mole percent of each component**

Ontario: Typical Gas Higher Heating Value [Union Gas Ltd. service area]		**Jan-Jun 2013**	**Jul-Dec 2013**
Natural Gas HHV	(GJ/standard* m3)	0.038	0.038
Ontario: Typical Gas Composition [Union Gas Ltd. service area]			
Methane	mole %	94.85	94.66
Ethane	mole %	3.40	3.77
Propane	mole %	0.16	0.17
Butane	mole %	0.04	0.03
Pentanes	mole %	0.01	0.00
Hexanes+	mole %	0.01	0.00
Nitrogen	mole %	0.80	0.76
Carbon dioxide	mole %	0.69	0.56
Oxygen	mole %	0.01	0.02
Hydrogen	mole %	0.03	0.03
Total	mole %	100.00	100.00

*Standard conditions: 15°Celsius, 101.325 kPa

This information is provided solely for the use of the reporting operations related to their compliance reporting obligation under Ontario Regulation 452/09 under the Environmental Protection Act, where applicable. While every effort has been made to ensure the accuracy of this information, Union Gas does not warrant accuracy of the information for any purpose. Union Gas provides no guarantee regarding gas composition or high heating value for any specific delivery point.

4) **Gas flow rate, temperature and pressure at each input location**
- Please see the chart below for flow rates. Pressures are noted on the map provided.

Location	Max Hourly Volume (m3/hour)
Harrietsville	2,950
Putnam	3,258
Eden	1,250
Bayham	2,000
Walsingham	1,250
Belmont	538
Brownsville	170

5) **Gas flow rate and pressure at each take-off point;**
- Not applicable

6) **Location, type and Cv of all valves**
- The locations of all valves are located on the base map that was previously provided. In terms of the type of valve and CV that information in not available.

7) **Location and performance information and control logic for all compressor stations**
- There are no compressor stations in our franchise area.

8) **Set points for all controls on the system (discharge pressure, back pressure, flow rate, etc.)**
- Pressures and flow rates are variable based on the customer load/season requirements and commercial customer requirements.

9) **Pressure reduction station locations and pressure reduction set-points**
- See Appendix B

10) **Schematic diagrams for the system**
- You may find this detail on the base System Map already provided

11) **System operating manuals (or philosophy/procedure)**
- Per Z662.07 as per Regulations and Codes. Maintenance Protocol is available if required

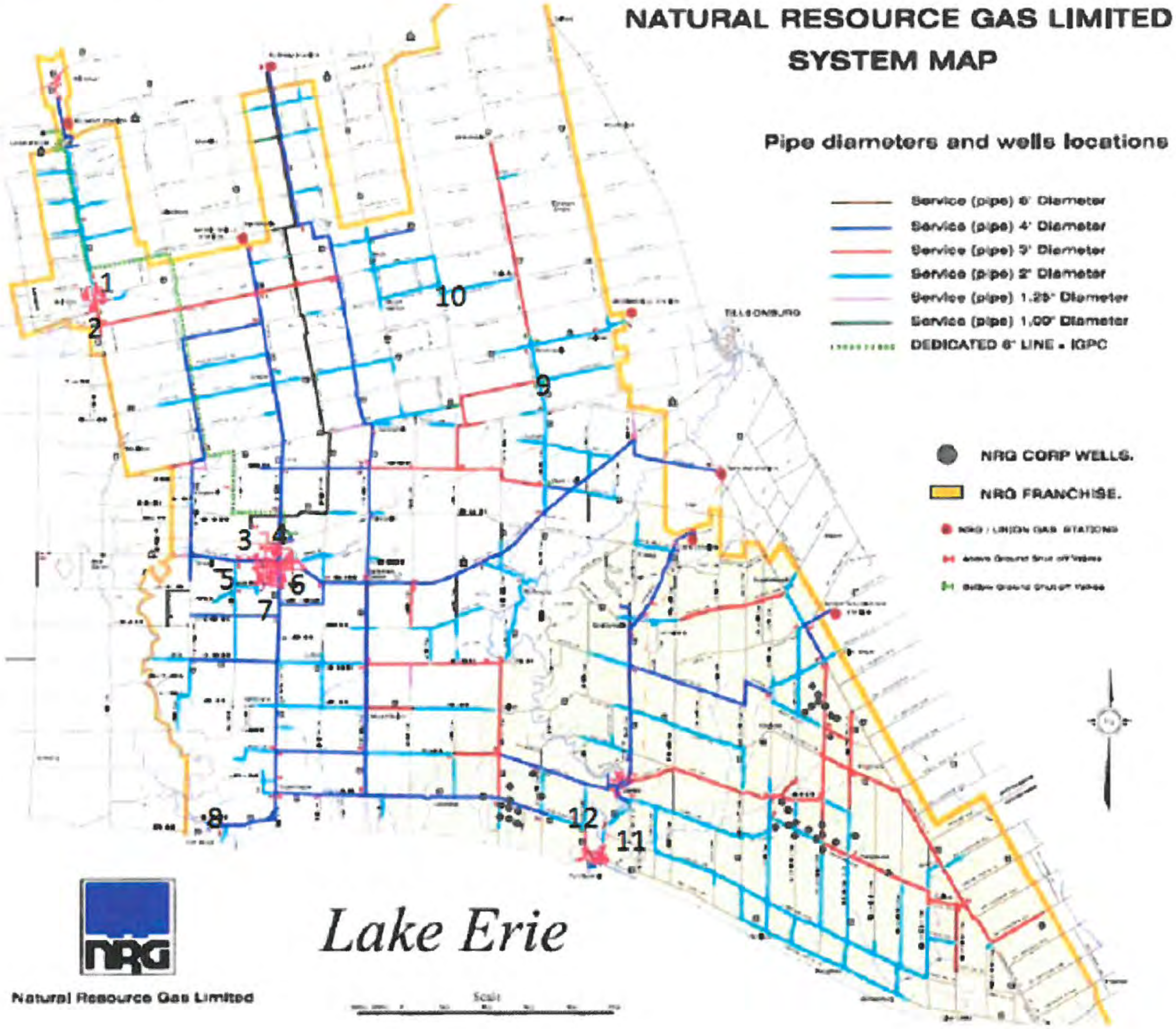
12) **P&IDs for the system**
- N/A

13) **Maximum and minimum ground temperatures at pipe burial depth and soil thermal conductivities**

Cond. mS/cm	Rating
0-0.25	Low
0.26-0.45	Medium
Temp range	SW. ON

14) **Pipe burial depth**
- 20" to 48" maximum depth per code.

Appendix B



Outlet Pressures from each Transfer Station	Map No.	Governed Pressure
Belmont Station: 30 PSI to Nilestown	1	30 PSI outlet to Belmont
Putnum Station: 60-80 PSI outlet pressure	2	30 PSI outlet to Belmont
Harrietsville Station: 60-80 PSI outlet pressure	3 – 7	30 PSI outlet to Aylmer
Brownsville Station: 30 PSI outlet pressure	8	30 PSI outlet to Port Bruce
Bayham Station: 60-80 PSI outlet pressure	9 + 10	30 PSI outlet to Brownsville
Eden Station: 60-80 PSI outlet pressure	11 + 12	30 PSI outlet to Port Burwell
N. Wallingham Station: 60-80 PSI outlet pressure		

PERFORMANCE PIPE
A Division of Chevron Phillips Chemical Company LP

PerformancePipe.com

DRISCOPLEX® 6500
MDPE PIPE and FITTINGS DATA SHEET

DriscoPlex® 6500 Pipe and Fittings meet or exceed:

ASTM D2513, D2683, D3261
CAN/CSA-B137.4
UPC
ASTM D3350, cell classification PE234373E and PE234375E
PPI TR-4 designations PE2708 (PE2406) and PE80
PPI TN-30

DriscoPlex® 6500 Yellow MDPE Pipe and Fittings for

Natural Gas Distribution, LPG and Propane Gas Distribution, Yard Gas
Iron Pipe Size OD (IPS) ½" to 24",
Copper Tube Size OD (CTS) ½" to 1 ¼"
Coils available up through 6"

Outdoor Storage up to Three (3) Years per ASTM D2513

NOMINAL PIPE PROPERTIES [1]	UNIT	TEST METHOD	VALUE
Density	gms / cm^3	ASTM D1505	0.939 (yellow)
Melt Index (MI) Condition 190°C / 2.16kg	gms / 10 min	ASTM D1238	0.18
Hydrostatic Design Basis 73°F (23°C)	psi	ASTM D2837	1250
Hydrostatic Design Basis 140°F (60°C)	psi	ASTM D2837	1000
Minimum Required Strength	MPa (psi)	ISO 9080	8.0 (116)
Rapid Crack Propagation (Pc) 0°C (32°F) [3]	Bar (psi)	ISO 13478	8.5 (123)
Color; UV Stabilizer [E]	--	ASTM D3350	Yellow; UV stabilized
Pipe Test Category	--	ASTM D2513	CEE
NOMINAL MATERIAL PROPERTIES [1] [2]	**UNIT**	**TEST METHOD**	**VALUE**
Flexural Modulus at 2% secant	psi	ASTM D790	>90,000
Tensile Strength at Yield	psi	ASTM D638 Type IV	2,800
Elongation at Break 2 in / min., Type IV bar	%	ASTM D638	>800
Hardness	Shore D	ASTM D2240	63
PENT	hrs	ASTM F1473	>2,000
Vicat Softening Temperature	°F	ASTM D1525	227
Brittleness Temperature	°F	ASTM D746	< -103

1. This is not a product specification and does not guarantee or establish specific minimum or maximum values or manufacturing tolerances for material or piping products to be supplied.
2. Values obtained from tests of specimens taken from piping product may vary from these typical values.
3. Determination made on 8" DR-11 pipes for Full Scale test. Pc calculated in accordance with ISO 13478.

When Performance Matters Rely on Performance Pipe

Bulletin: PP107 / March 2010

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PERFORMANCE PIPE
A DIVISION OF CHEVRON PHILLIPS CHEMICAL COMPANY LP

DriscoPlex® 6500 Series PE2708 (PE2406) Standard Size and Dimension Sheet

Please visit www.performancepipe.com for the most up-to-date information

NOTE: The sizes and packaging shown represent typical Performance Pipe products. Other sizes and/or packaging may be available. Contact Performance Pipe for additional information. Pipe weights are calculated in accordance with PPI TR-7. Dimensions and weights are subject to change without notice.

CTS = COPPER TUBE SIZE

Part Number	Nominal Size (Inches)	Minimum Wall (Inches)	Nominal Outside Diameter (Inches)	Dimension Ratio	MAOP (psig per CFR Part 192 @ 73.4° F or less)	Weight per 100 ft.	Coil/ Joint (feet)	Nominal Packing Dimensions ID/OD/Width	Number Coils/Joints Per Pallet or Bundle	Pallet / Bundle Footage	Number Pallet / Bundles Per Truck	48 ft. Truck
1002425	1/2"	0.090	0.625	7.0	100	6.5	1,000'	30" / 44" / 6"	12	12,000'	26	312,000'
1002445	1"	0.099	1.125	11.5	76	14.0	500'	30" / 42" / 11"	8	4,000'	26	104,000'

IPS = IRON PIPE SIZE

Part Number	Nominal Size (Inches)	Minimum Wall (Inches)	Nominal Outside Diameter (Inches)	Dimension Ratio	MAOP (psig per CFR Part 192 @ 73.4° F or less)	Weight per 100 ft.	Coil/ Joint (feet)	Nominal Packing Dimensions ID/OD/Width	Number Coils/Joints Per Pallet or Bundle	Pallet / Bundle Footage	Number Pallet / Bundles Per Truck	48 ft. Truck
1002239	3/4"	0.095	1.050	11	80	12	500'	30" / 44" / 10"	7	3,500'	26	91,000'
1002249	1"	0.120	1.315	11	80	19	500'	30" / 44" / 12"	6	3,000'	26	78,000'
1002263	1 1/4"	0.166	1.660	10	89	33	500'	48" / 72" / 7½"	12	6,000'	7	42,000'
1002284	2"	0.216	2.375	11	80	63	500'	52" / 78" / 13"	7	3,500'	7	24,500'
1002323	3"	0.304	3.500	11.5	76	131	40'	soft bundles	50	2,000'	14	28,000'
1002318							500'	70" / 96" / 23¾"	4	2,000'	6	12,000'
1002349	4"	0.391	4.500	11.5	76	217	40'	soft bundles	29	1,160'	14	16,240'
1088779							600'	70" / 93" / 49½"	upright		12	7,200'
1010590							1,000'	84" / 116" / 49"	upright		8 coils	8,000'
1002367	6"	0.576	6.625	11.5	76	471	40'	soft bundles	13	520'	14	7,280'
1002363							500'	84" / 120" / 50"	upright		8 coils	4,000'
1002373		0.491		13.5	64	407	40'	soft bundles	13	520'	14	7,280'
1002368							500'	84" / 120" / 50"	upright		8 coils	4,000'
1002384	8"	0.750	8.625	11.5	76	798	40'	soft bundles	9	360'	10	3,600'
1071013		0.639		13.5	64	690						
1007003	12"	0.944	12.750	13.5	64	1507	40'	bulk packs	8 jts/layer	320'	6	1,920'

NOTE: The August revision was strictly for ease in reading columns for minimum wall and DR. No specific data was changed.

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DRISCOPLEX® 6500
MODEL SPECIFICATION

The user may choose to adopt part or all of this Model Specification; however, the user should ensure that all parts used are appropriate for the user's purpose. See notice below.

1 General Terms and Conditions

1.1 Scope. This specification covers requirements for DriscoPlex® 6500 PE2708 (PE2406) polyethylene pipe and fittings for underground gas distribution systems. All work shall be performed in accordance with these specifications.

1.2 Engineered and Approved Plans. Underground gas distribution piping construction shall be performed in accordance with engineered construction plans for the work prepared under the direction of a Professional Engineer. Plans shall conform to the standards and regulations for gas distribution piping. Pipe, fittings, and the installation shall meet the applicable requirements of the U. S. Department of Transportation, Pipeline Safety Regulations, Title 49, Code of Federal Regulations, and Part 192. Private systems shall meet relevant requirements of NFPA 54/ANSI Z223.1, or NFPA 58, or ASME B31.8.

1.3 Referenced Standards. Where all or part of a Federal, ASTM, ANSI, NFPA, etc., standard specification is incorporated by reference in these Specifications, the reference standard shall be the latest edition and revision.

1.4 Licenses and Permits. A licensed and bonded Contractor shall perform all underground gas distribution piping construction work. The Contractor shall secure all necessary permits before commencing construction.

1.5 Inspections. All work shall be inspected by an Authorized Representative of the Owner or Operator who shall have the authority to halt construction if, in his opinion, these specifications or standard construction practices are not being followed. Whenever any portion of these specifications is violated, the Project Engineer or his Authorized Representative shall, by written notice, order further construction to cease until all deficiencies are corrected. A copy of the order shall be filed with the Contractor's license application for future review. If the deficiencies are not corrected, performance shall be required of the Contractor's surety.

2 Polyethylene Pipe and Fittings

2.1 Qualification of Manufacturers. The Manufacturer shall have manufacturing and quality control facilities that are capable of producing and assuring the quality of the pipe and fittings required by these Specifications. The Manufacturer's production facilities shall be open for inspection by the Customer or his Authorized Representative. The pipe and fitting manufacturer shall be ISO Certified in accordance with the current edition of ISO 9001 and a documented quality management system that defines product specifications and manufacturing and quality assurance procedures that assure conformance with customer and applicable regulatory requirements. Upon request, the manufacturer shall provide a current Certificate of Compliance form and independent ISO 9000 Registrar.

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MODEL SPECIFICATION

2.2 Approved Manufacturers. Manufacturers that are qualified and approved by the Project Engineer are listed below. Products from unapproved manufacturers are prohibited. Performance Pipe, a division of Chevron Phillips Chemical Company LP

2.3 Materials. Materials used for the manufacture of polyethylene pipe and fittings shall be PE 2708 (PE2406) medium density polyethylene meeting cell classification 234373E per ASTM D 3350; and shall be Listed in PPI (Plastics Pipe Institute) TR-4 with standard grade HDB ratings of 1250 psi at 73°F, and 1000 psi at 140°F. All pipe and fittings materials shall be opaque yellow in color. Materials shall be stabilized against ultraviolet deterioration and shall be suitable for unprotected outdoor storage for at least four (4) years.

2.4 Polyethylene Pipe. Pipe shall be DriscoPlex® 6500 PE 2708 (PE2406) polyethylene pipe, and shall be manufactured and tested in accordance with the latest published edition of ASTM D 2513.

2.5 Polyethylene Fittings. Polyethylene heat fusion fittings shall be manufactured and tested by the pipe manufacturer in accordance with ASTM D 2513 and D.O.T. requirements.

2.6 Manufacturer's Quality Control. The pipe and fitting manufacturer shall have an established quality control program responsible for inspecting incoming and outgoing materials. Incoming polyethylene materials shall be inspected for density, melt flow rate, UV protection and contamination. The supplier shall certify the cell classification properties of incoming material. Incoming materials shall be approved by Quality Control before processing into finished goods.

2.6.1 Outgoing materials shall be checked for diameter, wall thickness, roundness, concentricity, toe-in, inside and outside surface finish, markings, and end cut. Quality control shall verify production checks, and test for density, melt flow rate, hoop tensile strength and ductility. X-ray inspection procedures shall be used to inspect molded fittings for voids, and knit line strength shall be tested. All fabricated fittings shall be inspected for joint quality and alignment. Representative tests to verify long-term performance shall include slow crack growth, pipe inside surface ductility, and ambient and elevated temperature sustained pressure testing.

2.6.2 Permanent Records. The Manufacturer shall maintain records of manufacturing location, pipe production and resin lots for at least 50 years.

2.7 Compliance Tests. The Manufacturer shall certify the inspection and testing of the materials and products. In case of conflict with Manufacturer's certifications, the Contractor, Project Engineer, or Operator may request retesting by the Manufacturer or have retests performed by an outside testing service. All retesting shall be at the requestor's expense, and shall be performed in accordance with the Specifications.

3 Joining

3.1 Heat Fusion Joining. Butt, socket, and saddle fusion joints in polyethylene gas piping shall be made using procedures that have been qualified and approved by the Operator in accordance with Title 49, CFR, and Part 192.283.

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3.1.1 In accordance with CFR. 49, part 192, Section 192.285, the Operator shall ensure that all persons making heat fusion joints have been qualified to make joints in accordance with the Operator's Approved Qualified Fusion Procedures. The Operator shall maintain records of qualified personnel, and shall certify that qualification training was received not more than 12 months before commencing construction. The Contractor shall ensure that all persons making heat fusion joints are qualified in accordance with this section.

3.1.2 The Manufacturer shall offer qualified fusion procedures and training materials for the use of the Operator.

3.1.3 Butt Fusion of Unlike Wall Thickness. Butt fusion shall be performed between pipe ends, or pipe ends and fitting outlets that have the same outside diameter and are not different in wall thickness by more than one Standard DR, for example, SDR 9 (9.3, 9.33) to SDR 11 (11.5), or SDR 11 (11.5) to SDR 13.5. Transitions between unlike wall thickness greater than one SDR shall be made with a transition nipple (a short length of the heavier wall pipe with one end machined to the lighter wall) or by mechanical means or electrofusion. Standard DR's for polyethylene pipe are 7.3, 9, 11, 13.5, 17 and 21.

3.2 Joining by Other Means. Polyethylene gas pipe and fittings may be joined together or to other materials by transition fittings, fully restrained mechanical couplings, or electrofusion. These devices shall be designed for joining polyethylene to another material and shall be approved by the Operator for use in his gas distribution system. When joining by other means, the installation instructions of the joining device manufacturer shall be observed.

3.2.1 When mechanical OD compression couplings are used, polyethylene gas pipe shall be reinforced with a stiffener in the pipe bore. Stiffeners shall be properly sized for the diameter and wall thickness of polyethylene pipe being joined. For service pipe connections, the stiffener length shall match the pipe end penetration depth into the coupling.

4 Installation

4.1 General. Polyethylene gas distribution piping shall be installed be in accordance with CFR 49, Part 192, Subpart G (mains), Subpart H (service lines), applicable codes and regulations and ASTM D 2774.

4.1.1 When delivered, a receiving inspection shall be performed, and any shipping damage shall be reported to the Manufacturer within 7 days.

4.2 Burial Depth. All polyethylene gas distribution piping shall be installed in accordance with applicable federal, state and local codes and shall have at least 12" of cover in private property, and at least 18 inches of cover in streets and roads.

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4.3 Excavation. Trench excavations shall conform to the plans and drawings, as otherwise authorized in writing by the Project Engineer or his Approved Representative, and in accordance with all applicable codes. The Contractor shall remove excess groundwater. Where necessary, trench walls shall be shored or reinforced, and all necessary precautions shall be taken to ensure a safe working environment.

4.4 Foundation & Bedding. Pipe shall be laid on grade and on a stable foundation. Unstable trench bottom soils shall be removed, and a 6" foundation or bedding of compacted Class I material shall be installed to pipe bottom grade. A trench cut in rock or stony soil shall be excavated to 6" below pipe bottom grade, and brought back to grade with compacted Class I bedding. All ledge rock, boulders and large stones shall be removed.

4.5 Pipe Handling. Pipe shall be handled in a safe manner that avoids damage to the product. When lifting with slings, only wide fabric choker slings capable of safely carrying the load, shall be used to lift, move, or lower pipe and fittings. Wire rope or chain shall not be used. Slings shall be of sufficient capacity for the load and shall be inspected before use. Worn or damaged equipment shall not be used.

4.6 Backfilling. Embedment material soil type and particle size shall be in accordance with ASTM D 2774. Embedment shall be placed and compacted to at least 90% Standard Proctor Density in 6" lifts to at least 6" above the pipe crown. During embedment placement and compaction, care shall be taken to ensure that the haunch areas below the pipe springline are completely filled and free of voids.

4.7 Protection against shear and bending loads. In accordance with ASTM D 2774, connections shall be protected where an underground polyethylene branch or service pipe is joined to a branch fitting such as a service saddle, branch saddle or tapping tee on a main pipe, and where pipes enter or exit casings or walls. The area surrounding the connection shall be embedded in properly placed, compacted backfill, preferably in combination with a protective sleeve or other mechanical structural support to protect the polyethylene pipe against shear and bending loads.

4.8 Final Backfilling. Final backfill shall be placed and compacted to finished grade. Native soils may be used provided the soil is free of debris, stones, boulders, clumps, frozen clods or the like larger than 8" in their largest dimension.

5 Testing

5.1 Fusion Quality. The Contractor shall ensure the field set-up and operation of the fusion equipment, and the fusion procedure used by the Contractor's fusion operator while on site. Upon request by the Owner, the Contractor shall verify field fusion quality by making and testing a trial fusion. The trial fusion shall be allowed to cool completely; then test straps shall be cut out and bent strap tested in accordance with ASTM D 2657. If the bent strap test of the trial fusion fails at the joint, the field fusions represented by the trial fusion shall be rejected. The Contractor at his expense shall make all necessary corrections to equipment, set-up, operation and fusion procedure, and shall re-make the rejected fusions.

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5.2 Leak Testing. Leak testing shall be conducted in accordance with Performance Pipe Technical Note 802 *Leak Testing*.

5.2.1 Polyethylene gas distribution systems that are subject to D.O.T. Pipeline Safety Regulations shall be tested in accordance CFR 49, Part 192, Sections 192.509, 192.511, or 192.513 as applicable.

5.2.2 The Contractor shall take all precautions to eliminate hazards to persons near lines being tested. Pipes being tested shall be supervised at all times.

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Huddleston, Alex

From: Brian Lippold [brian@nrgas.on.ca]
Sent: November 20, 2014 12:52 PM
To: Huddleston, Alex
Cc: lomeara@cpirentals.com; Mark McCord
Subject: RE: SNC Lavalin Study

Okay Alex, Go ahead and use 2400 M3 on the high side. 2009 on the average or even low side.

Thanks,

Brian

From: Mark McCord
Sent: November-20-14 2:40 PM
To: Brian Lippold
Cc: Huddleston, Alex; lomeara@cpirentals.com
Subject: Re: SNC Lavalin Study

Ya, that sounds like a fair assessment to me.

Mark

On Nov 20, 2014, at 2:07 PM, Brian Lippold <brian@nrgas.on.ca> wrote:

1. should we use the 2009 m^3/year as the normal average flow rate and some higher flow rate, say 2300 m^3/year, as the coldest day of the year flow rate?

The question was really should we do this with a high and a normal flow rate (household consumption). Last year, we were 29% colder in the 4 traditional winter months. It stands to reason that the average home would be about 350 m3 on a normal winter month. So for assumption purposes, I used the 4 consumption months x 350 x 1.29 (29% above the avg. year) to get 1820 for those cold months. I then added the 609 for the remaining 8 months. That gave me 2429m3/year. So if Alex used 2400 as an extreme years flow that would be safe. Do you agree with that loose analysis?

From: Mark McCord
Sent: November-20-14 12:41 PM
To: Brian Lippold
Cc: Huddleston, Alex; lomeara@cpirentals.com
Subject: Re: SNC Lavalin Study

Which question are you referring to?

Mark

On Nov 20, 2014, at 12:22 PM, Brian Lippold <brian@nrgas.on.ca> wrote:

We can run the report for the schools and government buildings as they are under DP accounts. We would really don't have any large consuming department stores of significance.

2009 cubic meters is what is still listed as the average house by CMHC and the OEB. People put more appliances in today but they are more efficient than ever. I think Alex was good with that number but there was a question about psi that might be a challenge to answer.

Sent from my iPhone

On Nov 20, 2014, at 11:59 AM, Mark McCord <mmccord@nrgas.on.ca> wrote:

1. I am not sure what to use for a residential load. I have never looked at the average total volume for a residential dwelling.
2. We have many customers, my guess would be hundreds that impact the system when they run. Schools, manufacturing, stores and many others. We do not separate most of these from our residential accounts. We would have total annual volumes for these places, but really no way to develop a list. Also, we would have to check billing volumes for these places to determine what time of year their greatest load is. Our billing department may be able to put a list together of the customers with the most consumption in say the month of January or February. We could start there, but we would need volume parameters to develop that.

3. I believe Brian answered this.

Thanks
Mark

On Nov 20, 2014, at 10:36 AM, Brian Lippold <brian@nrgas.on.ca> wrote:

Mark, I need your thoughts and comments on this as soon as possible to keep Alex going. Please reply all.

Alex, Each of those small villages are less than 150 homes. You can count them but they are not large factors. They are also not very concentrated. You can certainly add them if the load total is significant to you.

Thanks,

Brian

From: Huddleston, Alex [mailto:Alex.Huddleston@snclavalin.com]
Sent: November-20-14 10:01 AM
To: Brian Lippold
Cc: lomeara@cpirentals.com; Mark McCord
Subject: RE: SNC Lavalin Study

Brian,

I was out of the office for a couple of weeks (surgery) and have just returned to work. I need a few more clarifications for the study:

1. Can we use 1900 m^3/year as the normal winter day flow rate and 2100 m^3/year as the extreme flow rate during the coldest day of the year when your system is at its limits –or– should we use the 2009 m^3/year as the normal average flow rate and some higher flow rate, say 2300 m^3/year, as the coldest day of the year flow rate?
2. A critical heating load is any load that impacts the system that isn't already accounted for in the above rates (school, hospital, factory, greenhouses, etc)
3. We've identified 3 other population centers that don't have dwelling counts: Brownsville, Vienna, and Straffordville. Can you please provide the number of dwellings at these

locations or can we exclude them from this study?

We are planning to model the pipeline system at two snapshots in time:

- During a normal winter day when the system can provide gas to all of your customers
- During the coldest winter day when the system is pushed to its limits and may not be able to provide gas to all customers

Comparing these two snapshots we can determine where changes need to be made to the system to allow the gas to get where it needs to go. To create these snapshots, we need to include the flow rate of all gas coming into the system—which you've provided. And we also need to include the flow rate of all gas taken out of the system. Since home heating is the single largest load on the system we've concentrated on it, but we also need to include any other large loads in the system.

Thanks,

Alex Huddleston
Department Manager, Pipelines
Oil & Gas

Tel.: +1 403-294-2714
Cell.: +1 403-461-1102

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<image001.jpg>

<image002.jpg>

From: Brian Lippold [mailto:brian@nrgas.on.ca]
Sent: November 6, 2014 8:06 AM
To: Huddleston, Alex
Cc: lomeara@cpirentals.com; Mark McCord
Subject: SNC Lavalin Study

Hi Alex,

Mark and I have added comments to keep you moving forward. Please see the comments in Red and specific residential data that I have provided at bottom. We would not have gas at every home but safe to say 95% in core areas.

On Nov 4, 2014, at 11:12 AM, Brian Lippold <brian@nrgas.on.ca> wrote:

We agreed to an earlier set of assumptions.

There appears to be some additional analysis required. Can you please look at what you can answer and I'll pull the meter data by book in the most major centres like Aylmer, Belmont, Port Burwell. Can you identify those locations on Mercury's or P accounts on the map. I.e. the college, the major dryers, et cetera.

Do you also agree with the additional assumptions?

- Assume that the gas demand for each house is identical, so we only need to establish a single representative flow rate to a house for the two scenarios we'll study
  - It would range from 1900 M3/year to 2100 M3/year from bungalow to 2 story house. 2009 is the number that we can use to get the practical average
- the normal winter day

That is an Environment Canada question but Degree days are entered into our billing system so we'd have a history. I don't know of a formula to determine and average day

- the coldest day of the coldest year

it was -27 before wind chill one night in February this year and that apparently broke the record

- Assume that the gas flow to each house can be modeled as a constant flow rate; we won't model the on-off cycling of a gas furnace –Nothing is constant. Thermostats determine peak times i.e. Morning 5-7 am heat-up and 4-7pm heat-up
- Only model the main pipelines; the pipelines within the towns can be excluded- That should be fine
- Use a single take-off for each town (consisting of the number of homes in the town times the representative flow rate) That would work, but we don't have customer counts for some of the towns, like aylmer, port burwell. The billing books do not start and stop by town, only area.
- Other critical heating loads (schools, hospitals, etc.) can be some number of the representative flow rates At what level makes it a critical hearing load? Most customers we have monthly volumes for, but nothing else. We have daily volumes for our large customers, but there are many other customers that make an impact on our system
- Take-offs from the main pipelines will also be modeled as a single take-off (again consisting of the number of

homes and other critical heating loads on the main pipeline times the representative flow rates)Sounds fine

Population Centres in the Area:

Belmont:555
Residential homes
Aylmer: 2030
Residential Homes
Port Burwell: 319
Residential Homes
Port Bruce: Malahide
(township): 6255
Homes include Port
Bruce but estimate 150
Year round dwellings
South Dorchester
(township):Nilestown
100 Dwellings
Springfield (village):
235

From: Huddleston, Alex
[mailto:Alex.Huddleston@snclavalin.com]
Sent: November-04-14 9:12 AM
To: Brian Lippold
Cc: Martyn, Bradley; Mark McCord; lomeara@cpirentals.com
Subject: RE: SNC Lavalin Study

Brian,

Sorry, I should have followed up on my previous email sooner. We need your agreement that the assumptions I've highlighted in green below are reasonable for your system and we're expecting you to provide the data I've highlighted in yellow below.

Thanks,

Alex Huddleston
Department Manager, Pipelines
Oil & Gas

Tel.: +1 403-294-2714
Cell.: +1 403-461-1102

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<image001.jpg>

<image002.jpg>

From: Brian Lippold [mailto:brian@nrgas.on.ca]
Sent: November 3, 2014 6:24 PM
To: Huddleston, Alex
Cc: Martyn, Bradley; Pakravesh, Hallas; Mark McCord; lomeara@cpirentals.com
Subject: SNC Lavalin Study

Hi Alex,

I am just following up to see how this is coming.

Can you please provide an update and let me know if you are having any challenges that I might assist you with.

Thanks,

Brian Lippold,
General Manager
Natural Resources Gas Ltd.
39 Beech St. E. | Aylmer, ON N5H 3J6
P: 519 773 5321 ext 205 | F: 519 773-5335
Mail to : brian@nrgas.on.ca

<image003.jpg>

From: Huddleston, Alex [mailto:Alex.Huddleston@snclavalin.com]
Sent: October-09-14 9:22 AM
To: Brian Lippold; Mark McCord

Cc: Martyn, Bradley; Pakravesh, Hallas
Subject: RE: Queries and Assumptions

Thanks for the information you provided during our teleconference. I believe I have a better understanding of the issues and complexities of the NRG system.

The main issue is that on the peak demand days the system is getting very close to its capacity and risks not being able to provide gas to customers in certain locations. This usually occurs during the coldest winter days, when the bulk of the gas demand is for heating homes. There are other large gas demands in the system, but they either aren't running during the coldest winter days or can be shutdown when a cold front is forecast.

Based on this I believe that the best path forward is to develop a model of the system for a normal winter day and then simulate what happens to the system when a cold front moves into the area. Using the normal winter day as the starting point establishes the line pack in the system, which is then depleted when as cold front arrives and the gas demand spikes. To do this we'll need representative gas flow rate data for a normal cold winter day and representative gas flow rate data for the coldest day of the coldest year.

I know this sounds like a lot of data, but we can reduce the amount of data required by making the following assumptions:

- Assume that the gas demand for each house is identical, so we only need to establish a single representative flow rate to a house for the two scenarios we'll study:
  - the normal winter day
  - the coldest day of the coldest year

- Assume that the gas flow to each house can be modeled as a constant flow rate; we won't model the on-off cycling of a gas furnace
- Only model the main pipelines; the pipelines within the towns can be excluded
- Use a single take-off for each town (consisting of the number of homes in the town times the representative flow rate)
- Other critical heating loads (schools, hospitals, etc) can be some number of the representative flow rates
- Take-offs from the main pipelines will also be modeled as a single take-off (again consisting of the number of homes and other critical heating loads on the main pipeline times the representative flow rates)

To make this work we'll need the following information:

- A normal winter day constant gas flow rate for a single house (an average flow rate on a normal winter day,)
- A coldest day of the coldest year constant gas flow rate for a single house (the worst case or peak flow rate on the coldest day of the coldest year)
- Number of households in each town
- Number of large heating loads in each town
- Location of any large heating loads not in a town
- Pressure regulator set-point at each house

Working together we'll tune the model varying (or adding and removing) gas take-offs until we achieve a steady state result that matches your experience running the system for the two scenarios.

Please review the above and provide your
comments.

Thanks,

Alex Huddleston
Department Manager, Pipelines
Oil & Gas

Tel.: +1 403-294-2714
Cell.: +1 403-461-1102

SNC-Lavalin Inc.
605 - 5th Avenue SW, 14th Floor
Calgary | Alberta | Canada | T2P 3H5
<image001.jpg>

<image004.jpg> <image005.jpg>

From: Brian Lippold [mailto:brian@nrgas.on.ca]
Sent: September 25, 2014 1:20 PM
To: Mark McCord
Cc: Huddleston, Alex
Subject: RE: Queries and Assumptions

The dwg is the updated map from Bruckie. The base map that provided was a pdf; I should have been more clear to Alex that the PDF was an illustration of station locations only. Can you please look at Alex's comments below and see if we can help them get to the starting point.

I agree with their assumptions.

I am going to call Alex directly to see if we can help get them closer.

From: Huddleston, Alex [mailto:Alex.Huddleston@snclavalin.com]
Sent: September-11-14 5:30 PM
To: Brian Lippold

Cc: laurie.omeara@cpirentals.com
Subject: Queries and Assumptions

Hi Brian,

After reviewing the data you've provided and beginning to build the model, we have the following questions. Your answers to these questions may prompt other questions:

1. To model the pipeline system we need to know the inputs into the system and the deliveries from the system. You've provided us the input into the system (Harrietsville, Putnam, Eden, Bayham, etc), but we still need the deliveries from the system. To simplify the amount of data required, you can provide a single amount at the end of each pipe that is the total maximum flow rate out of the pipeline. If that is still too much data to collect, we can exclude certain laterals, and have even larger flow rates further upstream of the excluded laterals. We also need the flow rates to Belmont (2 locations), Aylmer, Port Bruce, Brownsville, Port Burwell, and Nilestown
2. There are a number of discrepancies between the system map and the dwg files, especially in the Putnam area. Laterals shown in the dwg files don't appear on the system map and vice-versa. Which source should we assume is correct (system map or dwg files)?

Assumptions:

1. The dedicated 6" line IGPC is excluded from the scope of this study

2. Gas temperature is the same temperature as the ground (0°C in winter and 10°C in summer)
3. Burial depth is 20"
4. All valves shown on the system map of the .dwg files are open
5. Elevation doesn't have a large effect on gas flow, so we'll assume that the elevation profile is flat

Thanks,

Alex Huddleston
Department Manager, Pipelines
Oil & Gas

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Cell.: +1 403-461-1102

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<image001.jpg>

<image004.jpg> <image005.jpg>

From: Brian Lippold [mailto:brian@nrgas.on.ca]
Sent: September 11, 2014 1:13 PM
To: Huddleston, Alex
Cc: laurie.omeara@cpirentals.com
Subject: follow-up
Importance: High

Hi Alex,

I was just following up on the emails that I have sent over the past 5 weeks. I have not received any response.

The Executive and I are looking to move this process forward. We are hoping that you can arrange a time to discuss via conference call or provide a detailed response to my earlier emails.

Thanks,

Brian Lippold,
General Manager
Natural Resources Gas Ltd.
39 Beech St. E. | Aylmer, ON N5H 3J6
P: 519 773 5321 ext 205 | F: 519 773-5335
Mail to : brian@nrgas.on.ca

<image003.jpg>

NATURAL RESOURCE GAS LIMITED
DIRECT PURCHASE TWELVE MONTH VOLUME REPORT (Cu M)
CONTRACT NUMBER: ENER001
REPORT DATE: 11/21/2014

ACCOUNT # NAME	OCT/14 APR/14	SEP/14 MAR/14	AUG/14 FEB/14	JUL/14 JAN/14	JUN/14 DEC/13	MAY/14 NOV/13	TOTAL
A00199-01 TOWN OF AYLMER (PAC)	121.1 1346.7	2.8 1955.3	.0 2276.5	.0 2011.6	47.9 1512.9	414.2 648.0	10337.0
A12596-01 TOWN OF AYLMER (PAC)	10666.7 17248.1	11976.8 18442.7	8373.3 22291.3	7916.9 23195.6	9229.8 16402.9	12351.5 15408.4	173504.0
B14610-01 CORP OF TOWN OF AYLMER (PAC)	11.3 .0	33.8 .0	157.8 .0	143.7 .0	.0 .0	.0 .0	346.6
B14620-01 TOWN OF AYLMER PUBLIC WORKS DEPT	2.8 352.2	2.8 571.9	2.8 1459.4	.0 1110.1	5.6 712.8	67.6 152.1	4440.1
B21899-02 AYLMER POLICE SERVICES (PAC)	250.7 980.5	90.2 1656.6	70.4 1907.4	90.2 1665.1	93.0 1329.8	540.9 743.8	9418.6
C00100-01 CORP OF TOWN OF AYLMER (PAC)	42.3 309.9	45.1 864.9	47.9 1169.2	42.3 879.0	42.3 639.5	78.9 76.1	4237.4
C17000-01 LCBO	400.1 1507.3	121.1 2454.0	25.4 2921.6	14.1 2411.7	160.6 1952.5	831.1 1248.1	14047.6
D07610-01 TOWNSHIP OF MALAHIDE AYLMER	73.3 445.1	25.4 718.4	36.6 935.4	19.7 845.2	31.0 518.4	135.2 340.9	4124.6
D49528-01 TOWN OF AYLMER (PAC)	374.7 2755.4	59.2 4626.2	36.6 5251.6	31.0 5198.1	84.5 3003.3	825.5 1639.7	23885.8
G05800-01 LCBO	76.1 524.0	33.8 755.1	.0 890.3	8.5 901.6	19.7 670.5	225.4 484.6	4589.6
H00101-01 MALAHIDE TOWNSHIP SPRINGFIELD	2.8 504.3	.0 662.1	.0 780.4	2.8 583.2	14.1 301.5	143.7 50.7	3045.6
H05820-01 TOWNSHIP OF MALAHIDE SPRINGFIELD	31.0 14.1	8.5 28.2	11.3 14.1	5.6 39.4	5.6 11.3	8.5 14.1	191.7
H31000-01 TOWNSHIP MALAHIDE SPRINGFIELD	56.3 755.1	19.7 1141.0	36.6 1211.5	19.7 1279.1	28.2 608.6	253.6 205.7	5615.1
H33801-02 TOWNSHIP OF MALAHIDE SPRINGFIELD	211.3 3614.7	290.2 5099.5	301.5 5927.8	357.8 4958.6	453.6 2814.6	1324.2 1127.0	26480.8
H48060-03 TOWNSHIP OF MALAHIDE SOUTH DORCHESTER (LYONS)	56.3 1631.3	33.8 1938.4	42.3 2639.9	67.6 2465.2	397.3 1290.4	853.7 729.7	12145.9
H48061-01 TOWNSHIP OF MALAHIDE LYONS	28.2 1265.0	39.4 1611.6	42.3 2634.3	56.3 2053.9	36.6 622.6	253.6 202.9	8846.7
I34092-01 TOWNSHIP OF MALAHIDE AYLMER	118.3 2518.8	62.0 3730.2	36.6 5772.9	33.8 4837.5	76.1 2586.4	1112.9 977.6	21863.1
M10180-01 LCBO	2.8 377.5	.0 614.2	.0 873.4	.0 794.5	.0 400.1	84.5 143.7	3290.7
M10190-01 BELMONT PUBLIC LIBRARY	5.6 [illegible]	.0 [illegible]	.0 [illegible]	.0 [illegible]	5.6 [illegible]	59.2 [illegible]	[illegible]

NATURAL RESOURCE GAS LIMITED

DATE: 10/31/2014

GAS/CUSTOMER ANALYSIS
AS OF SEP/14

<------------MONTHLY FIGURES--------------> <--------YEAR TO DATE FIGURES-------->

<----- GAS VOLUME IN M3 SEP/14	SEP/13	CHANGE	% ----><	- NUMBER OF CUSTOMERS SEP/14	SEP/13	CHANGE	% ->		<------ GAS VOLUME IN M3 CURRENT	LAST	CHANGE	% ------><	- NUMBER OF CUSTOMERS SEP/14	SEPT	CHANGE	% -->
								SALES								
352992	294334	58658	20	7467	7174	293	4	RESIDENTIA	16088024	13531207	2556817	19	7467	7174	293	4
76323	60208	16115	27	62	59	3	5	IND-RATE 1	1534158	1422336	111822	8	62	59	3	5
36091	28005	8086	29	33	31	2	6	IND-RATE 4	903962	710717	193245	27	33	31	2	6
118641	118951	310-	0	403	385	18	5	COMMERCIAL	4829642	4122306	707336	17	403	385	18	5
899257	865533	33724	4	63	63	0	0	SEASONAL	1955810	1960797	4987-	0	63	63	0	0
60264	55954	4310	8	3	3	0	0	CON-RATE 3	1794655	1636204	158451	10	3	3	0	0
1690	1127	563	50	3	3	0	0	CON-RATE 5	990936	904723	86213	10	3	3	0	0
1545258	1424112	121146	9	8034	7718	316	4	TOTAL SALE	28097187	24288290	3808897	16	8034	7718	316	4

				% THIS	% LAST			% THIS	% LAST
						DELIVERIES INTO SYSTEM						
1342434	1277493	64941	5	86	86	WEST GAS	26409678	22440583	3969095	18	91	89
45698	12256	33442	273	3	1	HEMLOCK	452559	402043	50516	13	2	2
167973	199894	31921-	16-	11	13	NORFOLK	2103386	2402847	299461-	12-	7	10
1556105	1489643	66462	4	100	100	TOTAL PURCHAS	28965623	25245473	3720150	15	100	101

10847 .7 %	65531 4.6 %	54684-	504	GAS LOSS (GAIN)	868436 3.0 %	957183 3.9 %	88747-	10

2526334	2712282	185948-	7-	0	0	0	0	ETHANOL	31527596	31357510	170086	1	0	0	0	0

SEPARATE SYSTEM (INC. PIPELINE)

DEGREE DAYS

64.7	94.9	30.2	32% WARMER THIS YEAR	ACTUAL	4347.0	3786.7	560.3	15% COLDER THIS YEAR
102.7	102.7			NORMAL	4057.7	4057.7		

(A Degree Day is the average daily temperature below 18 degrees Celsius.)

Definition of rates:

NATURAL RESOURCE GAS LIMITED
DIRECT PURCHASE TWELVE MONTH VOLUME REPORT (Cu M) PAGE: 1
CONTRACT NUMBER: TVDSB01
REPORT DATE: 11/21/2014

ACCOUNT #	NAME	OCT/14	SEP/14	AUG/14	JUL/14	JUN/14	MAY/14	
		APR/14	MAR/14	FEB/14	JAN/14	DEC/13	NOV/13	TOTAL
	AYLMER							
C39790-01	THAMES VALLEY DISTRICT SCHOOL BO	791.7	149.3	64.8	107.1	1045.3	3566.8	
		5632.0	14419.4	16284.6	14247.6	11531.6	5927.8	73768.0
	AYLME							
D07800-01	THAMES VALLEY DISTRICT SCHOOL BO	983.3	36.6	33.8	36.6	400.1	2014.4	
		5260.1	8187.4	8514.2	9838.4	5741.9	3761.2	44808.0
	STRAFFORDVILLE							
E47800-01	THAMES VALLEY DISTRICT SCHOOL BO	1377.7	174.7	98.6	90.2	132.4	2544.1	
		6029.2	9122.7	12796.6	12951.6	8542.4	5136.1	58996.3
	PORT BURWELL							
G28300-01	THAMES VALLEY DISTRICT SCHOOL BO	712.8	50.7	22.5	28.2	70.4	1104.4	
		3549.9	4834.7	6440.6	6387.0	4113.4	2961.1	30275.7
	SPRINGFIELD							
H22623-01	THAMES VALLEY DISTRICT SCHOOL BO	115.5	16.9	22.5	25.4	419.8	1414.3	
		4181.0	6130.7	8559.3	7539.4	3307.6	1867.9	33600.3
	SOUTH DORCHESTER							
H47925-01	THAMES VALLEY DISTRICT SCHOOL BO	191.6	22.5	16.9	22.5	45.1	2659.6	
		5037.5	6071.5	7437.9	6618.1	3671.1	2665.3	34459.6
	AYLMER (JAFFA)							
I38083-01	THAMES VALLEY BOARD OF EDUCATION	19.7	22.5	22.5	19.7	19.7	231.0	
		442.3	729.7	972.0	890.3	504.3	267.7	4141.4
	AYLMER.							
P10000-01	THAMES VALLEY DISTRICT SCHOOL BO	2442.7	2099.0	2087.7	2160.9	4640.3	26852.6	
		52741.7	56604.4	65138.3	53668.6	37412.2	14737.8	320586.2
	GRAND TOTAL	6635.0	2572.2	2369.3	2490.6	6773.1	40387.2	
		82873.7	106100.5	126143.5	112141.0	74824.5	37324.9	600635.5

M12000-01 BELMONT FIREHALL	19.7	14.1	14.1	11.3	101.4	577.6	
	1400.2	1312.9	1989.1	1752.4	955.1	191.6	8339.5
M33400-01 BELMONT ARENA	890.3	177.5	309.9	211.3	369.1	2518.8	
	7508.4	9339.7	12069.7	10235.6	6333.5	4209.2	54173.0
GRAND TOTAL	13441.7	13036.2	9545.4	9032.6	11202.0	22660.6	
	45272.7	57827.2	73415.9	67592.1	42849.8	28672.8	394549.0

NATURAL RESOURCE GAS LIMITED
DIRECT PURCHASE TWELVE MONTH VOLUME REPORT (Cu M) PAGE: 1
CONTRACT NUMBER: FIRE004
REPORT DATE: 11/21/2014

ACCOUNT # NAME	OCT/14 APR/14	SEP/14 MAR/14	AUG/14 FEB/14	JUL/14 JAN/14	JUN/14 DEC/13	MAY/14 NOV/13	TOTAL
H52098-01 1064540 ONTARIO INC	.0	2341.3	3262.5	2034.2	1921.5	1752.4	
AYLMER	324.0	425.4	487.4	287.4	2434.2	890.3	16160.6
P30000-01 KINGSMILL GRAINS	1631.3	8142.3	6508.2	.0	619.8	817.0	
HIGH CONSUMER, AYLMER	2859.7	1011.4	2561.0	22573.0	206123.7	77867.3	330714.7
GRAND TOTAL	1631.3	10483.6	9770.7	2034.2	2541.3	2569.4	
	3183.7	1436.8	3048.4	22860.4	208557.9	78757.6	346875.3

NATURAL RESOURCE GAS LIMITED
DIRECT PURCHASE TWELVE MONTH VOLUME REPORT (Cu M) PAGE: 1
CONTRACT NUMBER: CESI001
REPORT DATE: 11/21/2014

ACCOUNT # NAME	OCT/14 APR/14	SEP/14 MAR/14	AUG/14 FEB/14	JUL/14 JAN/14	JUN/14 DEC/13	MAY/14 NOV/13	TOTAL
H04660-02 JOANNE SAARLOOS (PAC)	366.3 338.1	284.6 295.8	239.5 560.7	242.3 521.2	611.4 509.9	281.7 284.6	4536.1
P03000-04 ELGIN FEEDS AYLMER	.0 .0	.0 .0	.0 .0	.0 12402.2	.0 26303.2	.0 14368.7	53074.1
GRAND TOTAL	366.3 338.1	284.6 295.8	239.5 560.7	242.3 12923.4	611.4 26813.1	281.7 14653.3	57610.2

Gas Day of November 12/14

Location	Pressure (PSI)	Type	Description
North Walsingham	83	Union Gas Input into NRG System	
Bayham (New England)	79	Union Gas Input into NRG System	
Putnam Station	81	Union Gas Input into NRG System	
Harrietsville Station	89	Union Gas Input into NRG System	
Eden (Ridge Rd)	83	Union Gas Input into NRG System	
Rogers Rd and Talbot Ln	42	Feeding Town of Aylmer	Feeds east into Aylmer on Talbot Ln at 28psi
Hacienda Rd and Talbot Ln	52	Feeding Town of Aylmer	SE corner Feeding into Aylmer at 28psi
John St S at Bradley Creek	51	Feeding Town of Aylmer	Feeds North into Aylmer on Imperial Rd at 28psi
Beech St	65	Feeding Town of Aylmer	Feeds south into Aylmer on Imperial Rd at 28psi
Belmont South	78	Feeding Town of Belmont	Feeds north into Belmont on Belmont Rd at 35psi
Belmont North	33	Feeding Town of Belmont	Feeds south into Belmont on Belmont Rd at 35psi (drooping to 31)
Port Bruce	53	Feeding Town of Port Bruce	Feeding south to Port Bruce
Brownsville South	38	Feeding Town of Brownsville	NE corner of Hawkins Rd and Culloden Ln, feeding north at 35psi
Vanmoerkerke	63	Customer	Carson Ln, on curve almost to Talbot Ln
YPMA	9	Customer	NW corner of Ostrander Rd and Culloden Ln
Sylvite Avon	55	Customer	North sd of Avon Dr west of Putnam Rd
FS Partners Straffordville	54	Customer	North sd of Jackson Ln East of Plank Rd (south of Straffordville)
Klassen Farms	55	Customer	Regional Rd #28 North of Fairground Rd
Kingsmill Grain	21	Customer	Ron McNeil Ln west of Springwater Rd at the very end of the Main (Large Customer)
Graydon Farms	33	Customer	SE corner of Hawkins Rd and Culloden Ln
Isaak Bartsch	59	Customer	Fairground Rd east of 5th Conc Enr
Best Ln Farms	35	Customer	SE Corner of Best Ln and Somers Rd
Herman	74	Check point	SE corner of Toll Gate Rd and Heritage Ln
Doerksen	60	Check point	NE corner of Regional Rd #23 and Regional Rd #60
Whittaker Rd and Yorke Ln	79	Check point	SW corner of Whittaker Rd and Yorke Ln

Huddleston, Alex

From: Mark McCord [mmccord@nrgas.on.ca]
Sent: January 7, 2015 1:09 PM
To: Huddleston, Alex
Cc: Brian Lippold
Subject: Re: Helpful System info

That was my mistake

North walsingham =walsingham
New England = Bayham
Ridge Rd = Eden

We didn't have pressure reading for belmont and Brownsville.

Thanks
Mark

On Jan 6, 2015, at 4:30 PM, Huddleston, Alex <Alex.Huddleston@snclavalin.com> wrote:

Mark, Brian,

No, I didn't receive the spreadsheet that Mark initially sent on Dec 23rd.

You've used a number of different names for the flow inputs: The GCA report has deliveries into the system at West Gas, Hemlock, and Norfolk, while Mark's pressure data has delivery pressures at North Walsingham, New England, Putnam Station, Harrietsville Station, and Ridge Road, and the initial locations where gas is input into the system are Harrietsville, Putnam, Eden, Bayham, Walsingham, Belmont, and Brownsville. Can you tell us how to correlate this data. We need to have a flow rate and pressure, if available, for each delivery point into the system. I've summarized t in a table below:

GCA Report	Mark's Pressure Spreadsheet	Initial Delivery Point Information
West Gas		
Hemlock		
Norfolk		
	North Walsingham	Walsingham
	New England	
	Putnam Station	Putnam
	Harriestville Station	Harriestville
	Ridge Rd	
		Eden
		Bayham
		Belmont

		Brownsville

Once we resolve this question, we'll input this data into the model and see if it converges. If the model converges, we'll be able to start the analysis, otherwise we'll see what additional data we need.

Thanks,

Alex Huddleston
Department Manager, Pipelines
Oil & Gas

Tel.: +1 403-294-2714
Cell.: +1 403-461-1102

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<image002.jpg>

<image003.jpg>

From: Mark McCord [mailto:mmccord@nrgas.on.ca]
Sent: January 5, 2015 9:07 AM
To: Huddleston, Alex
Subject: RE: Helpful System info

Alex

Did you get this attachment, I sent you on Dec 23? It has the pressures we experienced on that peak grain drying day.

Thanks

From: Huddleston, Alex [mailto:Alex.Huddleston@snclavalin.com]
Sent: Monday, January 05, 2015 10:17 AM
To: Mark McCord
Cc: 'lomeara@cpirentals.com'; Brian Lippold
Subject: RE: Helpful System info

Mark,

Have you been able to review this email I sent last year?

Thanks,

Alex

From: Huddleston, Alex
Sent: December 17, 2014 5:47 PM
To: Mark McCord
Cc: lomeara@cpirentals.com; Brian Lippold
Subject: RE: Helpful System info

Mark,

My comments below.

Thanks,

Alex

From: Brian Lippold [mailto:brian@nrgas.on.ca]
Sent: December 17, 2014 1:31 PM
To: Huddleston, Alex
Cc: lomeara@cpirentals.com; Mark McCord
Subject: Helpful System info

Alex

So we can best assist you in reaching your end goal we are hoping that you might clarify your approach. The following 2 questions may dig up enough that we can come up with some ideas to move you in a direction of success:

1. Which scenario are you working at modeling?
   - summer
   - winter Winter. I understood that the coldest winter month had the highest demand on the system and that the largest demand from the system was for residential heating. We planned on modeling two flow rates for a typical residence: the normal winter month and the coldest winter month. For a typical residential home you directed us to use 2009 m3/yr for a normal winter flow rate and 2400 m3/yr for the coldest winter month.
   - grain drying (autumn to winter cross-over)
   - peak demand times (residential wake-up and evening)
2. What specific time frames in the above period, are you looking at modeling?
   - Hour
   - day
   - month
   - annual

   I understood that you don't have the data to support any of these time frames. We planned to model the system as a cold front moves into the area and the demand increases from normal winter flow rates to coldest winter month flow rates. We wouldn't be modeling the system for a particular time period, but at two instances in time: before and after the cold front moves in. I understood that during these times the system pressure, in some areas, drops to the point that it is very close to or below the town gate regulating pressure.

Here are some key points and observations. These points were made by Mark McCord. So any clarification that you may require should be directed to him. Please copy me on the responses.

- We observe the time when our system is pushed to its limits occurs in the crossover of winter heating load and grain drying season.

- Grain drying occurs in October and November. OK. Can you please send us a Gas/Customer Analysis report for a worst case month where your system was pushed to its limits. We can use these rates as a starting point to set up the system
- If we experience cold weather during the grain drying, it results in an increase in natural gas consumption

From what I understand, you are trying to simulate our system performance based on various supplies and consumptions throughout our system. With almost 8000 customers, it is difficult to account for the load of each individual customer. We have daily consumption volume figures from our larger customers. For the most part our consumption volumes are taken on a monthly basis and the reading are staggered throughout any given month. We plan to use the normal and coldest day residential flow rates above for the majority of the load, and get volumes from other large customers from the CGA report.

We avoided the worst case scenario this past November because we were saved by a snowfall which forced farmers to delay harvest and winter temperatures began to rise and fall into the seasonal average. On the days with the largest consumptions, we monitored our system pressures very closely. We would see pressure drops across our system of around 50-70psi (tremendous drop for an 80 psi system). To illustrate, the Union gas inlet stations of Harrietsville and Putnam were introducing 80psi into our system; however, we were seeing pressures of 10psi just north of Brownsville and 40psi along the shore of Lake Erie. Each town of significance is regulated and therefore cannot flow gas through the town - only around its perimeter. As a result of this, we should treat each town as a single point customer. We are treating each town as a single customer. We're summing the residences in the town multiplying by the residential flow rate and adding the large customers for the town as identified in the CGA report.

Is it possible for you to model the system using the pressures taken at various points throughout our system? Yes, please provide pressure readings for a worst case time where your system was pushed to its limits. Most pressures would be instantaneous pressures and some are daily averages. Please identify if the pressure is an average or instantaneous. I could identify where the pressure readings were taken and if it is a customer (an exit of gas) or a pipeline checkpoint. The more pressures you are able to provide the more accurate our model will be. And differentiating between the customers and the checkpoints is critical. Is it possible for the modeling software to then solve for the exit flowrate based on each pressure reading location? Yes, the model can solve for an exit flow rate. We can then use the CGA report (or some other information) for the same time period so that we can check the exit flow rates that the model calculates. During these high demand days, I could also identify the volume of gas purchased into our system on a daily basis at each of the delivery points. Yes, please provide the gas purchases and the location of these purchase for this worst case time period.

I think that using inlet flow rates and line pressures at all end-points and at various locations along the system will be the best approach. I'd like to model two scenarios:

- Before the grain dryers are turned on and the cold snap moves in
- After the grain dryers are turned on and the cold snap moves in

Can you provide pressure readings and flow rates for these two scenarios? We'd also like to compare the flow rates calculated by the model with your records, so please provide a CGA report for these periods or some other record of flow rates if available.

It might be worth a discussion to clarify any points above as we feel it will help move you forward if you are stuck.

Brian Lippold,
General Manager
Natural Resources Gas Ltd.
39 Beech St. E. | Aylmer, ON N5H 3J6
P: 519 773 5321 ext 205 | F: 519 773-5335
Mail to : brian@nrgas.on.ca

Huddleston, Alex

From: Mark McCord [mmccord@nrgas.on.ca]
Sent: January 7, 2015 12:54 PM
To: Huddleston, Alex; Brian Lippold
Subject: RE: Helpful System info

1. That is correct
2. That is correct
3. This regulator can be placed on Imperial Rd, South of Nova Scotia Ln
4. Klassen Farms is on regional rd #28, north of Fairgound Rd. (east Side)
5. Isaak Bartsch is on Fairground Rd East of 5th Conc ENR.

Which regulator stations are you referring to?

Thanks
Mark

From: Huddleston, Alex [mailto:Alex.Huddleston@snclavalin.com]
Sent: Wednesday, January 07, 2015 9:15 AM
To: Mark McCord; Brian Lippold
Subject: RE: Helpful System info

Mark, Brian,

In addition to our questions of yesterday can you please clarify the following:

1. Belmont South – The DWG files do not show a regulator station on the south end of Belmont. We will assume that there is a regulator station here feeding into Belmont.
2. Belmont North – The DWG files do not show a regulator station on the north end of Belmont. We will assume that there is a regulator station here feeding into Belmont.
3. Port Bruce - The DWG files do not show a regulator station near Port Bruce. We do not have a separate DWG file for the Port Bruce & Copenhagen area. Location of this regulator needs to be identified.
4. Klassen Farms – Location could not be found.
5. Isaak Bartsch – Location could not be found.

Can you also provide pressures data for the other gas regulator stations shown in the .DWG files?

Thanks,

Alex Huddleston
Department Manager, Pipelines
Oil & Gas

Tel.: +1 403-294-2714
Cell.: +1 403-461-1102

SNC-Lavalin Inc.
605 - 5th Avenue SW, 14th Floor
Calgary | Alberta | Canada | T2P 3H5

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KENTZ
Engineers & Constructors
Member of the SNC-Lavalin Group

From: Huddleston, Alex
Sent: January 6, 2015 2:29 PM
To: 'Mark McCord'; 'Brian Lippold'
Subject: RE: Helpful System info

Mark, Brian,

No, I didn't receive the spreadsheet that Mark initially sent on Dec 23rd.

You've used a number of different names for the flow inputs: The GCA report has deliveries into the system at West Gas Hemlock, and Norfolk, while Mark's pressure data has delivery pressures at North Walsingham, New England, Putnam Station, Harrietsville Station, and Ridge Road, and the initial locations where gas is input into the system are Harrietsville Putnam, Eden, Bayham, Walsingham, Belmont, and Brownsville. Can you tell us how to correlate this data. We need to have a flow rate and pressure, if available, for each delivery point into the system. I've summarized t in a table below:

GCA Report	Mark's Pressure Spreadsheet	Initial Delivery Point Information
West Gas		
Hemlock		
Norfolk		
	North Walsingham	Walsingham
	New England	
	Putnam Station	Putnam
	Harriestville Station	Harriestville
	Ridge Rd	
		Eden
		Bayham
		Belmont
		Brownsville

Once we resolve this question, we'll input this data into the model and see if it converges. If the model converges, we'll be able to start the analysis, otherwise we'll see what additional data we need.

Thanks,

Alex Huddleston
Department Manager, Pipelines
Oil & Gas

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KENTZ
Engineers & Constructors
Member of the SNC-Lavalin Group

From: Mark McCord [mailto:mmccord@nrgas.on.ca]
Sent: January 5, 2015 9:07 AM
To: Huddleston, Alex
Subject: RE: Helpful System info

Alex
Did you get this attachment, I sent you on Dec 23? It has the pressures we experienced on that peak grain drying day.

Thanks

From: Huddleston, Alex [mailto:Alex.Huddleston@snclavalin.com]
Sent: Monday, January 05, 2015 10:17 AM
To: Mark McCord
Cc: 'lomeara@cpirentals.com'; Brian Lippold
Subject: RE: Helpful System info

Mark,

Have you been able to review this email I sent last year?

Thanks,

Alex

From: Huddleston, Alex
Sent: December 17, 2014 5:47 PM
To: Mark McCord
Cc: lomeara@cpirentals.com; Brian Lippold
Subject: RE: Helpful System info

Mark,

My comments below.

Thanks,

Alex

From: Brian Lippold [mailto:brian@nrgas.on.ca]
Sent: December 17, 2014 1:31 PM
To: Huddleston, Alex
Cc: lomeara@cpirentals.com; Mark McCord
Subject: Helpful System info

Alex

So we can best assist you in reaching your end goal we are hoping that you might clarify your approach. The following 2 questions may dig up enough that we can come up with some ideas to move you in a direction of success:

1. Which scenario are you working at modeling?
   - summer
   - winter Winter. I understood that the coldest winter month had the highest demand on the system and that the largest demand from the system was for residential heating. We planned on modeling two flow rates for a typical residence: the normal winter month and the coldest winter month. For a typical residential home you directed us to use 2009 m3/yr for a normal winter flow rate and 2400 m3/yr for the coldest winter month.
   - grain drying (autumn to winter cross-over)
   - peak demand times (residential wake-up and evening)
2. What specific time frames in the above period, are you looking at modeling?
   - Hour
   - day
   - month
   - annual

   I understood that you don't have the data to support any of these time frames. We planned to model the system as a cold front moves into the area and the demand increases from normal winter flow rates to coldest winter month flow rates. We wouldn't be modeling the system for a particular time period, but at two instances in time: before and after the cold front moves in. I understood that during these times the system pressure, in some areas, drops to the point that it is very close to or below the town gate regulating pressure.

Here are some key points and observations. These points were made by Mark McCord. So any clarification that you may require should be directed to him. Please copy me on the responses.

- We observe the time when our system is pushed to its limits occurs in the crossover of winter heating load and grain drying season.
- Grain drying occurs in October and November. OK. Can you please send us a Gas/Customer Analysis report for a worst case month where your system was pushed to its limits. We can use these rates as a starting point to set up the system
- If we experience cold weather during the grain drying, it results in an increase in natural gas consumption

From what I understand, you are trying to simulate our system performance based on various supplies and consumptions throughout our system. With almost 8000 customers, it is difficult to account for the load of each individual customer. We have daily consumption volume figures from our larger customers. For the most part our consumption volumes are taken on a monthly basis and the reading are staggered throughout any given month. We plan to use the normal and coldest day residential flow rates above for the majority of the load, and get volumes from other large customers from the CGA report.

We avoided the worst case scenario this past November because we were saved by a snowfall which forced farmers to delay harvest and winter temperatures began to rise and fall into the seasonal average. On the days with the largest consumptions, we monitored our system pressures very closely. We would see pressure drops across our system of around 50-70psi (tremendous drop for an 80 psi system). To illustrate, the Union gas inlet stations of Harrietsville and

Putnam were introducing 80psi into our system; however, we were seeing pressures of 10psi just north of Brownsville and 40psi along the shore of Lake Erie. Each town of significance is regulated and therefore cannot flow gas through the town - only around its perimeter. As a result of this, we should treat each town as a single point customer. We are treating each town as a single customer. We're summing the residences in the town multiplying by the residential flow rate and adding the large customers for the town as identified in the CGA report.

Is it possible for you to model the system using the pressures taken at various points throughout our system? Yes, please provide pressure readings for a worst case time where your system was pushed to its limits. Most pressures would be instantaneous pressures and some are daily averages. Please identify if the pressure is an average or instantaneous. I could identify where the pressure readings were taken and if it is a customer (an exit of gas) or a pipeline checkpoint. The more pressures you are able to provide the more accurate our model will be. And differentiating between the customers and the checkpoints is critical. Is it possible for the modeling software to then solve for the exit flowrate based on each pressure reading location? Yes, the model can solve for an exit flow rate. We can then use the CGA report (or some other information) for the same time period so that we can check the exit flow rates that the model calculates. During these high demand days, I could also identify the volume of gas purchased into our system on a daily basis at each of the delivery points. Yes, please provide the gas purchases and the location of these purchase for this worst case time period.

I think that using inlet flow rates and line pressures at all end-points and at various locations along the system will be the best approach. I'd like to model two scenarios:

- Before the grain dryers are turned on and the cold snap moves in
- After the grain dryers are turned on and the cold snap moves in

Can you provide pressure readings and flow rates for these two scenarios? We'd also like to compare the flow rates calculated by the model with your records, so please provide a CGA report for these periods or some other record of flow rates if available.

It might be worth a discussion to clarify any points above as we feel it will help move you forward if you are stuck.

Brian Lippold,
General Manager
Natural Resources Gas Ltd.
39 Beech St. E. | Aylmer, ON N5H 3J6
P: 519 773 5321 ext 205 | F: 519 773-5335
Mail to : brian@nrgas.on.ca

NRG
Natural Resource Gas Limited

Huddleston, Alex

From:	Brian Lippold [brian@nrgas.on.ca]
Sent:	January 5, 2015 12:55 PM
To:	Huddleston, Alex
Cc:	Mark McCord
Subject:	RE: Helpful System info
Attachments:	NRG Gas Analysis.pdf

Happy New Year.

Please see our Nov Gas Analysis for that peak period in Nov. Mark forwarded some pressure data with specific pressures and corresponding dates. Let's schedule a call and determine how to get the cheese at the end of the maze. When are you available?

Thanks,

Brian Lippold,
General Manager
Natural Resources Gas Ltd.
39 Beech St. E. | Aylmer, ON N5H 3J6
P: 519 773 5321 ext 205 | F: 519 773-5335
Mail to : brian@nrgas.on.ca

Natural Resource Gas Limited

From: Huddleston, Alex [mailto:Alex.Huddleston@snclavalin.com]
Sent: January-05-15 10:17 AM
To: Mark McCord
Cc: 'lomeara@cpirentals.com'; Brian Lippold
Subject: RE: Helpful System info

Mark,

Have you been able to review this email I sent last year?

Thanks,

Alex

From: Huddleston, Alex
Sent: December 17, 2014 5:47 PM
To: Mark McCord
Cc: lomeara@cpirentals.com; Brian Lippold
Subject: RE: Helpful System info

Mark,

My comments below.

Thanks,

Alex

From: Brian Lippold [mailto:brian@nrgas.on.ca]
Sent: December 17, 2014 1:31 PM
To: Huddleston, Alex
Cc: lomeara@cpirentals.com; Mark McCord
Subject: Helpful System info

Alex

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It might be worth a discussion to clarify any points above as we feel it will help move you forward if you are stuck.

Brian Lippold,
General Manager
Natural Resources Gas Ltd.
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Mail to : brian@nrgas.on.ca

nRG
Natural Resource Gas Limited

NATURAL RESOURCE GAS LIMITED

DATE: 12/31/2014

GAS/CUSTOMER ANALYSIS
AS OF NOV/14

MONTHLY FIGURES									YEAR TO DATE FIGURES							
GAS VOLUME IN M3				NUMBER OF CUSTOMERS					GAS VOLUME IN M3				NUMBER OF CUSTOMERS			
NOV/14	NOV/13	CHANGE	%	NOV/14	NOV/13	CHANGE	%		CURRENT	LAST	CHANGE	%	NOV/14	SEPT	CHANGE	%
								SALES								
1676212	1563487	112725	7	7555	7264	291	4	RESIDENTIA	2513543	2332018	181525	8	7555	7467	88	1
383223	296785	86438	29	62	60	2	3	IND-RATE 1	587259	538095	49164	9	62	62	0	0
626759	355640	271119	76	34	33	1	3	IND-RATE 4	876380	704772	171608	24	34	33	1	3
476309	456982	19327	4	402	391	11	3	COMMERCIAL	710379	681642	28737	4	402	403	1-	0
117063	80662	36401	45	63	63	0	0	SEASONAL	409734	376630	33104	9	63	63	0	0
195105	184173	10932	6	3	3	0	0	CON-RATE 3	302307	278866	23441	8	3	3	0	0
694827	607657	87170	14	3	3	0	0	CON-RATE 5	842515	874126	31611-	4-	3	3	0	0
4169498	3545386	624112	18	8122	7817	305	4	TOTAL SALE	6242117	5786149	455968	8	8122	8034	88	1
				% THIS	% LAST			DELIVERIES INTO SYSTEM					% THIS	% LAST		
4415371	3629458	785913	22	95	94			WEST GAS	6134097	5633558	500539	9	93	92		
45163	64011	18848-	29-	1	2			HEMLOCK	95820	76802	19018	25	1	1		
164311	183131	18820-	10-	4	5			NORFOLK	338313	386434	48121-	12-	5	6		
4624845	3876600	748245	19	100	101			TOTAL PURCHAS	6568230	6096794	471436	8	99	99		
455347 10.9 %	331214 9.3 %	124133	27					GAS LOSS (GAIN)	326113 5.2 %	310645 5.3 %	15468	5				

[redacted]

DEGREE DAYS

503.7	493.3	10.4	2% COLDER THIS YEAR	ACTUAL	741.1	717.4	23.7	3% COLDER THIS YEAR
446.7	446.7			NORMAL	725.6	725.6		

(A Degree Day is the average daily temperature below 18 degrees Celsius.)

Definition of rates:

Huddleston, Alex

From: Huddleston, Alex
Sent: May 5, 2015 9:49 AM
To: Orr, John
Subject: FW: Status Update

From: Brian Lippold [mailto:brian@nrgas.on.ca]
Sent: May 5, 2015 9:47 AM
To: Huddleston, Alex
Cc: Mark McCord
Subject: FW: Status Update

I thought that Mark sent this directly to you the day of our last conversation about the wells and using the Max draw on worst day (highest consumption).

See his data below.

Brian Lippold,
General Manager
Natural Resources Gas Ltd.
39 Beech St. E. | Aylmer, ON N5H 3J6
P: 519 773 5321 ext 205 | F: 519 773-5335
Mail to : brian@nrgas.on.ca

Natural Resource Gas Limited

Alex

Here are the daily volumes at each of the union gas station inputs on Nov 12/14

-Belmont Station – 12509m3
-Harrrietsville Station – 86919m3
-Putnam Station - 38513m3
-Brownsville Station – 1183m3
-Bayham Station – 28962m3
-Eden Station – 28005m3
-North Walsingham Station – 23919m3

The well inputs are as follows

- Nova Scotia Ln Between Richmond Rd and Woodworth Rd – 1888m3/day
- Fairground Rd and Regional Rd #28 – 4888m3/day
- On 2nd Conc ENR North of Barth Sd Rd – 4888m3/day

Lastly the town of Port Burwell is regulated to 30psi. The East side of the town is disconnected at Plank Rd and Teall Neville Ln and the west side is disconnected at Brown Rd and Nova Scotia ln. There is only one pipeline on Vienna Ln that connects the system East of Plank Rd to the System West of Plank Rd.

Thanks
Mark

From: Huddleston, Alex [mailto:Alex.Huddleston@snclavalin.com]
Sent: Tuesday, February 17, 2015 12:19 PM
To: Brian Lippold
Cc: Mark McCord
Subject: Status Update

Hi Brian,

Please see the attached file. Printing it in 11x17 is OK, but please print as large as you can. The file contains a representation of the NRG system in the SPS model based on the pressures you provided for grain drying on Nov 12th, '14.

We've placed a node at each intersection in the network and color coded the node according to its pressure:

- The darker colors show higher pressure
- Green is between 40 and 50 psi
- Yellow is between 30 and 40 psi
- Red is less than 30 psi

The legend on the chart also states the number of nodes in each pressure range

The pressure and flow rate coming in from each station are shown adjacent to the station's location. The total flow into the system is about 7570 m3/hr, which is approximately 20% higher than the highest average monthly rate that we've seen. The flow rates coming into the system are rounded to the nearest 100 on the attached file. We also limited the inlet pressures to 80 psi, which is the MAOP of the pipelines.

We didn't receive a pressure at Brownsville Station so we limited it to 170 m3/hr, which is its maximum hourly volume. We also didn't receive a pressure at Belmont Station, and it's maximum hourly flow is 538 m3/hr, but in the model only 50 m3/hr are required to feed the town of Belmont from the North.

The pressure at each location you supplied are also shown. In most cases, the pressure calculated in the model matches the pressure you provided. The only exceptions are:

- at Beach St., where the model pressure is 5 psi higher than the provided pressure
- at Herman, where the model pressure is 4 psi lower than the provided pressure
- at Issak Bartch, where the model has calculated the equivalent of a 50 m3/hr input into the system—which I believe can be attributed to flow from the local well sites

We've added two loops into the system that are currently inactive in the model: at John Wise and along Wilson between Whitaker and Prigham. The nodes are showing red and yellow respectively in the model.

The main areas of concern (where there are a number of yellow and red nodes) are in the Aylmer region and in the Brownsville region. The next step we'll take is to modify the system to alleviate the low pressure areas by looping or adding laterals. We'll send another chart like the attached showing the system pressures after looping or additional laterals have been added to the system.

The model has been revised to run on inlet and outlet pressures, so if you can provide pressures for other extreme days, that are different from Nov 12th, '14, we can complete a chart like the attached in about 8 hours and it will increase our understanding of the system and how we can alleviate the low pressure areas.

Thanks,

Alex Huddleston
Department Manager, Pipelines
Oil & Gas

Tel.: +1 403-294-2714
Cell.: +1 403-461-1102

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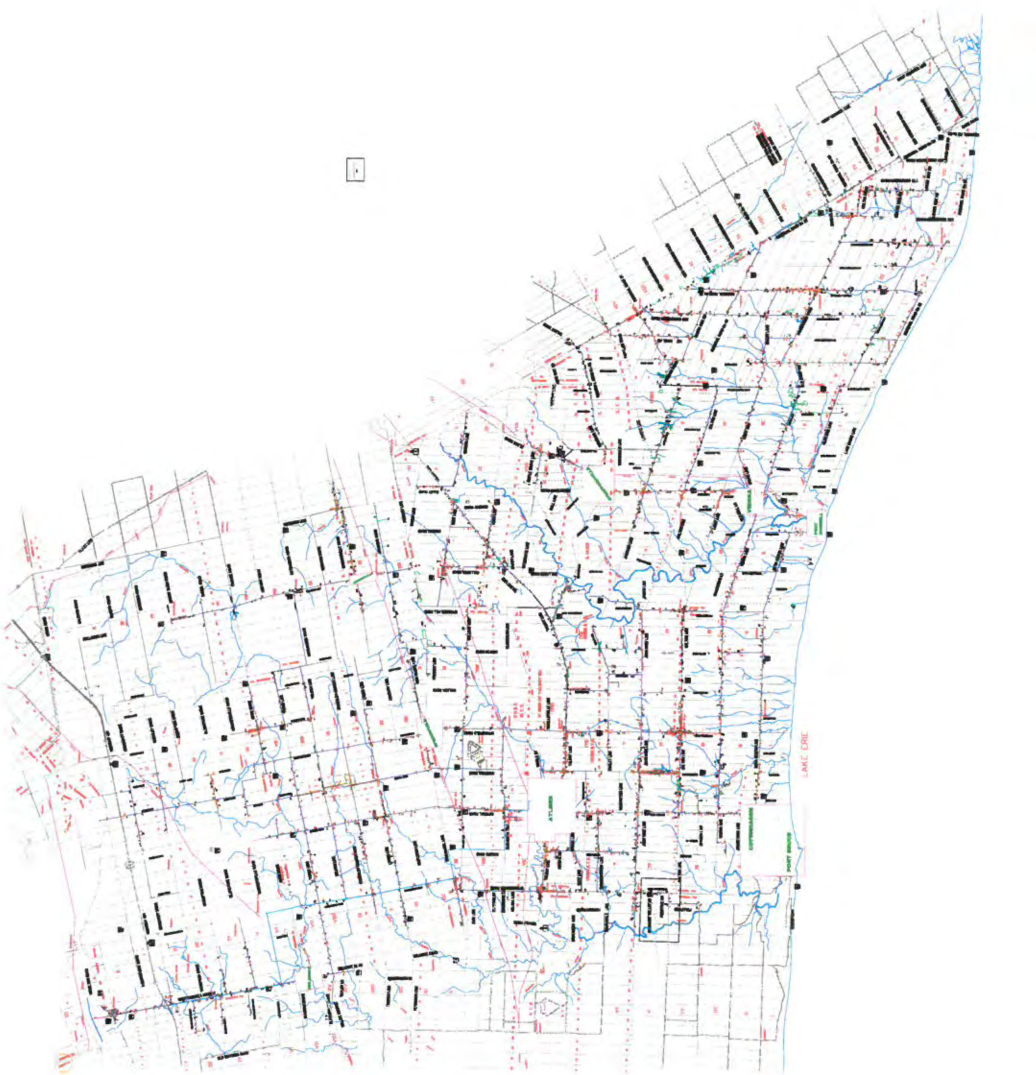
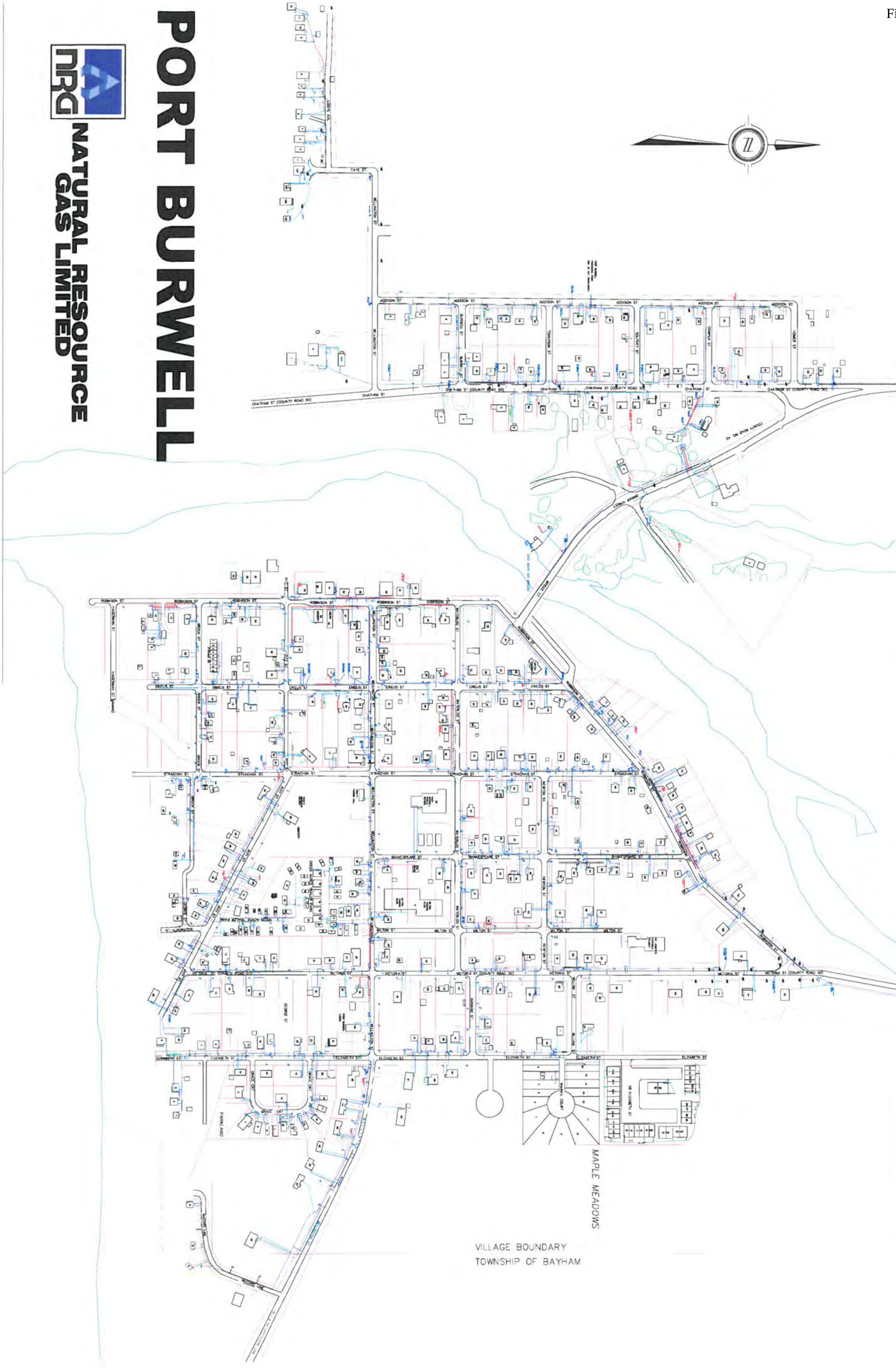
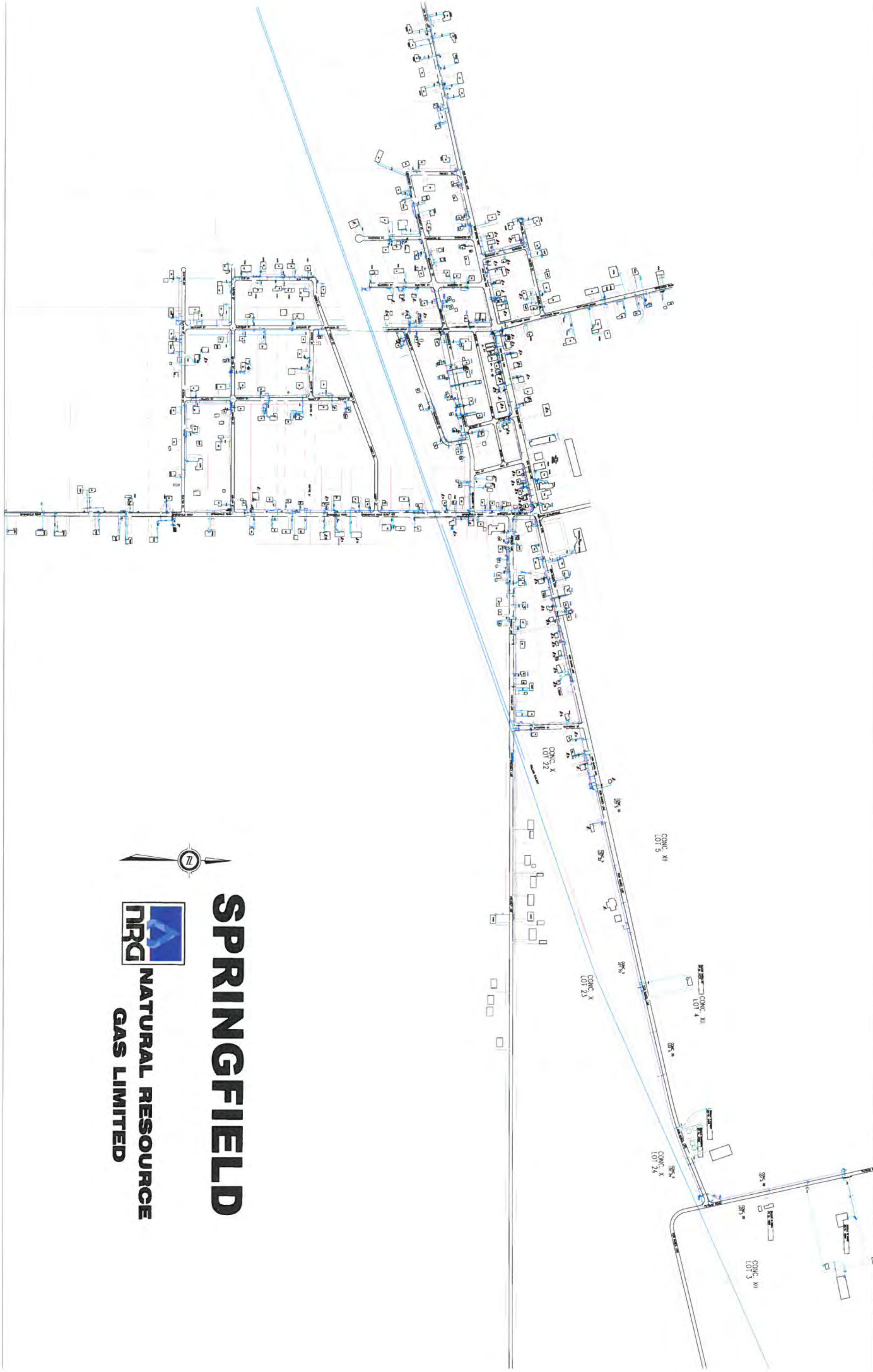
Contracted Labour and Material Cost Estimates for SW Ontario Market			
Action/Task	Per metre Material Cost	Labour cost Per metre or Hourly	Conditions
Directional Drilling/Boring		\$55/m @4" \$75/m @6"	30" or greater required by a local; Water, sub road; below culvert; inclines/declines of greater than 15 degrees. Protected area; walkways, gardens or areas that require significant restoration
Trenching with sticks (3/4")		\$31.25/m	36" or less below grade; accessible road allowance; grade without considerable slope (0= >15 degrees); only 3 or 4" PE 3", 4" and 6"
Trenching with rolls		\$15/m @2" \$27.50 @3"	1 to 3" OD maximum
Fusing/ Capping	n/a	n/a	Included in installation cost
Marker/ Signage Installation		75/hour	Every valve; High pressure; Road Crossing; 500m min standard
Hot Tapping + Connection	n/a	n/a	Engineered by pipe size- only applicable to the dedicated 6" IGPC steel pipeline
Dry Tapping + Connection			Included in installation costs
Clean, Dry, Pig, Leak Test			Included in installation cost
PE Pipe Pricing	1" 2" 3"Roll 3" Stick 4" 6"	\$ 2.79 \$ 4.92 \$12.00 \$15.00 \$21.00 \$30.00	Contractor requoted pricing –Feb 2016
PE Fittings	n/a	n/a	Various by diameter and function-too broad

1- The projects that have been identified would all be completed using PE (plastic) pipe.
2- That installation of tracer wire is included in all boring or trenching costs
3- All provided material or labour-costs are average prices from within a 36 month period.
4- Hourly or task costs include equipment required
5- No surveying required in our Franchise area

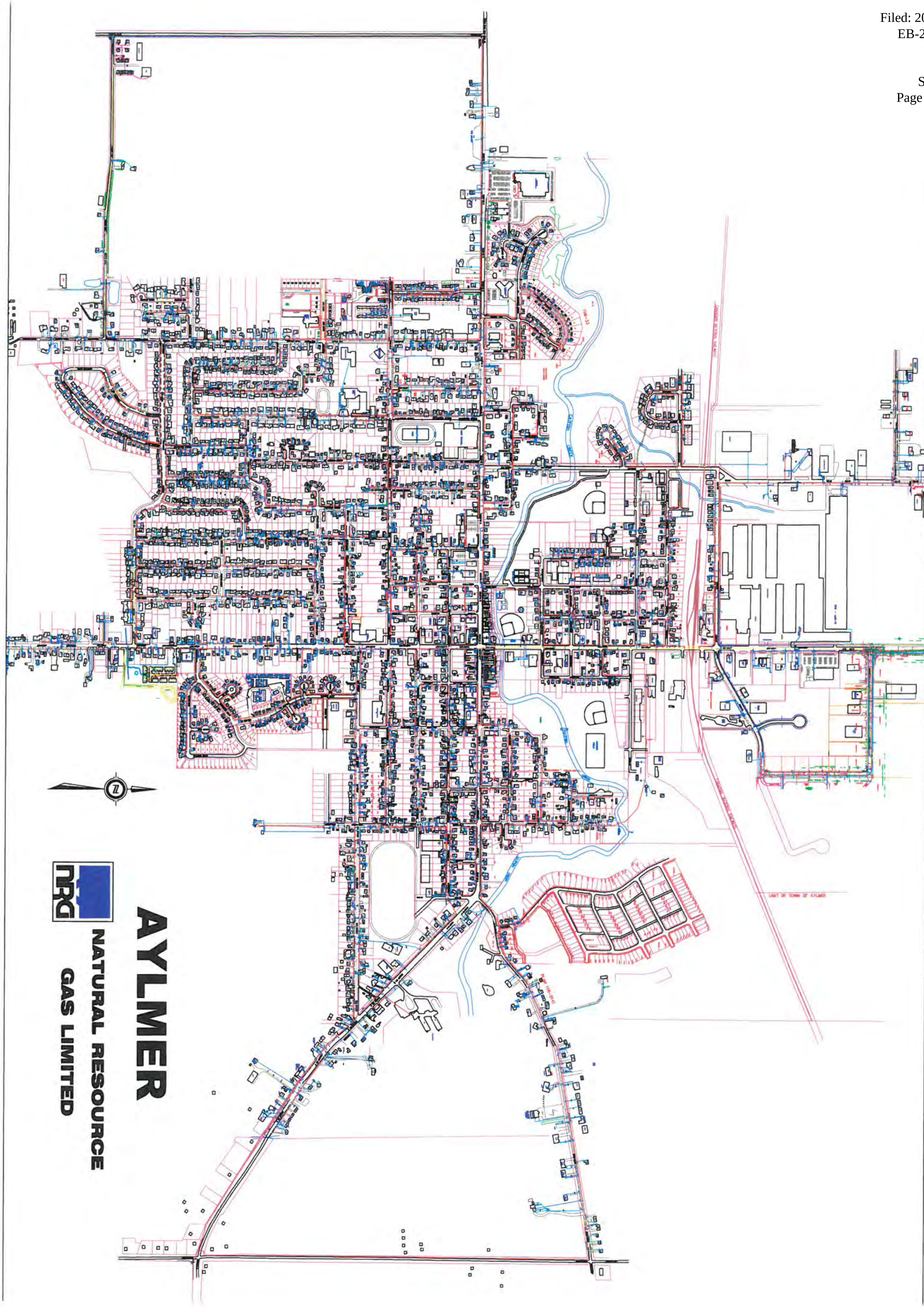

LAKE ERIE


PORT BURWELL
NRG
NATURAL RESOURCE GAS LIMITED
MAPLE MEADOWS
VILLAGE BOUNDARY
TOWNSHIP OF BAYHAM

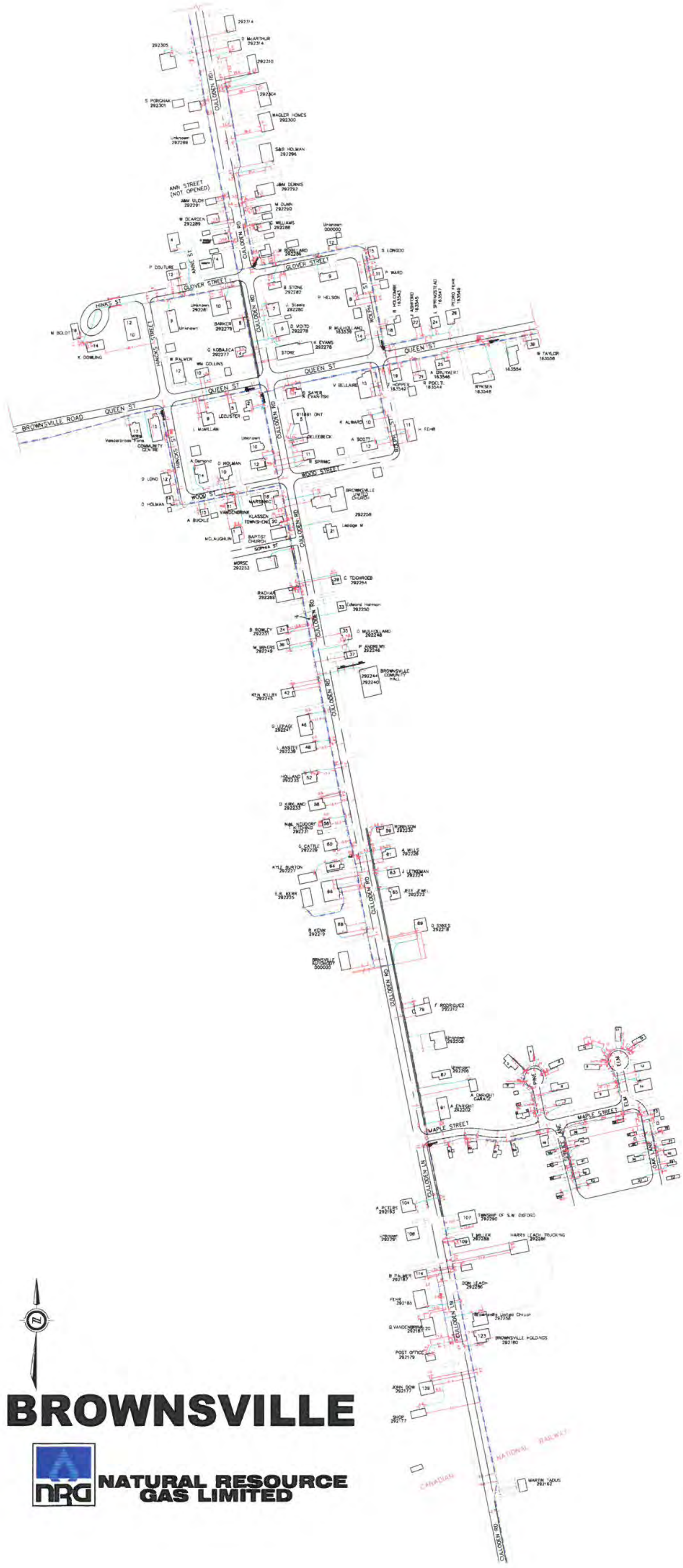

SPRINGFIELD
NRG
NATURAL RESOURCE
GAS LIMITED
CONC. X
LOT 22
CONC. XII
LOT 5
CONC. X
LOT 23
CONC. XII
LOT 4
CONC. X
LOT 24
CONC. XII
LOT 3


STRAFFORDVILLE
NATURAL RESOURCE
GAS LIMITED


VIENNA
NATURAL RESOURCE
GAS LIMITED


AYLMER
NATURAL RESOURCE
GAS LIMITED


BELMONT
NATURAL RESOURCE
GAS LIMITED


BROWNSVILLE
NATURAL RESOURCE GAS LIMITED
NRG
CULLODEN RD
QUEEN ST
GLOVER STREET
WOOD STREET
MAPLE STREET
BROWNSVILLE ROAD

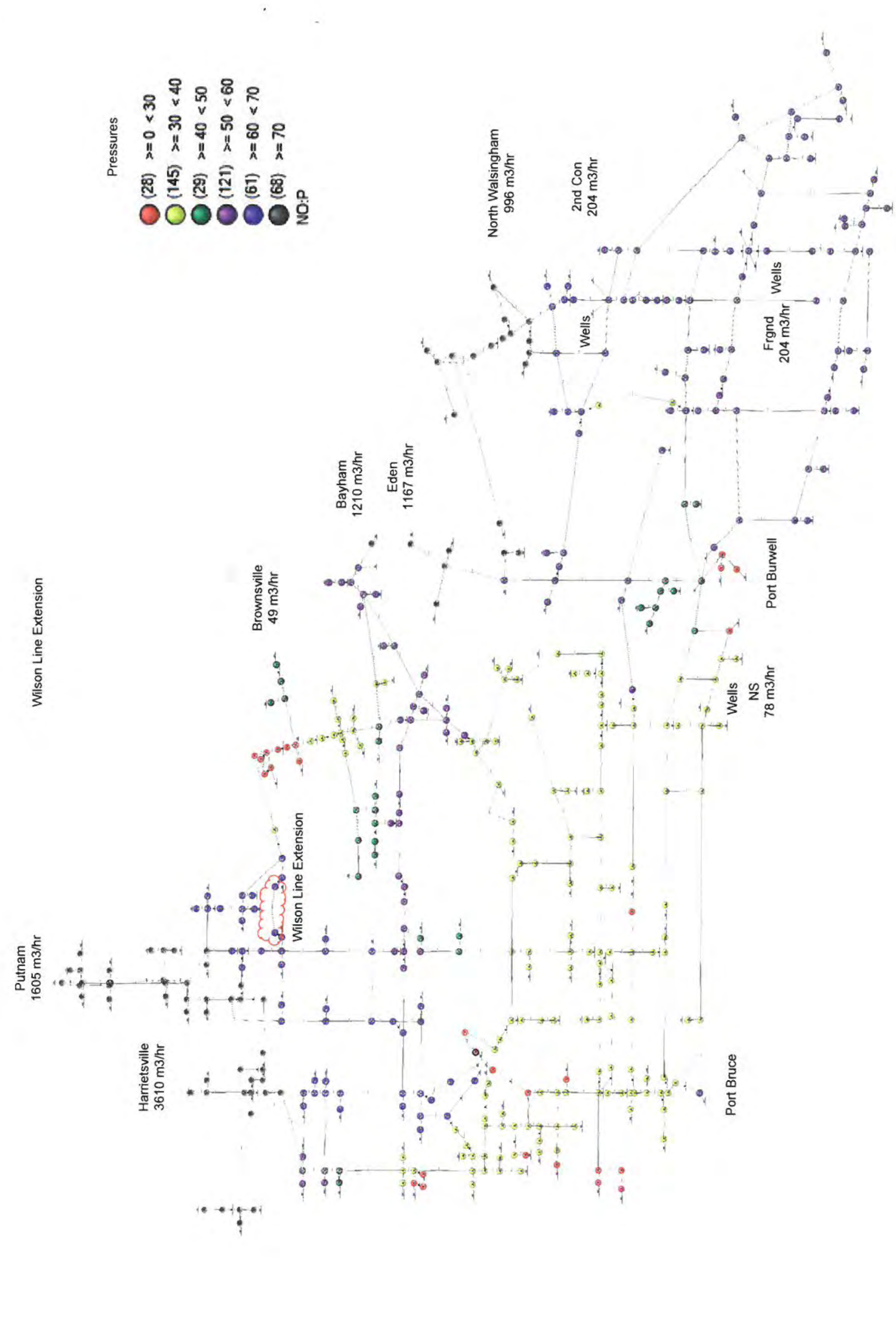
Appendix C – Benchmark Results Schematic

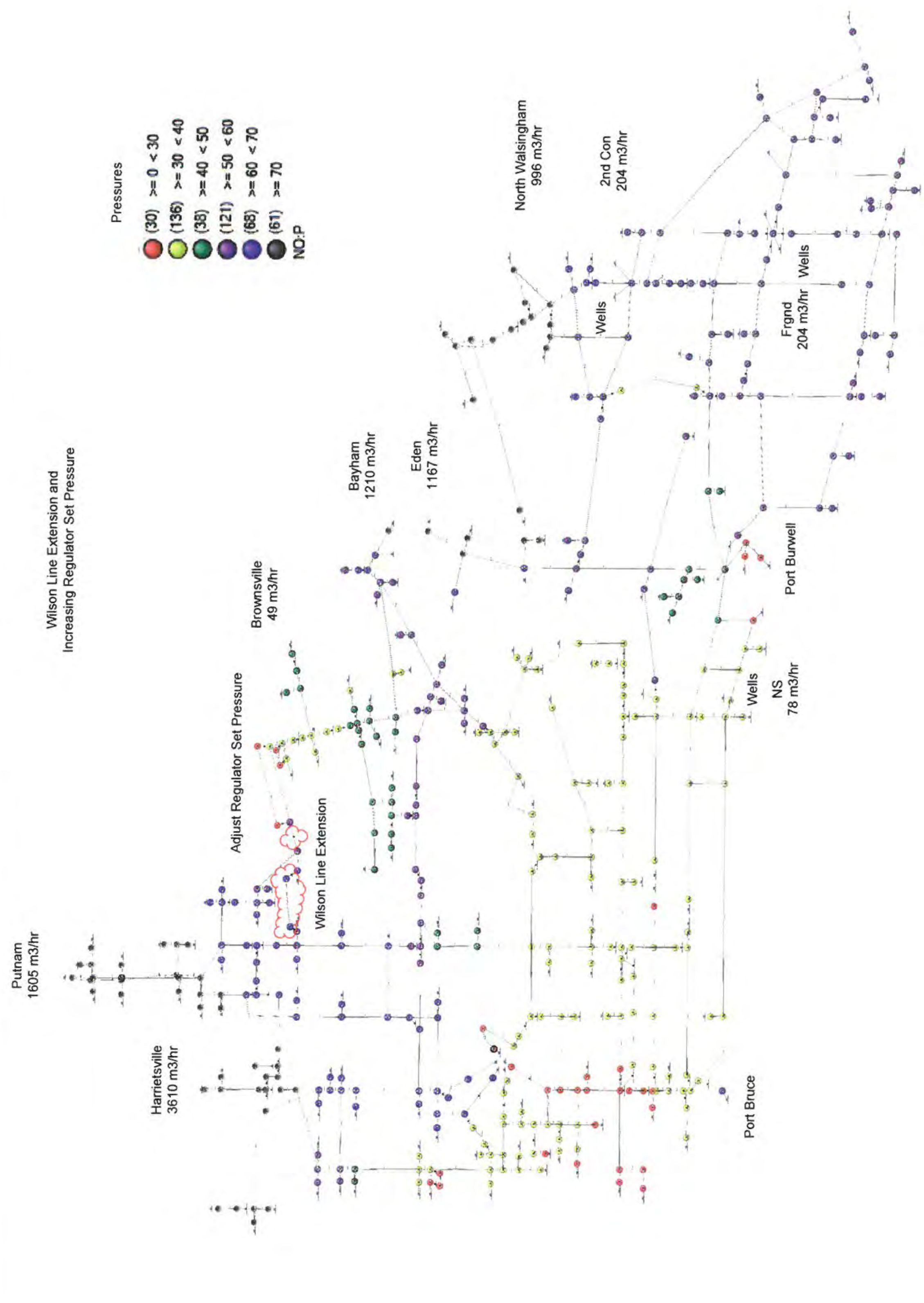

Base Case - Nov 12, 2014
Benchmark Results Schematic
Pressures
(26) >= 0 < 30
(149) >= 30 < 40
(36) >= 40 < 50
(123) >= 50 < 60
(51) >= 60 < 70
(67) >= 70
NO P
North Walsingham
996 m3/hr
2nd Con
204 m3/hr
Wells
Wells
Frgnd
204 m3/hr
Bayham
1210 m3/hr
Eden
1167 m3/hr
Brownsville
49 m3/hr
Port Burwell
Wells
NS
78 m3/hr
Putnam
1605 m3/hr
Harrietsville
3610 m3/hr
Port Bruce

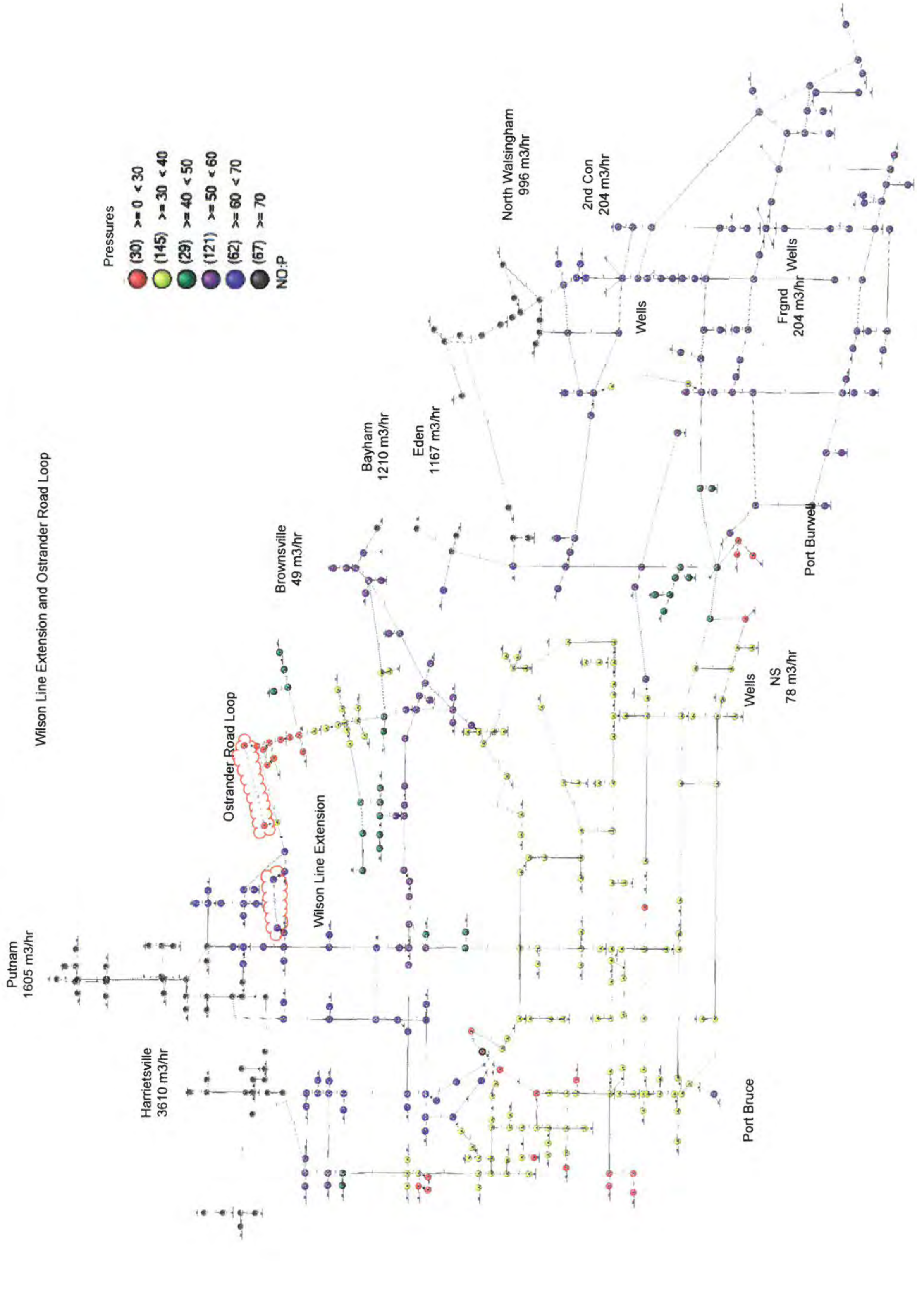
Appendix D – LOOPS AND LINE EXTENSIONS

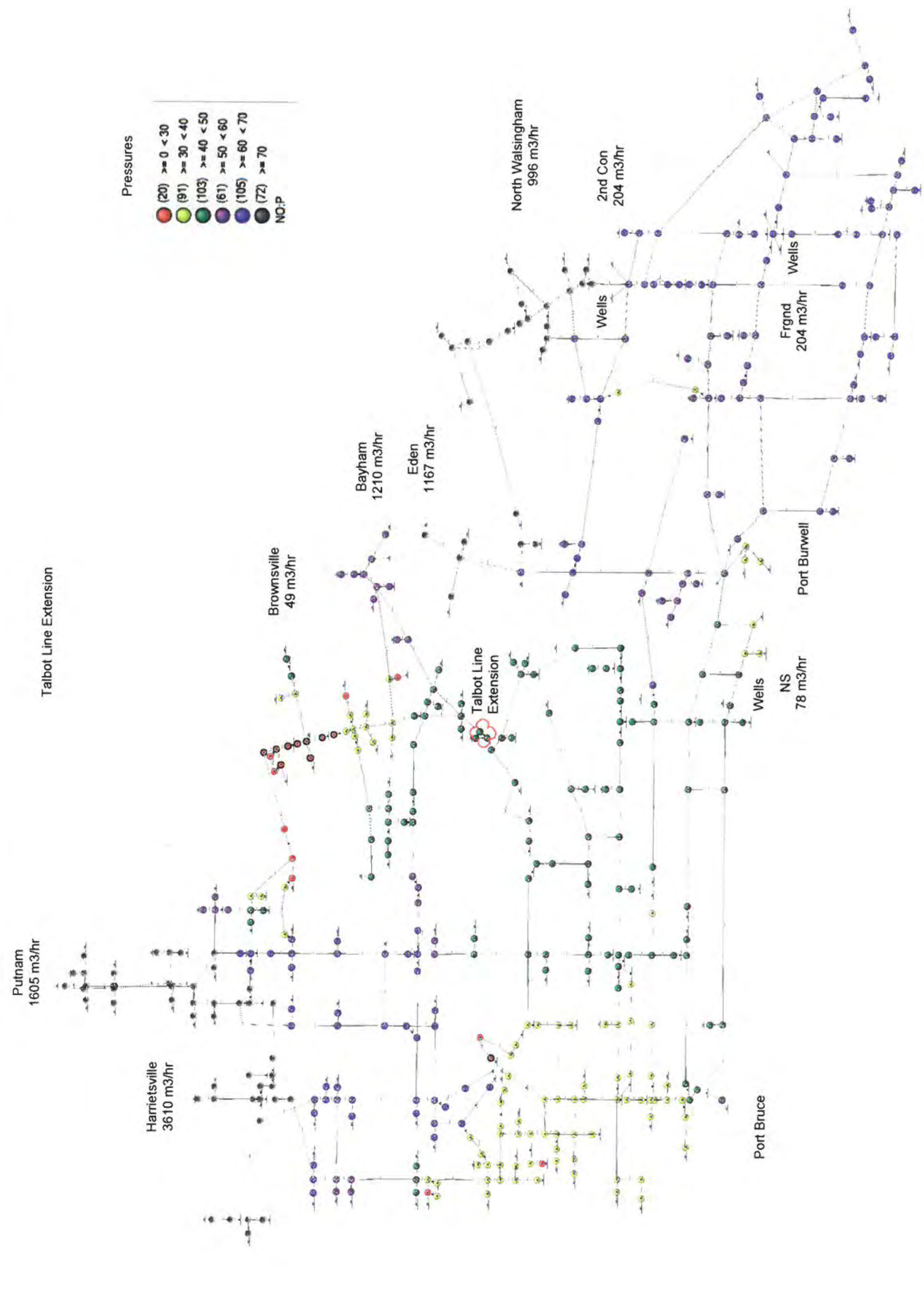

John Wise Line Loop
Pressures
(25) >= 0 < 30
(149) >= 30 < 40
(38) >= 40 < 50
(126) >= 50 < 60
(52) >= 60 < 70
(62) >= 70
NO:P
Putnam
1605 m3/hr
Harrietsville
3610 m3/hr
Brownsville
49 m3/hr
Bayham
1210 m3/hr
Eden
1167 m3/hr
North Walsingham
996 m3/hr
2nd Con
204 m3/hr
Wells
Wells
Frgnd
204 m3/hr
Port Burwell
Wells
NS
78 m3/hr
John Wise Line Loop
Port Bruce


Glencolin Line Extension
Pressures
(17) >= 0 < 30
(33) >= 30 < 40
(140) >= 40 < 50
(127) >= 50 < 60
(70) >= 60 < 70
(65) >= 70
ND:P
Putnam 1605 m3/hr
Harrietsville 3610 m3/hr
Brownsville 49 m3/hr
Bayham 1210 m3/hr
Eden 1167 m3/hr
North Walsingham 996 m3/hr
2nd Con 204 m3/hr
Wells
Wells
Frgnd 204 m3/hr
Port Burwell
Wells
NS 78 m3/hr
Port Bruce
Glencolin Line Extension

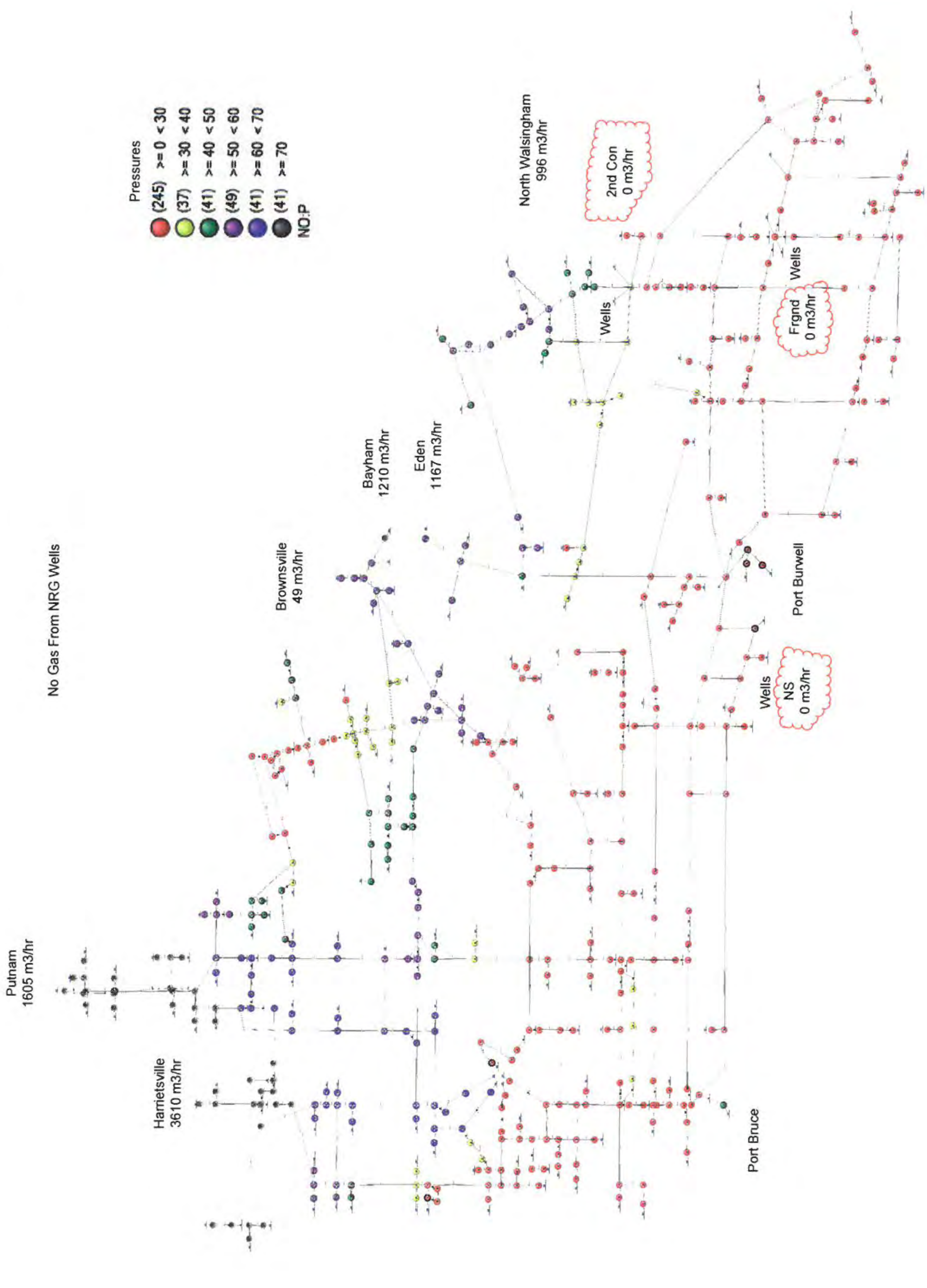

Pressures
(28) >= 0 < 30
(145) >= 30 < 40
(29) >= 40 < 50
(121) >= 50 < 60
(61) >= 60 < 70
(68) >= 70
NO:P
Wilson Line Extension
Putnam
1605 m3/hr
Harrietsville
3610 m3/hr
Wilson Line Extension
Brownsville
49 m3/hr
Bayham
1210 m3/hr
Eden
1167 m3/hr
North Walsingham
996 m3/hr
2nd Con
204 m3/hr
Wells
Wells
Frgnd
204 m3/hr
Port Burwell
Wells
NS
78 m3/hr
Port Bruce


Pressures
(30) >= 0 < 30
(136) >= 30 < 40
(38) >= 40 < 50
(121) >= 50 < 60
(68) >= 60 < 70
(61) >= 70
NO:P
Wilson Line Extension and
Increasing Regulator Set Pressure
Putnam
1605 m3/hr
Harrietsville
3610 m3/hr
Brownsville
49 m3/hr
Adjust Regulator Set Pressure
Wilson Line Extension
Bayham
1210 m3/hr
Eden
1167 m3/hr
North Walsingham
996 m3/hr
2nd Con
204 m3/hr
Wells
Frgnd
204 m3/hr
Wells
Port Burwell
Wells
NS
78 m3/hr
Port Bruce


Wilson Line Extension and Ostrander Road Loop
Pressures
(30) >= 0 < 30
(145) >= 30 < 40
(29) >= 40 < 50
(121) >= 50 < 60
(62) >= 60 < 70
(67) >= 70
NO:P
Putnam
1605 m3/hr
Harrietsville
3610 m3/hr
Ostrander Road Loop
Wilson Line Extension
Brownsville
49 m3/hr
Bayham
1210 m3/hr
Eden
1167 m3/hr
North Walsingham
996 m3/hr
2nd Con
204 m3/hr
Wells
Frgnd
204 m3/hr
Wells
Port Burwell
Wells
NS
78 m3/hr
Port Bruce


Talbot Line Extension
Pressures
(20) >= 0 < 30
(91) >= 30 < 40
(103) >= 40 < 50
(61) >= 50 < 60
(105) >= 60 < 70
(72) >= 70
NO:P
Putnam
1605 m3/hr
Harrietsville
3610 m3/hr
Brownsville
49 m3/hr
Bayham
1210 m3/hr
Eden
1167 m3/hr
North Walsingham
996 m3/hr
2nd Con
204 m3/hr
Wells
Wells
Frgnd
204 m3/hr
Talbot Line
Extension
Port Burwell
Wells
NS
78 m3/hr
Port Bruce

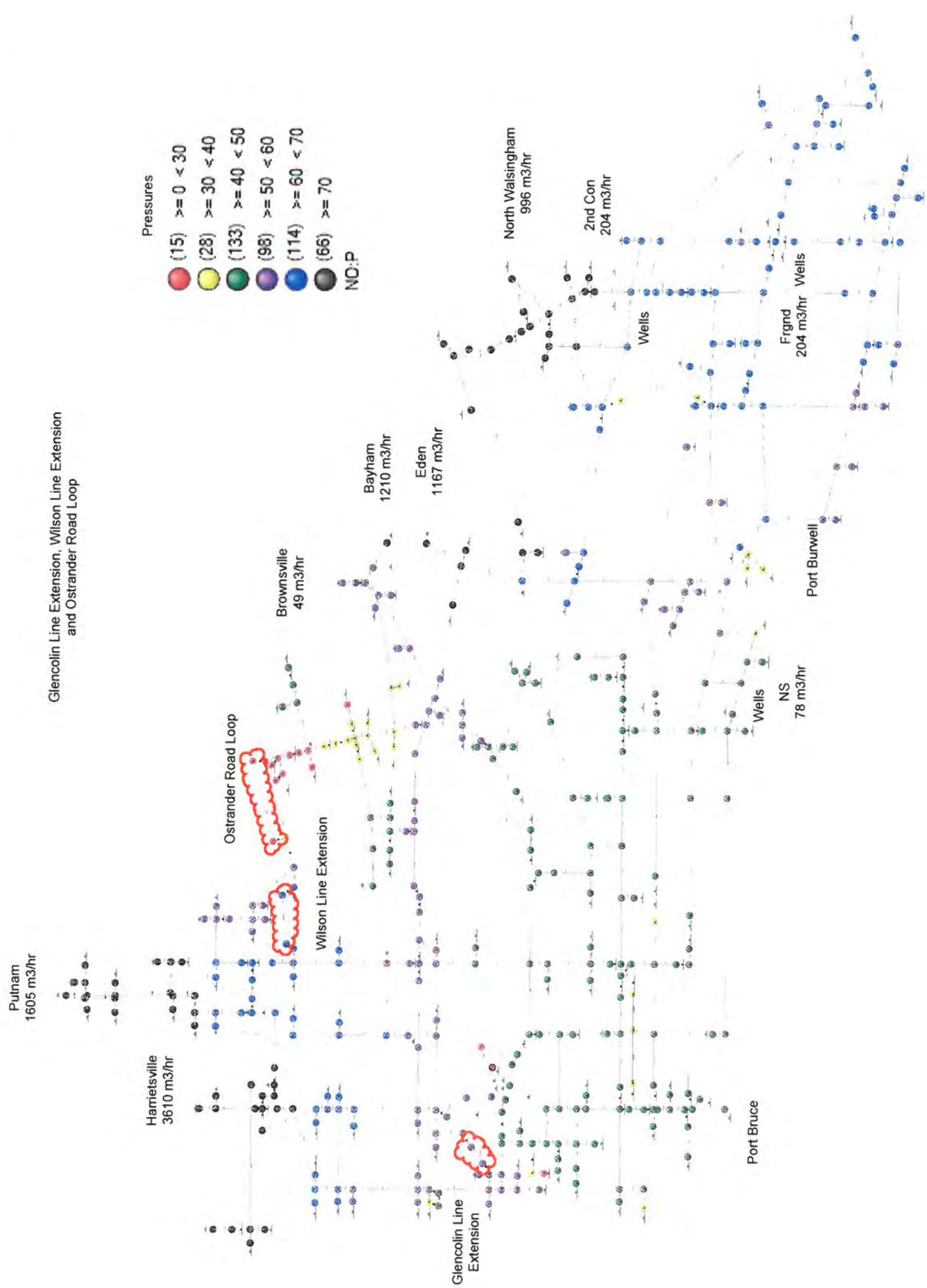
Appendix E – INCREASE UGL STATION GAS FLOW


Pressures
(245) >= 0 < 30
(37) >= 30 < 40
(41) >= 40 < 50
(49) >= 50 < 60
(41) >= 60 < 70
(41) >= 70
NO:P
No Gas From NRG Wells
Putnam
1605 m3/hr
Harrietsville
3610 m3/hr
Brownsville
49 m3/hr
Bayham
1210 m3/hr
Eden
1167 m3/hr
North Walsingham
996 m3/hr
2nd Con
0 m3/hr
Wells
Wells
Frgnd
0 m3/hr
Port Burwell
Wells
NS
0 m3/hr
Port Bruce


Increased Gas From NRG Wells
Pressures
(12) >= 0 < 30
(21) >= 30 < 40
(147) >= 40 < 50
(59) >= 50 < 60
(132) >= 60 < 70
(83) >= 70
NO:P
Putnam
1605 m3/hr
Harrietsville
3610 m3/hr
Brownsville
49 m3/hr
Bayham
1210 m3/hr
Eden
1167 m3/hr
North Walsingham
996 m3/hr
2nd Con
204 m3/hr
Wells
Wells
Frgnd
204 m3/hr
Port Burwell
Wells
NS
551 m3/hr
Port Bruce


Increased Gas From NRG Wells and John Wise Loop
Pressures
(12) >= 0 < 30
(27) >= 30 < 40
(153) >= 40 < 50
(52) >= 50 < 60
(127) >= 60 < 70
(83) >= 70
NO:P
Putnam 1605 m3/hr
Harrietsville 3610 m3/hr
Brownsville 49 m3/hr
Bayham 1210 m3/hr
Eden 1167 m3/hr
North Walsingham 996 m3/hr
2nd Con 204 m3/hr
Wells
Frgnd 204 m3/hr
Wells
Port Burwell
Wells
NS 393 m3/hr
John Wise Loop
Port Bruce

Appendix F – FINAL RESULTS


Glencolin Line Extension, Wilson Line Extension
and Ostrander Road Loop
Pressures
(15) >= 0 < 30
(28) >= 30 < 40
(133) >= 40 < 50
(98) >= 50 < 60
(114) >= 60 < 70
(66) >= 70
NO:P
Putnam
1605 m3/hr
Harrietsville
3610 m3/hr
Ostrander Road Loop
Wilson Line Extension
Brownsville
49 m3/hr
Bayham
1210 m3/hr
Eden
1167 m3/hr
North Walsingham
996 m3/hr
2nd Con
204 m3/hr
Wells
Frgnd
204 m3/hr
Wells
Port Burwell
Wells
NS
78 m3/hr
Port Bruce
Glencolin Line
Extension

Appendix G – Expansion Costs

NRG System Expansion Costs

Pipeline Segment	Pipe Size (NPS)	Pipe Price ($/m)	Length (m)	Pipe Price ($)	Drct Drills (m)	Drct Drills ($/m)	Drct Drills ($)	Trench (m)	Trenching ($/m)	Trench ($)	Marker/ Sign ($/500m)	Mob/ Demob ($)	Marker/ Sign ($)	Subtotal ($)	Cntngncy (20%)	Total ($)
Glencolin Line Extension	4	21	3,200	67,200	170	55	9,350	3,030	31.25	94,688	75	6,400	480	178,118	35,624	213,741
Wilson Line Extension	3	12	500	6,000	100	55	5,500	400	27.5	11,000	75	6,400	75	28,975	5,795	34,770
Ostrander Road Loop	3	12	4,060	48,720	215	55	11,825	3,845	27.5	105,738	75	6,400	609	173,292	34,658	207,950
Total	-	-	7,760	-	485	-	26,675	7,275	-	211,425	-	19,200	1,164	380,384	76,077	456,461

Assumptions

1) Number and length of Directional Drills/Bores
- Glencolin Line Extension 6 at 20 m each and 1 at 50 m
- Wilson Line Extension 5 at 20 m each
- Ostrander Road Loop 7 at 20 m each and 1 at 75 m

2) Cost of Directional Drill/bore for NPS 3 is the same as NPS 4

3) Cost of dry tapping and connection or fusing is included in above costs

4) Cost of clean, drying, pigging, and leak testing is included in above costs

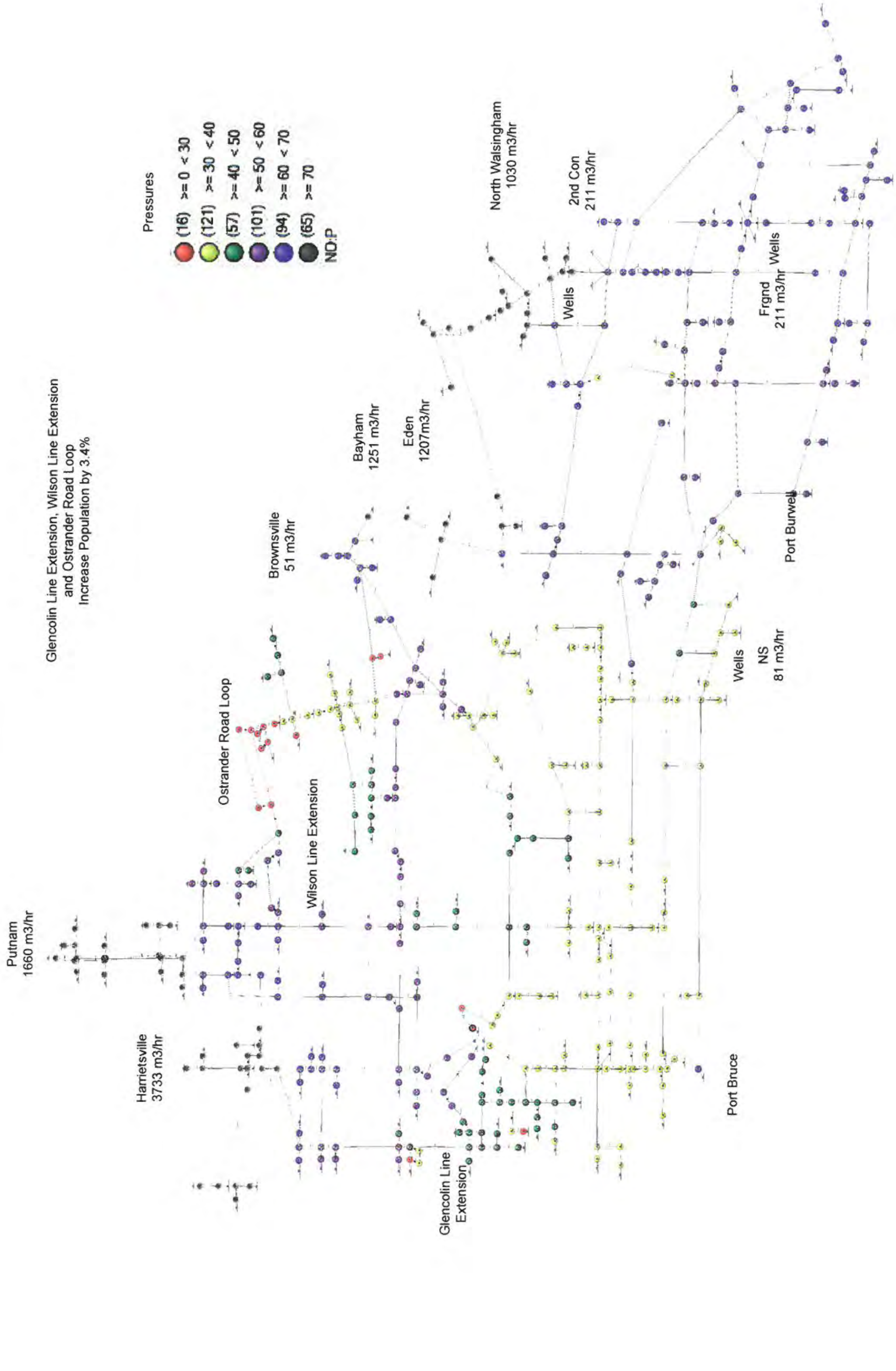
5) Installation of trace wire is included in above costs

6) Above costs are all-in including labour, management, equipment, fuel, contractors profit, etc

7) Above costs exclude
- Owner's costs
- Land costs
- Telecommunications costs
- Environmental assessment costs
- Legal and Regulatory costs
- Public/Third Party Consultation costs
- Escalation
- Construction survey costs

8) Includes Mobilization/Demobilization costs of $3200/day for 2 days

Appendix H – POPULATION INCREASE


Glencolin Line Extension, Wilson Line Extension
and Ostrander Road Loop
Increase Population by 3.4%
Pressures
(16) >= 0 < 30
(121) >= 30 < 40
(57) >= 40 < 50
(101) >= 50 < 60
(94) >= 60 < 70
(65) >= 70
NO P
North Walsingham
1030 m3/hr
2nd Con
211 m3/hr
Wells
Frgnd
211 m3/hr
Wells
Bayham
1251 m3/hr
Eden
1207m3/hr
Brownsville
51 m3/hr
Port Burwell
Wells
NS
81 m3/hr
Ostrander Road Loop
Wilson Line Extension
Putnam
1660 m3/hr
Harrietsville
3733 m3/hr
Port Bruce
Glencolin Line
Extension