EPCOR RESPONSES TO IGPC INTERROGATORIES

EPCOR Natural Gas Limited Partnership

Application for Rates October 1, 2016 to December 31, 2019, a Fixed Monthly Charge for Rate 6, Disposition of Deferral and Variance Accounts and Approval to Change Rate Year from October 1 to January 1 effective January 1, 2020

EB-2018-0235

IGPC-1

Evidence Reference: Exhibit A, Exhibit B, Exhibit C

Preamble: ENGLP's predecessor filed an application for rates, EB-2016-0236, which is currently in abeyance. As such, the current rates continue to be premised upon the rates approved in EB-2010-0018 and escalated through the IRM approved as part of EB-2010-0018 and subsequent Board Orders. As part of proceeding EB-2016-0236, the rates charged by ENGLP and its predecessor NRG, have been interim since October 1, 2016. IGPC is interested in understanding the implications of the current application on the interim rates that are currently in place and ENGLP's position regarding consideration of the assessment of just and reasonable rates.

Questions:

- **a) Confirm that under the current proposal in Exhibit A, Exhibit B and Exhibit C that rates charged would be considered final. If not, please explain.**
- **b) Confirm there has been no review of ENGLP's (or NRG's) distribution costs since EB-2010-0018.**
- **c) Confirm that the costs (amount of rate base, OM&A) approved in EB-2010-0018 continue to form the basis of the current rates. If not please, explain.**

Responses:

a) EPCOR Natural Gas Limited Partnership (EPCOR) confirms that its current proposal is to finalize rates for the time period October 1, 2016 to December 31, 2019 as outlined in the various exhibits within this proceeding.

b) Confirmed.

c) The costs and resulting revenue requirement approved in EB-2010-0018 form the basis for current rates.

IGPC-2

Evidence Reference: Exhibit A, Exhibit B, Exhibit C

Preamble: IGPC is interested in understanding the implications of the current application on the interim rates that are currently in place and the dependency of certain approvals on other relief sought by ENGLP as part of this Application.

Questions:

a) Do all rate classes have to be subjected to the same percentage rate increase? Please explain why or why not.

b) Would ENGLP's financial wherewithal be materially impacted if the increases sought in Exhibit A, Exhibit B and Exhibit C were not granted?

c) What programs, services or capital projects would be deferred or cancelled as a result of a denial of the relief sought in Exhibit A, Exhibit B or Exhibit C?

<u>Responses:</u>

a) Per section 3.2.1.1of the Board's Filing Requirements for Electricity Distribution Rate Applications, Chapter 3 - 4th Generation Incentive Rate-setting and Annual Incentive Rate-setting Index dated July 17, 2013, the annual adjustment mechanism should apply to distribution rates uniformly across customer rate classes. This is also consistent with Natural Resource Gas's (NRG) most recently approved (EB-2010-0018) incentive rate mechanism.

b) An assessment of the impact of the increases sought on the utility's financial wherewithal is not part of the IRM framework and therefore isn't appropriate for this application. The assessment of the utility's revenue sufficiency or deficiency will be subject to review as part of the next cost of service application.

c) Should the relief sought in Exhibits A, B and C be denied, EPCOR would assess its programs, services and capital projects at that time.

IGPC-3

Evidence Reference: Exhibit A, Exhibit B, Exhibit C

Preamble: IGPC understands that ENGLP intends to apply a formulaic approach to rates that would increase rates using the IRM formula used by electricity distributors and that the formula incorporates an efficiency or productivity improvement factor. IGPC understands that where a distributor chooses to remain in an IRM formula rather than being subject to a cost of service review or customized IR that the distributor must apply the worst (largest) efficiency or productivity factor. IGPC is interested in understanding how ENGLP's (and NRG's) assessment of its efficiency and the changes in operations, revenues and costs since EB-2010-0018 to provide some context to the improvements that NRG and ENGLP have already undertaken and those planned for the next year.

Questions:

a) Has ENGLP, or its predecessor NRG, performed any studies to determine the efficiency or productivity of its operations? If so, please provide such studies or reports.

b) What efficiency matters or productivity improvements have been implemented by NRG/ENGLP since 2011? Please provide details including a description of the improvement, when implemented, the savings and expected persistence of the savings.

c) Please provide a chart(s) with the applicable factors for the IRM formula for each electricity distributor group, for each year since 2011.

d) What has ENGLP's, or NRG's, return on equity (actual and deemed), been for each of the past 5 years.

e) What has been the historical Full Time Equivalents for ENGLP and its predecessor for each of the past 7 years.

f) What has been the actual customer count for each rate class for each of the past 7 years?

g) What has ENGLP's distribution and other revenue been for each of the past 5 years?

<u>**Responses:**</u>

a) EPCOR has not performed any such studies and is not aware of any performed by NRG.

b) EPCOR does not have detailed knowledge of the operations prior to the transition to EPCOR. Over the last twelve months since the transition to EPCOR the operational focus has been on integration of the assets to EPCOR's systems and processes.

c) The OEB establishes productivity and stretch factor components on 5-year terms. For the years 2009 to 2013, the productivity factor was 0.72% and there were three stretch factor groups. For the years 2014 to 2018 the productivity factor was set to 0% and the number of stretch factor groups was changed to five. In the first period the groupings were based on ranked performance. LDCs were assigned to quartiles with the middle two quartiles combined into one group. The groupings were changed in 2014 and were based on performance relative to predicted costs. Determination of the stretch factor groups for 2014-2019 is outlined in the following OEB table[1]:

Table 3: Demarcation Points and Stretch Factor Values

Group	Demarcation Points for Relative Cost Performance	Stretch Factor
I	Actual costs are 25% or more below predicted costs	0.00%
II	Actual costs are 10% to 25% below predicted costs	0.15%
III	Actual costs are within +/-10% of predicted costs	0.30%
IV	Actual costs are 10% to 25% above predicted costs	0.45%
V	Actual costs are 25% or more above predicted costs	0.60%

The inflation, productivity and stretch factors for each group for the time periods requested are presented below in tables based on the OEB's 5 year term for establishing the factors.

2011-2013 Period

		2011	2012	2013
Inflation Factor	**Jan**	*1.3%	1.7%	2.2%
	May	1.3%	2.0%	1.6%
Productivity Factor		0.72%	0.72%	0.72%
Stretch Factor	**Quartile**			
	1	0.2%	0.2%	0.2%
	2	0.4%	0.4%	0.4%
	3	0.4%	0.4%	0.4%
	4	0.6%	0.6%	0.6%
IRM Adjustment	**1**	0.38%	0.78%	1.28%
	2	0.18%	0.88%	0.48%
	3	0.18%	0.88%	0.48%

[1] EB-2010-0379- Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, Issued on November 21, 2013 and as corrected on December 4, 2013,page 21

	4	-0.02%	0.68%	0.28%

*In 2012 and 2013 different inflation factors were provided for January and May application filers. The IRM adjustments use January inflation factors for those years. Until 2012, the inflation factor was set in May. The 2011 January inflation factor (1.3%) was set in May 2010.

2014-2018 Period

		2014	**2015**	**2016**	**2017**	**2018**
Inflation Factor		1.7%	1.6%	2.1%	1.9%	1.2%
Productivity Factor		0.00%	0.00%	0.00%	0.00%	0.00%
Stretch Factor	**Group**					
	1	0.00%	0.00%	0.00%	0.00%	0.00%
	2	0.15%	0.15%	0.15%	0.15%	0.15%
	3	0.30%	0.30%	0.30%	0.30%	0.30%
	4	0.45%	0.45%	0.45%	0.45%	0.45%
	5	0.60%	0.60%	0.60%	0.60%	0.60%
IRM Adjustment	**1**	1.70%	1.60%	2.10%	1.90%	1.20%
	2	1.55%	1.45%	1.95%	1.75%	1.05%
	3	1.40%	1.30%	1.80%	1.60%	0.90%
	4	1.25%	1.15%	1.65%	1.45%	0.75%
	5	1.10%	1.00%	1.50%	1.30%	0.60%

The Board has indicated that the productivity factors from the 2014 to 2018 period will continue into 2019 as well as the methodology and process for establishing the stretch factor groupings[2]. However, the 2019 inflation and stretch factors have not yet been established at the time of this response.

d) The deemed return on equity is the Board allowed return on equity from EB-2010-0018, which was 9.85%[3]. NRG's actual annual return on equity as published in the Board's Yearbooks of Natural Gas Distributors since 2011 has been:

Year	ROE
2011	4.44%
2012	11.38%
2013	6.96%
2014	9.33%
2015	-3.65%
2016	9.22%
2017	7.02%

[2] Letter from the Board Secretary to all Licensed Electricity Distributors Re: I. Updated Filing Requirements II. Process for 2019 Incentive Regulation Mechanism (IRM) Distribution Rate Applications, July, 12, 2018, page 2

[3] EB-2010-0018 – NRG Draft Rate Order, December 30, 2010, page 3

e) The historical full time equivalents for the past 7 years are as follows[4]:

Year	FTE 4
2011	19.3
2012	21.5
2013	21.3
2014	21.6
2015	21.4
2016	21
2017	20

f) Actual customer count for each rate class for each of the past 7 years[5] are:

Year	Rate 1	Rate 2	Rate 3	Rate 4	Rate 5	Rate 6
2010	6889	66	4	23	5	1
2011	7013	64	4	23	5	1
2012	7271	67	4	23	5	1
2013	7590	65	4	31	5	1
2014	7895	65	4	33	5	1
2015	8176	63	4	34	5	1
2016	8494	60	4	36	5	1
2017	8538	53	5	36	5	1

g) Distribution and other revenue for NRG for each of its past 5 fiscal years (in thousands of dollars) is as follows[6]:

Year	Distribution & Transportation Revenue	Other Revenue
2013	5991	940
2014	6602	953
2015	6707	858
2016	6502	125
2017	6856	110

[4] 2011 through 2015 from EB-2016-0236 – Application and Evidence, August 9, 2016, Exhibit 4 Tab 1 Schedule 2, page 4; 2016 to 2017 as calculated by EPCOR

[5] 2010 through 2015 from EB-2016-0236 – Application and Evidence, August 9, 2016, Exhibit 3 Tab 1 Schedule 3, page 2; 2016 and 2017 as obtained from NRG's RRR reporting records.

[6] 2013 through 2015 from EB-2016-0236 – Application and Evidence, August 9, 2016, Exhibit 3 Tab 1 Schedule 3, page 1; 2016 and 2017 obtained from NRG's audited Financial Statements for the respective years

IGPC-4

Evidence Reference: EB-2016-0236, page 254 of 432 in pdf of Application; Exhibit 8, Tab 1, Schedule 3, page 1, Lines 16 to 17; EB-2010-0018

Preamble: IGPC is interested in determining the reasonableness of the current and proposed rates being applied to IGPC. IGPC understand that under EB-2016-0236 that the proposed rates for IGPC would have reduced for the then approved rates.

Questions:

a) **Please provide the annual revenue, earned by ENGLP and NRG from Rate 6 since EB-2010-0018.**
b) **What was the net income of NRG/ENGLP for each year since EB-2010-0018?**
c) **What was the amount of rate base that formed the basis of Rate Class 6 in EB-2010-0018?**
d) **What amounts have been added to the rate base for Rate Class 6 since EB-2010-0018?**
e) **What is the annual amount of depreciation for Rate Class 6 that was approved by the Board in EB-2010-0018?**
f) **What is the amount of rate base for Rate Class 6 for each year since EB-2010-0018.**
g) **Please provide a table showing the actual and deemed cost of long-term debt, short-term debt and equity for each year since EB-2010-0018.**
h) **Has the rate base of Rate Class 1 thru 5 increased since EB-2010-0018? If so, by approximately how much?**
i) **Please provide copies of all agreements between ENGLP and IGPC.**

<u>Responses:</u>

a) The annual revenue earned by NRG from rate 6[7] since EB-2010-0018 is:

	Rate 6 Revenue
2010	-
2011	1,478,179
2012	1,485,545
2013	1,491,329
2014	1,499,258
2015	1,531,844
2016	1,783,621
2017	1,797,592

[7] 2010 through 2015 from EB-2016-0236 – Application and Evidence, August 9, 2016, Exhibit 3 Tab 1 Schedule 3, page 1; 2016 and 2017 as obtained from NRG's RRR reporting records.

b) The annual net income for each year since EB-2010-0018 as reported by NRG[8] is:

	Net Income
2010	549,293
2011	243,750
2012	704,815
2013	463,107
2014	684,895
2015	(160,222)
2016	436,957
2017	684,083

c) Based on the evidence filed in EB-2010-0018, the rate base that formed the basis of rate class 6 was the 2011 test year rate base of $4,222,558[9] which is based on an original amount closed to rate base of $4,872,182[10].

d) Since EB-2010-0018 the amount that has been added to the rate base for rate 6 up to December 31, 2017 is approximately $70,000. See the response to IGPC-10 for details on work underway for 2018.

e) Based on the evidence filed in EB-2010-0018, the annual amount of depreciation for rate class 6 that was approved by the Board in EB-2010-0018 is $243,609[11] which is based on 5% or a useful life of 20 years.

f) The amount of rate base for rate class 6 for each year since EB-2010-0018 is as follows:

	Rate Base
2009	4,587,971
2010	4,466,167
2011	4,222,558
2012	3,978,949
2013	3,735,340
2014	3,491,731
2015	3,248,122
2016	3,011,454
2017	2,788,844

g) The deemed cost of debt is as approved in EB-2010-0018 which was 7.67% for Long-term debt and 2.07% for Short-term debt[12]. EPCOR does not have

[8] Natural Resource Gas Limited's audited Financial Statements for the respective years
[9] EB-2010-0018 NRG IR Responses dated January 17, 201, Attachment H, page 1
[10] EB-2010-0018 NRG IR Responses dated January 17, 201, Attachment H, page 1
[11] EB-2010-0018 NRG IR Responses dated January 17, 201, Attachment H, page 1
[12] EB-2010-0018 – NRG Draft Rate Order, December 30, 2010, page 3

information on NRG’s actual cost of debt beyond what is disclosed in NRG’s annual financial statements. The notes to NRG’s financial statements indicate that interest on term notes was at prime and prime plus 0.25%. For information on return on equity please refer to EPCOR’s response to IGPC 3 d).

h) The rate base for rate classes 1 through 5 has increased by approximately $950,000 since the rate base for the 2011 test year in EB-2011-0018.

i) The agreements currently in place between EPCOR and IGPC are the Pipeline Cost Recovery Agreement and the Gas Delivery Agreement, both of which were assigned to EPCOR as part of the asset purchase transaction. The copies of these agreements that EPCOR obtained from NRG upon their assignment have been provided in Attachment 1.

IGPC-5

Evidence Reference: EB-2016-0236, EB-2010-0018

Preamble: IGPC is interested in determining the reasonableness of the current rates being applied, and the future rates that are proposed, for IGPC. IGPC understand that under EB-2016-0236 that the following: (a) proposed rates for IGPC would have reduced for the then approved rates; (b) the percentage of existing rate base of Rate 6 to total rate base had decreased; (c) the percentage of income of Rate 6 to total income had decreased; and (d) NRG/ENGLP has continued to add customers to every category. IGPC further understands the ENGLP will need to invest in rate base to reinforce the system to serve other existing customers.

Questions:

- **a) What was the amount of the proposed rate reduction that Rate Class 6 would have experienced had the proposal in EB-2016-0235 been approved?**
- **b) What would have been the annual savings to Rate Class 6 had the Board approved the requested rates in EB-2016-0236 through the period of October 1, 2016 to January 1, 2020?**
- **c) Please confirm that certain operating, maintenance and administration costs have been allocated to the various rate classes based upon the relative contribution to rate base of such class.**
- **d) Please provide for each rate class the operating, maintenance and administration costs and relative amounts from EB-2010-0018 that were allocated on basis of rate base.**
- **e) Is part of the delay or basis for the current request the need to develop a more robust system reinforcement plan to continue to supply ENGLP's customers (other than Rate 6) based upon updated system integrity analyses and plan.**

Responses:

a) Based on the evidence filed by NRG in EB-2016-0236 the relief proposed in that application would have resulted in a reduction of $252,384 for Rate 6:

Proposed Rate[13]	$1,017,300
Plus Union Gas flow through[14]	$334,400
Subtotal	$1,351,700
Less Current Rate[15]	$1,604,084
Net Reduction	$252,384

[13] EB-2016-0236 – Application and Evidence, August 9, 2016, Exhibit 9 Tab 2 Schedule 2
[14] EB-2016-0236 – Application and Evidence, August 9, 2016, Exhibit 8 Tab 1 Schedule 1
[15] EB-2016-0236 – Application and Evidence, August 9, 2016, Exhibit 9 Tab 2 Schedule 2

b) The annual savings to IGPC as noted in IGPC-5 a) above would have been adjusted annually by an IR adjustment calculated in accordance with the approved IR plan from EB-2016-0236.

c) The costs, resulting revenue requirement and associated allocations approved in EB-2010-0018 form the basis for current rates. The cost allocation model filed in that proceeding did allocate certain operating, maintenance and administration expenses to customer classes on the basis of the proportion of rate base allocated to the classes.

d) As EB-2010-0018 was filed a number of years prior to EPCOR's ownership of the assets, information beyond what is publicly available for this filing is not readily accessible.

e) The basis for EPCOR's approach to finalizing rates and addressing EB-2016-0236 is a result of EPCOR's review of EB-2016-0236 and determination that the filing includes a number of material deficiencies and it cannot simply be revised and updated to reflect EPCOR's cost structure as previously thought[16]. These deficiencies include lack of a Utility System Plan for the entire distribution system and the inclusion of a System Integrity Study that in the view of EPCOR does not adequately address potential solutions to ongoing concerns regarding system pressure in parts of the distribution system.

[16] EB-2016-0236, - EPCOR's letter to the Board, April 24, 2018

IGPC - 6

Evidence Reference: EB-2016-0236

Preamble: In EB-2016-0236, NRG had proposed using the rate base for the 2017 Test Year throughout the IR period. When there is no capital to be spent in a rate class during the IR period, IGPC is of the view such a rate class can over contribute to the earnings of the utility through such an IR period.

Questions:

a) **Do the Tables below provide an accurate summary of the change in Rate Base for Rate 6 over the IR period had the proposal by NRG been approved in EB-2016-0236? Explain?**

b) **Do the Tables below provide an accurate summary of the change in Revenue Requirement (Costs Allocated to IGPC) for Rate 6 over the IR period? Explain.**

c) **Do the Tables below provide an accurate estimation of the Rate 6 Revenue Requirement if rates were to be set upon the actual rate base rather than the inflated 2017 Test Year Rate Base? Explain.**

d) **Would depreciation actually increase when there are no expenditures on capital during the period?**

Impact of Proposed IR Approach on IGPC

	Adjustment for 2018 - 2021	IR (I + X + S)	2017 Re-Base (E8, T1, S3)	2018 IR	2019 IR	2020 IR	2021 IR
1 Costs Allocated to Rate 6 (IGPC) - as proposed in EB-2016-0236							
OM&A	IR	1.5%	205,073	208,149	211,271	214,440	217,657
Administrative and General	IR	1.5%	200,398	203,404	206,455	209,552	212,695
Property Tax	IR	1.5%	87,000	88,305	89,630	90,974	92,339
Depreciation	IR	1.5%	256,008	259,848	263,746	267,702	271,718
Return	IR	1.5%	200,779	203,791	206,848	209,950	213,100
Income Tax	IR	1.5%	62,167	63,100	64,046	65,007	65,982
IGPC Revenue Requirement (2017 - 2021) - Line A			1,011,425	1,026,596	1,041,995	1,057,625	1,073,490

Incentive Rate (IR) Setting Proposal (E1, T1, S2) -for 2018 - 2021 rates
Inflation factor (I), productivity factor (X), and a stretch factor (S)
Estimated IR Adjustment (I + X + S) 1.5%

2 Revised Approach to recognize declining Rate Base			2017	2018	2019	2020	2021	
IGPC Rate Base			(E2, T2, S1)					
IGPC Rate Base (previous year average)				2,924,759	2,668,751	2,412,743	2,156,735	
IGPC Depreciation Expense				(256,008)	(256,008)	(256,008)	(256,008)	
IGPC Rate Base			2,924,759	2,668,751	2,412,743	2,156,735	1,900,727	
% change in Rate Base from 2017				-8.8%	-17.5%	-26.3%	-35.0%	
Revised IGPC Revenue Requirement	Adjustment for 2018 - 2021			2018	2019	2020	2021	Total
OM&A	IR	1.5%		208,149	211,271	214,440	217,657	
Administrative and General	IR	1.5%		203,404	206,455	209,552	212,695	
Property Tax	IR	1.5%		88,305	89,630	90,974	92,339	
Depreciation	IR	1.5%		259,848	263,746	267,702	271,718	
Return (6.86% x IGPC Rate Base)	RoRB	6.86%		183,205	165,631	148,056	130,482	
Income Tax	IR	1.5%		63,100	64,046	65,007	65,982	
IGPC Revenue Requirement (2017) - Line B				1,006,011	1,000,779	995,731	990,872	

RoRB (E6, T1, S1) 6.86%

3 Impact of IR Approach	2018	2019	2020	2021	Total
Change in IGPC Revenue Requirement - Line (A - B)	(20,585)	(41,217)	(61,894)	(82,618)	(206,314)
% Reduction of Revenue Requirement	-2.0%	-4.0%	-5.9%	-7.7%	

Responses:

a) The 2017 test year rate base related to IGPC and the annual depreciation presented in table 2 (“Revised Approach to recognize declining Rate Base”) above match the amounts filled by NRG in EB-2016-0236[17]. The rate base used for the purposes of calculating the annual return in table 2 is being calculated as the ending balance instead of the average for each year as would be done for the purposes of setting rates; however the calculations in the table appear to otherwise be mathematically correct.

b) Although the approximately $6,000 related to IGPC’s share of allocable common costs as identified in EB-2016-0236 are missing from the revenue requirement calculation, table 1 (‘Costs Allocated to Rate 6 (IGPC)”) above appears to materially reflect the 2017 amounts filled by NRG in that filing[18]. The estimated IR adjustment also appears to be aligned with the proposed IR Plan filed by NRG in EB-2016-0236[19]. The calculations in the table appear to be mathematically correct.

c) See response to IGPC-6 a) and b) above.

d) When depreciation is calculated on assets on a straight-line basis, as is the case for the IGPC related assets (ethanol pipeline and the IGPC meters), the depreciation expense would not increase unless there were additions to the assets or an approved change in the depreciation rate as a result of determining that the asset(s) had a shorter useful life than originally estimated.

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[17] EB-2016-0236 – Application and Evidence, August 9, 2016, Exhibit 2 Tab 2 Schedule 1 and Schedule 2
[18] EB-2016-0236 – Application and Evidence, August 9, 2016, Exhibit 8 Tab 1 Schedule 3
[19] EB-2016-0236 – Application and Evidence, August 9, 2016, Exhibit 9 Tab 3 Schedule 1

IGPC-7

Evidence Reference: EB-2016-0351, E1, T1, S1, page 4, lines 1 to 7; EB-2018-0235, Exhibit A, Exhibit B, Exhibit C

Preamble: Under the current ENGLP proposal, all customers are being asked to pay more to ENGLP than current rates. In its application to acquire the assets of NRG, ENGLP had indicated that customers would pay lower rates than if NRG had continued to own and operate the distribution company.

Questions:

a) How does ENGLP expect to demonstrate that customers will be better off with their acquisition of the distribution company when all rate classes are seeing an increase in rates? Please explain in detail.

b) When will ratepayers expect to start to experience these benefits?

c) Does ENGLP have a rate trajectory that would demonstrate the benefits to customers to compare its current operation to that of NRG?

Responses:

a) In the evidence referenced above, the applicants had not indicated that customers would pay lower rates than if NRG had continued to own and operate the distribution assets but rather that the evidence filed demonstrated that the “no harm” test applied by the Board in deciding whether or not to grant leave in such applications was met as NRG’s customers will not be negatively affected by, and may in fact realize a modest benefit from, the proposed transaction. This was based on the rationale that EPCOR’s underlying cost structure, the costs to serve NRG’s customers post-transaction, are not expected to be higher than they otherwise would have been with NRG.

b) EPCOR’s cost of service application for rates effective January 1, 2020 will provide evidence in support of a revenue requirement reflective of EPCOR’s ownership of the system.

c) As EPCOR is still in the process of preparing its cost of service application for rates effective January 1, 2020, such information is not available.

IGPC - 8

Ref: EB-2016-0235, Exhibit 2; EB-2010-0018

Preamble: Please confirm that the current application incorporates a 5% depreciation rate for the Ethanol Pipeline. This is presumably based upon the Settlement Agreement in EB-2010-0018.

Questions:

a) **Confirm the depreciation in EB-2010-0018 for the Ethanol Pipeline was based upon the Settlement Agreement and set at a rate of 5%.**
b) **Is ENGLP aware of the depreciation rate used by Union Gas Ltd. or Enbridge Gas Distribution Inc. for steel main or for other natural gas utilities operated by ENGLP (or its related companies)? If so, please provide such depreciation rates.**
c) **Has NRG done any studies, analyses or reviews of the Ethanol Pipeline and an appropriate depreciation rate based upon the life expectancy of the asset? If so, please provide.**

<u>Responses:</u>

a) Confirmed. The depreciation rate for the Ethanol Pipeline was set at 5% (20 years) and was based upon Section 4.7 of the Settlement Agreement for EB-2010-0018 dated August 18, 2010.

b) According to evidence filed by Union Gas Limited and Enbridge Gas Distribution Inc. in their 2011 applications to the Board, the depreciation rates used for steel mains are as follows:

   - Union Gas Limited - rate of 1.98% (50.5 years)[20].
   - Enbridge Gas Distribution Inc. - rate of 1.64% (61 years)[21]

c) EPCOR is not aware of any studies or reviews of the depreciation rate or life expectancy of the ethanol pipeline completed by NRG.

[20] EB-2011-0210 - Application and Evidence, Exhibit D1, Tab 6, Appendix A, page 2
[21] EB-2011-0354- Application and Evidence, Exhibit D2, Tab 2, Schedule 1 page 36

IGPC-9

Evidence Reference: EB-2018-0235, Exhibit D, page 6

Preamble: IGPC is supportive of establishing a rate structure that is just and reasonable and reflect the elasticity of costs to be incurred by ENGLP in providing distribution service to IGPC.

Questions:

a) **Please confirm that no other ratepayers would be impacted by the switch to a fixed monthly rate for Rate 6.**
b) **Please confirm that under the current proposal the upstream supply by Union Gas would be fully covered by IGPC and other ratepayers of ENGLP would not be at risk.**
c) **Please confirm that this relief can be implemented even without the Board granting the relief sought in Exhibit A, Exhibit B or Exhibit C. If you cannot confirm this, please explain.**
d) **Please confirm that almost all expenses of ENGLP are independent of the volume consumed by IGPC. Which expenses, if any, are related to volume consumed? Please provide examples with related amounts.**
e) **Please confirm that other than the demand costs of Union Gas that all other cost incurred by ENGLP in respect of providing service to IGPC are independent of the actual demand of IGPC. If you cannot confirm this, please explain with amounts.**
f) **What are the approximate O&M costs applicable to IGPC in 2017 and 2018? Please provide a detailed chart.**
g) **What is the amount ($/unit/month) of the Union Gas charge? When does ENGLP expect this amount to change and by how much?**

<u>Responses:</u>

a) Confirmed.

b) Under the current proposal all upstream supply costs from Union Gas Limited associated with supplying gas to IGPC are covered under a separate agreement between EPCOR and Union Gas Limited. The costs under this agreement would be fully charged to IGPC under the Gas Delivery Contract between EPCOR and IGPC. Other ratepayers will not be charged for the costs associated with this contract.

c) Confirmed. Implementing a fixed rate for IGPC can be done independent of the relief sought in Exhibits A, B and C.

d) There is no direct relationship between IGPC's volume and EPCOR's operating, maintenance and administration costs. The only expenses to EPCOR that are dependent on volumes of IGPC are the amounts paid to Union Gas Limited under the contracts specific to the IGPC volumes. These charges are treated as a direct pass-through to IGPC under the Gas Delivery Agreement between EPCOR and IGPC.

e) Please see response to IGPC-9 d) above.

f) Please see response to IGPC-5 d) above.

g) The contract charges under EPCOR's M9 contract with Union Gas Limited for the volumes related to IGPC are made up of the following:

   i. Monthly demand charge of 23.5428 cents per m3 based on a monthly firm contract demand of 208,800 m3.
   ii. Delivery commodity charge of 0.1569 cents per m3

The M9 contract also includes provisions for overrun charges (authorized and unauthorized) for volumes in excess of 103% of the contracted rights, and IGPC is responsible for any such charges incurred.

EPCOR's Bundled T contract with Union Gas Limited related to IGPC's volumes does not have specified rates or amounts, however all charges from Union to EPCOR under this agreement are a direct pass through to IGPC in accordance with the Gas Delivery Agreement (i.e. such as recovery of excessive transactional costs related to balancing).

The delivery commodity charge in the M9 contract is based on Union Gas Limited's most recent approved QRAM filing and would change with each approved QRAM. The term of the current M9 contract ends on June 30, 2019 and the monthly demand rates may change at that time. EPCOR does not have an estimate of what the delivery commodity charge would be in Union Gas Limited's next QRAM or for the monthly demand charge or associated firm contracted demand upon renewal of the M9 contract.

IGPC-10

Evidence Reference: EB-2018-0235, page 5

Preamble: ENGLP has indicated that it is planning to invest approximately $600,000 in capital in 2018 to serve IGPC's increased consumption.

Questions:

- **a) Please provide a status of the capital expenditure referenced above and planned for 2018 in respect of IGPC?**
- **b) What is the current forecast of the amount of capital expenditure in 2019 to be made for serving IGPC?**
- **c) What is the amount that has been spent year to date in this regard?**
- **d) Which rate year, and how much, will those amounts be recorded?**
- **e) What is the approximate impact such an expenditure would have on ENGLP's revenue requirement in a cost of service rate application? Please show the calculation**
- **f) Has IGPC begun to operate its expanded facility?**
- **g) Have you started to invoice IGPC for the additional volumes? If so, how much?**

<u>Responses:</u>

a) EPCOR's capital expenditures for 2018 required to serve IGPC's increased consumption include a station replacement forecasted at $600,000 and the pigging installation project forecasted at $50,000 for total forecasted 2018 spending of $650,000. These projects are moving forward in the fourth quarter of 2018. The projects are forecasted to be fully completed prior to the end of November 2018 and put into service by the end of 2018. At the time of filing these responses, no amounts have been spent on these projects.

b) The only capital project planned for 2019 relates to a Ministry of Transportation project which requires EPCOR to replace three sections of the IGPC pipeline that interfere with the Ministry's interchange and bridge replacement project. Early project estimates are between $600,000 and $700,000. Final figures are expected once the competitive bidding process has been completed in early 2019.

c) Please see response to IGPC-10 a).

d) Please see response to IGPC-10 a).

e) The approximate impact of the forecasted $650,000 in capital expenditures described in a) above would be as follows:

	2018	2019	2020	2021
Incremental Rate Base Impacts				
PP&E, Beginning of year	-	650,000	1,050,000	1,050,000
Capital Additions	650,000	400,000		
PP&E, end of year	650,000	1,050,000	1,050,000	1,050,000
Accumulated Depreciation, beginning of year	-	16,250	58,750	111,250
Depreciation Expense (20 year life)	16,250	42,500	52,500	52,500
Accumulated Depreciation, end of year	16,250	58,750	111,250	163,750
Mid-Year Rate Base	316,875	812,500	965,000	912,500
Incremental Revenue Requirement Impact				
Depreciation Expense	16,250	42,500	52,500	52,500
Return on rate base	19,080	48,922	58,105	54,943
	35,330	**91,422**	**110,605**	**107,443**

For the purposes of the above calculations the following cost of capital parameters have been used which are based on the most recent cost of capital parameters (allowed return and deemed debt) from the Board:

Weighted Average Cost of Capital	Capital Structure	Rates of Return	Weighted Return
Short-term debt	4%	2.29%	0.09%
Long-term debt	56%	4.16%	2.33%
Total debt	60%		2.42%
Equity	40%	9.00%	3.60%
	100%		**6.02%**

f) IGPC began operating some aspects of its expanded facility after its plant shutdown in late September 2018 and volumes have begun increasing since that time. IGPC has indicated to EPCOR that the consumption volumes will continue to increase as various pieces of the expansion equipment are brought online.

g) EPCOR continues to bill IGPC based on the rate structure as developed in EB-2010-0018 and per EPCOR's most recent approved rate order. As described on page 5 of Exhibit D these charges include a monthly delivery charge which is a $ per m3 charge. Any volumes consumed to date would have been billed based on this rate. However, as IGPC's consumption has always been variable, EPCOR cannot quantify how much of the volumes billed to date are resulting from the expansion.

IGPC-11

Evidence Reference: EB-2018-0235, Exhibit E, page 5 and 6

Preamble: The credit balance for Rate Class 6 is $544,304 which includes $43,734. IGPC is interested in the disposition of the PGTVA and REDA Variance accounts.

Questions:

a) Please confirm the amounts to be disposed of have been audited and as of which date was the audit completed.
b) Does ENGLP have the funds currently available to repay the amounts that are to be disposed of in this Application.
c) Please confirm the request in Exhibit E is independent of the requests in Exhibit A, Exhibit B, Exhibit C, and Exhibit D. If not confirmed, please explain.
d) Please provide a copy of NRG's audited financial statements for the fiscal years ending September 30, 2016 and September 30, 2017.
e) Please provide any audited financial statements for the period since September 30, 2017. If none are available, please provide any unaudited available statements.

<u>Responses:</u>

a) The amounts to be disposed of are the September 30, 2017 balances, and Natural Resource Gas Limited financial statements for the period ending September 30, 2017 were audited.

b) Yes.

c) Confirmed.

d) NRG's audited financial statements for the fiscal years ending September 30, 2016 and September 30, 2017 have been provided as Attachment 2.

e) EPCOR Natural Gas Limited Partnership's audited financial statements for the fiscal year ending December 31, 2017 has been provided in Attachment 3. These statements comprise the two-month period of operations since the assets were acquired from NRG on November 1, 2017.

ATTACHMENT 1 as associated with IGPC 4

Agreements in place between EPCOR and IGPC

GAS DELIVERY AGREEMENT

This natural gas delivery agreement (the "**Agreement**") made this 30th day of June 2015 (the "**Effective Date**")

BETWEEN:

NATURAL RESOURCE GAS LIMITED, (the "**Utility**"),

and

IGPC ETHANOL INC. (the "**Customer**"),

(each a "**Party**" and collectively the "**Parties**")

WHEREAS the Customer requires the delivery of natural gas to its ethanol facility located in the Town of Aylmer and Utility has the franchise for the distribution of natural gas in the Town of Aylmer;

NOW THEREFORE, in consideration of the mutual covenants and agreements contained in this Agreement, and for other good and valuable consideration (the receipt and adequacy of which are hereby acknowledged), the Parties agree as follows:

TYPE OF SERVICE:

___ Firm Demand

___ Interruptible Demand

___ Combined Firm and Interruptible Demand

RATE CLASS: 6

DAY OF FIRST DELIVERY: July 1, 2015

PART 1 - DEFINITIONS

(a) For the purpose of interpreting this Agreement, the capitalized terms shall have the following meaning, unless the context requires otherwise:

(i) "**Agreement**" means this Gas Delivery Agreement including schedules as such may be amended from time to time;

(ii) "**Applicable Rate**" means the distribution rate, including rate riders and rate adders, approved by the OEB that the Utility is authorized to charge the Customer;

(iii) "**Business Day**" means any day that is not a Saturday, Sunday or statutory holiday in the Province of Ontario;

(iv) "**Customer Delivery Point**" means the Customer's facility located at the address known municipally as 89 Progress Drive, Aylmer, Ontario;

(v) "**Force Majeure**" has the meaning ascribed to it in Schedule B;

(vi) "**Joint Rate Proposal**" has the meaning ascribed to it in Part 5 of this Agreement;

(vii) "**Maximum Daily Volume**" means the maximum daily volume of natural gas required to be delivered by Utility to Customer pursuant to Part 4 of this Agreement;

(viii) "**Maximum Hourly Volume**" means the maximum hourly volume of natural gas required to be delivered by Utility to Customer pursuant to Part 4 of this Agreement;

(ix) "**Minimum Volume**" means the minimum volume of natural gas that the Customer is required to accept and pay for over any particular period of time during the Term, as set out in Part 4 of this Agreement;

(x) "**Governmental Authority**" means any federal, provincial, regional, municipal or local government or authority or other political subdivision thereof, and any Person, court, tribunal, agency, board, commission or department, exercising executive, legislative, judicial, regulatory, or administrative functions of, or pertaining to, government or having jurisdiction in the relevant circumstances, including, without limitation, the Ontario Energy Board;

(xi) "**Ontario Energy Board**" or "**OEB**" means the Ontario Energy Board or any successor organization that has authority to set rates for the provision of natural gas delivery service in Ontario.

PART 2 - TERM & TERMINATION

This Agreement shall be effective as of the Effective Date first written above and, unless terminated earlier in accordance with the provisions hereof, shall expire on September 30, 2020 (the "**Term**").

PART 3 - PURCHASE AND SALE

During the Term, except during periods of curtailment, discontinuance or Force Majeure:

(a) the Utility agrees to deliver natural gas from the Union Gas Limited distribution system to the Customer Delivery Point, up to the Maximum Daily Volume and Maximum Hourly Volume set out in Part 4; and

(b) Customer agrees that it will receive from the Utility all of the natural gas delivered to the Utility by the Customer, up to the Maximum Daily Volume and Maximum Hourly Volume set out in Part 4.

The natural gas received by the Utility and delivered to the Customer shall be commercially free from sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to or interference with the proper operation of the lines, regulators, meters or other appliances through which it flows. Neither Party is responsible for any loss, damage, or injury resulting from such Party's delivery of gas that does not conform to any specifications set forth in this section, except to the extent any loss, damage or injury arises as a result of such Party's negligence or wilful misconduct.

PART 4 - MAXIMUM DAILY VOLUME AND MINIMUM VOLUME

First Period Contract Parameters:

For the period from July 1, 2015 to earlier of the commencement of the Second Period or Third Period (the "**First Period**"):

(a) Maximum Daily Volume: The Maximum Daily Volume of firm gas the Utility is required to deliver to the Customer in any day (which shall be a 24 hour period commencing 10:00 a.m. Eastern Standard Time) shall not exceed 108,188 m^3.

(b) Maximum Hourly Volume: The Maximum Hourly Volume of firm gas the Utility is required to deliver to the Customer in any hour shall not exceed 5,410 m^3.

(c) Minimum Volume: The Minimum Volume of natural gas that the Customer is required to accept and pay for in each month of the First Period shall be 2,784,718 m^3.

(d) Utility Curtailment Right: Should the Customer consume more than 5,410 m^3 during any hour and such excess consumption is adversely impacting the Utility's ability to operate its distribution system, the Utility may curtail service to a volume of 5,410 m^3/hour. Consumption in excess of 5,410 m^3/hour by the Customer shall not be considered to be a breach of this Agreement.

(e) New Maximum Daily Volume: Should the Customer exceed the Maximum Daily Volume on any day before the new rate structure is effective, then this higher number will be the new Maximum Daily Volume under this Agreement until a new rate structure is effective, and the Maximum Hourly Volume specified herein shall be adjusted accordingly, subject to being able to make any arrangements with Union Gas Limited that may be required.

Second Period Contract Parameters:

The Utility shall make commercially reasonable efforts to amend its M9 contract with Union Gas Limited (for dedicated supply to the Customer) to increase the Maximum Daily Volume to

130,000 m^3 and the Maximum Hourly Volume to 6,100 m^3 by October 1, 2015. If NRG is able to amend its upstream M9 contract with Union Gas Limited (the "**Amended M9 Contract**"), then the First Period parameters shall no longer be applicable, and the following parameters shall apply until such time as the OEB establishes new rates for NRG based on a re-basing rate application (the "**Second Period**"):

(a) Maximum Daily Volume: The Maximum Daily Volume of firm gas the Utility is required to deliver to the Customer in any day (which shall be a 24 hour period commencing 10:00 a.m. Eastern Standard Time) shall not exceed the Firm Contract Demand in the Amended M9 Contract.

(b) Maximum Hourly Volume: The Maximum Hourly Volume of firm gas the Utility is required to deliver to the Customer in any hour shall not the Maximum Hourly Flow in the Amended M9 Contract.

(c) Minimum Monthly Volume: The Minimum Volume of natural gas that the Customer is required to accept and pay for in each month of the Second Period shall be 2,784,718 m^3.

(d) Utility Curtailment Right: Should the Customer consume more than the Maximum Hourly Flow in the Amended M9 Contract during any hour and such excess consumption is adversely impacting the Utility's ability to operate its distribution system, the Utility may curtail service to a volume equivalent to the Maximum Hourly Flow in the Amended M9 Contract. Consumption in excess of the Maximum Hourly Flow in the Amended M9 Contract by the Customer shall not be considered to be a breach of this Agreement.

(e) New Maximum Daily Volume: Should the Customer exceed the Maximum Daily Volume on any day before the new rate structure is effective, then this higher number will be the new Maximum Daily Volume under this Agreement until a new rate structure is effective, and the Maximum Hourly Volume specified herein shall be adjusted accordingly, subject to being able to make any arrangements with Union Gas Limited that may be required.

The Customer agrees that it shall be responsible for any costs billed by Union Gas Limited to NRG associated with the Amended M9 Contract, including without limitation, any capital costs to accommodate the increased volumes. Such costs will not be marked up by NRG.

Third Period Contract Parameters:

For the period commencing with the establishment of new rates for NRG based on a re-basing rate application, and ending on the earlier of the Termination of this Agreement or September 30, 2020 ("**Third Period**"):

(a) Maximum Daily Volume: The Maximum Daily Volume of firm gas the Utility is required to deliver to the Customer in any day (which shall be a 24 hour period commencing 10:00 a.m. Eastern Standard Time) shall only be limited by the capacity limits of the Utility's distribution system and the upstream Union Gas Limited distribution system.

(b) Maximum Hourly Volume: The Maximum Hourly Volume of firm gas the Utility is required to deliver to the Customer in any hour shall only be limited by the capacity limits of the Utility's distribution system and the upstream Union Gas Limited distribution system. Revisions to the Maximum Hourly Volume and therefore the Fixed Contract Demand will be subject to approval of Union Gas Limited and Customer.

(c) Minimum Volume: If the OEB approves the Joint Rate Proposal set out in Part 5 below, the Customer shall have no Minimum Volume obligation under this Agreement. If the OEB does not approve the Joint Rate Proposal set out in Part 5 below, the Customer and Utility will negotiate in good faith to establish an annual Minimum Volume obligation that enables the Utility to recover that portion of its revenue requirement allocated to the Customer.

(d) Utility Curtailment Right: Should the Customer consume at any time an amount that is adversely impacting the Utility's ability to safely and reliably operate its distribution system, the Utility may curtail service to a volume equivalent to the Maximum Hourly Flow in the Amended M9 Contract. Consumption in excess of the Maximum Hourly Flow in the Amended M9 Contract by the Customer shall not be considered to be a breach of this Agreement.

PART 5 - RATE

Subject to the provisions of the paragraph 1.2 of the General Terms and Conditions attached as Schedule B, the Customer shall pay for all natural gas delivered under this Agreement at such rates and charges (including, without limitation, any applicable administration charge, minimum bill per month, penalty for late payment and unauthorized overrun gas rate) applicable to or for such service, in accordance with the provisions of the Utility's Rate 6 schedule in effect at any time during the term of this Agreement.

Utility shall use commercially reasonable efforts to have a new rate application finally determined by the OEB by September 30, 2016.

For the period prior to the new rate structure being effective, if the Utility, pursuant to Part 8 of this Agreement, or due to an event of Force Majeure as described in the General Terms and Conditions, fails or is unable to deliver the amount of firm natural gas which the Customer desires to take during any one or more days in a month, up to the Customer's Maximum Daily Volume in effect on such days, then the minimum bill for that month shall be reduced by an amount equal to the Firm Delivery Rate applied to the volume by which the Maximum Daily Volume exceeds the volume of gas delivered to the Customer Delivery Point on such a day, for each day in the month in which the inability to deliver continues.

The Utility shall, at its next cost of service rebasing application for distribution rates, currently forecasted to commence October 1, 2016, propose a new Rate 6 schedule wherein the Customer would pay a flat monthly fixed charge that would enable the Utility to recover the forecasted annual revenue requirement allocated to Customer (the "**Joint Rate Proposal**") in 12 monthly payments. The Joint Rate Proposal shall be composed of the following two components:

(a) a fixed monthly charge to permit recovery of the cost of distribution service as determined by the OEB, excluding the M9 charges of Union Gas Limited; and

(b) the pass-through, without mark-up, of all charges billed to the Utility by Union Gas Limited related to all gas supplied to the Utility's distribution system for Customer. For greater certainty, this shall include all Union Gas Limited charges to the Utility under the M9 Contract or Amended M9 Contract between the Utility and Union Gas Limited (Union Contract ID SA008936, as amended or replaced from time to time), and the Bundled-T Contract between the Utility and Union Gas Limited (Union Contract ID SA008937, as amended or replaced from time to time).

Rater riders and rate adders shall be applicable as determined by the OEB.

In addition, the new Rate 6 should permit Utility to recover each month any penalties in respect of the Customer's deliveries or consumption of natural gas properly imposed by a third party (including without limitation, Union Gas Limited) on a cost pass-through basis, with no separate unauthorized overrun charge levied by NRG.

Provided the Utility has received approval as to the form of the Joint Rate Proposal from the Customer, the Customer agrees to support the form of the Joint Rate Proposal at NRG's next application for distribution rates before the OEB. The Customer may intervene in the rate application and take any position it deems appropriate regarding the Utility's revenue requirement, cost allocation and quantum of the proposed Rate 6 or other aspect of the Utility's rate application other than the form of the Joint Rate Proposal.

For the period following the effective date of new rate structure, if the Utility, pursuant to Part 8 of this Agreement, or due to an event of Force Majeure as described in the General Terms and Conditions, fails or is unable to deliver the amount of firm natural gas which the Customer desires to take during any one or more days in a month, then the monthly bill for that month shall be reduced on a proportional basis to the amount that the Customer would have taken in the month in the absence of any curtailment or discontinuance.

PART 6 - POINT OF DELIVERY

The Customer Delivery Point of all natural gas delivered by the Utility is at the outlet of the Utility's metering equipment at the Customer's Facility. The Utility shall at no time assume title to the gas that the Customer is supplying into the Utility's distribution system. The Utility agrees to deliver gas at the outlet of its metering equipment at a minimum pressure of 60 psig or 420 kPa.

PART 7 - PRIORITY OF SERVICE

In the event of an actual or threatened shortage of natural gas due to circumstances beyond the control of the Utility, or when curtailment or discontinuance of supply is ordered by an authorized Governmental Authority, the Customer shall at the direction of the Utility, curtail or discontinue use of natural gas during the period specified by the Utility so as to safeguard the health and safety of the public. Such curtailment or discontinuance shall be made on a prorated basis as maybe ordered by such Governmental Authority among all industrial Rate 3 and Rate 6 customers of the Utility. The Utility shall not be liable for any loss of production or for any damages whatsoever by reason of any such curtailment or discontinuance or because of the length of advance notice given directing such curtailment or discontinuance.

PART 8 - CURTAILMENT OR DISCONTINUANCE OF SERVICE

Firm service under this Agreement will be provided up to the Maximum Daily Volume.

Notice of curtailment or discontinuance of service may be conveyed by telephone, in person, by mail, facsimile or email to Customer. If notice is conveyed by telephone or in person then the Utility shall at the earliest possible time thereafter confirm in writing the details of the notice and provide the reasons for the curtailment or discontinuance of service and the anticipated duration of the curtailment if the curtailment or discontinuance is continuing at the time of the written notice.

Service will be resumed as soon as possible when these conditions cease to be operative.

PART 9 - GENERAL TERMS AND CONDITIONS

The General Terms and Conditions attached as Schedule B form part of this Agreement.

PART 10 - SECURITY DEPOSIT

During the Term of this Agreement, the Customer shall provide and maintain a security deposit in respect of the distribution service with the Utility in an amount equal to the maximum amount of distribution services for a period of two months, as calculated below, using the Applicable Rate at the Day of First Delivery. The security deposit may be in the form of a letter of credit, guarantee or other mutually agreeable method of providing financial assurance. The amount of any security deposit shall be subject to adjustment on an annual basis on the anniversary of the Day of First Delivery using the Applicable Rate on such date.

During the First Period and Second Period, the maximum amount of the security deposit will be equal to:

Security Deposit = Monthly Customer Charge + Demand Charge + Delivery Charge

Where:

Monthly Customer Charge = the fixed monthly charge specified in Rate 6 x 2

Demand Charge = Firm Agreement Demand x Firm Demand Rate x 2

Delivery Charge = Firm Delivery Rate x Firm Agreement Demand x 60

During the Third Period, the maximum amount of the security deposit will be equal to:

Security Deposit = (Monthly charge to permit recovery of the cost of NRG's distribution service PLUS Monthly charge to permit recovery by Utility of the M9 charges from Union Gas Limited) x 2

The Utility shall not be entitled to draw upon the security deposit while the Customer is in compliance with the terms of this Agreement and shall not be entitled to draw upon security deposit during any dispute, unless such dispute has been finally resolved and the Buyer has not made payment with ten (10) Business Days of the final resolution of such dispute.

For greater certainty, if the Utility is entitled to draw upon the security deposit and draws down upon the security deposit in whole or in part, the Customer shall replenish the amount of the security deposit in the same form and to the maximum amount noted above within 15 Business Days.

If Customer shall be indebted (whether past, present, or future, liquidated or unliquidated) to Utility under this Agreement, Utility has the right to reduce any amount payable by Utility to Customer under this Agreement by an amount equal to the amount of such indebtedness to Utility. As part of this remedy, Utility may take title to any or all of Customer's gas in Utility's system. Such gas shall be valued at the day price for gas at Dawn as listed in Canadian Gas Price Reporter for the day of non-payment.

PART 11 - INVOICING & PAYMENT

All invoices from Utility to Buyer will be delivered to Customer's address as noted below. Monthly invoices will be prepared in accordance with the General Terms and Conditions and the Customer shall pay such invoices within the time frames provided in the General Terms and Conditions.

In the event the Customer does not pay the invoice within the timeframes provided, then the Utility shall provide notice to the Customer that the Customer is not in compliance and the Customer shall have three (3) Business Days to remedy such non-payment.

In the event the Customer does not make payment within three (3) Business Days of receiving notice then Utility shall be entitled to draw upon the security deposit for the amount owed.

In the event of a dispute regarding the amount of any invoice delivered by the Utility to the Customer, the Customer shall pay the undisputed portion within the time required in the General Terms and Conditions. The Customer shall at the time of payment of the undisputed portion of the invoice give notice to the Utility of the dispute and the reasons it is disputing such amount. Upon receipt of such notice of disputed amount, the Parties shall enter into good faith discussions to resolve the dispute. In the event the Parties are unable to resolve the dispute within fifteen (15) Business Days then the Customer may refer the matter for dispute resolution.

Disputes relating to metering will be subject to the dispute resolution mechanisms established pursuant to the *Electricity and Gas Inspection Act*. Disputes within the jurisdiction of the OEB shall be referred to the OEB for resolution. The Customer may refer all other disputes for arbitration under the *Arbitration Act 1991* (Ontario) before a single arbitrator. If the Customer has not given written notice that the Customer is referring the dispute for resolution within five (5) Business Days, the Customer will be deemed to have abandoned the dispute and shall pay any amount still owing within five (5) Business Days.

Monies found to be owing to the Utility at the resolution of the dispute shall be paid by the Customer within five (5) Business Days of such final resolution. If upon resolution of the matter, the amount owed by the Customer is less than the amount originally withheld by the Customer, then interest will not be calculated during the time period prior to the resolution of the dispute.

The Utility shall also be entitled to recover its OEB approved late payment charge for any late payment, including any payment that is unsuccessfully disputed by the Customer. Costs will be determined under the *Electricity and Gas Inspection Act* or by the arbitrator or the OEB as applicable.

This Agreement is subject to the consent of the Customer's Lenders. The Customer agrees to use reasonable efforts to secure such consent in a timely manner. This paragraph is entirely for the benefit of the Customer. The Customer shall waive this condition in writing.

PART 12 - NOTICE OF COMMUNICATION

Except for the notice for curtailment of service set out in Part 8 above, or of an event of Force Majeure, any notice or other communication required to be given by either Party to this Agreement to the other shall be deemed to have been given 72 hours after such notice of communication shall have been mailed in a postage prepaid envelope addressed, in the case of notice to the Utility, to it at:

Natural Resource Gas Limited
39 Beech St. E.
P.O. Box 307
Aylmer, Ontario N5H 281
Telephone: 519-773-5321
Facsimile: 519-773-5335

Or in the case of notice to the Customer, except notice of Force Majeure or curtailment, to it at:

IGPC Ethanol Inc.
89 Progress Drive
Aylmer, Ontario

Attention: Mr. Jim Grey, President and CEO
Telephone: (519) 765-2575 ext. 228
Facsimile: (519) 765-2775

Or in the case of Force Majeure or curtailment, to the Customer at:

IGPC Ethanol Inc.

Attention: Plant Manager
Telephone: (519) 765-2575 ext. 231

or in each case to such other address as the particular Party may furnish to the other from time to time during the term of this Agreement, provided that any such notice or other communication may be given by delivery at the above addresses and shall be deemed to have been given at the time of such delivery. All invoices from Utility to Customer will be hand delivered to Customer's address as noted above.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement.

NATURAL RESOURCES GAS LIMITED

By: ______________________________
Name: ANTHONY N. GRAAT
Title: PRESIDENT

By: ______________________________
Name:
Title:
I/We have authority to bind the corporation.

IGPC ETHANOL INC.

By: ______________________________
Name: Jim Grey
Title: President and CEO

By: ______________________________
Name:
Title:
I/We have authority to bind the corporation.

Or in the case of Force Majeure or curtailment, to the Customer at:

IGPC Ethanol Inc.

Attention: Plant Manager
Telephone: (519) 765-2575 ext. 231

or in each case to such other address as the particular Party may furnish to the other from time to time during the term of this Agreement, provided that any such notice or other communication may be given by delivery at the above addresses and shall be deemed to have been given at the time of such delivery. All invoices from Utility to Customer will be hand delivered to Customer's address as noted above.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement.

NATURAL RESOURCES GAS LIMITED

By: ______________________________
Name:
Title:

By: ______________________________
Name:
Title:
I/We have authority to bind the corporation.

IGPC ETHANOL INC.

By: ______________________________
Name: Jim Grey
Title: President and CEO

By: ______________________________
Name:
Title:
I/We have authority to bind the corporation.

SCHEDULE A
OEB APPROVED RATE SCHEDULE

NATURAL RESOURCE GAS LIMITED

RATE 6 – Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility

Rate Availability

Rate 6 is available to the Integrated Grain Processors Co-Operative, Aylmer Ethanol Production Facility only.

Eligibility

Integrated Grain Processors Co-Operative's ("IGPC") ethanol production facility located in the Town of Aylmer

Rate

1. Bills will be rendered monthly and shall be the total of:

a) Monthly Customer Charge of $150.00 for firm services

Rate Rider for reduction in Aid to Construct - effective until September 30, 2016	$(41,786.54)
Rate Rider for Shared Tax Savings - effective until September 30, 2015	$(602.26)

b) A Monthly Demand Charge:

A Monthly Demand Charge of 18.6158 cents per m^3 for each m^3 of daily contracted firm demand.

c) A Monthly Delivery Charge:

(i) A Monthly Firm Delivery Charge for all firm volumes of 3.8432 cents per m^3,

(ii) A Monthly Interruptible Delivery Charge for all interruptible volumes to be negotiated between the company and IGPC not to exceed 10.9612 cents per m^3 and not to be less than 7.9412 per m^3.

d) Gas Supply Charge and System Gas Refund Rate Rider (if applicable) Schedule A

e) Overrun Gas Charges:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, IGPC should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to IGPC on such day, or if, on any day, IGPC fails to comply with any curtailment notice reducing IGPC's take of gas, then,

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized firm overrun gas taken in any month shall be paid for at the Rate 6 Firm Delivery Charge in effect at the time the overrun occurs. In addition, the Contract Demand level shall be adjusted to the actual maximum daily volume taken and the Demand Charges stated above shall apply for the whole contract year, including retroactively, if necessary, thereby requiring recomputation of bills rendered previously in the contract year.

Any unauthorized interruptible overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any Gas Supply Charge applicable.

For any unauthorized overrun gas taken, IGPC shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company's suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c)(ii) above, the matters to be considered include:

a) The volume of gas for which IGPC is willing to contract;
b) The load factor of IGPC's anticipated gas consumption, the pattern of annual use, and the minimum annual quantity of gas which IGPC is willing to contract to take or in any event pay for;
c) Interruptible or curtailment provisions;
d) Competition.

3. In each contract year, IGPC shall take delivery from the company, or in any event pay for it if available and not accepted by the IGPC, a minimum volume of gas as specified in the contract between the parties. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this minimum shall be 3.1530 cents per m^3 for firm gas and 5.4412 cents per m3 for interruptible gas.

4. The contract may provide that the Monthly Demand Charge specified in Rate Section 1 above shall not apply on all or part of the daily contracted firm demand used by the IGPC during the testing, commissioning, phasing in, decommissioning and phasing out of gas-using equipment for a period not to exceed one year (the transition period). In such event, the contract will provide for a Monthly Firm Delivery Commodity Charge to be applied on such volume during the transition of 5.7163 cents per m^3 and a gas supply commodity charge as set out in Schedule A, if applicable. Gas purchased under this clause will not contribute to the minimum volume.

Bundled Direct Purchase Delivery

Where IGPC elects under this rate schedule to directly purchase its gas from a supplier other than NRG, IGPC or its agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to IGPC if it elects said Bundled T transportation service.

Unless otherwise authorized by NRG, IGPC, when delivering gas to NRG under direct purchase arrangements, must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: July 01, 2015
Implementation: All bills rendered on or after July 01, 2015
EB-2015-0191

NATURAL RESOURCE GAS LIMITED

SCHEDULE A – Gas Supply Charges

Rate Availability

Entire service area of the company.

Eligibility

All customers served under Rates 1, 2, 3, 4, 5 and 6.

Rate

The Gas Supply Charge applicable to all sales customers shall be made up of the following charges:

PGCVA Reference Price	(EB-2015-0191)	20.1173 cents per m^3
GPRA Recovery Rate	(EB-2015-0191)	0.6337 cents per m^3
System Gas Fee	(EB-2010-0018)	0.0363 cents per m^3
Total Gas Supply Charge		20.7873 cents per m^3

Note:
PGCVA means Purchased Gas Commodity Variance Account
GPRA means Gas Purchase Rebalancing Account

Effective: July 01, 2015
Implementation: All bills rendered on or after July 01, 2015
EB-2015-0191

SCHEDULE B
GENERAL TERMS AND CONDITIONS

PART 1 - RATES

1.1 Bills are issued monthly, being due when rendered in accordance with the provisions of the gas delivery contract and the approved rate schedule. If payment in full is not received within 15 days of rendering the bill, any amount owing shall be increased by 1.5% on the next bill.

1.2 In the event of any increase,

(a) in the cost of gas to the Utility under its gas purchase contracts;

(b) in the cost of gas to the Utility resulting from the application of any valid law, order, rule or regulation of any legislative body or duly constituted authority now or hereafter having jurisdiction;

(c) in the costs of the Utility resulting from any changes in, or the imposition of any taxes, excises or duties by any Governmental Authority during the lifetime of this contract, on the importation, transmission, storage, purchase or sale of gas; or

(d) in the charges or rates approved or fixed by the Ontario Energy Board for the delivery or sale of gas by the Utility to the Customer, including retroactive rate increases authorized by the Ontario Energy Board.

then to the extent that such increases in the case of (a), (b) or (c) above are paid by the Utility on the gas delivered to the Customer, or such increase in the case of (d) above is ordered by the Ontario Energy Board to be charged to the Customer, the rates to be paid by the Customer to the Utility, pursuant to the gas delivery contract, shall be increased accordingly for all gas delivered subsequent to that increase in costs or charges, provided that the increased rates shall not exceed rates fixed by order of the Ontario Energy Board from time to time.

1.3 In the event the terms and conditions of the agreement between Utility and Customer are changed by Order of the Ontario Energy Board, such changed terms and conditions shall be deemed to be in effect between the Utility and the Customer. If the Utility becomes aware of any proposed change to this Agreement being considered by the Ontario Energy Board, the Utility shall provide the Customer with notice of such proposed change.

PART 2 - UNAUTHORIZED OVER-RUN GAS PENALTY

2.1 If, on any day, the Customer takes without the Utility's advance approval, a volume of gas in excess of the maximum hourly or daily quantity of firm or interruptible gas which the Utility is obligated to deliver to the Customer on such day, or if, on any day, the Customer fails to comply with any curtailment order of the Utility reducing either the Customer's hourly or daily take of gas, the volume of gas taken in excess of the Utility's maximum delivery obligation or curtailed maximum delivery obligation shall constitute unauthorized over-run gas.

2.2 In the event the Customer on any day takes a volume of gas constituting unauthorized over-run gas:

(a) the Utility may curtail gas service to the Customer during such a day when required to avoid adverse impacts to the Utility's distribution system;

(b) the Customer shall pay the Utility a penalty as stipulated in the Rate 6 rate schedule.

PART 3 - METERING AND SERVICE

3.1 The Utility agrees to install, operate and maintain measurement equipment of suitable capacity and design to measure the gas supplied. The Utility acknowledges that the existing measurement facilities are suitable for measurement of the Maximum Daily Volumes and Maximum Hourly Volumes set out in Part 4 of this Agreement.

3.2 The measurement and regulating equipment shall be installed on the Customer's premises at a site located as near as possible to the point of utilization in accordance with safety regulations.

3.3 Each Party shall have the right to enter the measurement and regulating location at any reasonable time and shall have the right to be present at the time of installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating or adjusting of measurement equipment.

3.4 The Utility's measurement equipment shall be examined by the Utility at least once every nine months and, if requested by Customer, in the presence of a representative of the Customer, but the Utility shall not be required as a matter of routine to examine such equipment more frequently than once in any nine month period. The Utility, following such inspection, shall forthwith take any and all corrective action necessary to ensure compliance with the *Electricity and Gas Inspection Act*, R.S.C. 1985, c. E-4, as amended from time to time.

3.5 All natural gas delivered to the Customer shall be measured utilizing equipment and procedures that conform to the *Electricity and Gas inspection Act*, R.S.C. 1985, c. E-4, as amended from time to time.

PART 4 - EQUIPMENT

4.1 The title to all service pipes, meters, regulators, attachments and equipment placed on the Customer's premises and not sold to the Customer shall remain with the Utility, with right of removal, and no charge shall be made by the Customer for use of premises occupied thereby, and the Customer agrees to be responsible for any loss or damage thereto resulting from wilful or negligent acts of the Customer or its agents or employees or persons acting under the authority of or with the permission of the Customer.

4.2 Utility may be required from time to time to perform maintenance or carry out construction on its facilities, which may impact Utility's ability to meet Customer's requirements. In such event, Utility will have the right to suspend any service in whole or in part but will use reasonable efforts to determine a mutually acceptable period during which such maintenance or construction will occur and also to reasonably limit the extent and duration of any impairments. Utility shall provide at least fifteen (15) days' notice (except in cases of emergency, in which event it may be done immediately with notice provided as soon as reasonably possible afterwards) to Customer of the extent that Utility's ability to provide service may be impaired. During any such curtailment, Customer will be relieved of all demand charges for services directly related to the said curtailment, but commodity and proportionate demand charges for services available to Customer will be payable.

PART 5 - FORCE MAJEURE

5.1 In the event that either the Customer or the Utility is rendered unable, in whole or in part, by Force Majeure, to perform or comply with any obligation or condition of this Agreement, then the obligations (other than the obligations to make payment of money then due) of both parties so far as they are directly related to and affected by such Force Majeure, shall be suspended during the continuance of the Force Majeure.

5.2 The Party claiming Force Majeure shall give Notice, with full particulars, to the other Party as soon as possible after the occurrence of Force Majeure.

5.3 The Party claiming Force Majeure shall also give Notice to the other Party as soon as possible after the Force Majeure is remedied in whole or part.

5.4 "Force Majeure" means:

(a) Acts of God, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to its machinery or equipment or lines of pipe;

(b) freezing or failure of wells or lines of pipe;

(c) curtailment of firm transportation or firm storage by other natural gas service providers;

(d) strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections, civil disturbance, acts of terrorism, wars, arrests or restraint of governments and people;

(e) any laws, orders, rules, regulations, acts of any government body or authority, civil or military;

(f) any act or omission by parties not controlled by the Party claiming Force Majeure; and

(g) any other similar causes not within the control of the Party claiming Force Majeure

which by the exercise of due diligence such Party is unable to prevent or overcome. The Party claiming Force Majeure shall make commercially reasonable efforts to avoid, or correct the Force Majeure and to remedy the Force Majeure once it has occurred in order to resume performance.

5.5 Neither Party shall be entitled to claim Force Majeure if any of the following circumstances prevail:

(a) the failure resulting in a claim of Force Majeure was caused by the negligence or wilful misconduct of the Party claiming suspension or a person for whom such Party is responsible for at law;

(b) the failure was caused by the Party claiming suspension where such Party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation);

(c) the Party claiming suspension failed to resume the performance of such conditions or obligations with reasonable dispatch;

(d) the failure was caused by lack of funds, which shall include funds no longer available under any government grant, assistance or program; and

(e) the Party claiming suspension did not give to the other Party the required notice as soon as possible after determining or within a period within which it should have determined, acting reasonably, that the occurrence was in the nature of Force Majeure and would affect its ability to observe or perform any of its conditions or obligations under the Agreement.

5.6 During a Force Majeure declared by the Utility, the Customer will be responsible for any commodity charges and will only be relieved of the demand charges applicable to that part of the services not available to the Customer as a result of the Force Majeure. The Utility will not be responsible for any charges by any other natural gas service providers.

5.7 During a Force Majeure declared by the Customer, all demand charges and all commodity charges otherwise payable under this Agreement will continue to be payable. The Minimum Volume shall be reduced in the same proportion as the number of days of Force Majeure in the time period covered by the Minimum Volume requirement.

5.8 The term of this Agreement shall be extended by the length of any Force Majeure event.

PART 6 - AGREEMENTS OF INDEMNITY

6.1 The Utility and the Customer shall save harmless and indemnify the other from any injury, loss or damages to persons or property caused by its negligence or wilful misconduct or by the negligence or wilful misconduct of its agents or employees or persons acting under its authority or with its permission.

PART 7 - MISCELLANEOUS

7.1 No waiver by either Party of any one or more defaults by the other in the performance of any provisions of the contract shall operate or be construed as a waiver of any future default or defaults, whether of a like or different character.

7.2 This Agreement shall be interpreted, performed and enforced in accordance with the laws of the Province of Ontario and the laws of the Canada applicable therein.

7.3 No additions, deletions or modification of the terms and provisions of this contract shall be effective except by the execution of a new contract.

7.4 This Agreement shall be binding upon, and inure to the benefit of the Parties hereto and their respective successors and assigns but shall not be assigned or be assignable by the Customer without the prior written consent of the Utility. The Utility agrees that such consent shall not be unreasonably withheld. For greater certainty an assignment by way of security to the Customer's lenders shall be considered reasonable.

7.5 This Agreement may be executed by the parties in counterparts and may be executed and delivered by facsimile or other electronic means and all such counterparts, facsimiles or other electronic means shall together constitute one and the same agreement.

This **PIPELINE COST RECOVERY AGREEMENT** ("Agreement"), made as of the 31st day of January, 2007.

BETWEEN:

NATURAL RESOURCE GAS LIMITED,
a corporation formed under the laws of Ontario.

(the "Utility")

- and -

INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC.,
a co-operative corporation formed under the laws of Ontario.

(the "Customer")
(collectively the "Parties")

RECITALS:

WHEREAS the Customer is developing an ethanol facility (the "Customer Facility") in the Town of Aylmer, Ontario;

AND WHEREAS the Utility must expand its current natural gas distribution infrastructure to deliver natural gas to the Customer Facility to meet the volume, pressure and delivery requirements of the Customer;

AND WHEREAS the Utility has a franchise agreement to distribute natural gas in the Town of Aylmer;

AND WHEREAS the Utility has entered or will enter into an agreement with Union Gas Limited to install new facilities or modify existing facilities to supply the Utility with natural gas, such that Union Gas Limited will be capable of meeting the total supply requirements of the Utility, including the supply needs of the Customer;

AND WHEREAS the Utility and Union Gas Limited have reached an understanding regarding the Utility Connection Facilities crossing the Union Gas Limited franchise area;

AND WHEREAS the Customer has paid to the Utility a deposit of $130,000.00 against any Aid-to-Construct that may be owed to the Utility;

AND WHEREAS the Utility and the Customer have entered into an agreement dated January 31, 2007, as the same may be amended, modified, supplemented or restated (the "Gas Delivery Contract") providing for the Utility to deliver natural gas to the Customer Facility, among other things;

AND WHEREAS the Customer, or its representative, will be purchasing the Customer's gas directly and arranging for transportation, and the Utility and the Customer will enter into a Bundled T-Service Receipt Contract;

AND WHEREAS the Utility has determined that approximately 28.53km of NPS 6 steel pipeline and related facilities are required to be installed to deliver natural gas to the Customer Facility;

AND WHEREAS the Customer has requested and the Utility has agreed to construct approximately 28.53km of NPS 6 steel pipeline and related facilities (the "Utility Connection Facilities") and to arrange with Union Gas Limited for the construction by Union for facilities required to complete the connection between the Utility Connection Facilities and the Union Gas Limited system (the "Union Gas Connection Facilities"), to deliver natural gas from the Union Gas Limited system to the Customer Facility, on the terms and conditions set forth in this Agreement; and

IN CONSIDERATION of the mutual covenants contained herein, the receipt and sufficiency of which is hereby acknowledged and accepted, the Parties to this Agreement agree as follows:

ARTICLE I – ATTACHMENTS AND INTERPRETATION

1.1 The following are hereby incorporated into and form part of this Agreement:

(a) Schedule A - Pipeline Work

(b) Schedule B - Project Map

1.2 For the purpose of this Agreement:

(a) "Actual Aid-To-Construct" means the Aid-To-Construct calculated by the Utility using the Actual Capital Cost, as provided for in Article III;

(b) "Actual Capital Cost" means the reasonable actual Capital Cost, as provided for in Article III;

(c) "Aecon" means Aecon Utilities - A Division of Aecon Construction Inc., or any successor thereto;

(d) "Aid-to-Construct" means the amount by which the Capital Cost exceeds the revenue recovered by the Utility through rates, as calculated in accordance with EBO 188;

(e) "Applicable Law" means all federal, provincial, county, municipal or local laws, by-laws, statutes, rules, regulations ordinances, directives, or any decisions of a Governmental Authority.

(f) "Business Day" means a day, other than a Saturday or Sunday or statutory holiday in the Province of Ontario or any other day on which banking institutions in Ontario are not open for the transaction of business;

(g) "Capital Cost" means the total capital cost of the Utility Connection Facilities and the Union Gas Aid-to-Construct;

(h) "Construction" means construction and installation of the Utility Connection Facilities;

(i) "Construction Agreement" means the agreement between the Utility and a contractor for the completion of the Construction;

(j) "Cubic metres" or "m^3" means the volume of gas which at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa") occupies one cubic metre;

(k) "Customer Facility" means the ethanol facility proposed to be built and operated by the Customer in the Town of Aylmer with an output capacity of approximately 150 million litres of ethanol annually;

(l) "Customer Meter Facility" means the Utility's equipment to measure the gas consumed by the Customer, located at the Customer Facility, and includes but is not limited to all meters, pressure regulators, valves, fittings and communications equipment, and forms part of the Utility Connection Facilities;

(m) "EBO 188" means the Final Report of the Board, dated January 30, 1998 regarding the economic evaluation of the expansion of natural gas systems;

(n) "Event of Default" means either a Customer Event of Default or a Utility Event of Default;

(o) "Governmental Authority" means any federal, provincial, municipal or local government, parliament or legislature, or any regulatory authority, agency or tribunal, commission, board or department of any such government, parliament or legislature or any court or other law, regulation or rule-making entity having jurisdiction in the relevant circumstances;

(p) "GST" means the goods and service tax exigible pursuant to the *Excise Tax Act* (Canada) as amended from time to time;

(q) "Initial Estimated Aid-To-Construct" means the Aid-To-Construct calculated in accordance with EBO 188 using the Initial Estimated Capital Cost;

(r) "Initial Estimated Capital Cost" means the estimated Capital Cost provided by Aecon, including the Union Gas Aid-to-Construct;

(s) "In-Service Date" means the later of November 1, 2007 and the date on which the pipeline is able to deliver the full amount of the gas contemplated by the Gas Delivery Contract;

(t) "Insolvency Legislation" means the *Bankruptcy and Insolvency Act* (Canada), the *Winding Up and Restructuring Act* (Canada) and the *Companies' Creditors*

Arrangement Act (Canada) and the bankruptcy, insolvency, creditor protection or similar laws of any other jurisdiction (regardless of the jurisdiction of such application or competence of such law), as they may be amended from time to time.

(u) "Leave-to-Construct" means the application, decision, order or approval as the context requires pursuant to section 90 of the *Ontario Energy Act, 1998* as amended;

(v) "MMBTU" means one million British Thermal Units;

(w) "NPS" means nominal pipe size;

(x) "OEB" means the Ontario Energy Board or any successor organization;

(y) "Overhead" shall, to the extent not included in other consulting costs, include the reasonable engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes and other similar items allocated to the Utility Connection Facilities;

(z) "Pipeline Work" means the work required to plan, design, construct, install, test and commission the Utility Connection Facilities and the Union Gas Connection Facilities;

(aa) "Prime Rate" means the prime rate of interest of the Bank of Nova Scotia;

(bb) "Revised Estimated Aid-To-Construct" means the estimated Aid-To-Construct calculated in accordance with EBO 188 using the Revised Estimated Capital Cost;

(cc) "Revised Estimated Capital Cost" means the estimated Capital Cost, using the most current information available, in accordance with Article III;

(dd) "Utility Connection Facilities" means the pipeline and ancillary facilities to be completed by the Utility to serve the Customer;

(ee) "Union Gas Aid-To-Construct" means the Aid-To-Construct payable to Union Gas Ltd. by the Utility in respect of the Union Gas Connection Facilities, calculated in accordance with EBO 188;

(ff) "Union Gas Connection Facilities" means the pipeline and ancillary facilities to be completed by Union Gas Limited upstream of the Utility Connection Facilities, that are necessary to serve the Customer.

ARTICLE II – REPRESENTATIONS AND WARRANTIES

2.1 The Customer represents and warrants to the Utility that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority and capacity to enter into this Agreement and to perform its obligations under it;

(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate action and does not result in a violation, a breach or a default under: (i) its charter or by-laws; (ii) any contracts or instruments to which it is bound; or (iii) any Applicable Law;

(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;

(e) this Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms; and,

(f) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

2.2 The Utility represents and warrants to the Customer that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority and capacity to enter into this Agreement and to perform its obligations under it;

(c) the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate action and does not result in a violation, a breach or a default under: (i) its charter or by-laws; (ii) any contracts or instruments to which it is bound; or (iii) any Applicable Law;

(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;

(e) this Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;

(f) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution; and,

(g) the calculation of the Initial Estimated Aid-To-Construct has been completed in accordance with EBO 188.

ARTICLE III – CAPITAL COST AND AID-TO-CONSTRUCT

3.1 The Initial Estimated Capital Cost is estimated at $9,100,000.00, comprised of approximately $8,920,000.00 for the Utility Connection Facilities and $180,000.00 for the Union Gas Aid-To-Construct. The Initial Estimated Capital Cost is included in the Leave-to-Construct application filed by the Utility with the OEB.

3.2 Based upon the Initial Estimated Capital Cost and applying the Utility's current OEB-approved Rate 3 to a minimum annual volume of 33,416,618 m^3 and a firm contract demand of 108,188 m^3/day over a seven year period, the Initial Estimated Aid-to-Construct is $3,790,000.00, to be paid by the Customer.

3.3 The Customer shall make payments toward the Initial Estimated Aid-to-Construct, as follows:

(a) $130,000.00 on or before October 16, 2006, payment of which has been received and acknowledged;

(b) Prior to the award of the Construction Agreement, the amount of the monthly invoices provided by the Utility for reasonable internal, consulting and third party expenses incurred in the prior calendar month within fifteen (15) Business Days of receiving such invoice; and

(c) Payment, in advance as required by the Utility, of an amount equal to any required payment to be made by Utility for procuring the station material and pipe;

the total of which payments shall not exceed the Initial Estimated Aid-to-Construct.

3.4 Prior to the execution of the Construction Agreement, the Utility shall provide the Customer with a Revised Estimated Capital Cost and a Revised Estimated Aid-to-Construct, based on the most current information available at the time, including the successful bid for the Construction Agreement, calculated in accordance with EBO 188, and:

(a) The Customer shall pay the Utility an amount equal to the amount, if any, by which the Revised Aid-To-Construct exceeds the total of all payments made by the Customer to the Utility under Section 3.3. In the event that the amount paid by the Customer pursuant to Section 3.3 exceeds the Revised Estimated Aid-To-Construct then the Utility shall forthwith pay to Customer an amount equal to the payments made less the Revised Estimated Aid-To-Construct; and

(b) The Utility shall provide the Customer with a detailed written breakdown of the Revised Estimated Capital Cost including, but not limited to Overhead, engineering, surveying, consultant, legal, major materials (pipe, meters, major equipment, heating equipment costs), easement, internal and external construction and commissioning costs when it is available to the Utility and a copy of the cost breakdown for the Union Gas Connection Facilities as provided to the Utility by Union Gas Limited.

3.5 In the event that the Commencement Date under the Gas Delivery Contract is later than the In-Service Date, the Utility shall invoice and the Customer shall pay an amount equal to the Utility's reasonable debt financing costs incurred in each month between the In-Service Date and the Commencement Date under the Gas Delivery Contract.

3.6 The contingency amount to be included in the Revised Estimated Capital Cost shall be limited to a maximum of ten percent of the Construction Agreement cost.

3.7 The Utility, in its sole discretion, may elect not to proceed any further with any of its obligations under this Agreement if the Customer fails to make any payment or provide any letter of credit required under this agreement until such payment or letter of credit is delivered by the Customer to the Utility and the Utility shall not be liable for any liabilities, damages, losses, payments, costs, or expense that may be incurred by the Customer as a result.

3.8 From the date required for any payment required by this Agreement, all unpaid amounts will bear interest at the rate of the Prime Rate plus 1.00% per annum payable quarterly on the last day of each calendar quarter.

3.9 The Utility shall use best efforts to minimize the actual Capital Cost, and shall advise the Customer of actual costs as incurred, in accordance with Article IV. At a minimum, the Utility shall ensure the award of the Construction Agreement is completed through a competitive tender process unless otherwise agreed to in writing by the Customer. The Utility shall ensure that the procurement of pipe, major equipment and appliances is done using a competitive quotation process wherever possible. The Utility shall inform the Customer where a competitive process is not utilized and provide an explanation as to why a competitive process is not required. Prior to committing to any expenditure in excess of $100,000.00, the Utility shall obtain the written consent of the Customer, such consent not to be unreasonably withheld.

3.10 The Utility shall request Union Gas Limited to provide it with the actual capital cost of the Union Gas Connection Facilities and the actual Union Gas Aid-to-Construct within 30 Business Days or other mutually agreeable timeframe of the pipeline being put into service.

3.11 The Customer and the Utility acknowledge that the Initial Estimated Capital Cost and the Revised Estimated Capital Cost may be different from the Actual Capital Cost incurred and the parties agree that the Actual Aid-to-Construct and Delivery Letter of Credit (as defined in Article VII) shall be adjusted based on an economic evaluation carried out in accordance with EBO 188.

3.12 The Customer reserves its rights to dispute the reasonableness of costs incurred in completing the Pipeline Work, provided that the Customer does so within 5 Business Days when such costs are provided by the Utility to the Customer.

3.13 Within forty-five (45) Business Days or some other mutually agreeable timeframe of the pipeline being put into service, the Utility shall provide the Customer with the Actual Capital Cost and Actual Aid-To-Construct, along with a summary of the information provided pursuant to Section 4.3 and copies of any invoices and supporting documentation not previously provided to Customer. If the Customer agrees with the Actual Capital Cost and Actual Aid-To-Construct, and

(a) if the Actual Aid-To-Construct is greater than the Revised Estimated Aid-To-Construct, then the Customer shall pay to the Utility the difference between the Actual Aid-To-Construct and the Revised Aid-To-Construct within five (5) Business Days; and

(b) if the Revised Estimated Aid-To-Construct exceeds the Actual Aid-To-Construct then the Utility shall pay to the Customer the difference between the Actual Aid-To-Construct and the Revised Aid-To-Construct within five (5) Business Days.

3.14 If the Customer does not agree with the Actual Capital Cost and Actual Aid-To-Construct, the Parties shall negotiate in good faith for a period of 20 Business days to establish an Actual Capital Cost. If the Parties are unable to agree after such negotiations then either party may refer the matter to the OEB for resolution. In determining reasonable costs attributable to the Capital Cost, the following considerations will be taken into account:

(a) Legal costs will include the reasonable legal costs of the Utility to establish gas distribution service for the Customer, including the reasonable legal cost to prepare and obtain the Leave to Construct from the OEB; acquire any temporary or permanent land rights required to complete the Pipeline Work; review any procurement or tendering documentation, and draft and negotiate this Agreement and any other agreement required to provide gas distribution service to the Customer;

(b) Consultant costs will include the reasonable cost of consultants incurred by the Utility to provide gas distribution service to the Customer, including the reasonable cost to complete the economic analysis to determine the Initial Estimated Aid-to-Construct, the Revised Estimated Aid-to-Construct and the Actual Aid-to-Construct; to carry out title searches to identify adjacent landowners and others with interests in adjacent lands that may be impacted by the Utility Connection Facilities; and the estimated cost of a Surveyor in the amount of $52,400;

(c) The Capital Cost will include the cost of services provided to the Utility by Aecon and any sub-contractors to Aecon, to complete the design of the Utility Connection Facilities, obtain all permits and approvals, , prepare and complete the request for quotation documents for the Construction Agreement and all other competitive processes for services and materials, and the cost estimated by Aecon to be in the range of $30,000 to $50,000 for the third party borehole drilling sub-contractor for the completion of boreholes used in the preparation of the Tender Package;

(d) Utility costs shall include the reasonable cost of interest during construction calculated in accordance with the OEB approved methodology and Overhead related to the Pipeline Work. Internal utility costs will include reasonable administrative and supervisory costs; and technician and field personnel required for the testing and commissioning of the Utility Connection Facilities.

(e) The reasonable costs of non-destructive testing of the welds and third party inspection of the Construction.

(f) The reasonable cost of the completion of as-built drawings for the Utility Connection Facilities.

(g) All consulting and third party costs include reasonable disbursements made by the third party or consultant unless such disbursements are included in a fixed fee quotation.

3.15 The Utility shall calculate and provide a partial refund of the Actual Aid-To-Construct, using the same methodology used to calculate the Actual Aid-To-Construct, if available capacity is assigned to another customer within seven years of the date on which the Utility Connection Facilities come into service, provided that the Utility is permitted by the Board to obtain any financial contribution that might be required from the subsequent customer to cover the amount of the refund. The calculation will be carried out once a year, based on the aggregate customer additions for the year. The calculation for the refund will be based on the same inputs used for the original calculation of the Actual Aid-To-Construct, except for the Capital Cost of the facilities which shall be prorated on the basis of the total capacity of the Utility Connection Facilities minus the capacity assigned to any subsequent customers.

ARTICLE IV – CONSTRUCTION

4.1 Prior to awarding of the Construction Contract, the Customer shall enter into a seven year gas delivery agreement as mutually agreed to by the Parties with a minimum annual volume of 33,416,618 m^3 and a firm contract demand of 108,188 m^3/day (Gas Delivery Agreement).

4.2 The timely completion of the Utility Connection Facilities is in the interest of the Parties. As part of the Construction Agreement, the Utility shall require the contractor to post a performance bond, including a liquidated damages provision, or other performance assurance measures acceptable to the Customer acting in a reasonable manner.

4.3 Prior to the termination of this Agreement, the Utility shall provide the Customer with weekly updates in writing as to costs incurred, costs committed to but not yet incurred and projected costs associated with the Pipeline Work. The Utility shall provide all supporting documentation (quotations, estimates, invoices, bills of lading, receipts, timesheets, etc.) for all costs incurred. As part of the updates, the Utility shall provide the Customer with a description of upcoming work; the anticipated procurement method and a recommended course of action. The Customer and the Utility shall discuss significant upcoming expenditures prior to committing to such expenditures and shall work co-operatively to meet all timelines and to minimize the costs in the circumstances. The Customer shall consent to such significant expenditures prior to the Utility committing to such expenditures, such consent to be given in a timely manner and not to be unreasonably withheld.

4.4 The Parties acknowledge that any change in the scope of the Pipeline Work may result in a change to the Capital Cost, the Aid-to-Construct, the Customer Letter of Credit and the Construction schedule. A change in scope of the Pipeline Work may come about as a result of any of the following:

(a) a Customer-initiated scope change;

(b) a requirement or condition imposed by a Governmental Authority, including without limitation, the OEB;

(c) unplanned delays on the part of the Customer or Subcontractor; or

(d) an event of Force Majeure (as determined in accordance with Article VI).

4.5 In the event of a change in the scope of the Pipeline Work, as contemplated in Section 4.4, in excess of $25,000, the Utility shall inform the Customer immediately of the nature of the change and the corresponding impact on the cost of the Pipeline Works. In the event such change will cause an increase in the Actual Capital Cost, the Utility shall obtain the Customer's consent to such increase prior to incurring such cost, such consent not to be unreasonably withheld and to be provided within 3 Business Days of receiving the information. In the event the Customer's consent has not been given within 3 Business Days, the Customer shall be deemed to have given consent to complete such work.

4.6 The Utility shall use all reasonable efforts to have the Pipeline Work (as described in Schedule A) completed by November 1, 2007 provided that:

(a) the Customer executes and returns this Agreement to the Utility by no later than February 1, 2007 (the "Execution Date");

(b) the Pipeline Work is completed in accordance with Schedule A of this Agreement;

(c) the Customer is in compliance with its obligations under this Agreement;

(d) there are no delays associated with third parties, including but not limited to Union Gas Limited, the Utility's lender and any companies selected to carry out Construction;

(e) the Utility is granted Leave-to-Construct by March 1, 2007; and,

(f) the Utility does not have to use its employees, agents and contractors performing the Pipeline Work elsewhere on its system due to an emergency, or an event of Force Majeure. For the purposes of this paragraph, an emergency means a line-break, leak, fire or similar event requiring an immediate response from the Utility.

4.7 As soon as the Utility becomes aware of any delay that may prevent the Utility from achieving the November 1, 2007 deadline, the Utility shall provide the Customer with notice in writing of such potential delay, the length of the anticipated delay and the reasons for such potential delay.

ARTICLE V – DEFAULT AND REMEDIES

5.1 Each of the following will constitute an Event of Default by the Customer ("Customer Event of Default"):

(a) The Customer fails to make any payment when due, if such failure is not remedied within ten (10) Business Days after written notice of such failure from the Utility.

(b) The Customer fails to deliver or maintain the Customer Letter of Credit or the Delivery Letter of Credit when due.

(c) The Customer fails to perform any material covenant or obligation set forth in this Agreement if such failure is not remedied within fifteen (15) Business Days after written notice of such failure from the Utility.

(d) Any representation made by the Customer in this Agreement is not true or correct in any material respect when made and is not made true or correct in all material respects within thirty (30) Business Days after receipt by the Customer of written notice of such fact from the Utility.

(e) An effective resolution is passed or documents are filed in an office of public record in respect of, or a judgment or order is issued by a court of competent jurisdiction ordering, the dissolution, termination of existence, liquidation or winding up of the Customer, unless such filed documents are immediately revoked or otherwise rendered inapplicable, or unless there has been a permitted and valid assignment of this Agreement by the Customer under this Agreement to a person which is not dissolving, terminating its existence, liquidating or winding up and such person has assumed all of the Customer's obligations under this Agreement.

(f) The Customer makes an assignment for the benefit of its creditors generally under any Insolvency Legislation, or consents to the appointment of a receiver, manager, receiver-manager, monitor, trustee in bankruptcy, or liquidator for all or part of its property or files a petition or proposal to declare bankruptcy or to reorganize pursuant to the provision of any Insolvency Legislation, or otherwise seeks the protection of Insolvency Legislation regardless of whether a proposal or plan is proposed.

(g) A receiver, manager, receiver-manager, liquidator, monitor or trustee in bankruptcy of the Customer or of any of the Customer's property is appointed by a Governmental Authority or pursuant to the terms of a debenture or a similar instrument, and such receiver, manager, receiver-manager, liquidator, monitor or trustee in bankruptcy is not discharged or such appointment is not revoked or withdrawn within thirty (30) days of the appointment.

(h) By decree, judgment or order of a Governmental Authority, the Customer is adjudicated bankrupt or insolvent or any substantial part of the Customer's property is sequestered, and such decree continues undischarged and unstayed for a period of thirty (30) days after the entry thereof.

(i) A petition, proceeding or filing is made against the Customer seeking to have the Customer declared bankrupt or insolvent, or seeking adjustment or composition of any of their respective debts pursuant to the provisions of any Insolvency Legislation, and such petition, proceeding or filing is not dismissed or withdrawn within thirty (30) days.

5.2 Each of the following will constitute an Event of Default by the Utility ("Utility Event of Default"):

(a) The Utility fails to perform any material covenant or obligation set forth in this Agreement if such failure is not remedied within fifteen (15) Business Days after written notice of such failure from the Customer.

(b) Any representation made by the Utility in this Agreement is not true or correct in any material respect when made and is not made true or correct in all material respects within thirty (30) Business Days after receipt by the Utility of written notice of such fact from the Customer.

(c) An effective resolution is passed or documents are filed in an office of public record in respect of, or a judgment or order is issued by a court of competent jurisdiction ordering, the dissolution, termination of existence, liquidation or winding up of the Utility, unless such filed documents are immediately revoked or otherwise rendered inapplicable, or unless there has been a permitted and valid assignment of this Agreement by the Utility under this Agreement to a person which is not dissolving, terminating its existence, liquidating or winding up and such person has assumed all of the Utility's obligations under this Agreement.

(d) The Utility makes an assignment for the benefit of its creditors generally under any Insolvency Legislation, or consents to the appointment of a receiver, manager, receiver-manager, monitor, trustee in bankruptcy, or liquidator for all or part of its property or files a petition or proposal to declare bankruptcy or to reorganize pursuant to the provision of any Insolvency Legislation, or otherwise seeks the protection of Insolvency Legislation regardless of whether a proposal or plan is proposed.

(e) A receiver, manager, receiver-manager, liquidator, monitor or trustee in bankruptcy of the Utility or of any of the Utility's property is appointed by a Governmental Authority or pursuant to the terms of a debenture or a similar instrument, and such receiver, manager, receiver-manager, liquidator, monitor or trustee in bankruptcy is not discharged or such appointment is not revoked or withdrawn within thirty (30) days of the appointment.

(f) By decree, judgment or order of a Governmental Authority, the Utility is adjudicated bankrupt or insolvent or any substantial part of the Utility's property is sequestered, and such decree continues undischarged and unstayed for a period of thirty (30) days after the entry thereof.

(g) A petition, proceeding or filing is made against the Utility seeking to have the Utility declared bankrupt or insolvent, or seeking adjustment or composition of any of their respective debts pursuant to the provisions of any Insolvency Legislation, or such petition, proceeding or filing is not dismissed or withdrawn within thirty (30) days.

(h) A failure to maintain in good standing any franchise agreement or any other approval, permit or license from any Governmental Authority required for the construction and operation of the Pipeline Works and the supply of natural gas to the Customer Facility.

ARTICLE VI – FORCE MAJEURE

6.1 In the event that either the Customer or the Utility is rendered unable, in whole or in part, by Force Majeure, to perform or comply with any obligation or condition of this Agreement, then the obligations (other than the obligations to make payment of money then due and to provide or maintain any letter of credit) of both parties so far as they are directly related to and affected by such Force Majeure, shall be suspended during the continuance of the Force Majeure.

6.2 The party claiming Force Majeure shall give notice in writing, with full particulars, to the other party as soon as possible after the occurrence of Force Majeure.

6.3 The party claiming Force Majeure shall also give notice to the other party as soon as possible after the Force Majeure is remedied in whole or part.

6.4 Force Majeure means:

(a) Acts of God, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to its machinery or equipment or lines of pipe;

(b) freezing or failure of wells or lines of pipe; curtailment of firm transportation or firm storage by other natural gas service providers;

(c) strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections, civil disturbance, acts of terrorism, wars, arrests or restraint of governments and people;

(d) any laws, orders, rules, regulations, acts of any government body or authority, civil or military;

(e) any act or omission by parties not controlled by the party claiming Force Majeure; and

(f) any other similar causes not within the control of the party claiming Force Majeure

which by the exercise of due diligence such party is unable to prevent or overcome. The party claiming Force Majeure shall make reasonable efforts to avoid, or correct the Force Majeure and to remedy the Force Majeure once it has occurred in order to resume performance.

6.5 Neither party shall be entitled to claim Force Majeure if any of the following circumstances prevail:

(a) the failure resulting in Force Majeure was caused by the negligence of the party claiming suspension;

(b) the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation);

(c) the party claiming suspension failed to resume the performance of such conditions or obligations with reasonable dispatch;

(d) the failure was caused by lack of funds; and

(e) the party claiming suspension did not give to the other party the required notice as soon as possible after determining or within a period within which it should have determined, acting reasonably, that the occurrence was in the nature of Force Majeure and would affect its ability to observe or perform any of its conditions or obligations under the Agreement.

ARTICLE VII – SECURITY AND PERFORMANCE ASSURANCE

7.1 Prior to the Utility ordering the pipe and the stations, the Customer shall provide to the Utility an irrevocable letter or letters of credit ("Customer Letter of Credit") in an amount equal to the quoted cost of the pipe and the stations minus any payments made by the Customer to the Utility in respect of the pipe and the stations. The Customer shall be entitled to reduce the Customer Letter of Credit by the amount of any subsequent payments by the Customer to the Utility in respect of the pipe and the stations, upon making such payments. The Utility shall be entitled to draw upon the Customer Letter of Credit in the following circumstances:

(a) Subject to (b), if the Customer fails to make a payment of the Aid-to-Construct in accordance with Article III, such draw not to exceed the amount owed by the Customer to the Utility.

(b) Notwithstanding (a) the Utility shall not be entitled to draw upon the Customer Letter of Credit within any cure periods established in Article V, in which the Customer may make payment to the Utility.

7.2 The Utility shall return the Customer Letter of Credit upon receipt of any payment required from the Customer in accordance with section 3.4 and delivery of the Delivery Letter of Credit required under section 7.3.

7.3 Prior to the award of the Construction Agreement by the Utility, the Customer shall provide to the Utility an irrevocable letter of credit ("Delivery Letter of Credit") in an amount equal to the difference between the Revised Estimated Capital Cost and the Revised Estimated Aid-to-Construct.

7.4 The Utility shall be entitled to draw upon the Delivery Letter of Credit if:

(a) The Customer terminates this Agreement prior to the In-Service Date and fails to pay any amount owing to the Utility within 30 Business Days of receiving the invoice for monies owed for actual reasonable costs incurred prior to Termination; or

(b) The Customer terminates this Agreement and the Gas Delivery Contract after the In-Service Date but prior to the seventh anniversary of the Commencement Date under the Gas Delivery Contract;

(c) For any year, the Customer fails to take receipt of the Minimum Annual Volume under the Gas Delivery Contract and the Customer fails to pay the invoice for such failure to take the Minimum Annual Volume within 15 days of receiving such invoice;

(d) For reasons other than Force Majeure, the Customer ceases taking service for a period of 30 days during the term of the Gas Delivery Contract or at any time after that where service has continued past the end of the term of the Gas Delivery Contract;

(e) the Delivery Letter of Credit will not be maintained and the Customer fails to provide a substitute acceptable to the Utility and its lender; or

(f) The Customer commits a Customer Event of Default listed in 5.1 (e), (f), (g), (h) and (i).

(g) The Customer fails to restore the balance of the Delivery Letter of Credit as required by 7.5.

7.5 The Customer shall maintain the Delivery Letter of Credit for as long as the Customer continues to receive service from the Utility. In the event that the Utility draws on the Delivery Letter of Credit pursuant to 7.4(c), the Customer shall restore the Delivery Letter of Credit to the balance that existed immediately prior to the draw, within 10 Business Days from the date of the draw.

7.6 Subject to section 7.7, the Customer shall be entitled to reduce the amount of the Delivery Letter of Credit on each anniversary of the commencement of deliveries under the Gas Delivery Agreement to an amount equal to the net book value of the Utility Connection Facilities allocated to the Customer at the time, as determined by the Utility in accordance with OEB-approved methodology.

7.7 Any letter of credit shall be in a form acceptable to the Utility and its lender. The Utility shall have its lender provide a draft form of letter of credit for review and comment by the Customer's lender.

7.8 The costs and expenses of establishing, renewing, substituting, cancelling, increasing and reducing the amount of (as the case may be) any letter of credit required under this Agreement shall be borne by the Customer.

7.9 The Utility shall return any letter of credit held by the Utility to the Customer, if the Customer is substituting a letter of credit with another letter of credit or such other financial assurance, where that substitute is acceptable to the Utility and its lender.

ARTICLE VIII – TERMINATION

8.1 This Agreement terminates upon the placing into service of the Utility Connection Facilities and the Union Gas Connection Facilities and the commencement of the delivery of natural gas to the Customer Facility. All payment obligations and all obligations in relation to the Customer Letter of Credit and Delivery Letter of Credit shall survive termination of this Agreement until they are fulfilled.

8.2 In the event that the Utility is unable to secure all necessary permits, approvals, licenses certificates necessary to complete the Pipeline Work and supply natural gas to the Customer Facility, or obtains such permits, approvals, licenses or certificates on terms and conditions that are unacceptable to the Customer, acting in a commercially reasonable manner, then the Customer has the option to terminate this Agreement. The Customer shall, however, be responsible for all actual or committed to costs incurred by the Utility and Union Gas Limited up to and including the date of termination.

8.3 The Utility may terminate this Agreement if a Customer Event of Default has occurred and the Utility has given notice to the Customer of such Customer Event of Default and such default is not remedied within the applicable cure period upon receiving such notice of default. Termination pursuant to this section shall not be permitted where such default has been submitted to a dispute resolution process under Article IX.

8.4 Subject to Section 8.5, in the event the Revised Estimated Aid-To-Construct has been paid, in full or in part, by the Customer to the Utility and the Agreement is terminated prior to completion of the Pipeline Work, then the Utility shall return to the Customer any amount of the Revised Estimated Aid-To-Construct paid by the Customer that is in excess of the actual reasonable cost incurred by the Utility up to and including the date of termination. In the event the actual reasonable cost incurred by the Utility exceed the amount of the Revised Estimated Aid-To-Construct, the Customer shall pay that amount, upon receipt of which the Utility shall forthwith return the Delivery Letter of Credit.

8.5 In the event Utility invokes Force Majeure and the event of Force Majeure or the aggregate duration of all such Utility events of Force Majeure exceeds 60 days in any 12 consecutive month period, then the Customer shall have the right to terminate this Agreement upon fifteen (15) Business Days written notice. Upon termination of this Agreement pursuant to this section, the Utility shall return all security and financial assurance provided by Customer, and an amount, if any, equal to any Aid-To-Construct paid by the Customer to the Utility less the Utility's reasonable costs incurred prior to the event of Force Majeure.

ARTICLE IX – DISPUTE RESOLUTION

9.1 In the event of any dispute arising between the Parties regarding the subject matter of this Agreement, then the Parties shall negotiate in good faith to resolve such matters.

9.2 In the event the Parties are unable to resolve a dispute, then either Party may refer the matter to the OEB for resolution.

ARTICLE X – INDEMNIFICATION

10.1 The Utility agrees to indemnify, defend, and hold harmless the Customer in respect of all actions, causes of action, suits, proceedings, claims, demands, losses, damages, penalties, fines, costs, obligations and liabilities ("Damages") arising out of the construction, installation, testing, commissioning and operation of the Utility Connection Facilities, other than any Damages caused by the negligence or wilful misconduct of the Customer.

10.2 The Customer agrees to indemnify, defend and hold harmless the Utility in respect of all Damages arising out of the construction, installation, testing, commissioning and operation of the Utility Connection Facilities caused by the negligence or wilful misconduct of the Customer.

ARTICLE XI – GENERAL

11.1 Any written notice required by this Agreement shall be deemed properly given only if either mailed or delivered to:

(a) To the Utility:

Natural Resource Gas Limited
P.O. Box 307
39 Beech Street East
Aylmer, Ontario N5H 2S1

Tel: (519) 773-5321
Fax: (519) 773-5335

Attention: Steve Millar, General Manager
c.c. Mark Bristoll, President

(b) To the Customer:

Integrated Grain Processors Co-operative Inc.
701 Powerline Road
Brantford, Ontario N3T 5L8

Tel: (519) 752-0447
Fax: (519) 752-1887

Attention: Chair

ELECTRONIC NOTICE

A faxed notice will be deemed to be received on the date of the fax if received before 4 p.m. or on the next Business Day if received after 4 p.m. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

11.2 This Agreement:

(a) constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement;

(b) shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein, and the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of this Agreement;

(c) may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement; and

(d) shall not be assigned without the prior written consent of the other party, such consent not to be unreasonably withheld. For greater certainty an assignment by way of security to the Customer's lenders shall be considered reasonable.

11.3 No modification of or amendment to this Agreement will be valid or binding unless set forth in writing and duly executed by both of the parties hereto and no waiver of any breach of any term or provision of this Agreement will be effective or binding unless made in writing and signed by the party purporting to give the same and, unless otherwise provided, will be limited to the specific breach waived.

11.4 If any provision of this Agreement is determined to be invalid or unenforceable or in breach of any Applicable Law in whole or in part, such invalidity or unenforceability will attach only to such provision or part thereof which provision or part shall be severed from the Agreement and the remaining part of such provision and all other provisions hereof will continue in full force and effect.

11.5 Notwithstanding the termination or expiration of this Agreement:

(a) Section 3.15 shall survive for the period of time provided in which a refund is to be calculated.

(b) The obligation to make any payment shall survive until all such payments are determined and paid.

(c) Article 7 shall survive until the Utility no longer requires financial assurance from the Customer.

(d) Article IX shall survive until the final resolution, including all appeals, of any dispute arising out of this Agreement.

11.6 Each Party shall from time to time execute and deliver all such further documents and instruments and do all acts and things as the other party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement.

11.7 This Agreement will enure to the benefit of and be binding upon the respective successors and permitted assigns of the Parties hereto.

11.8 Time is of the essence in the performance of the Parties' respective obligations under this Agreement.

11.9 Any reference to funds is a reference to Canadian currency.

11.10 This Agreement is subject to the consent of the Customer's Lenders. The Customer agrees to use reasonable efforts to secure such consent in a timely manner. This paragraph is entirely for the benefit of the Customer. The Customer shall waive this condition in writing.

11.11 This Agreement is subject to the consent of the Utility's Lenders. The Utility agrees to use reasonable efforts to secure such consent in a timely manner. This paragraph is entirely for the benefit of the Utility. The Utility shall waive this condition in writing.

11.12 In the event of a change of law affecting any of the rights or obligations of one Party to the other Party, the Utility shall continue to deliver gas and the Customer shall continue to pay for the delivery of gas as if the change had not occurred unless prohibited by law. In such event the Parties shall negotiate in good faith to preserve the original intent of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the day and year first written above.

NATURAL RESOURCE GAS LIMITED

____

Per: Mark Bristoll
Title: President

I have authority to bind the corporation.

INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC.

____

Per: Tom Cox
Title:

I have authority to bind the corporation.

____

Per: Brent McBlain
Title:

I have authority to bind the corporation.

Schedule A - Pipeline Work

In carrying out the Pipeline Work (as depicted in the figure attached as Schedule B to this Agreement), the Utility or a subcontractor to the Utility will need to complete the following:

Pipeline Work Planning

Utility Connection Facilities

1. The Utility shall design, construct, install, commission and operate the Utility Connection Facilities in accordance with all Applicable Laws and good utility practice.

2. The Utility shall be responsible for making applications to all Governmental Authorities for all permits, approvals, licenses and certificates necessary to undertake and complete the Utility Connection Facilities, including without limiting the foregoing, the Leave-to-Construct from the OEB. The Utility shall be responsible for maintaining all such permits, approvals, licenses in good standing.

3. The Utility shall only contract with suppliers and contractors competent to perform their tasks and shall undertake to secure competitive bids from competent suppliers and contractors for the Utility Connection Facilities.

4. The Utility and the Customer shall agree to a suitable location at the Customer Facility for the Customer Meter Facility.

5. The Utility shall coordinate the design, construction, testing and operation of the Utility Connection Facilities with Union Gas Limited such that Union Gas Limited will be able to supply the Utility with sufficient quantities of natural gas to meet the Customer's requirements by the In-Service Date.

6. The Utility shall furnish the Customer with a complete set of engineered stamped drawings of the Utility Connection Facilities before tendering for the Construction Agreement. The engineer shall be qualified to practice engineering in Ontario.

7. The Utility shall provide a flanged connection at the outlet of the Customer Meter Facility to which the Customer may connect the house-piping for the Customer Facility. In the event the Customer installs the house-piping with flanged connection prior to the Utility, the Utility shall be responsible for completing the connections. The flanged connection shall be adequately protected to prevent the entry of dirt, water or other extraneous materials from entering the Customer Meter Facility or the house-piping.

8. The Utility shall ensure the Customer Meter Facility is properly insulated from the Customer Facility.

9. The Utility shall furnish the Customer the required communications specifications for the Customer Meter Facility with the stamped drawings.

Access To Customer Facility

10. The Customer shall provide the Utility and its contractor with reasonable access to the Customer Facility to construct, install, test, commission and operate the Customer Meter Facility.

11. The Utility shall ensure that all employees of the Utility or its contractor obey all safety requirements of the Customer while on the Customer Facility.

Pipeline Work Testing and Commissioning

12. The Utility shall coordinate hydrotesting or any other testing, including non-destructive testing of welds, of the Utility Connection Facilities with the Customer and the Utility shall not interfere with the construction, installation, testing or commissioning of the Customer Facility.

13. The Utility shall ensure that the Utility Connection Facility is completely dewatered. Dewatering shall not occur on the Customer Facility.

Union Gas Connection Facilities

14. The Utility shall coordinate the construction of the Utility Connection Facilities with Union Gas Ltd. to facilitate the completion of the Union Gas Connection Facilities by or before November 1, 2007.

SCHEDULE B - PROJECT MAP

[To be inserted]

IGPC

February 20,2 008

Natural Resource Gas Limited
P.O.B ox 307
39 Beech Street East
Aylmer, Ontario N5H 2S1

Attention: Mark Bristoll

Dear Sir:

Re: Pipeline Cost Recovery Agreement ("PCRA") made of as January 31, 2007 between Natural Resource Gas Limited ("NRG") and Integrated Grain Processors Co-operative Inc. as assigned to IGPC Ethanol Inc. pursuant to an assignment agreement dated June 30, 2007

IGPC Ethanol Inc. is making a payment to Union Gas Ltd. in the amount of$ 700,000 in respect of the natural gas pipeline and ancillary facilities Union Gas is to construct (the "Union Gas Connection Facilities")to deliver natural gas to NRG forI GPC Ethanol Inc. NRG acknowledges thata ny amountp aid by IGPC EthanolI nc. to Union Gas as an Union Gas Aid-to-Construct in respect of the Union Gas Connection Facilities will reduce, on a dollar for dollar basis, any obligation that IGPC Ethanol Inc. would have owed to NRG in respect of the Union Connection Facilities and the Revised Estimated Aid-to-Construct and the Actual Aid-to-Construct. NRG further acknowledges that any payment made by IGPC Ethanol Inc. to Union Gas that is in excess of the Union Gas Aid-to-Construct to which Union Gas is rightfully entitled is the property of and shall be payable to IGPC Ethanol Inc. The Initial Estimated Capital Cost provided by NRG of $9,100,000 included $180,000 in respect of an estimate of the Union Gas Aid-to-Construct for the Union Gas Connection Facilities.

All capitalized terms which are not defined herein shall have the meanings ascribed thereto in the PCRA.

Yours very truly,

IGPC ETHANOL INC.

By: ________________________
Name: Tom Cox
Title: President

By: ________________________
Name: Brent McBlain
Title: Vice President

The forgoing is herebya cknowledged, agreed and accepted by Natural Gas Resources Limited by its duly authorized signing officer dated this 21 day of February,2 008.

NATURAL GAS RESOURCES LIMITED

By: ________________________
Name: Mark Bristoll
Title: President

I have authority to bind the corporation.

ATTACHMENT 2 as associated with IGPC 11

Natural Resource Gas Limited's audited financial statements for the fiscal years ending September 30, 2016 and September 30, 2017

NATURAL RESOURCE GAS LIMITED

Financial Statements

Year Ended September 30, 2016

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

	Page
INDEPENDENT AUDITOR'S REPORT	1 - 2
FINANCIAL STATEMENTS	
Balance Sheet	3 - 4
Statement of Deficit	5
Statement of Income	6
Statement of Cash Flow	7
Notes to Financial Statements	8 - 18
Schedule of Operating Expenses *(Schedule 1)*	19

Tel: 519 432 5534
Fax: 519 432 6544
www.bdo.ca

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

London, Ontario
November 15, 2016

Chartered Professional Accountants
Licensed Public Accountants

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.

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)

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)

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)

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).

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.

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.

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.

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.

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.

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

	Page
INDEPENDENT AUDITOR'S REPORT	1
FINANCIAL STATEMENTS	
Balance Sheet	2 - 3
Statement of Deficit	4
Statement of Income	5
Statement of Cash Flow	6
Notes to Financial Statements	7 - 18
Schedule of Operating Expenses *(Schedule 1)*	19

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BDO Canada LLP
633 Colborne St., Suite 230
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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.

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. 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)

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)

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

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.

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.

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).

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.

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)

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.

ATTACHMENT 3 as associated with IGPC 11

EPCOR Natural Gas Limited Partnership's audited financial statements for the fiscal year ending December 31, 2017

Financial Statements of

EPCOR Natural Gas Limited Partnership

Year ended December 31, 2017

Independent Auditors' Report 1

Financial Statements:

Statement of Comprehensive Income 2

Statement of Financial Position 3

Statement of Changes in Equity 4

Statement of Cash Flows 5

Notes to the Financial Statements 6

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BDO Canada LLP
633 Colborne St., Suite 230
London ON N6B 2V3

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 exposur*e

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.