uniongas
A Spectra Energy Company

March 5, 2012

Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

EB-2011-0283/EB-2011-0242 – Union Gas Limited – Renewable Natural Gas - Updated evidence, Appendix 3 - Ipsos Reid Report

Dear Ms. Walli:

As noted in response to CME Interrogatory #10 (Exhibit I-6-10), the Utilities became aware that the most up to date Ipsos Reid report (Exhibit B, Tab 1, Appendix 3) was not included in the prefiled evidence as filed with the Board on September 30,2011. An updated report had been prepared to correct the wording of the 4 questions as show in pages 36-39 of the report, but the uncorrected version was inadvertently filed in the package. Union is resubmitting the PDF of the prefiled evidence package with the updated report included and labelled as “Updated”. No other changes to the package have been made.

This submission has been filed through the Board’s RESS and 2 hard copies of the Updated Appendix 3 will be sent to the Board via courier.

Should you have any questions or concerns with respect to this submission, please contact me at 519-436-5473.

Sincerely,

[original signed by]

Karen Hockin
Manager, Regulatory Initiatives

cc: EB-2011-0283 Intervenors
A. Smith (Torys)
N. McKay (Board staff)
M. Kitchen (Union Gas)

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ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders approving and setting Ontario RNG supply prices for Union's purchase of renewable natural gas;

APPLICATION

1. Union Gas Limited ("Union") is a business corporation, incorporated under the laws of Ontario, with its head office in the Municipality of Chatham-Kent.

2. Union conducts an integrated natural gas utility business that combines the operations of selling, distributing, transmitting and storing gas within the meaning of the *Ontario Energy Board Act, 1998* (the "Act").

3. As part of its efforts to investigate new and innovative sources of natural gas, Union has identified Renewable Natural Gas ("RNG") as a potential Ontario gas supply source that offers certain environmental, economic and waste management benefits over conventional gas supply sources.

4. RNG (also known as biomethane) is processed from biogas (produced by anaerobic digesters) and landfill gas (produced in landfill facilities). Biogas and landfill gas result from the decomposition of organic material in an oxygen-free environment, either as a result of a controlled process within an anaerobic digester or as a result of a natural process in a landfill site.

5. Union proposes to acquire RNG as part of its gas supply portfolio for customers who purchase their natural gas from Union ("Sales Service Customers").

6. Union therefore hereby applies for an order or orders:

   (a) establishing a 20-year price for the purchase of RNG that will apply for the purposes of the fixing or approval of rates for the sale of gas to Sales Service Customers pursuant to subsection 36(2) of the Act;

   (b) directing that the costs of acquiring RNG by Union be recorded in Union's TCPL Tolls and Fuel – Northern and Eastern Operations Area deferral account (Deferral Account No. 179-100), the North Purchase Gas Variance Account (Deferral Account No. 179-105) and the South Purchase Gas Variance Account (Deferral Account No. 179-106) for disposition though the Quarterly Rate Adjustment Mechanism ("QRAM");

   (c) directing that the purchase of RNG by Union will be limited to a maximum volume of 2.2 PJs, (which represents less than 2% of the total volume of the Company's supply portfolio for Sales Service Customers); and

   (d) directing that the future acquisition of RNG by Union will continue until the earlier of: (i) the date on which the maximum volume referred to in para. (c), above, is reached; or (ii) the five year anniversary of the date of a final Board order in this proceeding.

7. Union also applies to the Board for such further or other final or interim orders, directions, accounting orders and deferral and variance accounts as may be necessary or appropriate.

8. Union further applies to the Board for all necessary orders and directions concerning pre-hearing and hearing procedures for the determination of this application.

9. This application is supported by written evidence. This evidence may be amended from time to time as required by the Board, or as circumstances may require.

10. The persons affected by this application are Union's Sales Service Customers. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

11. The address of service for Union is:

Union Gas Limited
P.O. Box 2001
50 Keil Drive North
Chatham, Ontario N7M 5M1

Attention: Karen Hockin
Manager, Regulatory Initiatives
Telephone: (519) 436-5473
Fax: (519) 436-4641

- and –

Torys LLP
79 Wellington Street West,
Suite 3000
Box 270, TD Centre
Toronto, Ontario M5K 1N2

Attention: Alexander Smith
Telephone: (416) 865 8142
Fax: (416) 865-7380

DATED: September 30, 2011

UNION GAS LIMITED

By its Solicitors

[original signed by]

Torys LLP
79 Wellington Street West,
Suite 3000
Box 270, TD Centre
Toronto, Ontario M5K 1N2

Attention: Alexander Smith
Telephone: (416) 865-8142
Fax: (416) 865-7380

Renewable Natural Gas Application
Common Evidence (Enbridge Gas Distribution Inc. and Union Gas Limited)

PURPOSE

The purpose of this application is to establish a Renewable Natural Gas ("RNG") Program (The "Program") to enable the development of a viable RNG industry in Ontario. This will allow the benefits outlined in this evidence to be realized. The benefits represent significant opportunities, including the opportunity to offer greater choice for energy consumers, and the opportunity to maximize the efficient use of biogas resources. Establishing a RNG Program now, when these opportunities are available, will ensure that these benefits are not passed over.

The proposed RNG Program consists of four integrated and essential facets:

1. A pricing framework approving Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union") (together, the "Utilities") to purchase RNG from Ontario producers at specified prices and for a 20-year term as part of their existing system supply portfolios.

   These proposed Ontario RNG Supply Prices are required to support the development of the RNG market. Currently, they are proposed at levels higher than market-based prices of conventional natural gas. RNG purchased by the Utilities will be incorporated into each utility's gas supply portfolio under the established and Board-approved QRAM processes.

2. A maximum annual volume cap of 3.3 petajoules (87 million m^3) of RNG for EGD and 2.2 petajoules (58 million m^3) for Union.

   This maximum volume cap, which represents less than 2% of system gas supply, will limit the total amount of RNG that each utility can add to their overall gas supply portfolio under this Program. The volume limit, combined with specified

RNG prices, restricts the customer bill impact to a level supported by a majority of customers surveyed.

3. A supporting structure that includes:

   i. connection procedures and capital cost contributions for potential RNG producers to inject the gas into the Utilities' network;

   ii. gas quality standards that must be met; and

   iii. an allocation mechanism to ensure equitable access to the utility distribution and transmission system for potential RNG producers.

   This supporting structure will include clear and transparent information and communications regarding the entire Program to all potential RNG producers.

4. A five-year contract acceptance window following Board approval of the RNG Program.

   Only contracts for RNG supply entered into in the five years immediately following the approval of this RNG Program will be considered to form part of this Program. During the five years, the Utilities may enter into contracts for RNG supply in accordance with the approved requirements of the Program. Each contract will be effective as of the commercial operation date of the facility, and end at a maximum of 20 years thereafter.

The Utilities are requesting that the RNG Program for each utility be granted approval by the Board, and be permitted to begin in early 2012, such that contracts can be issued starting in 2012.

OVERVIEW

The evidence is set out below in the following Parts:

I. Background on RNG

II. Benefits of RNG

III. The Need for Ontario RNG Supply Prices

IV. The Role of Utilities in Enabling a Viable RNG Industry

V. Market Considerations

VI. Regulatory Developments in Other Jurisdictions

VII. The Principles of the Proposed RNG Program

VIII. Details of the Proposed RNG Program

IX. Operational Impacts of RNG Supply

EVIDENCE

Part I: Background on RNG

RNG is a potential Ontario natural gas supply source that offers environmental, economic and waste management benefits. RNG (also known as "biomethane") is refined from gas produced from organic waste, such as that found on farms, at waste water treatment plants, food processing facilities and in landfills. The process that creates gas from this waste is called anaerobic digestion.

Anaerobic digestion takes place when organic material decomposes in an oxygen-free environment, either controlled within an anaerobic digester, or naturally in a landfill. The main products of anaerobic digestion are methane (CH_4) and carbon dioxide (CO_2), the combination of which is commonly referred to as biogas when produced in digesters, and landfill gas when produced in landfills.

A detailed explanation of all of the sources and the market potential of RNG is provided in the report "Potential Production of Renewable Natural Gas from Ontario Wastes" prepared by Alberta Innovates for the Utilities and attached as Exhibit B, Tab 1, Appendix 1.

Production of Biogas in Digesters

For the purposes of waste management, digesters can be constructed in a number of different places including:

- On farms, using manure, crop residue and other wastes such as fats, oil and grease obtained off-farm.
- At waste water treatment plants, using the biosolids from the treatment process.
- At municipal sites, using materials from source-separated organics collection programs (*e.g.* "Green Bin").
- At sites such as breweries, food and beverage plants and food processing companies, using the respective waste products.

In each of these cases, anaerobic digestion can significantly reduce the amount of organic matter which might otherwise be spread on land, sent to landfills, incinerated or disposed of in some less useful manner. The products of a digester are biogas, which is energy, and the digestate, which can be employed as fertilizer.

Many waste streams which undergo natural anaerobic digestion release methane and CO_2 into the atmosphere as they decompose. Relative to CO_2, methane has the effect of creating 21 times more greenhouse gases ("GHGs"). The proposed RNG Program enables capture and redirection of methane that would otherwise be released into the atmosphere and turns the methane into a useful energy source. This conversion of potentially wasted energy is critical when evaluating the environmental impact of generating RNG.

Using and Refining Biogas and Landfill Gas

Raw biogas typically consists of 55 to 60% methane with the remaining 40 to 45% being CO_2 and small amounts of impurities such as hydrogen sulphide (H_2S). Raw biogas is typically used in two ways:

1. After some of the impurities are removed, the biogas can be burned in an engine or turbine to generate electricity. Biogas used for this purpose is typically only cleaned of contaminants that impact the reliability of generators; therefore the resulting gas offers a lower heat value than natural gas or RNG. The electrical conversion efficiency of these on-site generators is normally less than 40%.[1]

2. RNG is created from the raw biogas by removing the CO_2 and other impurities. Existing technology is available for this cleanup process which produces RNG that is interchangeable with natural gas. The RNG can then be injected into the local natural gas utility's distribution or transmission system. The RNG is transported to utility customers' homes and businesses where it is burned in existing heating, water heating, and process equipment. As indicated in the Alberta Innovates report attached as Exhibit B, Tab 1, Appendix 1, the RNG process can produce full-cycle efficiencies of up to 80% depending on the end-use natural gas equipment.

[1] Terasen Gas Inc., Biomethane Application, June 8, 2010

Landfill gas is similarly used to produce electricity or RNG, the only difference is that there are other impurities in landfill gas that must be removed. Cleanup processes and technologies exist and are commercially available to do this.

As set out above, the production of RNG and injection into the natural gas system is a more efficient use of energy than electricity generation, and more desirable than flaring or venting to the atmosphere.

Part II: Benefits of RNG

As set out in greater detail below, using existing landfills and new and existing digesters to create RNG can provide environmental, economic and waste-related benefits. The opportunity to make use of these benefits has been recognized in the increasing number of provinces and communities that have adopted programs to separate organic waste from the landfill stream (*i.e.* through "Green Bin" type programs), and that are considering processing facilities which include anaerobic digestion. Exploiting the benefits offered by RNG is consistent with and complementary to the stated objectives of Ontario public policy.[2]

Benefits Specific to Landfills

Under conventional waste management practices, much of the organic waste generated by society was sent to landfills. These sites continue to generate gas long after the landfill has closed, and it is now recognized that these landfills are significant emitters of GHGs.

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[2] Ontario Green Energy and Green Economy Act, 2009

In June 2008, amendments to Ontario Regulation 232/98 and Revised Regulations of Ontario 1990, Regulation 347 under the Environmental Protection Act resulted in requirements for all landfills emitting in excess of 1.5 million m^3 to collect landfill gas and flare it or use it in a manner that achieves a similar end. These requirements had previously applied only to landfills emitting in excess of 3 million m^3, and to those landfills that were new and expanding.

The 2008 amendments ensured the reduction of the total emissions from landfills in Ontario, as collecting and flaring the gas (rather than releasing it to the atmosphere) significantly reduces the GHG potency of the landfill gas. However, under the new regulatory regime, gas in landfills smaller than 1.5 million cubic metres may still be released into the atmosphere. As discussed above, the methane in that gas is a potent GHG that has a global warming potential 21 times that of CO_2.

In addition, collecting and flaring the landfill gas represents a lost opportunity to further reduce GHGs by capturing the energy naturally generated from organic waste decomposition in the landfill and using it to offset conventional natural gas supply.

RNG produced from landfill gas has the dual potential benefits of reducing the total amount of methane released directly into the atmosphere (with significant environmental impacts), and averting a lost opportunity to make productive use of this gas.

Benefits Specific to Anaerobic Digesters

The benefits of anaerobic digestion facilities on farms and in waste processing facilities (such as municipal waste water treatment and source separated organics facilities) include an opportunity to increase organic waste diversion rates, reduce waste management costs, improve odour control and reduce the level of pathogens[3] through

[3] http://www.omafra.gov.on.ca/english/engineer/facts/07-057.htm, cited September 21, 2011

the treatment of manure and other organic materials that might otherwise be disposed of on land.

In acknowledging these benefits, the Ontario Ministry of Agriculture, Food and Rural Affairs launched the Ontario Biogas Systems Financial Assistance Program in 2008, providing farmers and food processing facilities with funding for biogas feasibility studies, construction and implementation. The program concluded in 2010. The Ministry said it had contributed significant funding, resources and training to establish the biogas sector and would continue to support the industry through training opportunities and technology improvements.[4]

Overall RNG Benefits

A. Reduction in GHG Emissions

RNG reduces Ontario's GHG emissions, as explained in Exhibit B, Tab 1, Appendix 1, by reducing the methane emissions that will otherwise occur through natural decay, and by replacing conventional[5] natural gas through the RNG produced. According to the Alberta Innovates report, the maximum near-term (up to 10 years) potential of GHG emissions reduction from RNG in Ontario is 13 million tonnes of CO_2 e/year, or more than 45% of Ontario's 2020 GHG emissions reduction target.

B. Consumer-Friendly Approach to Meeting GHG Reduction Targets

Ontario has set GHG reduction targets of 15% by 2020 and 80% by 2050. With the scheduled closing of the province's coal-fired generation plants in 2014, the remaining

[4] http://www.omafra.gov.on.ca/english/engineer/biogas/program.htm cited September 21, 2011

[5] The Utilities' use of the term 'conventional natural gas' refers to gas that does not include a renewable component.

major sources of emissions are from transportation fuels and natural gas use.[6] GHG reductions from conventional natural gas consumption can be achieved through demand-side solutions such as energy efficiency programs, fuel switching, building envelope improvements and other conservation measures. Some of these alternatives require behavioural change on the part of the consumer and most would require the customer to make an up-front capital investment.

The injection of RNG into the Utilities' pipeline systems provides a supply-side alternative to the options cited above, requiring no behavioural change and no up-front capital investment for customers.

The proposed RNG Program is an economical approach that complements existing demand-side options and can help the province meet its GHG reduction targets.

C. Waste Alleviation

RNG offers a solution to an existing environmental waste problem because the source materials are derived from wastes in farm, food, waste treatment areas and from existing landfills.

D. Support for Ontario Economy

RNG results in a "made in Ontario" energy supply that provides economic benefits through local job creation while adding to the diversity and security of gas supply. Procurement of local supply also means financial payments stay within the province, to the benefit of Ontario farmers, municipalities or businesses.

E. Flexibility

RNG is a renewable, non-intermittent form of energy generated from waste. Unlike some other forms of renewable energy, it can be stored and dispatched as necessary through injection into the natural gas distribution or transmission systems.

[6] Ontario Climate Change Action Plan, 2008-2009 Annual Report.

F. More Efficient Alternative to Electricity Generation

As cited above, RNG results in increased energy utilization efficiency relative to the current alternative of generating electric power for connection to the electricity grid under the OPA Feed-in Tariff (FIT) program.

G. Conservation

By displacing conventional natural gas, the use of RNG contributes towards the conservation of non-renewable natural resources, consistent with the Board's mandate in energy conservation.

Part III: The Need for Ontario RNG Supply Prices

In order to realize the benefits of RNG in Ontario, a viable RNG industry must be enabled. It is the view of the Utilities and the experts retained for the purpose of this Application that, unless RNG prices are set (as proposed in the RNG Program), a viable RNG industry will not develop in Ontario in the near term. The purchase of conventional natural gas supply is based on a market model whereby the market price of natural gas fluctuates continually. While this market-based pricing model operates effectively in the conventional (and mature) North American natural gas business, it does not provide a sufficient level of income or planning certainty for the revenue stream to be realized from the sale of the RNG commodity in an emerging RNG industry. As noted above, an alternative is electricity generation as part of the OPA's FIT program. For those projects where that option is available, the FIT program approach provides a predictable revenue stream over a 20-year term. A similar approach is required to enable a viable RNG industry.

Part IV: The Role of Utilities in Enabling a Viable RNG Industry

The Utilities believe that a viable Ontario-based RNG industry will realize the benefits outlined above, and will help to make the product delivered to customers more sustainable. The Utilities' view in this regard is supported by the RNG community, several of whom have filed letters (see Exhibit B, Tab 1, Appendix 2), indicating their support for a utility-led RNG Program.

The Utilities are uniquely positioned within the provincial energy market to enable the RNG industry on behalf of consumers throughout the province. The Utilities' size, scope and stability position them to enable a RNG industry. This has been recognized by potential producers and stakeholders from industry, agriculture and municipalities**.**

The emerging RNG industry requires a foundation to be built over a longer-term horizon so that a viable market can develop. Under the proposed RNG Program, the RNG Prices paid by the Utilities will allow the emerging market to establish itself until it matures through technology development, producer sophistication, increasing natural gas prices and the potential development of a carbon price (based on a GHG trading value). Following this maturation process, RNG should be able to compete with conventional natural gas supplies.

Part V: Market Considerations

Market Support

In the fall of 2010, the Utilities commissioned Ipsos Reid, an independent market research firm, to determine the attitudes of residential and commercial customers on issues related to RNG. The firm conducted an online survey of 1,052 residential natural gas customers and a telephone survey of 500 commercial customers. The full report is found in Exhibit B, Tab 1, Appendix 3.

The research indicates that a majority of residential and commercial natural gas customers are concerned about the environment, are supportive of their gas utilities purchasing RNG supply, and are willing to pay a bill increase of up to 4% to pay for the RNG. The key findings of the research are summarized below.

A. Concern for the Environment

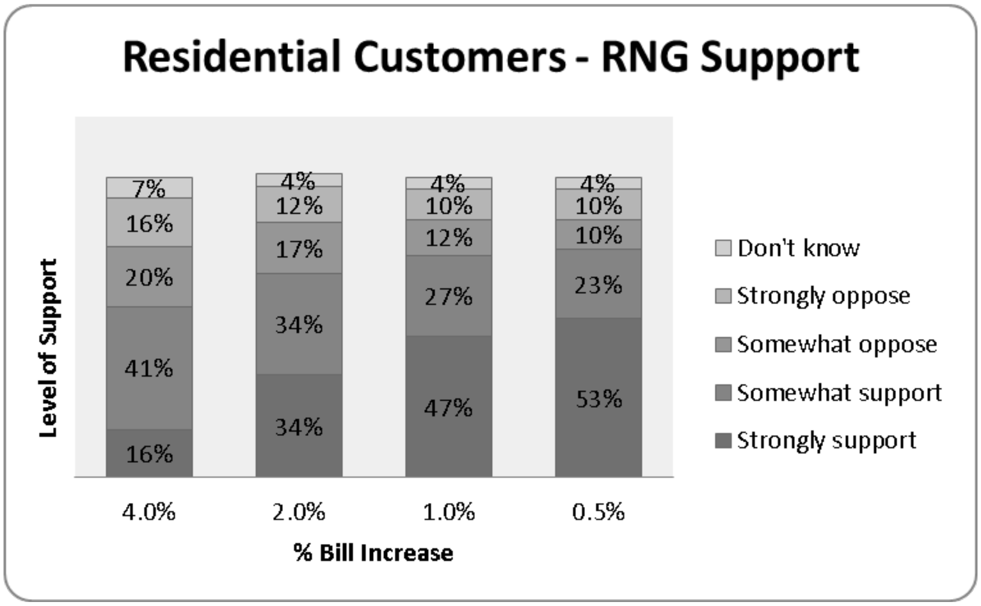
A majority of Ontario's residential gas customers, 8 out of 10, said they are concerned about GHG emissions, the effect of GHG emissions on global warming, and government or industry leadership on environmental issues.

B. Support for Utility Involvement in RNG

87% of residential respondents supported their gas utilities purchasing RNG to meet their supply needs. Survey results from commercial customers are similar to the residential customer findings.

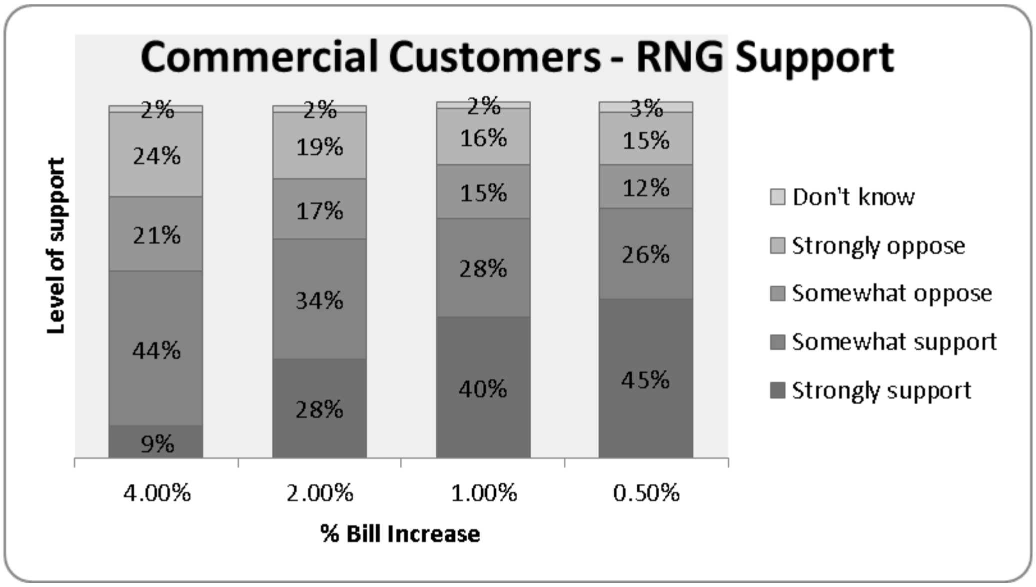
C. Levels of Support for RNG Based on Customer Bill Impact Levels

Survey results also indicated support for a low-percentage increase (ranging from 0.5% to 4%) on customers' monthly gas bills in order to enable the utility's purchase of RNG supply.



74% of residential natural gas customers expressed support for their utility purchasing RNG if the result is a 1% ($9.60/year) increase in their gas bill. If the increase in respondents' natural gas bills due to RNG were set at 2% ($18/year), the utility's purchase of RNG is still supported by 68% or over two-thirds of respondents. At the highest bill increase level surveyed, 4% ($36/year), 57% of residential customers support the purchase of RNG by their utility.

The survey results of commercial customers also indicated support for RNG, with 68% supporting a 1% increase in their gas bill, 62% supporting a 2% gas bill increase, and 53% support for a 4% gas bill increase.



This market research demonstrates that by managing the customer bill impact as proposed through RNG prices and a volume cap, the majority of residential and commercial customers would support the proposed RNG Program.

RNG Stakeholder Meetings

Aside from the residential and commercial customer research cited above, the Utilities also met with a number of other stakeholders on the proposed RNG Program between November 2010 and August 2011.

Traditional regulatory intervenors representing a wide spectrum of advocacy perspectives were invited to participate in a joint session hosted by the Utilities on July 19, 2011.

Face-to-face meetings were also held with energy retailers, municipal and industry associations, as well as provincial government representatives and select municipalities in each utility's franchise. To hear the industry's view point, web meetings were also organized with waste disposal firms and biogas technology and service companies from across Canada.

Each of the briefings mentioned above provided an overview of the key elements of the proposed RNG Program and offered participants an opportunity to ask questions.

Written letters of support offered by stakeholders are attached in Exhibit B, Tab 1, Appendix 2.

Part VI: Regulatory Developments in Other Jurisdictions

Canada

In Canada, there is some development of biogas electricity generating systems, primarily in Ontario, due to favourable renewable electricity pricing. However, currently there is no development of RNG injection into the natural gas distribution system for broad consumption. In the absence of RNG prices and a supporting program, the development of this market is unlikely in the next several years.

The Ontario Power Authority ("OPA") established a Renewable Energy Standard Offer Program (RESOP) in 2006, which included premium electricity rates for the development of landfill and digester-based biogas projects (among other renewable energy sources) in the Province of Ontario.

As a follow-up to the RESOP program, the OPA introduced a Feed-in-Tariff (FIT) program in 2009 for the Province of Ontario. The FIT program rate schedule was designed to accommodate the development of digester-based and landfill gas for use in power projects (among other renewable energy sources), with tiered pricing tranches for varied project sizes.

In Quebec, Tembec's mill in Matane will receive funding from the federal government's Pulp and Paper Green Transformation Program and the Province of Quebec through the Agence de l'efficacité énergétique's Heavy Oil Consumption Reduction Program.

The funding will enable a new anaerobic reactor to convert 65% of the mill effluent into biogas and the modification of burners to use biogas to dry pulp.

In its June 2008 feasibility study (*Biogas Upgrading and Grid Injection in the Fraser Valley, British Columbia*[7]), the BC Innovation Council determined that in British Columbia, conversion of biogas energy into RNG presents clear economical and environmental advantages to conversion into electricity. The Council concluded that, because electricity can be generated through hydroelectric production in a manner that is both inexpensive and does not emit GHGs, production of RNG to displace natural gas presents a more sensible alternative use of biogas energy. Locally produced RNG has the advantage of a carbon tax exemption ($1.50/GJ in 2012) and avoids pipeline transportation costs that natural gas from Alberta and northern BC will carry.

Subsequent to the feasibility study, FortisBC (Terasen Gas) has moved forward in buying RNG for its renewable, carbon neutral benefits and its prospective price stability. FortisBC has taken steps to roll out a Biomethane Service Offering as a result of a December 2010 Decision by the BC Utilities Commission. In the first phase, customers will have the option of designating 10% of the natural gas they use as RNG. FortisBC will then inject the equivalent amount of renewable gas into its system. Currently, FortisBC has two sources of biomethane (expected to deliver an annual amount in the range of 60,000 – 70,000 GJs of biomethane into FortisBC's distribution system by the end of 2011).

United States

Anaerobic digestion and biogas upgrading are common and mature technologies used extensively in the United States.

The U.S. Environmental Protection Agency (EPA) has developed a guide to actual market opportunities for the operation of biogas recovery systems. As of 2007, the EPA

[7] This study was conducted by Electrigaz Technologies Inc.

estimates that roughly 110 anaerobic digesters were operating at commercial livestock facilities in the U.S. The majority of operating digesters are located on the West Coast, in the Midwest, and in the Northeast of the U.S. Beyond the current numbers of systems in operation or planning, the EPA has determined that technical feasibility for biogas exists at approximately 2,600 dairy operations in the United States.

In 2010, the National Association of Regulatory Utility Commissioners ("NARUC") announced a policy resolution to support pipeline-quality RNG development as a renewable gas resource in the clean energy economy. The NARUC resolution on RNG[8] urged the U.S. Congress to pass legislation to provide "unequivocal support for pipeline quality RNG development in order to achieve significant greenhouse gas reductions in the transition to a clean energy economy". It also noted that biogas "can be captured, cleaned and converted into RNG through the use of proven gas conditioning technologies, transported by the existing gas pipeline system, stored and/or delivered for productive use in renewable electricity generation, clean transportation, or commercial, industrial and residential end use". NARUC asked that federal incentives for the development of pipeline-quality biomethane gas be provided on par with incentives afforded for other resources for producing renewable electricity.

Other Jurisdictions

In Germany, the federal government has set as its goal an annual supply of 6 billion m^3 (225 PJ) of biomethane by the year 2020. By 2030, its target is 10 billion m^3 (380 PJ), about one tenth of German natural gas consumption. In February 2011, France established a biogas feed in tariff for gas injected into natural gas distribution systems.

[8] http://www.naruc.org/Resolutions.cfm Resolution Supporting Pipeline Quality Biomethane Development as a Renewable Gas Resource in the Clean Energy Economy (adopted February 17 2010)

Part VII: Principles of the Proposed RNG Program

In enabling the emerging market, the Utilities acknowledge the need to appropriately manage customer bill impacts while providing support to the RNG industry. In establishing a RNG Program, the Utilities considered the following important principles:

1. Manageable customer bill impact
2. Market transparency
3. Appropriate cost recovery
4. Return on investment for producers
5. Consistency with Ontario government policy

Manageable Customer Bill Impact

The Utilities propose a RNG annual volume cap of 3.3 petajoules (87 million m^3) of RNG for EGD and 2.2 petajoules (58 million m^3) for Union, representing less than 2% of system gas supply. Given that the RNG prices will be known, setting a volume limit allows for a maximum bill impact to be calculated. Information on the customer bill impacts and RNG system supply volume limit are included on page 23 of this evidence, and details of customer support for the proposed bill impact are included pages 11 to 14 of this evidence.

Market Transparency

The Utilities have considered the need for market transparency regarding contracts under the RNG Program. The RNG prices proposed under the RNG Program will be for specified prices per source type, annual site volume and a fixed term. The Ontario RNG Supply Prices (as filed in this evidence) will, following Board approval of the RNG Program, be posted on the Utilities' respective websites along with other aspects of the RNG Program.

Appropriate Cost Recovery

As the Utilities are purchasing RNG supply to meet system supply requirements, the costs of RNG supply will be incorporated in the Utilities' system gas costs portfolios. RNG purchased will be incorporated into each utility's system gas portfolio using Board-approved QRAM methodology.

Return on Investment for Producers

The price paid to a RNG producer should reflect a reasonable return on the incremental capital and operating costs incurred to develop the RNG supply stream and to connect to the utility distribution system. See the report prepared by Electrigaz, in conjunction with EGD and UGL, "Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Grid in Ontario—RNG Program Pricing Report " attached as Exhibit B, Tab 1, Appendix 5, for full economic analysis.

Consistency with Government Policy

The proposed RNG prices are consistent with Ontario Government policy, particularly as reflected in the 2009 *Green Energy Act (GEA)*. The GEA states:

> The Government of Ontario is committed to fostering the growth of renewable energy projects, which use cleaner sources of energy, and to removing barriers to and promoting opportunities for renewable energy projects and to promoting a green economy.

In April 2009, the OPA specifically noted its direct support of the objectives spelled out in the GEA when it introduced its incentive program for renewable power generation. These objectives included broad program participation, including different technologies, project sizes and proponents, and price stability to promote investment.

The RNG Program complements the above-noted principles in that it promotes broad participation, including different technologies, project sizes and producers of RNG by providing price stability through the proposed RNG Prices. In this way the proposed

RNG Program is entirely consistent with Ontario Government policy by providing a complementary approach to the existing programs for renewable electricity generation.

The province of Ontario's Climate Change Action Plan calls for GHG reductions of 15% (based on 1990 levels) by 2020. The provincial government has projected that this target will not be met.[9]

Canada's 2011 National Inventory Report placed Ontario's total 2009 GHG emissions at 165 million tonnes. According to the report prepared by Alberta Innovates and attached as Exhibit B, Tab 1, Appendix 1, the use of near-term RNG could lead to a potential reduction in GHG emissions of approximately 13 million tonnes of CO2e, or more than 45% of Ontario's 2020 GHG emissions reduction target.

Part VIII: Details of the Proposed RNG Program

The RNG Program contains the following features:

1. Duration
2. Price
3. Volume cap
4. Regulatory treatment of costs
5. Ownership of environmental attributes
6. Capacity allocation
7. Contract

[9] Climate Progress Ontario's Plan for a Cleaner, More Sustainable Future Annual Report 2009-2010

Duration

Each of the Utilities proposes to end its respective RNG Program when its RNG volume limit (87million m^3 (EGD) and 58 million m^3 (Union)) is met, or at the end of five years, whichever comes earlier. Given the planning and construction periods of potential RNG projects, including the need to finance, engineer, procure and construct, many projects may take two or more years to start commercial operation. Therefore, a five-year window is required in order to allow the market to adequately respond to the RNG Program. The RNG purchase contracts have a maximum term of twenty years.

Price

Under the Proposed RNG Program, the following RNG prices would be provided to Ontario producers who contract with their respective gas utility to inject RNG into the gas pipeline network:

• **Source**	• **Annual Breakpoint (per site)**	• **Under Breakpoint**	• **Over Breakpoint**
• Landfill	• 150,000 GJ	• $13/GJ	• $6/GJ
• AD	• 50,000 GJ	• $17/GJ	• $11/GJ

Electrigaz calculated biomethane production costs in nine production scenarios. Full details of capital and operating costs can be found in Exhibit B, Tab 1, Appendix 4 "Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Grid in Ontario—Biogas Plant Costing Report.

Based on its calculation of costs in each scenario, Electrigaz then determined the prices which would be required to support a Return On Equity (ROE) of 11% for the producer in each scenario. The 11% ROE level was selected because of its consistency with the

ROE in the OPA Feed in Tariff program, taken to be representative of the industry/marketplace.

Using these prices, Electrigaz then worked with EGD and Union to develop a single, simple pricing model for each of AD and landfill-sourced RNG. The pricing models were developed with a view to settling on prices that would support an ROE in the proximity of 11% in a number of scenarios, without the price exceeding a threshold determined by the Utilities to be excessive and unlikely to be supported by their customer base. The simplified pricing models, applied to each of Electrigaz's production scenarios, resulted in a range of projected ROEs, provided in the "Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Grid in Ontario—RNG Program Pricing Report ", attached at Exhibit B, Tab 1, Appendix 5. In certain cases, the application of the model to a production scenario resulted in a negative ROE, indicating that production would not be viable at that price level. Where ROEs were negative, no figure was included in the table.

The pricing models recommend pricing tiers for landfills and anaerobic digestion systems that are intended to recognize the cost efficiencies of high-volume RNG projects. By way of example, the large landfill scenario, as noted on page 5 of the "RNG Program Pricing Report" would receive an average of approximately $7.50/GJs based on receiving $13/GJ for the first 150,000 GJs and $6/GJ for the remaining volume in the same year.

This pricing model offers a straightforward approach to dealing with potential RNG developments, whether they are small, medium or large.

An illustrative example of a Source Separated Organics RNG facility is included at Enbridge's utility-specific evidence found in EB-2011-0242 at Exhibit C, Tab 1, Schedule 3.

Volume Cap

The Utilities are mindful of the need to manage cost impacts related to the Program so that it retains the support of the participating customer base.

The approach proposed by the Utilities is to ensure any maximum impacts are within the parameters identified in the survey of residential and commercial customers conducted by Ipsos Reid in October 2010. The study is provided in Exhibit B, Tab 1, Appendix 3 of the filing.

Based on the results of the survey, a cost impact of not more than $18-$20 per year is considered acceptable by more than two thirds of both companies' residential customers. Future natural gas price increases could reduce the relative customer bill impact of RNG.

Using the rates in effect at the time of filing, and limiting the impact on a standard residential customer to approximately $18 per year, the Utilities propose to the Board that no more than 3.3 petajoules (87 million m^3) of EGD's and 2.2 petajoules (58 million m^3) of Union's current system supply portfolios be purchased from RNG producers within this Program. The derivation of the volume cap and bill impact for each of the individual Utilities can be found in their respective evidence at EB-2011-0242 (Enbridge) Exhibit C, Tab 1, Schedule 1 and EB-2011-0283 (Union) Exhibit C.

Regulatory Treatment of Costs

Under the proposed RNG Program, the RNG producer will pay a capital contribution equal to the cost of assets required to measure and deliver RNG to the Utility.

At EGD, operations and maintenance costs for RNG connection facilities will be recovered from producers through the RNG Gas Purchase Agreement. See details in Enbridge's evidence at EB-2011-0242 Exhibit C, Tab 1, Schedule 2. These revenues will be deducted from the utility's revenue requirement annually.

EGD may, in the future, develop a transportation rate for RNG producers who do not participate in this Program but wish to connect to EGD's network. The rate will be subject to Board's approval.

Union will recover operating, maintenance and capital-related costs associated with the pipe and station through a monthly fixed charge to the producer. This charge will be included in the RNG Purchase Agreement. Union proposes to charge RNG producers the Board-approved monthly fixed charge per customer station as identified in the M13 Rate schedule page 1. See details in Union's evidence at EB-2011-0283 Exhibit C.

For both utilities, gas supply costs will be treated like other system supply purchases and will be recovered from system gas customers and accounted for through the QRAM process.

Ownership of Environmental Attributes

As the RNG Program will be funded by system gas customers and applied uniformly, the Utilities will use existing systems to ensure that any and all environmental attributes and benefits will accrue to gas purchase costs to the benefit of system gas customers.

Capacity Allocation

Upon the approval of an Ontario RNG Supply Price, it is anticipated that RNG producers will come forward to determine if potential projects under consideration will be able to be connected to the EGD or Union distribution system. The first step by the utility will be to ascertain if there is sufficient year round take-away capacity to allow the requested volumes of the project to feed into the system. Given the possibility that more than one producer may approach the utility with a potential project in the same area and that the local distribution system may not have the capacity to accept more than one project, a transparent allocation system is required to ensure potential producers have equitable gas network access. This system is based on a first-come, first-served basis with an onus on the producer to confirm their serious intent to construct a project.

The process for capacity allocation is as follows:

1. RNG producers requesting determination of distribution capability for a potential project will be required to submit relevant information (in a Project Information Form to be developed).
2. The Project Information Forms will be time-stamped upon receipt by the utility.
3. The utility will identify the nearest potential tie-in opportunity and determine the seasonal market take-away capacity and provide an estimated capital cost for the producer to connect.
4. Where multiple parties seek the same or similar markets, the utility will notify the interested parties by the time based order in which inquiries were received.
5. Where the market capacity is limited, the allocation of the capacity will be on a first come basis with the following considerations:

    - The first project will be provided a six-month time frame for right of first refusal in anticipation of any subsequent requests.
    - At the end of that time frame, the producer will either have: Entered into a contractual arrangement with the utility for purchase of RNG; or Reserved capacity by providing a statement of intent which must be converted into a contractual arrangement with the utility within a six month period; or forfeit their market allocation reservation to the next party in the time-based queue.
    - In effect, the first project will have up to one full year to commit to their project and enter into a contractual agreement with the utility.

Contract

The Utilities will contract for RNG Supply with producers, using standard RNG contracts to be offered by each of EGD and Union respectively.

The contract will be made available to all potential Ontario participants through posting on websites and will contain the following key features:

1. The contract will be based on the current EGD and Union agreements for Ontario gas production with alterations or inclusions being made to facilitate RNG.
2. A definition of RNG specific to the source of RNG: anaerobic digester or landfill derived biomethane.
3. A definition of "Environmental Attributes", including carbon and methane offsets, and providing for transfer of environmental attributes to the utility.
4. A definition of the "Maximum Volume" that the utility agrees to accept into their system.
5. Maximum Volume will be limited by the ability of the utility's network to absorb the RNG.
6. A Price Schedule for the purchase of RNG, including:
    - Price for RNG from the specific source (anaerobic digester or landfill) and volume threshold for price adjustment.
    - Term as agreed to by the producer and the utility, not to exceed twenty (20) years from the commercial operations date of the producer.
    - An annual price escalator (30% of Consumers Price Index).
7. The utility has exclusivity of contracted RNG volume from the producer.
8. Charges to producer:
    - Capital costs of connection and upgrades to the network to be borne by the producer.
    - Operations and maintenance charges for station and connecting pipe.

Limited Scope of RNG Program

The Utilities recognize that the Board has previously indicated in the Natural Gas Forum Report (RP-2003-0213) that it is not in favour of new long-term utility supply contracts. For clarity, the Utilities are not proposing to pursue any long-term fixed price supply contracts outside of this RNG Program. The RNG Program relates to contracts that are narrowly defined with respect to term, price and volumes, for the purpose of enabling the development of a viable RNG industry in Ontario. Only those RNG supply contracts will be pursued, and only within the limits of the Program.

Part IX: Operational Impacts of RNG Supply

Distribution System Capacity

When RNG is produced and injected into the natural gas network there are operational implications that need to be considered. Each RNG project will need to be evaluated individually to determine the capability of the surrounding natural gas pipelines to accept the RNG. This can be performed using modeling tools and real-time testing. The ability to connect RNG supply to the utility's gas pipeline system is dependent on the market takeaway capacity. Each utility pipeline system is unique as the local market demand is influenced by the number and type of customers attached within that specific network. Typically, acceptable RNG limits at any injection point will be based on the gas pipeline network's summer capacity as this is when natural gas is at its lowest demand during the year.

Another operational implication to consider when injecting RNG into a natural gas pipeline system is the operating pressure of the injection point. In order for the RNG to flow into the distribution or transmission system, it needs to be at a higher pressure than the natural gas already flowing through the pipeline. Each utility has different pipeline systems that service different customer profiles which affect the pressure of the pipelines. Therefore each RNG project will have different injection pressure specifications based on the specific injection point.

RNG Gas Quality

Under the proposed RNG Program, producers will be responsible for meeting gas quality standards and if not met, producers will be prevented from injecting into the pipeline until the quality issue is resolved.

The safety and integrity of the distribution network is the primary focus of the Utilities. To that end, the Utilities have evaluated the following: historical and trending system gas compositions; raw biogas compositions from common sources; efficiency and efficacy of cleanup technologies; composition of resultant RNG; and the potential impact of contaminants not currently found in system gas.

Separately, the Canadian Gas Association ("CGA") formed a working technical committee on which both the Utilities participated, to define a set of technical guidelines for an acceptable composition of RNG. The various analyses conducted by the Utilities were combined with the technical guidelines provide by the CGA committee to establish renewable natural gas specifications for each of the Utilities. The different operational requirements and pipeline network characteristics within the Utilities account for the differences in the RNG specifications.

These specifications are minimum requirements set in place to ensure the continued safe and reliable operation of the distribution network required by our customers.

Potential Production of Renewable Natural Gas from Ontario Wastes

By

Salim Abboud and Brent Scorfield
Alberta Innovates Technology Futures

May 2011

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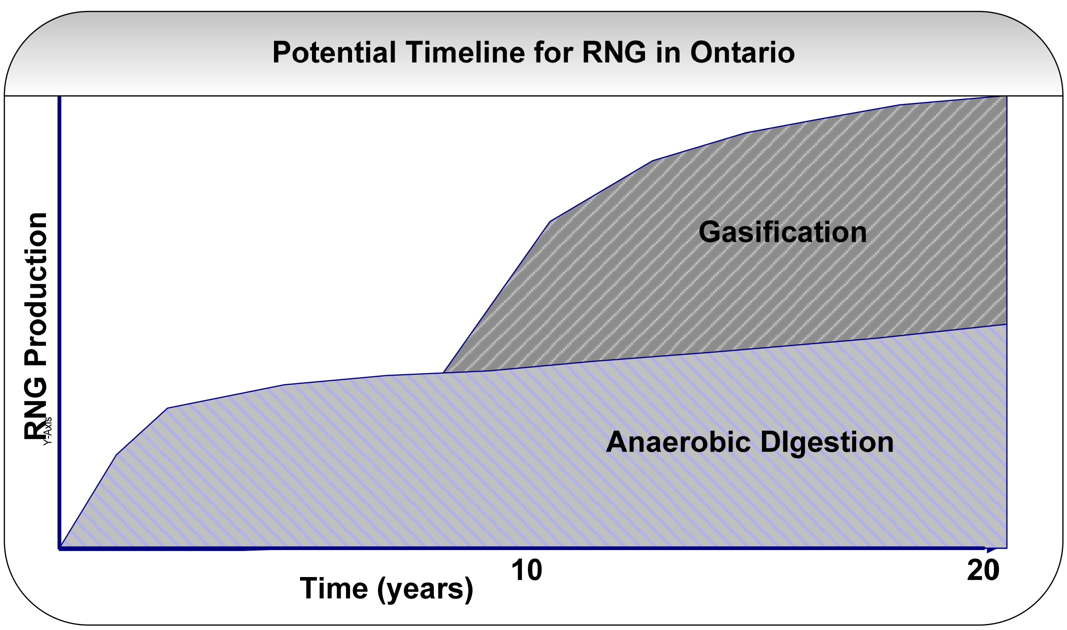
EXECUTIVE SUMMARY

This report evaluates the Ontario waste market potential, and role that these feedstocks can play in producing energy (in the form of methane gas) from waste biomass, which can then be used as a source for renewable natural gas (RNG). Our objective was to conduct a literature based study whose aim will be to assess the potential for methane generation from Ontario wastes, and the relative greenhouse gas (GHG) impacts of capturing the generated methane.

The production of RNG from Ontario wastes, following the separation and cleaning of biogas was shown to arise from the application of two well used and understood processes: Anaerobic Digestion (AD), which produces biogas as landfill gas or through the use of anaerobic digesters, and Gasification. With the main focus of this report the production of methane from Ontario-generated waste biomass, we have narrowed our discussion of AD-produced raw biogas and biosolid-produced raw biosyngas. Based on our findings, it is envisioned that the AD process will be the primary source of RNG in the next 10 years (near-term time horizon) as this technology is already in use. Gasification will contribute beyond 10 years (long-term time horizon) subject to its acceptance by industry and the need for further technology development activities. Within the report, RNG potential production in Ontario is evaluated separately between the near-term (up to 10 year) and long-term (over 10 year) time horizons.

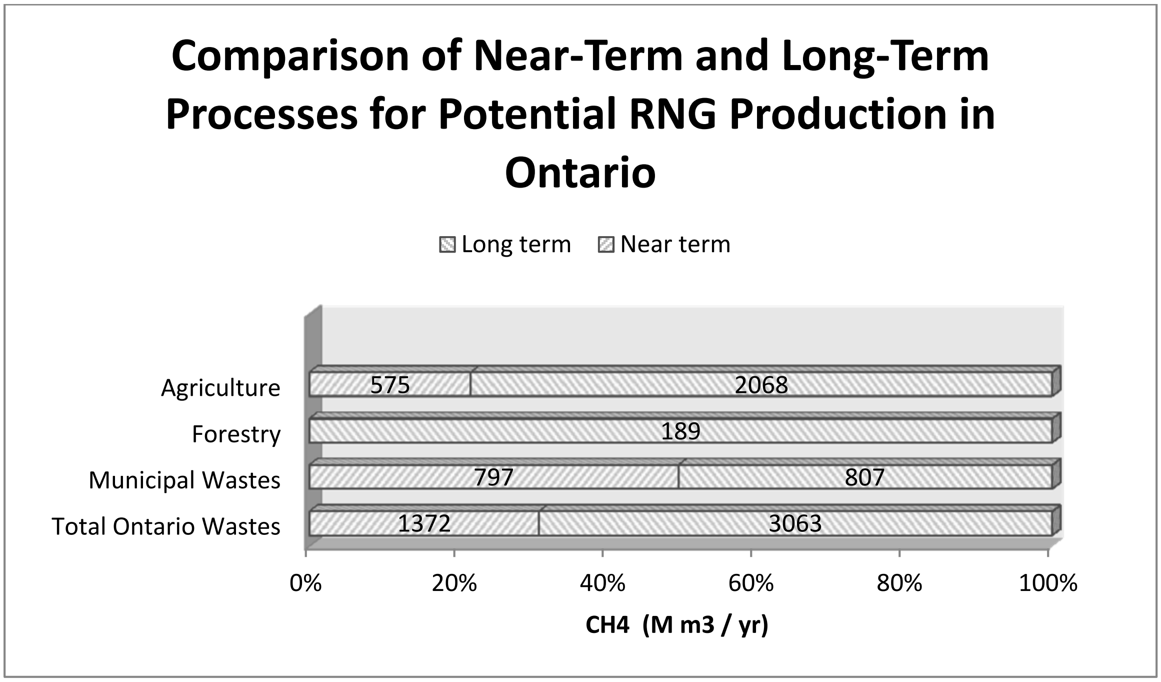


The Ontario wastes which are amenable to producing RNG are those containing significant amounts of biomass and are mostly generated by the agricultural, forestry and municipal sectors.

All of the potential RNG that can be produced from the total Ontario wastes that had been reviewed shows that a potential total of 4435 M m^3/yr of RNG can be produced. Agricultural waste has demonstrated the potential to produce 2643 M m^3/yr (60% of total), followed by 1604 M m^3/yr (36%) from municipal wastes and 188 M m^3/yr (4%) from forestry residues. RNG production is also broken out separately for Enbridge and Union Gas and summarized below.

Annual Potential RNG Production from Ontario Wastes											
	Agriculture Wastes				Forestry Residues	Municipal Wastes					Total Methane Production
	Manure		Crops			MSW		Landfill	WW	Biosolids	
	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Near-Term (AD)	Long-Term (Gas)	
	(M m^3/yr)										
Enbridge	41.2	64	69.1	322	4.85	18.2	297	395	41.5	41.8	1294
Union Gas	156	241	309	1440	184	27.2	441	289	26.6	26.9	3141
Ontario	197	306	378	1762	188	45.4	738	684	68.1	68.7	4435
Note: AD = anaerobic digestion process; Gas = gasification process MSW = Municipal Solid waste; WW = Wastewater											

Anaerobic digestion has the potential to produce 1372 M m^3/yr (31% of total) and represents the near-term potential of all the RNG production in Ontario. The use of gasification has the potential to produce most of the RNG as we estimated that an additional 3063 M m^3/yr (69% of total) can be produced by this process, however this potential would be realized over the long-term through further technology development.



We compared the relative size of our potential RNG estimates to the current natural gas consumption in the residential, commercial and industrial sectors. The potential Ontario generation of 4435 M m^3/yr of RNG (corresponding to an energy value of 167 PJ/yr, assuming 37.69 GJ/$10^3 m^3$, or 46,388 GWh of electricity) could account for a portion of the natural gas consumption. Within Ontario, our estimate is that if all methane from various wastes was captured, then 18% of current NG residential, commercial and industrial use can be replaced by the produced RNG over the long-term. However, in the near-term the potential Ontario generation of 1372 M m^3/yr (with an energy value of 52 PJ/yr, or 14,444 GWh of electricity) of RNG can account for about 6% of the residential, commercial and industrial use of NG. With gasification process capabilities becoming available over the long-term, then there would be an additional 3063 M m^3/yr (with an energy value of 115 PJ/yr, or 31944 GWh of electricity) of RNG, corresponding to an additional 12% of the current NG consumption in Ontario.

Enbridge and Union Gas were evaluated separately for market potential in order to have a better understanding of the allocation of waste sources in Ontario. This data is provided in detail throughout the report, but this information is of secondary importance to the total RNG which is potentially available within Ontario as a whole.

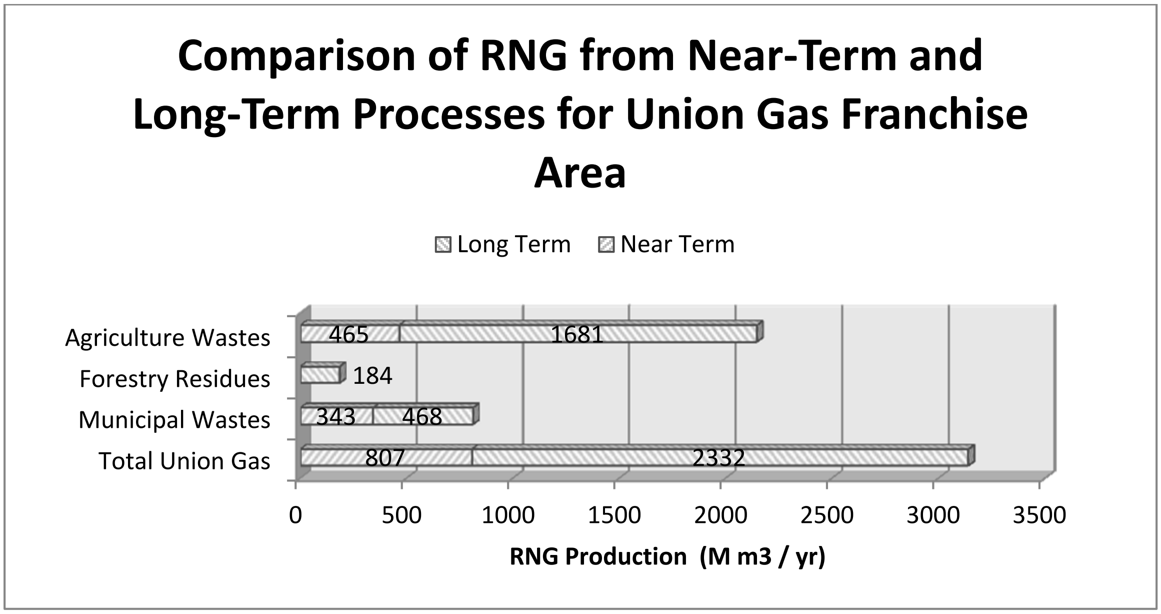
The following approach was used to allocate waste sources to either Enbridge or Union Gas. First, population data was reviewed on a county basis and allocated to either franchise based upon their service area. The ratio of Ontario population per franchise area was used for RNG calculations for all municipal wastes since that waste stream is directly proportional to the number of people residing in the area. Then the other waste materials, including agricultural and forestry residues, had RNG calculations based on Ontario government volume data provided on a county basis, and allocated to either franchise.

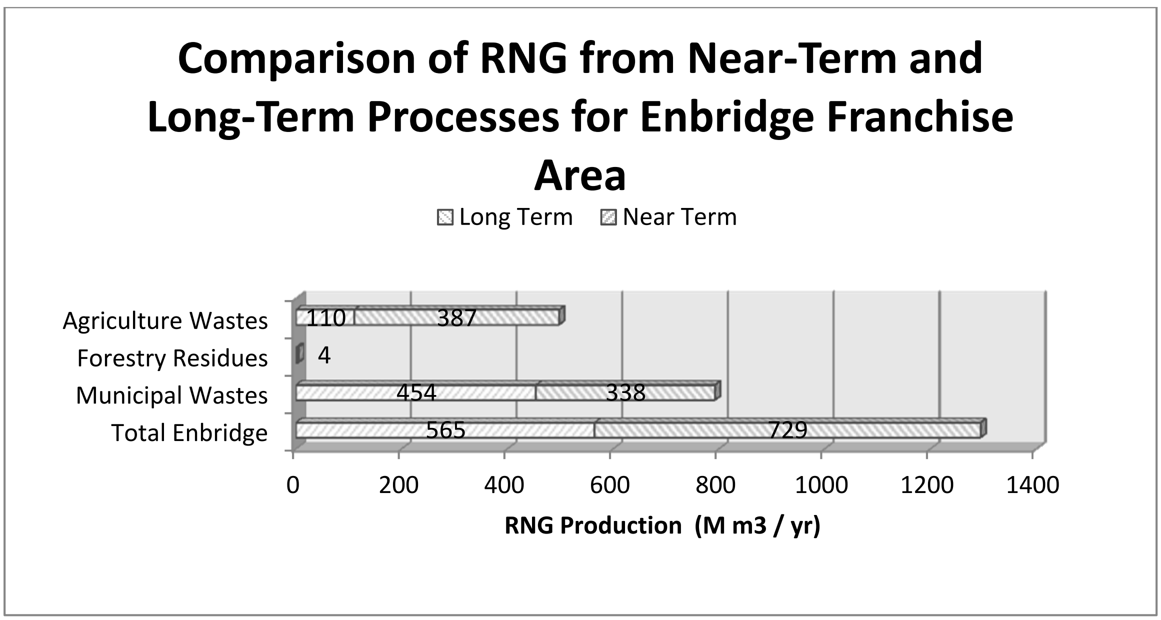
In a limited number of cases, some counties were serviced by both franchises. With these counties, the proportion of population was allocated to either franchise and this ratio was used on the waste volumes for RNG calculations. Additionally, the cities of Kitchener and Kingston operate independent municipal gas utility services. Both Kitchener and Kingston are surrounded by Union Gas' franchise area, as such, potential methane generation from municipal wastes in either location are included in the calculation of Union Gas' total potential.

It was also determined from the franchises' service directory that two Ontario counties (Haliburton, Manitoulin) and a few other small communities were not serviced by either franchise. The size of the market that neither company serviced, including 70,000 people and representing 0.5% of the Ontario population, was not considered as significant but census data was adjusted to account for these areas. It was determined that Enbridge service area includes 61% of the Ontario population with the remaining 39% serviced by Union Gas.

In evaluating the various waste sources that can produce RNG, results for Union Gas and Enbridge service areas show that of the 4435 M m^3 RNG potentially produced in Ontario annually, the market potential for Union Gas is 71% of the total (3141 M m^3). The market potential for Enbridge is 29% (1294 M m^3). Despite the lower population serviced by Union Gas, their market potential for RNG is greater due to higher proportion of rural waste materials, including agricultural and forestry residues. In addition, the majority of Toronto municipal solid waste is now trucked from the Enbridge service area into a landfill located in the Union Gas service area.

These results were broken out by waste source and availability in the near-term or long-term horizons, as shown below:





The production and capture of RNG from Ontario wastes contributes to GHG reduction through two processes: emission reduction and fuel substitution. Emission reduction values represent the potential methane capture from anaerobic digestion within landfills and from a portion of animal manure, where fuel substitution relates more broadly to the potential of displacing fossil-fuel based NG with RNG produced from all wastes.

Total GHG reductions were estimated as 18980 kt CO_2 eq/yr for Ontario with emission reductions contributing more of the GHG reductions than fuel substitution as seen in the table below. About 54% of the Ontario GHG reductions arise from emission reductions, while the rest (46%) arises from fuel substitution. Of the total GHG reductions for Ontario, Union Gas service area accounts for 56% of this with 10700 kt CO_2 eq. The Enbridge service area accounts for 44% of the total Ontario GHG reductions with 8280 kt CO_2 eq.

GHG Reductions Due to Production of Renewable Natural Gas within the Franchise Areas							
	Methane		GHG				
	Emission Reduction[1]	Fuel Substitution[2]	Emission Reduction[3]	Fuel Substitution[4]	Total[5]	Emission Reduction[6]	Fuel Substitution[6]
	(M m3/yr)		(kt CO_2 eq/yr)			(%)	
Near-Term	403	565	5755	1103	6857	84	16
Long-Term	-	729	-	1423	1423	0	100
Total Enbridge	403	1294	5755	2525	8280	70	30
Near-Term	320	807	4570	1575	6145	74	26
Long-Term	-	2332	-	4551	4551	0	100
Total Union Gas	320	3141	4570	6130	10700	43	57
Ontario	723	4435	10324	8655	18980	54	46

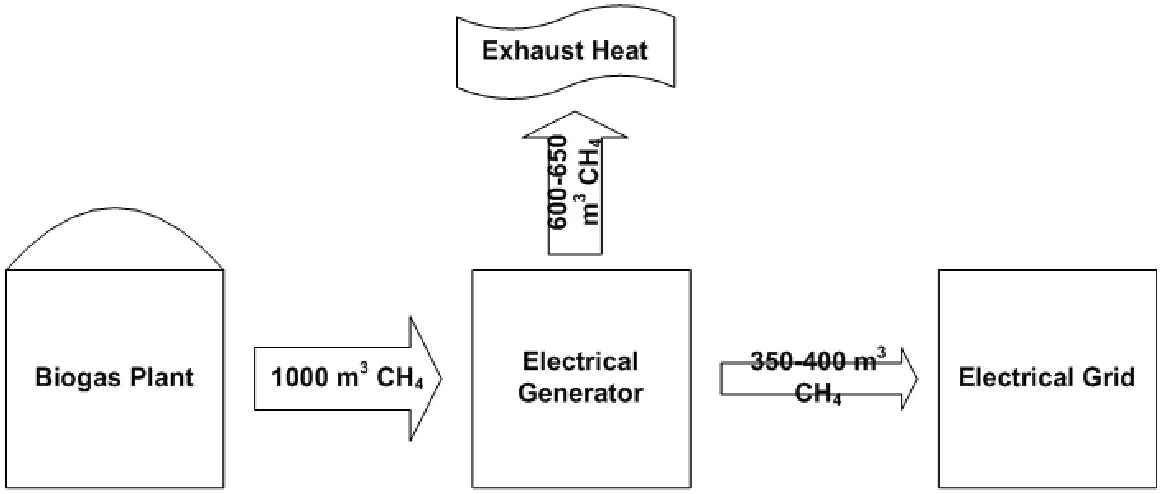
1 Calculated as the CH_4 generated in landfills plus 20% of the CH_4 generated from manure through AD
2 This is the total amount of potential CH_4 generated from all wastes
3 Calculated as column 2 (M m^3/yr) x 0.00068 (Mt CH_4/M m^3 CH_4) x 21 (Mt CO_2 eq/Mt CH_4) x 1000(kt CO2 eq/Mt CO2 Eq)
4 Calculated as column 3 (M m^3 CH_4/yr) x 0.00068 (Mt CH_4/M m^3 CH_4) x 2.87 (Mt CO_2 eq/Mt CH_4) x 1000(kt CO2 eq/Mt CO2 Eq)
5 Calculated as the sum of columns 4 and 5
6 Calculated as a percent of the total GHG (column 6)

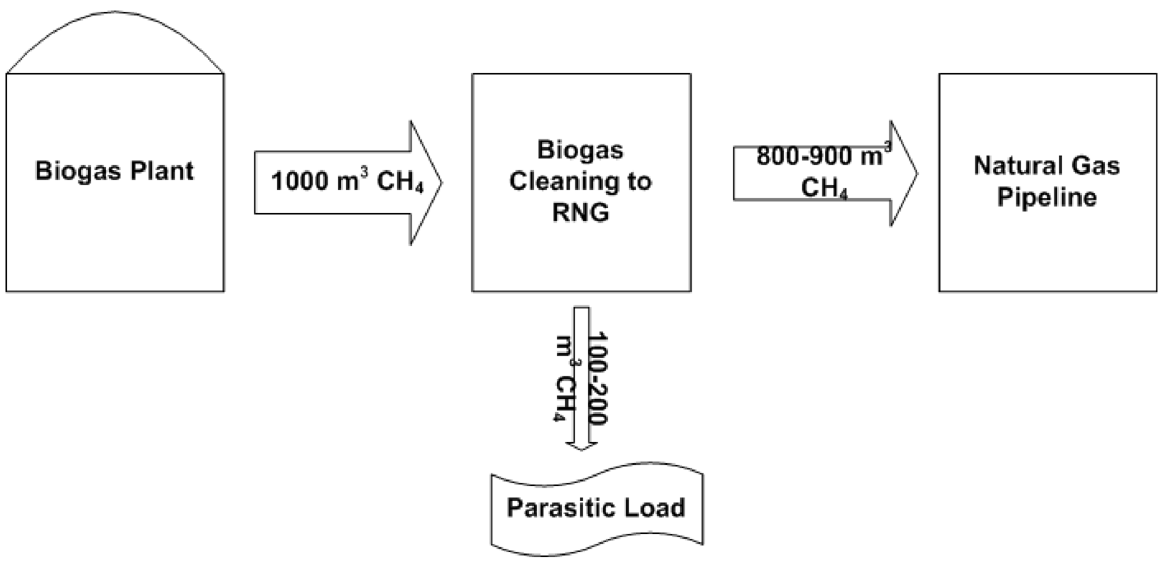
It has been shown that Enbridge has proportionately higher emissions reduction potential when compared to fuel substitution. This is a function of population size with associated municipal waste volumes, in addition to factoring in no forestry residues subject to gasification. In the near-term, Enbridge can realize GHG reductions of 6857 kt CO_2 eq/yr, representing 83% of its total potential GHG reductions. Over the long-term, an additional 1423 kt CO_2/yr (17%) of its total potential can be realized with further development of gasification processing.

Union Gas alternatively demonstrates higher fuel substitution potential when compared to emissions reduction. In the near-term, Union Gas can realize GHG reductions of 6145 kt CO_2 eq/yr, representing 57% of its total potential GHG reductions. Over the long-term, an additional 4551 kt CO_2/yr (43%) of its total potential can be realized with further development of gasification processing.

A comparison was made, as shown in the figure below, where biogas can be directed into electricity generation, or production of RNG for injection into a natural gas pipeline. As can be seen there is a wide difference in energy content retention with generating electricity (35-40% efficiency) compared to RNG production (80-90% efficiency).

It is evident that making RNG from existing biogas is a much preferable route energetically as it retains the most energy. If the raw biogas is used for RNG cleaning, in addition to improving the electric generator output by at least 100% (800 m^3 methane eq. vs 400 m^3 methane eq.) there is another beneficial consideration to be gained by producing RNG for the NG pipeline. This additional volume from energy efficiency represents fuel substitution of fossil fuel that would otherwise have to be provided in order to replace the inefficiency of electricity generation. As a result there are additional GHG emissions produced in electricity generation, which otherwise would be a GHG reduction in the NG pipeline as the RNG is a direct fuel substitution. It is evident that RNG from existing biogas is the preferable route energetically as well as providing the benefit of GHG reductions.


Exhaust Heat
600-650 m3 CH4
Biogas Plant
1000 m3 CH4
Electrical Generator
350-400 m3 CH4
Electrical Grid


Biogas Plant
1000 m3 CH4
Biogas Cleaning to RNG
800-900 m3 CH4
Natural Gas Pipeline
100-200 m3 CH4
Parasitic Load

GLOSSARY AND ABBREVIATIONS

AD	Anaerobic digestion
AITF	Alberta Innovates – Technology Futures
ARC	Alberta Research Council
BC	British Columbia
Biomethane	Biogas upgraded to natural gas quality
C	Carbon
CH_4	Methane
CO_2	Carbon Dioxide
C&D	Construction and Demolition
CGA	Canadian Gas Association
CH_4	Methane
CO_2	Carbon Dioxide
DM	Dry matter content
GHG	Greenhouse gases
GJ	Gigajoule, unit of energy
GWh	Gigawatthour, a unit of energy
ICI	Institutional, Commercial and Industrial
kt	kilo tonnes (1,000 tonnes) unit of mass
Mt	Mega tonnes (1,000,000 tonnes) unit of mass
kW	Kilowatt, unit of power
kWh	Kilwatthour, unit of energy
LFG	Landfill gas
M m3	Million cubic meters (1,000,000 m^3) a unit of volume
MSW	Municipal solid waste
MWh	Megawatthour, unit of energy
NG	Natural Gas
OMAFRA	Ontario Ministry of Agriculture and Rural Affairs
OME	Ontario Ministry of the Environment
PJ	Petajoule, a unit of energy
RNG	Renewable Natural Gas
Tonne	Metric ton (t)
WW	Waste water collected from municipal sewers
WWTP	Waste water treatment plant

CONSTANTS

Giga Joules (GJ)	1,000 Mega Joules (MJ)
Peta Joules (PJ)	1,000,000 Giga Joules (GJ)
Peta Joules (PJ)	277.77 Giga Watt hour (GWh)
RNG Density	0.00068 t/m^3
RNG Energy Content	37.69 GJ/(1,000 m^3)

1. INTRODUCTION

The use of biomass resources for energy production started early in human history, and continued to be the major source of energy until overtaken by coal then oil in the 19th and 20th centuries. Biomass supplies 5.9% of Canadian primary energy sources (through combustion and gasification and the production of biofuels), 15% of the world's energy and 35% of the developing countries' needs (Holmes and Edwards, 2003). The rest of the energy needs are supplied by fossil fuels. Concern about the use of fossil fuels and the resulting atmospheric buildup of carbon dioxide has led to a reevaluation of biomass resources for energy production.

The new efforts to use biomass for energy production centre on increasing efficiency, promoting sustainability of this resource and lowering carbon dioxide atmospheric levels by replacing fossil fuels.

There are energy production uses for biogas already established in Ontario. In 2009 the Province of Ontario passed into law the Green Energy Act, and adopted a green energy policy that includes a Feed-In Tariff (FIT) program delegating the responsibility for its implementation to the Ontario Power Authority (OPA). The program encourages investment in the generation, transmission and distribution, so that more renewable energy sources can be incorporated into Ontario's electricity system. The FIT program replaced the province's Renewable Energy Standard Offer Program (RESOP), which underwent review in 2008. As of the third quarter of 2009, the OPA had 1,422 MW of renewable energy supply capacity of which 87 MW are from bioenergy power generation projects under the RESOP Program. These projects provided the production of power from biomass sources but were not producing RNG for cleaning for NG pipeline.

In addition, there are several landfill operations in Ontario where methane gas is used as a fuel in generators to produce energy for their operation in the form of steam, electricity and heat. These operations include the EWSWA Regional Landfill (Essex Windsor); Glanbrook Landfill (Hamilton); Niagara Waste Systems Ltd. Landfill (Niagara Falls) and West Carlton Landfill (Ottawa).

This report evaluates the potential that Ontario wastes can produce energy from waste biomass by generating methane, which can then be used as a renewable natural gas (RNG) source. This path to energy production offers the advantages of new previously untapped sources of biomass and a solution to mounting waste problems.

1.1. OBJECTIVE

The objective of this project is to conduct a literature based study whose aim will be to assess the market potential for renewable natural gas generation from Ontario wastes, and its environmental benefits, including the relative greenhouse gas (GHG) impacts of capturing the generated methane. Specifically, it will:

- Provide data on market potential in Ontario for the generation of biogas (from agricultural, forestry, and municipal waste sources) based on a joint AITF-CGA study. It will also provide a breakdown of the LFG potential that is included in large landfills.
- Explain and quantify the reduction of greenhouse gas (GHG) release both in terms of methane destruction and in terms of natural gas displacement.
- Outline the efficiency differences of cleaning biogas into renewable natural gas vs. burning biogas in an engine for generating electrical power. It will include an explanation and diagrams that are understandable by a lay person on the range of difference in the "full cycle" efficiency between the two.
- Provide additional information germane to understanding the market potential and environmental benefits of biomethane in Ontario. It will evaluate market potential and environmental benefits for Ontario as a whole and separately for the Union Gas and Enbridge franchise areas.

1.2. APPROACH

We reviewed the literature with respect to the processes for converting waste into renewable natural gas (RNG), and evaluated these processes for availability in the near-term (up to 10 years) or long-term (over 10 years) time horizons (Figure 1). Then data was collected about the sources and quantities of wastes produced in Ontario and their geographical locations as they relate to the Enbridge and Union Gas franchise areas. We used the waste information to calculate potential quantities of RNG that can be produced from these wastes over the near-term and long-term horizons using assumptions about the conversion pathways and yields. These values were based on the scientific literature and our own experience and will be explained later in this report. The potential RNG production values are discussed for Ontario in terms of RNG production pathways, along with their technical feasibilities and the potential reduction in greenhouse gases realized from RNG production from waste.

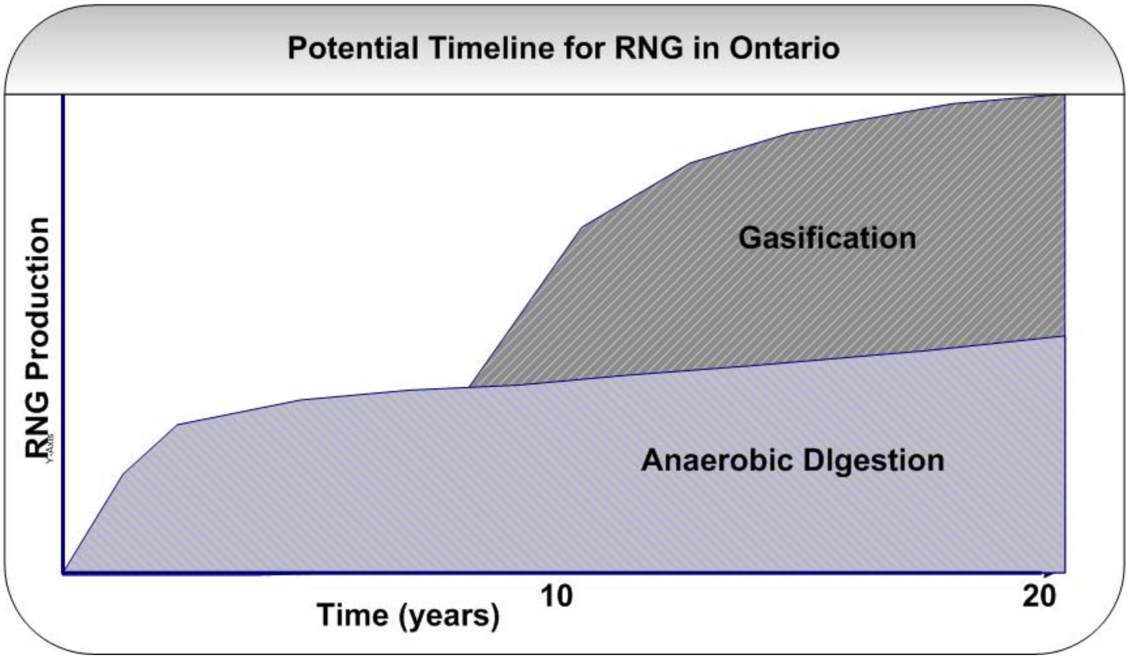


Figure 1. Potential Timeline for RNG Production in Ontario.

2. BIOGAS, SYNGAS AND RENEWABLE NATURAL GAS PRODUCTION PROCESSES FROM WASTES

Biomass can be converted to fuel for production of energy (electrical and thermal) or raw materials for the synthesis of chemicals, liquid or gaseous fuels such as hydrogen and methane. There are five different technological routes by which energy can be produced from biomass. These five processes are shown in Figure 2 and can be grouped into thermochemical (biomass combustion, gasification and pyrolysis) and non-thermal (anaerobic digestion and fermentation) processes. This report focuses on the two primary processes, anaerobic digestion and gasification, which are more directly related to the production of biogas and RNG.

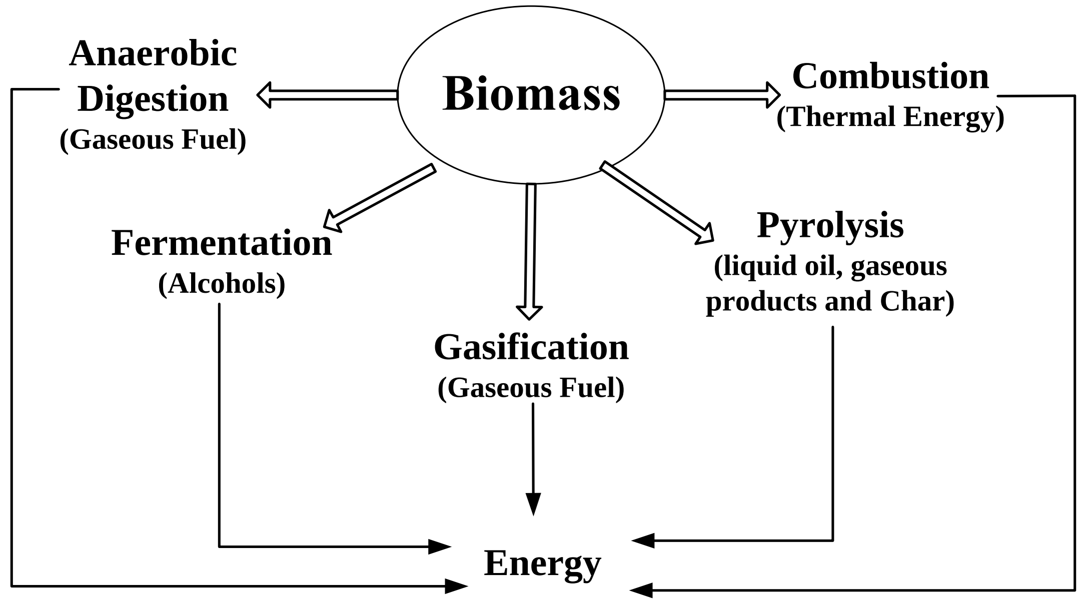


Figure 2. Potential Pathways for Energy Production from Biomass.

2.1. NEAR-TERM PROCESS AVAILABILITY

Anaerobic digestion (AD) through the use of digesters is now commonly employed for effluent and sewage treatment or for managing animal wastes. AD is a simple process that can greatly reduce the amount of organic matter which might otherwise end up in landfills or waste incinerators. In developing countries simple home and farm-based AD systems offer the potential for cheap, low cost energy from biogas. Environmental pressure on solid waste disposal methods in developed countries has increased the application of AD as a process for reducing waste volumes and generating useful byproducts. AD may either be used to process the source separated fraction of biodegradable waste, or alternatively combined with mechanical sorting systems, to process mixed municipal waste. Almost any biodegradable organic material can be processed with AD. This includes biodegradable waste materials such as waste paper, grass clippings, leftover food, sewage and animal waste. Anaerobic digesters can also be fed with specially grown energy crops or silage for dedicated biogas production. After sorting or screening the feedstock to remove physical contaminants, such as metals and plastics, the material is often shredded, minced, or hydrocrushed to increase the surface area available to microbes in the digesters and thereby increase the speed of digestion.

The material is then fed into an airtight digester where the anaerobic treatment takes place. There are four key biological and chemical stages of AD:

1. The first is the chemical reaction of hydrolysis, where complex organic molecules are broken down into simple sugars, amino acids, and fatty acids with the addition of hydroxyl groups.
2. The second stage is the biological process of acidogenesis where a further breakdown by acidogens into simpler molecules, volatile fatty acids (VFAs) occurs, producing ammonia, carbon dioxide and hydrogen sulfide as byproducts.
3. The third stage is the biological process of acetogenesis where the simple molecules from acidogenesis are further digested by acetogens to produce carbon dioxide, hydrogen and mainly acetic acid.
4. The fourth stage is the biological process of methanogenesis where methane, carbon dioxide and water are produced by methanogens.

A simplified generic chemical equation of the overall process is as follows:

$C_6H_{12}O_6 \rightarrow 3CO_2 + 3CH_4$

2.2. LONG-TERM PROCESS AVAILABILITY

Gasification is a process that converts carbonaceous materials, such as coal, petroleum, or biomass, into carbon monoxide, hydrogen and methane by the reaction of the raw organic feedstock at elevated temperatures with a controlled amount of oxygen (less than stoichiometric). The resulting gas mixture is called synthesis gas or syngas and is itself a fuel. Gasification is a very efficient method for extracting energy from many different types of organic materials. Its advantage is that using the syngas is more efficient than direct combustion of the original raw feedstock since more of the energy contained in the raw feedstock is extracted. Syngas may be burned directly in internal combustion engines, used to produce methanol and hydrogen, converted via the Fischer-Tropsch process into synthetic fuel, or converted to methane through catalytic methanation. Gasification can also begin with materials that are not otherwise as useful fuels, such as biomass or organic waste. In addition, the high-temperature combustion refines out corrosive ash elements such as chloride and potassium, allowing clean gas production from otherwise problematic fuels.

Gasification of coal is currently widely used on industrial scales to generate electricity. However, almost any type of organic material can be used as the raw material for gasification, such as wood, biomass, or even plastic waste. Thus, gasification may be an important technology for renewable energy over the long-term, with further process development to handle these additional organic raw materials. Gasification relies on chemical processes at elevated temperatures, 700°C-1800°C, which distinguishes it from biological processes such as anaerobic digestion that produce biogas.

3. PRODUCTION OF BIOGAS, SYNGAS AND RENEWABLE NATURAL GAS FROM ONTARIO WASTES

The Ontario wastes that are amenable to producing RNG are those containing significant amounts of biomass and are primarily generated by the agricultural, forestry and municipal sectors.

3.1. AGRICULTURAL WASTES

Agricultural wastes containing significant biomass are mostly made up of crop residues and animal manures. These wastes can be converted to biogas and syngas through AD and gasification. The produced biogas can be cleaned up of potential contaminants and separated into CH_4 and CO_2 both of which can be sold as RNG and industrial grade CO_2. Syngas can be cleaned up, methanated and then separated into CH_4 and CO_2.

3.1.1. Crop Residues

The crop residues amenable for producing RNG are made up of the unused part of the crops. We obtained crop production (e.g. grain) data for the major crops grown in Ontario from the Ontario Ministry of Agriculture Food and Rural Affairs 2009 field crop data (OMAFRA, 2009) and are presented in Table 11 (Appendix 1). The values used as multiplier factors to estimate recoverable residues from crop production were obtained from a US Department of Energy study (Perlack et al, 2005). We assumed that the removable residue will represent 50% of the recoverable volumes of crop residues and is available for RNG production. We chose the 50% figure as we believe that some of the crop residues should be left on site to reduce erosion and return some of the nutrients back to the soil.

The data demonstrates that the largest available crop residues in Ontario are those from grain corn (42%) followed by soybeans (29%) and wheat (21%). These 3 crop residues make up 92% of the available Ontario total. Any effort to harness this resource for RNG production will have to take into account the geographic distribution of these crops.

3.1.1.1 Near-Term RNG Potential from Crop Residues

Conversion of available crop residues to methane is shown in Table 1. The data shows the potential production of methane from biogas over the near-term through AD processing. Biogas generation from the crop residues assumes that only 20% of the material is amenable to digestion and that 300 m^3 CH_4/dry t of residues is produced (Wiese and Kujawski, 2007). The total Ontario potential RNG production from crop residues in the near-term is estimated to be 378 M m^3/yr from AD, or 18% of the total RNG potentially produced from this source.

3.1.1.2 Long-Term RNG Potential from Crop Residues

The data from Table 1 shows the longer-term potential production of methane from syngas through gasification of the residues not consumed in the AD process. Gasification of the crop residues assumes a process conversion efficiency of 65% according to the following reaction where 2 moles of carbon are required to produce 1 mole of CH_4 and 1 mole of CO_2:

$$2C + 2H_2O = CH_4 + CO_2$$

The combined gasification and methanation processes required to convert biomass to methane are reported to have efficiencies that vary from 64 to 79% (Mozaffarian et al, 2005 and Zwart and Rabou, 2006). We chose to use an efficiency of 65% as a conservative value.

Table 1. Potential RNG Production from Ontario Crop Residues

	Removable Residue[1]	Methane Production		
		Near-Term (AD[2])	Long-Term (Gasification[3])	Total[4]
	(kt dry/yr)	(M m^3/yr)		
Enbridge	1151	69.1	322	391
Union Gas	5148	309	1440	1749
Ontario	6299	378	1762	2140

1 Table 1
2 Calculated as crop residue (dry kt/yr)x10^{-3} (Mt/kt)x0.2x 300 (Mm3 CH_4/Mt dry). (Wiese and Kujawski, 2007). Assume that only 0.2 (20%) of the crop residue is amenable to AD.
3 Calculated from the AD residue as (dry Kt residue/yr)x10^{-3} (Mt/kt) x 0.5 (Mt C/Mt residue) x (16 Mt CH_4/ 24 Mt C) x 0.65. Assumes a gasification conversion efficiency of waste carbon to CH_4 and CO_2 carbon of 65%. Residues are assumed to be those not converted in the AD process.
4 Calculated as the sum of AD and gasification methane

The data shows that the greatest potential for producing RNG from crop residues can be realized over the long-term, through a gasification process (Table 1) as it consumes most of the biomass while AD is limited to about 20% of that biomass. The total Ontario potential RNG production from crop residues over the long-term is estimated to be 1762 M m^3/yr from gasification, or 82% of the total RNG potentially produced from this source.

3.1.2. Livestock Manure

Manure production on Canadian farms varies according to the type of animals and the animal population numbers but all are amenable for producing RNG. We estimated manure production for the major animal populations according to Ontario Ministry of Agriculture Food and Rural Affairs (OMAFRA, 2009b,c,d,e) data for cattle, hogs, sheep and poultry in Tables 12 to 14 (Appendix 1). Manure production was calculated using animal population numbers and a specific average daily manure production rate for each animal as suggested by Klass (1998). The average manure production rates (kg dry/head/day) varied with the animal type from a high of 4.64 kg/animal for cattle to 0.0101 for turkeys (Tables 12-14 of Appendix 1). The manures available for RNG production are less than what is produced as some of the manures are already used for other purposes. We estimated that the availability of cattle manure was 25% of the total cattle manure produced with different availability indices for hogs (85%), sheep (10%) and poultry (85%). These indices were used according to the data published for a BC bioenergy inventory report (Ralevic and Layzell, 2006).

The total Ontario manure production from each animal type available for AD and gasification are shown in Table 2. The Ontario data shows that the largest available manure residues representing 99% of the total are those from cattle (45%) followed by hogs (33%) and chickens (21%), with about 1% from turkey and sheep manures (Figure 3).

3.1.2.1 Near-Term RNG Potential from Manures

Conversion of available manure residues to methane is shown in Table 2. The data shows the potential production of methane from biogas over the near-term through AD processing. Biogas generation from the manures assumes that 116 Mm^3 CH_4/dry Mt of manure is produced. This number was calculated as an average from the specific biogas generation potentials for each manure (Electrigaz, 2007) multiplied by its manure production ratio (specific manure production/total manure production).

The total Ontario potential RNG production from manure residues is estimated to be 197 M m^3/yr in the near-term, or 39% of the RNG potentially produced from this source.

3.1.2.2 Long-Term RNG Potential from Manures

The data from Table 2 shows the longer-term potential production of methane from syngas through gasification of the manures not consumed in the AD process. Gasification of the manure residues assumes a process similar to that for crop residues at a conversion efficiency of 65% and a manure carbon content of 40% (Klass, 1998).

The data shows that the greatest potential for producing RNG from livestock manure can be realized over the long-term, through a gasification process (Table 2). The total Ontario potential RNG production from livestock manure over the long-term is estimated to be 306 M m^3/yr from gasification, or 61% of the total RNG potentially produced from this source.

Table 2. Potential RNG Production from Ontario Manures.

	Total Manure[8] (dry Mt/yr)	Near-Term (AD[9])	Long-Term (Gasification[10])	Total Manure[11]
		Methane (M m3/yr)		
Enbridge	0.356	41.2	64	105
Union Gas	1.351	156	241	397
Ontario	1.707	197	306	503

8 Calculated as the sum of all manures (cattle, hogs, sheep, chicken and turkey)
9 Calculated as total manure (dry Mt/yr) x 116 (Mm^3 CH_4/Mt dry manure) (Electrigaz, 2007)
10 Calculated from the AD residue as (dry Mt manure/yr) x 0.4 (Mt C/Mt manure) x (16 Mt CH_4/ 24 Mt C) x 0.65 x(1/ 0.00068 Mt CH_4/M m^3 CH_4) . Assumes a gasification conversion efficiency of waste carbon to CH_4 and CO_2 carbon of 65%
11 Calculated as the sum of AD and gasification methane

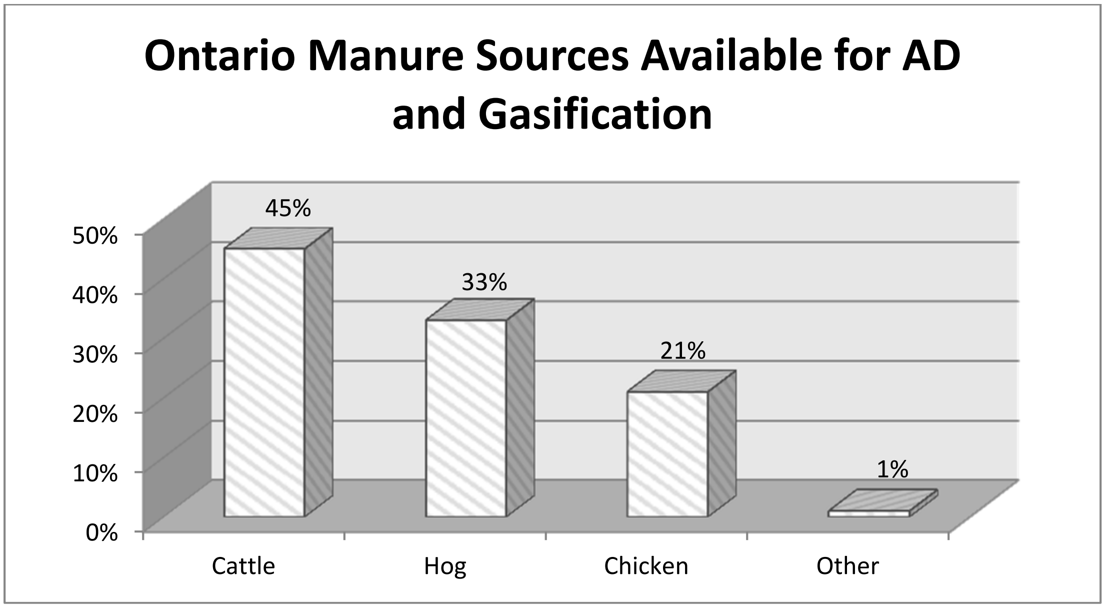


Figure 3. Ontario Manure Sources Available for AD and Gasification

3.1.3 Total Agricultural Waste

The potential RNG production arising from agricultural wastes consists of both the AD and gasification processes of manure and crop waste. In total, this represents 2643 M m^3/yr of RNG. Of this amount, the potential is 575 M m^3/yr (22%) over the near-term in Ontario; and an additional 2068 M m^3/yr (78%) over the long-term with new process developments for gasification.

3.2 FORESTRY WASTES

Forestry residues are made up of forest operation residues which are generated during harvest operations and subsequent wood treatment in either sawmills or pulp and paper plants. Production of forestry wastes was calculated from the data reported in the Ontario Ministry of Natural Resources Forest Biomass (2003) data (Norrie, 2011). Estimates were then made of total forest residues (kt Carbon/year) as by Wood and Layzell (2003). Gasification of the harvested forest residues to RNG is assumed to occur with a process efficiency of 65% as discussed in previous sections.

3.2.1 Long-Term RNG Potential from Forestry Wastes

Forest residue data are presented in Table 3. The total Ontario potential RNG production from forest residues is estimated as 188 M m3/yr. This RNG would be produced through a gasification process, and therefore represents long-term RNG potential. The AD process is not applicable to forestry wastes, and as a result there is no near-term RNG production potential with these waste materials.

Table 3. Potential RNG Production from Ontario Forestry Wastes			
	Forestry Biomass[1] m^3 (000's)	**Forestry Residues[2] (kt C / yr)**	**Total Methane Generation[3] (M m^3/yr)**
Enbridge	31.5	7.50	4.85
Union Gas	1211	288	184
Ontario Total	1242	296	188

1 Ontario Ministry of Natural Resources, Forest Biomass (2003) data (Norrie, 2011).
2 Assumes 4.2m^3 biomass/tonne carbon (Wood and Layzell, 2003)
3 Calculated as Column 3 (kt C/yr) x (16 kt CH_4/ 24 kt C) x (1 Mt CH_4/1000 kt CH_4) x 0.65 x (1/0.00068 M t CH_4/M m^3 CH_4). Assumes a gasification conversion efficiency of waste carbon to CH_4 and CO_2 carbon of 65%

The total RNG production from forestry residues in Ontario as calculated is viewed as a conservative estimate compared to the national report provided to the CGA. That report included data of the potential non-stem residue left onsite at forestry operations, whereas the dataset in this report focused on processed wastes from forestry operations including hog fuel, sawdust, shavings, bark etc. Although some of non-stem residue left onsite represents additional long-term RNG potential, in practical terms there will be a significant percentage which falls outside of the Union Gas service area in Northern Ontario, and it would be cost prohibitive to truck these residues from remote forestry regions into their service area.

3.3 MUNICIPAL WASTES

Ontario municipal wastes considered as potential sources for RNG production comprises of four types of waste materials: (1) solid wastes collected from homes and businesses by municipalities (MSW, including SSO); (2) landfill gas recovered from closed landfills (LFG); (3) wastewaters (WW) collected through municipal sewer systems, and (4) municipal biosolids which are the solid materials collected from the settling of the wastewaters.

3.3.1. Municipal Solid Waste

MSW residues are made up of wastes collected from residential areas (households), industrial and commercial and institutional (ICI) wastes, and construction and demolition (CD) wastes. Some of these wastes are collected by municipalities while others are collected by private companies.

The amounts of various Ontario-disposed MSW fractions are presented in Figure 4 for 2008 (Statistics Canada, 2010) and Table 15 (Appendix 1). The data shows that ICI wastes makes up the highest fraction of the total MSW at 47%, followed by household sources (34%) and CD wastes (19%). Statistics Canada reported only the total amounts of residential MSW and a combined number for the ICI and C&D wastes. We separated the ICI and C&D numbers by using the same ratio of these two wastes as reported by the city of Ottawa based on their waste production (City of Ottawa, 2007).

The amounts of MSW that are amenable to AD and gasification are reported in Table 15 (Appendix 1). We estimated that only 25% of the household wastes are amenable to AD (Ostrem, 2004) while none of the other wastes were considered to contain significant amounts of digestible wastes. This assumption underestimates the amount of digestible waste by not including the amount of food wastes disposed of from restaurants and institutional cafeteria. The gasifiable waste quantities were assumed to consist of the undigestible biomass from household wastes, 50% of the ICI wastes and 30% of the CD wastes (mostly wood products).

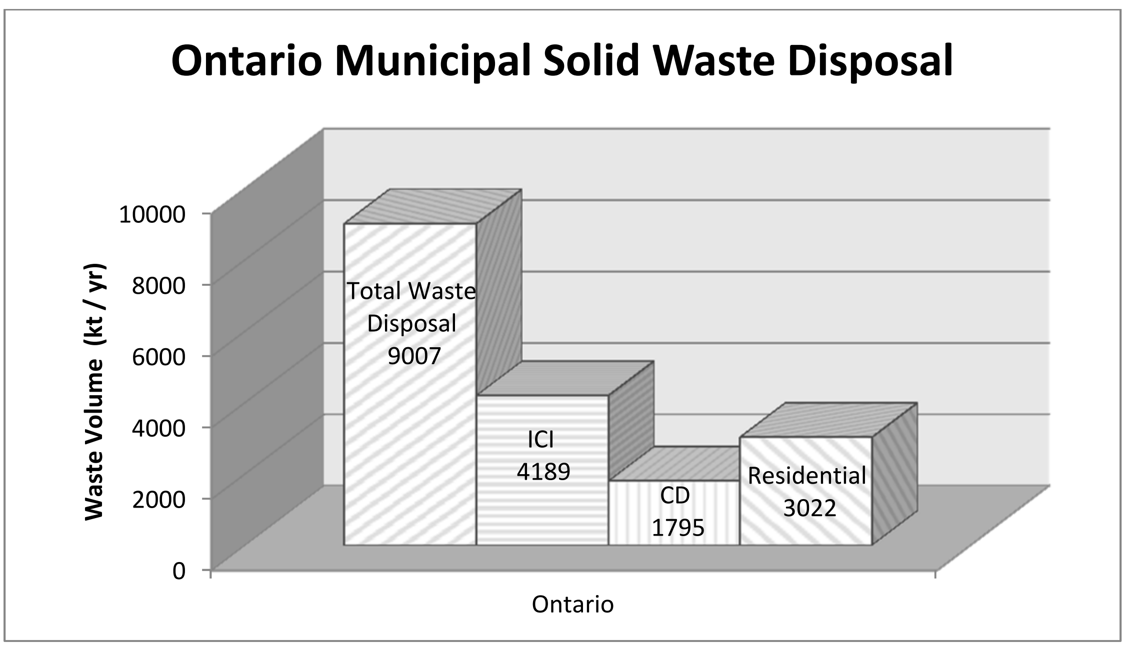


Figure 4. Ontario Municipal Solid Waste Disposal

3.3.1.1 Near-Term RNG Potential from Municipal Solid Waste

Generation of RNG from these wastes is presented in Table 4 showing that in Ontario AD can produce approximately 45 M m^3/yr. This represents 6% of the total potential RNG which could be produced from this waste source.

3.3.1.2 Long-Term RNG Potential from Municipal Solid Waste

Data presented in Table 4 shows that over the long-term in Ontario, gasification can potentially produce an additional 738 M m^3/yr of RNG. This represents 94% of the total potential RNG which can be produced from this waste source.

Table 4. Potential RNG Production from Ontario Municipal Solid Wastes (2005)

	Methane Production		
	Near-Term (AD[1])	**Long-Term (Gasification[2])**	**Total[3]**
	(M m^3/yr)		
Enbridge	18.2	297	315
Union Gas	27.2	441	469
Ontario	45.4	738	784

1 Calculated as Column 6 (Table 8) (dry kt /yr) x 172 (k m^3 CH_4)/(kt dry) x (1 M m^3/1000 k m^3) .
2 Calculated as Column 7 (Table 8) (dry kt C/yr) x (16 kt CH_4/24 kt C) x 0.65 x(1/0.00068 kt CH_4/k m^3 CH_4) x (1 M m^3/1000 k m^3). Assumes a gasification conversion efficiency of waste carbon to CH_4 and CO_2 carbon of 65%
3 Calculated as the sum of Methane generated by Anaerobic Digestion (column 2) and Gasification (column 3)

3.3.2. Wastewater

Wastewaters are the mixed liquid and solid wastes collected through sewers and delivered to a wastewater treatment plants. These wastes can produce RNG through AD in large digesters where some of the biomass solids are converted into CH_4 and CO_2. This practice is common for larger municipalities where the original aim was to reduce the solids contents of the wastes before discharge from the plants.

We estimated the generation for wastewaters for Ontario from Environment Canada data (Environment Canada, 2001) for the Canadian generation in 1999 and the population sizes in 2006 (Statistics Canada, 2007). Total population numbers were adjusted to reflect the county data for service provided by Enbridge and Union Gas. Environment Canada also reported that 97% of the Canadian population is served with some form of wastewater treatment.

3.3.2.1 Near-Term RNG Potential from Wastewater

The potential RNG produced from the AD of these wastes is presented in Table 5. We estimated the production of RNG using data reported for many Ontario wastewater anaerobic digesters by Wheeldon et al. (2005), where the specific methane production was reported as 0.0336 m^3 CH_4/m^3 wastewater. The total Ontario potential RNG production from wastewaters is estimated to be about 68 M m^3/yr in the near-term. Since the gasification process is not applicable to wastewater, the full potential of RNG production can be realized in the near-term through AD.

Table 5. Potential RNG Production from Ontario Wastewaters (2006)

	Population[1]	Wastewater Production		Near-Term Methane Production
	(000's)	(m3/d)[2]	(M m3/yr)[3]	(M m3/yr)[4]
Enbridge	7358	3376	1.23	41.5
Union Gas	4731	2171	0.79	26.6
Ontario	12089	5547	2.02	68.1

1 Statistics Canada. 2007
2 Calculated as Column 2 (p) x 0.97 x 0.474 (m^3/d/p). (In 1999, 97% of Canadians used Wastewater treatment facilities that produced 14,400,000 m^3/day (population of 30,404,000) or 0.474 m^3/person/day). (**Environment Canada. 2001.**)
3 Calculated as (Column 3 (m^3/d) x 365 d/yr)/(1000000 m^3/M m^3)
4 Calculated as Methane production (at 60% of biogas) = Column 4 (M m^3/yr) x 0.0336 (M m^3 CH_4/M m^3 wastewater) (**Wheeldon et al, 2005**)

3.3.3 Biosolids

Biosolids are the solids collected through solid liquid separation of the wastewaters before liquid discharge from the wastewater treatment plant. Some of these wastewaters would have previously undergone AD. Currently, biosolids are disposed on land, landfills or composted.

Quantities of biosolids also correlate well with population size. We estimated the amount of biosolids produced in Ontario from the population size and the specific biosolids production rate of 0.063 kg (dry Biosolids)/person/day (Klass, 1998). Similar to wastewater production, the total population numbers were adjusted to reflect the county data for service provided by Enbridge and Union Gas.

3.3.3.1 Long-Term RNG Potential from Biosolids

Production of RNG from biosolids is through gasification of the dried biosolids, and as a result this waste source represents a long-term RNG potential. We assumed that the carbon content to be 40% according to Klass (1998) and that the gasification efficiency is 65% as discussed earlier in this report. Table 6 shows the data for biosolids production and potential RNG generation from these wastes. The total long-term potential RNG production from biosolids in Ontario is estimated at 69 M m^3/yr. Since this waste source is not amenable to AD, there is no near-term RNG potential with it.

Table 6. Potential RNG Production from Ontario Biosolids (2006)

	Population[1]	**Biosolids Production**		**Long-Term Methane Production[4]**
	(000's)	**(kt dry/yr)[2]**	**(dry kt C/yr)[3]**	**(M m3/yr)**
Enbridge	7358	0.164	0.066	41.8
Union Gas	4731	0.105	0.042	26.9
Ontario	12089	0.269	0.108	68.7

1 Statistics Canada. (2007).
2 Calculated as Column 2 (p) x 0.97 x 0.063 (kg dry 16iosolids/d/p) x 365 (d/yr) x 10^{-3} (t/kg). (**Klass, 1998**)
3 Calculated as Column 3 x 0.4 (kt C/kt 16iosolids). Assumed a 40% carbon content for the Biosolids. (**Environment Canada. 2001.) and** (**Klass, 1998**)
4 Calculated as Column 4 (dry kt C/yr) x (10^{-3} Mt C/kt C) (16 Mt CH_4/ 24 Mt C) x (1/0.00068 Mt CH_4/ M m^3 CH_4) x 0.65. Assumes a gasification conversion efficiency of waste carbon to CH_4 and CO_2 carbon of 65%

3.3.4 Landfills

Landfills have been the traditional repositories for Canadian solid wastes. The large biomass quantities collected in these landfills after closure tends to anaerobically digest naturally to produce CH_4 and CO_2. Most of the produced gases escape to the atmosphere, but in some landfills they are collected and harnessed to produce power.

3.3.4.1 Near-Term RNG Potential from Landfill Gas

Table 7 shows the data for the estimated methane generation from Ontario landfills through AD, and represents the near-term potential for RNG production. The data also shows the amounts of methane captured and by difference from the generated values, the amount emitted to the atmosphere. Emitted methane gas is considered a greenhouse gas with potential activity equivalent to 21 times that of CO_2. Table 7 shows the amounts of greenhouse gas emitted (as CO_2 eq.) due to the release of methane from landfills. The total potential RNG generation from Ontario landfills is estimated at 684 M

m^3/yr with only 27% captured as of 2005 survey (Environment Canada). The potential exists to increase the capture of the generated methane due to the availability of established technology for landfill gas capture, cleaning and separation into CH_4 and CO_2.

Table 7. Potential RNG Generation and Capture from Ontario Landfills (2005)

	Near-Term Methane Generation[1]	GHG Generation[2]	LFG projects[3]	Methane Captured[3]	Methane Emitted[4]	GHG Emitted[2]
	(M m3/yr)	(kt CO_2 eq/yr)	Number	(M m3/yr)	(M m3/yr)	(kt CO_2 eq/yr)
Enbridge	395	5636	-	-	-	-
Union Gas	289	4129	-	-	-	-
Ontario	684	9,765	19	185	499	7,121

1 Thompson et al (2006)
2 Calculated as methane generation x 21
3 Environment Canada (2007b)
4 Calculated as the difference between the methane generated and captured

Ontario Ministry of the Environment Regulation 217/08 (amending O.Reg. 347/90) requires mandatory landfill gas collection and use or flaring (thermal destruction) for all operating or proposed new or expanding landfills with total waste disposal capacities larger than 1.5 million cubic metres. According to the Ontario MOE website, there are over 2300 MSW landfills in the province. Of these, 2283 are classed as small landfills (958 currently open; 1325 closed) and the remaining 32 are classed as large landfills with disposal capacities greater than 1.5 million cubic meters.

Of the 32 large landfills, 30 have reported Total Weight Received data for their facilities for 2009, as posted on the Ontario MOE website (Table 8), and this data was used to calculate the potential methane generation. Table 8 shows that these 30 large landfills are estimated to produce approximately 76 M m^3/yr of methane, which represents 11% of the total methane generation from all Ontario landfills (Table 8).

Methane generation data was reported in Table 7 for both Enbridge and Union Gas separately. These calculations were based on summed estimates from large landfills (Enbridge 31% of LFG volume; Union Gas 69% of LFG volume) and small landfills (using population ratios: Enbridge 61% of the remaining LFG volume; Union Gas 39% of remaining LFG volume). It should be noted that the large landfills are required to have LFG capture systems in place, however according to communication with the MOE, at least 10 are still in process of compliance. As a result, Table 7 has omitted specific data for Enbridge and Union Gas franchise areas for methane capture and emissions. These calculations are presented however in the Ontario total in Table 7.

Table 8. Potential RNG (2009) from Large Ontario MSW Landfills[1]

Landfill Site Name	Landfill Volume		Methane Generation[2]	Franchise Area
	Total Approved Capacity	Total Weight Received		
	(M m^3)	(kt/yr)	(M m^3/yr)	
Bensforth Rd. – Peterborough	4.5	69.3	1.04	Enbridge
City of Thunder Bay Solid Waste and Recycling Facility	8.7	141	2.11	Union Gas
Cornwall Landfill – Cornwall	3.3	62.4	0.94	Union Gas
Deloro Landfill	5.8	60.0	0.90	Union Gas
EWSWA Regional Landfill – Essex Windsor	12.8	159	2.40	Union Gas
Glanbrook – Hamilton	13.2	144	2.16	Union Gas
Green Lane – St. Thomas	16.7	320	4.81	Union Gas
Halton Regional Landfill – Milton	No information supplied		-	Union Gas
Humberstone – Niagara Region	No information supplied		-	Enbridge
Lafleche Stormont	7.4	269	4.04	Enbridge
Lindsay Ops – Kawartha Lakes	2.3	31.3	0.47	Enbridge
Line 5 Landfill – Sault Ste. Marie	2.3	59.4	0.90	Union Gas
Merrick Landfill – North Bay	2.8	49.3	0.74	Union Gas
Mohawk St. – Brantford	13.4	84.8	1.28	Union Gas
Newalta Stoney Creek Landfill	6.3	477	7.18	Union Gas
Niagara Regional Road 12	1.7	18.7	0.28	Enbridge
Petrolia – Lambton	4.7	364	5.49	Union Gas
Richmond – Napanee	2.8	10.0	0.15	Union Gas
Ridge Landfill – Blenheim	36.8	676	10.18	Union Gas
Salford – Oxford County	5.9	70.9	1.07	Union Gas
Sandy Hollow – Barrie	3.9	44.7	0.68	Enbridge
Springhill – Ottawa	1.2	101.9	1.53	Enbridge
Stratford – Stratford	5.3	25.7	0.38	Union Gas
Sudbury Regional Landfill	7.6	69.2	1.04	Union Gas
Tom Howe – Haldimand	1.9	49.9	0.75	Union Gas
Trail Road – Ottawa	17.0	258	3.93	Enbridge

W12A – London	13.8	274	4.12	Union Gas
Walker Bros – Niagara Falls	31.0	618.0	9.29	Enbridge
Warwick – Lambton	26.5	154	2.32	Union Gas
Waterloo Landfill	14.7	215	3.23	Union Gas
West Carlton – Ottawa Carp Rd.	8.7	72.5	1.09	Enbridge
WSI – Ottawa – Navan Rd.	7.6	121.1	1.82	Enbridge
Total	291	5072	76.3 [Enbridge: 24.1 Union Gas: 52.2	

[1]Ontario Ministry of the Environment website
http://www.ene.gov.on.ca/environment/en/monitoring_and_reporting/limo/index.htm
Landfill Inventory Management Ontario
[2] MSW organic fraction is assumed to generate methane through AD and is calculated similar to the MSW section discussed previously.

3.3.5 Total Municipal Wastes

A summary of the contributions of each municipal waste to the total municipal potential RNG production is presented in Table 9. The data shows that the largest sources of potential RNG are from solid wastes (MSW) and Landfills. In Ontario, MSW contributes 784 M m^3/yr of RNG while Landfills contribute 684 M m^3/yr with approximately 68 M m^3/yr each from wastewaters and Biosolids. This is understandable considering the much larger solid production of wastes from the primary two sources. Total potential RNG production in Ontario from municipal waste is 1604 M m^3/yr.

3.3.5.1 Near-Term RNG Potential from Municipal Wastes

Approximately 50% of the total potential RNG produced from the four municipal waste sources can be realized in the near-term with AD processes. Of the 797 M m^3/yr which could potentially be produced in the near-term, over 85% of it would be accessed from landfill gas. The remaining 15% would be split between wastewater and municipal solid waste.

3.3.5.2 Long-Term RNG Potential from Municipal Wastes

The remaining 50% of the total potential RNG produced from the four municipal waste sources could be realized over the long-term with gasification process. Of the additional 807 M m^3/yr which could potentially be produced in the long-term, over 90%

of it would be accessed from gasification of municipal solid waste. The remaining 10% would be available from Biosolids processing.

Table 9. Annual Potential RNG Production from Ontario Municipal Wastes

	LFG	MSW			Wastewater	Biosolids	Total Methane Production
	Near-Term (AD)	Near-Term (AD)	Long-Term (Gasification)	Total	Near-Term (AD)	Long-Term (Gasification)	
	(M m³/yr)						
Enbridge	395	18.2	297	315	41.5	41.8	793
Union Gas	289	27.2	441	469	26.6	26.9	812
ON	684	45.4	738	784	68.1	68.7	1604

4. SUMMARY OF TECHNICAL FEASIBILITY AND METHANE PRODUCTION FROM ONTARIO WASTES

Production of RNG from Ontario wastes was shown to arise from the application of two well used and understood processes: Anaerobic digestion (AD) and gasification.

AD is a naturally occurring process that has been used industrially to produce biogas from agricultural, municipal and industrial processes such as food processing. Production of RNG adds the processes of biogas cleaning and gas separation to the AD process, and with current technologies this is available in the near-term.

Gasification is an old industrial process that has been used mainly to process coals into gaseous products and to further use these gases to produce energy. Gasification of coal into RNG has been demonstrated in the US and Europe. The application of the technology has until recently been limited by the low NG prices. Gasification of wastes is an established process where the produced syngas is used to produce energy. Examples of using this technology for various wastes are found mostly in Europe and to a lesser degree in North America. Syngas is made up of hydrogen, carbon monoxide and smaller amounts of methane.

Production of RNG through gasification does require the cleaning of the syngas, methanation and further separation into methane and carbon dioxide. Methanation has been industrially applied in Europe for coal but much less for waste gasification. The processes of gas cleaning and separation are common to both AD and gasification. Gas cleaning is dependent on the nature of the contaminants to be removed and thus, the source of the biogas/syngas. Most contaminants can be removed by existing processes that have been applied industrially; the challenge is to integrate these technologies into the RNG production chain. Similarly, gas separation has been practiced for many industrial processes and the challenge is to adapt the existing technologies into the RNG production process. Due to the process development time frame, this would be considered a long-term potential.

Based on our findings, it is envisioned that the AD process will be the main source of RNG in the next 5 to 10 years with gasification contributing afterwards. This is based on the availability of the technologies, prior use and acceptance by industry, and the need for further technology development activities.

A summary of all potential RNG that can be produced from Ontario wastes is presented in Table 10 and Figure 5. The data shows that a potential total of 4435 M m^3/yr of RNG can be produced from Ontario wastes. Agricultural wastes have the potential to produce 2643 M m^3/yr (60% of total), followed by 1604 M m^3/yr from municipal wastes (36% of total) and 188 M m^3/yr from forestry wastes (4% of total).

Table 10. Annual Potential RNG Production from Ontario Wastes

	Agriculture Wastes				Forestry Residues	Municipal Wastes					Total Methane Production
	Manure		Crops			MSW		Landfill	WW	Biosolids	
	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Near-Term (AD)	Long-Term (Gas)	
	(M m^3/yr)										
Enbridge	41.2	64	69.1	322	4.85	18.2	297	395	41.5	41.8	1294
Union Gas	156	241	309	1440	184	27.2	441	289	26.6	26.9	3141
Ontario	197	306	378	1762	188	45.4	738	684	68.1	68.7	4435

Note: AD = anaerobic digestion process; Gas = gasification process

4.1 NEAR-TERM RNG POTENTIAL FROM ONTARIO WASTES

In the near-term AD has the potential to produce 1372 M m^3/yr (31% of total) from all of the various Ontario waste sources reviewed. Of this amount, almost 60% of it will come from municipal wastes, with the remaining 40% from agricultural sources.

4.2 LONG-TERM RNG POTENTIAL FROM ONTARIO WASTES

Over the long-term the use of gasification has the potential to produce most of the RNG in Ontario, as shown in Figure 6, with an additional 3063 M m^3/yr (69% of total) produced by this process. Of this amount 68% of the potential RNG can be produced from Agricultural wastes, with 26% coming from Municipal waste sources and the remaining 6% coming from forestry residues.

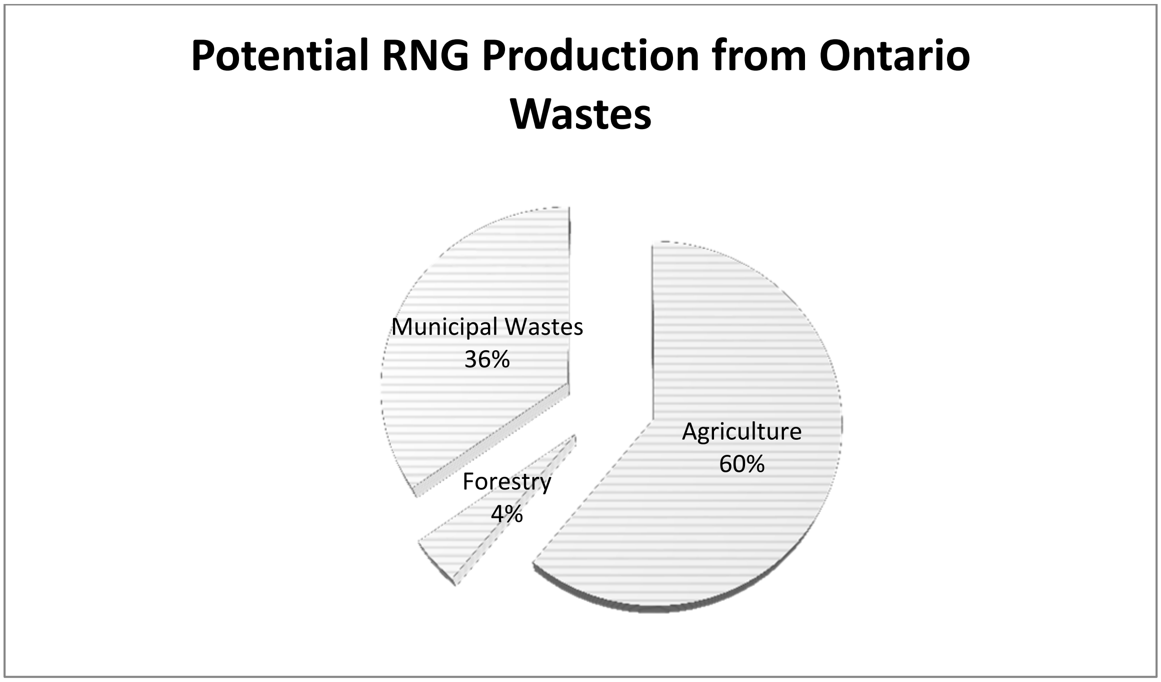


Figure 5. Potential RNG Production from Ontario Wastes.

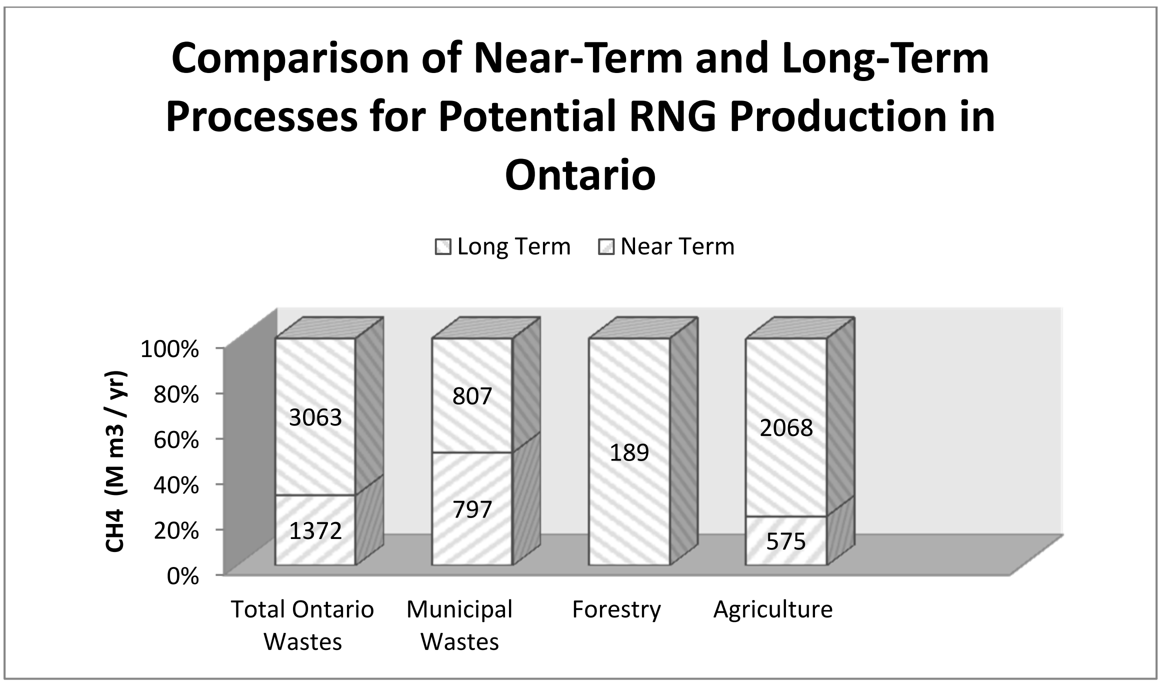


Figure 6. Comparison of Near-Term and Long-Term Processes for Potential RNG Production in Ontario.

We compared the relative size of our potential RNG estimates to the current NG use for the residential and commercial sectors and the results are presented in Figure 7 and Table 16 (Appendix 1). The potential Ontario generation of 1372 M m^3/yr of RNG in the near-term corresponds to an energy value of 52 PJ/yr or 14,444 GWh of electricity (Table 16). RNG production can account for a portion of the approximately 24,000 M m^3/yr of NG consumption in the near-term, (2010 distribution volume provided by Enbridge: 10,940 M m^3; Union Gas 13,300 M m^3) with up to 6% of the residential, commercial and industrial use potentially produced from Ontario wastes if all of the methane was able to be captured. Over the long-term with gasification process capabilities becoming available, there would be an additional 3063 M m^3/yr of RNG (115 PJ/yr of energy, or 31,944 GWh of electricity). Potentially over the long-term and if all methane were captured, this would correspond up to an additional 12% of the current NG consumption in Ontario, bringing the total over the long-term up to 18% of NG consumption.

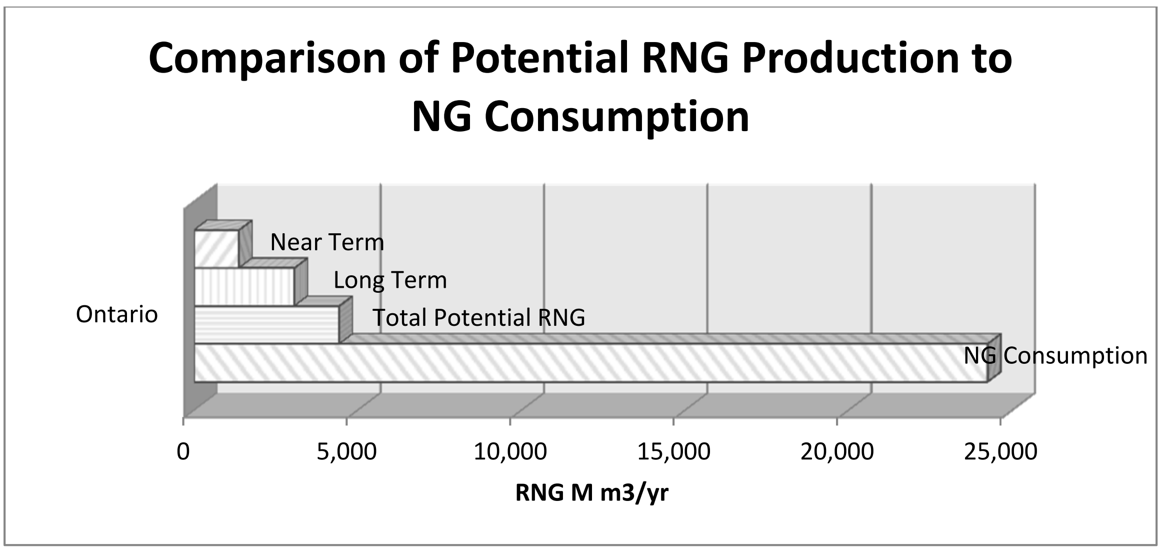


Figure 7. Comparison of Potential RNG Production to NG Consumption

5. GREENHOUSE GAS IMPACT OF METHANE CAPTURE FROM ONTARIO WASTES

The production and capture of RNG from Ontario wastes contributes to GHG reduction through two processes: emission reduction and fuel substitution. Emission reduction can be achieved through the capture of the emitted methane from landfills and the anaerobic digestion of animal manures, in particular hog manures. Figure 8 and Table 17 (Appendix 1) shows the results of our estimates where we assigned a value of 21 times CO_2 for the methane emission reductions. These estimates are based on best case scenario of all landfill gas and 20% of animal manures captured with methane no longer emitted into the atmosphere. Although we are using all landfill emissions to calculate GHG emission avoidance, we recognize that under Ontario regulations, some large landfills will not be permitted to claim carbon credits for the emission avoidance scenario. The manures that are likely to emit methane during storage are those associated with dairy cows and hogs, as these manures are often liquid and thus, stored under anaerobic conditions. Other manures that are stored dry and manures that are applied to land are unlikely to emit significant amounts of methane as these conditions tend to be predominantly aerobic. As shown in Table 7 earlier, only 27% of the methane from the largest landfills is currently captured. However, under government regulations the capture rate at these large landfills will be increasing over the next couple of years.

Fuel substitution applies to the use of RNG to replace any NG produced from fossil fuels. Table 17 and Figure 8 shows the results of our estimates where we assigned a value of 2.87 (NG GHG intensity, t CO_2 eq/t) for fuel substitution (Abboud et al. 2010). The value of 2.87 that we used is similar to the value of 2.79 used in a recent BC report (Electrigaz Technologies, 2008).

Total GHG reductions for Ontario were estimated as 18,984 kt CO_2 eq/yr. Emission reductions contribute slightly more GHG reductions than fuel substitutions in Ontario with 54% of the GHG reductions arising from emission reductions, while the remaining 46% arise from fuel substitution.

5.1 NEAR-TERM GHG IMPACTS FROM ONTARIO WASTES

Of the total GHG reductions, approximately 69% can be realized in the near-term through AD processing of Ontario wastes. This represents 13006 kt CO_2 eq/yr, where

79% of that would be offered through emission reductions and the remaining 21% fuel substitutions.

5.2 LONG-TERM GHG IMPACTS FROM ONTARIO WASTES

Over the long-term, with the development of gasification processes for Ontario wastes, there would be an additional 5978 kt CO_2 eq/yr generated. This represents an additional 31% of the total GHG reductions. All of this amount would be offered through fuel substitutions since technology for emission reductions is available in the near-term.

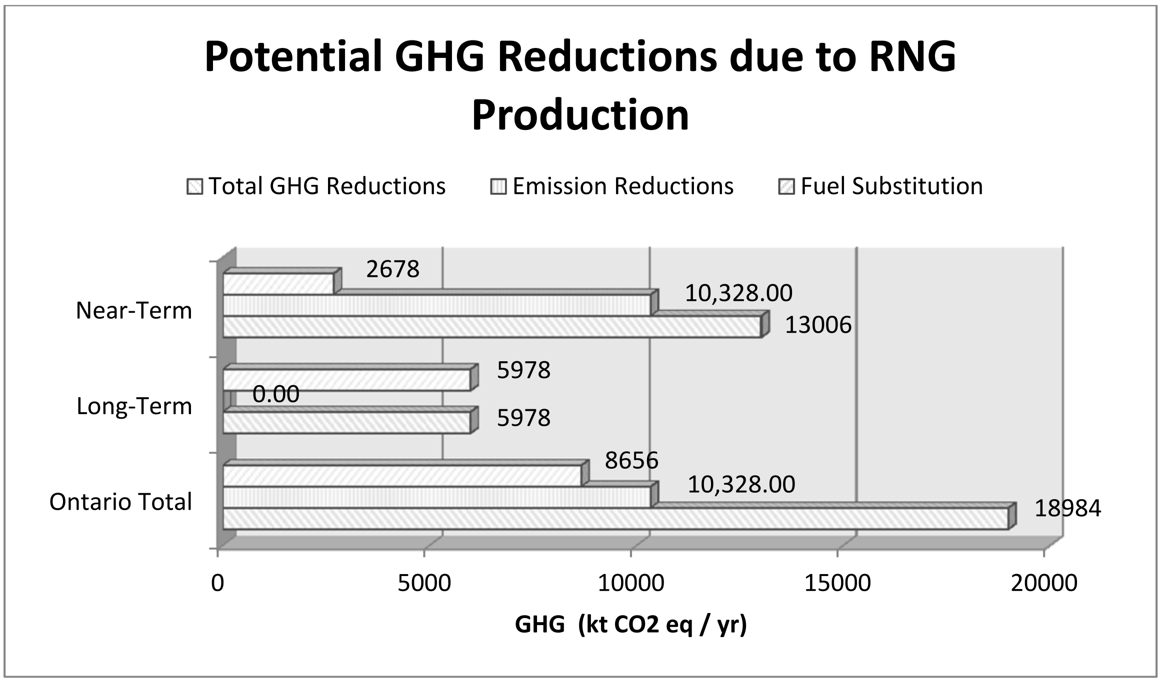


Figure 8. Potential GHG Reductions due to RNG Production

6. EFFICIENCY OF BIOGAS CLEANING COMPARED TO BIOGAS COMBUSTION

The declining reserves of fossil fuels coupled with their rising prices have spurred the development of alternative and renewable fuels and reemphasized the importance of energy efficiency in each energy conversion process. Currently, most biogas generated through AD is used for electricity generation with energy capture efficiencies that vary from 23% to 39% (Electrigaz, 2007) with an average around 35%. The development of more advanced and improved biogas cleaning and separation technologies allows for the production of pipeline grade RNG from biogas with efficiencies varying from 95 to 90% dependent on the raw biogas properties, volume and the type of employed cleaning and separation technologies.

Figure 9 illustrates the wide difference in energy content retention when one uses biogas for generating electricity (35-40% efficiency) versus manufacturing RNG (80-90% efficiency). It is evident that making RNG from existing biogas is a much preferable route energetically as it retains the most energy.

In addition to improving the electric generator output by at least 100% if the raw biogas was used instead to produce RNG, there is another beneficial consideration to be gained by producing RNG for the NG pipeline. This additional volume from energy efficiency represents fuel substitution of fossil fuel that would otherwise have to be provided in order to replace the inefficiency of electricity generation. As a result there are additional GHG emissions produced in electricity generation, which otherwise would be a GHG reduction in the NG pipeline as the RNG is a direct fuel substitution. It is evident that RNG from existing biogas is the preferable route energetically as well as providing the benefit of GHG reductions.

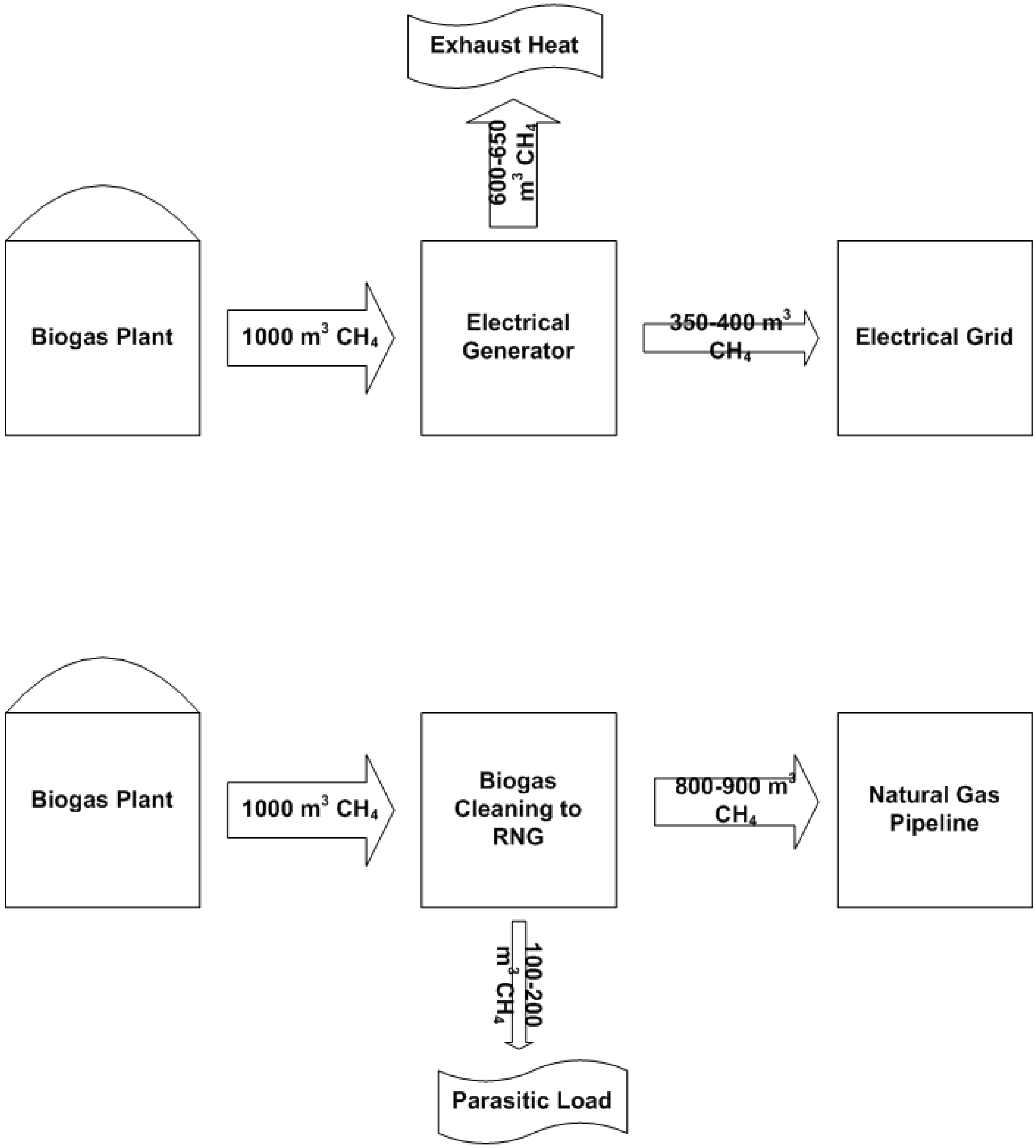


Figure 9. Comparison of Biogas Energy Retained when used for Electricity Generation or RNG.

7. CONCLUSIONS

Production of RNG from Ontario wastes was shown to arise from the application of two well used and understood processes: anaerobic digestion and gasification. Based on our findings, it is envisioned that anaerobic digestion process will be the main source of RNG in the next 5 to 10 years with gasification contributing afterwards. This is based on the availability of the technologies, prior use and acceptance by industry and the need for further technology development activities.

The Ontario wastes which are amenable to producing RNG are those containing significant amounts of biomass and are mostly generated by the agricultural, forestry and municipal sectors.

All of the potential RNG that can be produced from the total Ontario wastes that had been reviewed shows that a potential total of 4435 M m^3/yr of RNG can be produced. Agricultural waste has demonstrated the potential to produce 2643 M m^3/yr (60% of total), followed by 1604 M m^3/yr (36%) from municipal wastes and 188 M m^3/yr (4%) from forestry residues. Anaerobic digestion has the potential to produce 1372 M m^3/yr (31% of total) and represents the near-term potential of RNG production in Ontario. The use of gasification has the potential to produce most of the RNG as we estimated that an additional 3063 M m^3/yr (69% of total) can be produced by this process, however this potential would be realized over the long-term through further technology development.

We compared the relative size of our potential RNG estimates to the current natural gas use for the residential, commercial and industrial sectors. The potential Ontario generation of 4435 M m^3/yr of RNG corresponds to an energy value of 167 PJ/yr or 46,388 GWh of electricity. RNG production can account for a portion of the natural gas use. Within Ontario, our estimate is that if all methane from various wastes were captured, then 18% of current NG residential, commercial and industrial use can be replaced by the produced RNG over the long-term. However, in the near-term the potential Ontario generation of 1372 M m^3/yr of RNG corresponds to an energy value of 52 PJ/yr or 14,444 GWh of electricity and can account for about 6% of the residential, commercial and industrial use of NG. With gasification process capabilities becoming available over the long-term, there would be an additional 3063 M m^3/yr of RNG (115 PJ/yr of energy, or 31,944 GWh of electricity) corresponding to an additional 12% of the current NG consumption in Ontario.

The production and capture of RNG from Ontario wastes contributes to GHG reduction through two processes: emission reduction and fuel substitution. Emission reduction can be achieved through the capture of the emitted methane from landfills and the anaerobic digestion of animal manures. Fuel substitution applies to the use of RNG to replace any natural gas produced from fossil fuels.

Total GHG reductions were estimated as 18984 kt CO_2 eq/yr for Ontario with emission reductions contributing more of the GHG reductions than fuel substitution. About 54% of the Ontario GHG reductions arise from emission reductions, while the rest (46%) arises from fuel substitution.

Results were broken out separately for Union Gas and Enbridge service areas showing that of the 4435 M m^3 RNG potentially produced in Ontario annually, the market potential for Union Gas is 71% of the total (3141 M m^3). The market potential for Enbridge is 29% (1294 M m^3).

In reviewing the Union Gas service area, agricultural wastes (68%) are the largest waste source for potential RNG production, followed by municipal wastes (26%) and then forestry residues (6%). The majority of the RNG volume produced, at 74% would occur through gasification, with anaerobic digestion producing the remaining 26%. Therefore, in the near-term AD processing within the Union Gas area account for 807 M m^3/yr of its total RNG. Of this amount 58% comes from agricultural wastes, and the remaining 42% is generated from the AD processing of municipal waste. Over the long-term, an additional 2332 M m^3/yr (74%) could be generated in this franchise area through the development of gasification process for these waste materials and 72% (1681 M m^3) of this additional RNG could be generated from processing of agricultural wastes, with 20% (468 M m^3) coming from municipal waste materials, and the remaining 8% (184 M m^3) from forestry residues. The Enbridge service area shows that municipal wastes (61%) are the largest waste source for potential RNG production, with the remaining RNG produced from agricultural wastes (38%). There are negligible forestry residues producing RNG in this service area. Although gasification still produces the majority of the RNG at 56%, the anaerobic digestion process is more significant in this service area, due in part to more landfill gas production as well as no forestry residues available for gasification. Therefore in the near-term, AD processing within the Enbridge area accounts for 565 M m^3/yr (44%) of its total RNG and of this amount 80% comes from municipal wastes, and the remaining 20% is generated from the AD processing of agricultural waste. Over the long-term, an additional 729 M m^3/yr (56%) could be generated in this franchise area through the development of gasification process for these waste materials. Of this amount, 53% (387 M m^3) could be generated from processing of agricultural wastes, with 46% (338 M m^3) coming from municipal waste materials. Of the total GHG reductions for Ontario, 18,984 kt CO_2 eq/year, Union Gas service area accounts for 56% of this with 10,704 kt CO_2 eq. The Enbridge service area accounts for 44% of the total Ontario GHG reductions with 8280 kt CO_2 eq.

Within each service area, total GHG reductions were assessed by their constituent values for emission reduction and fuel substitution. Emission reduction values represent the potential methane capture from anaerobic digestion within landfills and from a portion of animal manure, where fuel substitution relates more broadly to the potential of displacing fossil-fuel based NG with RNG produced from all wastes.

It has been shown that Enbridge has proportionately higher emissions reduction potential when compared to fuel substitution. This is a function of population size with associated municipal waste volumes, in addition to factoring in no forestry residues subject to gasification. In the near-term, Enbridge can realize GHG reductions of 6856 kt CO_2 eq/yr, representing 83% of its total potential GHG reductions. Over the long-term, an additional 1424 kt CO_2/yr (17%) of its total potential can be realized with further development of gasification processing.

Union Gas alternatively demonstrates higher fuel substitution potential when compared to emissions reduction. In the near-term, Union Gas can realize GHG reductions of 6149 kt CO_2 eq/yr, representing 57% of its total potential GHG reductions. Over the long-term, an additional 4552 kt CO_2/yr (43%) of its total potential can be realized with further development of gasification processing.

A comparison was made where biogas can be directed into electricity generation, or production of RNG for injection into a natural gas pipeline. There is a wide difference in energy content retention with generating electricity (35-40% efficiency) compared to RNG production (80-90% efficiency). It is evident that making RNG from existing biogas is a much preferable route energetically as it retains the most energy. If the raw biogas is used for RNG cleaning, in addition to improving the electric generator output by at least 100% (800 m^3 methane eq. vs 400 m^3 methane eq.) there is another beneficial consideration to be gained by producing RNG for the NG pipeline. This additional volume from energy efficiency represents fuel substitution of fossil fuel that would otherwise have to be provided in order to replace the inefficiency of electricity generation. As a result there are additional GHG emissions produced in electricity generation, which otherwise would be a GHG reduction in the NG pipeline as the RNG is a direct fuel substitution. It is evident that RNG from existing biogas is the preferable route energetically as well as providing the benefit of GHG reductions.

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APPENDIX 1

Additional Tables

Table 11. Ontario 2009 Crop Production and Estimates of Crop Residues

Crop	Crop Production[1]	Recoverable Residue[2]	Removable Residue[3]
	(kt)	(kt)	(kt)
Soy Bean	2474	3711	1856
Grain Corn	5330	5330	2665
Winter Wheat	1466	249	1246
Barley	285	428	214
Mixed Grains	166	266	133
Spring Wheat	147	192	95.9
Oats	85.1	179	89.5
Total	**9953**	**12598**	**6299**

1 OMAFRA . 2009a. Field crop reporting series.
2 Calculated as Production x multiplier factor (soy bean 1.5; Grain Corn 1.0; Winter wheat 1.7; Barley 1.5; Mixed Grain 1.6; Spring wheat 1.3; Oats 2.1). (Perlack et al, 2005)
3 Calculated as 0.5 x recoverable residue

Table 12. Ontario Production of Cattle and Hog Manures.

	Cattle			Hogs		
	Number[1]	Manure Production		Number[2]	Manure Production	
	(x1000head)	(kg dry/head/d)[6]	(dry Mt/yr)[7]	(x1000)	(kg dry/head/d)[6]	(dry Mt/yr)[7]
Ontario	1827	4.64	0.774	3237	0.564	0.566

1 OMAFRA (2009b). Cattle Statistics.
2 OMAFRA (2009c). Hog Statistics.
3 OMAFRA (2009d). Sheep Statistics.
4 OMAFRA (2009e). Poultry Statistics.
6 Klass (1998)
7 Calculated as number (h) x manure production (kg dry/h/d) x 365 (d/yr) x (kg recovered/kg) x 10^{-6} (Mt/kg). Recovered manure was assumed as: Cattle (25%), Hogs (85%), Sheep (10%) and Chicken (85%) (Ralevic and Layzell, 2006)

Table 13. Ontario Production of Sheep and Chicken Manures.

	Sheep			Chicken		
	Number[3]	Manure Production		Number[4]	Manure Production	
	(x1000head)	(kg dry/head/d)[6]	(dry Mt/yr)[7]	(x1000)	(kg dry/head/d)[6]	(dry Mt/yr)[7]
Ontario	315	0.756	0.0087	45949	0.0252	0.3592

Table 14. Canadian Production of Turkey Manure.

	Turkey		
	Number[5]	Manure Production	
	(x1000head)	(kg dry/head/d)[6]	(dry Mt/yr)[7]
Ontario	3324.9	0.0101	0.0104

5 OMAFRA (2009e). Poultry Statistics.
6 Klass (1998)
7 Calculated as number (heads) x manure production (kg dry/head/d) x 365 (d/yr) x (kg recovered/kg) x 10^{-6} (Mt/kg). Turkey manure that can be recovered was assumed to be 85% (Ralevic and Layzell, 2006)

Table 15. Annual Ontario Municipal Solid Waste (MSW) Production (2005)

	Waste Disposal[1]				MSW Organic Fraction Subject to	
	Residential	Industrial, Commercial & Institutional	Construction & Demolition	Total	AD[2]	Gasification[3]
	(kt/yr)				(dry kt/yr)	(dry t C/yr)
Enbridge	1213.6	1682.3	720.9	3617.2	106.2	465.2
Union Gas	1808.4	2506.7	1074.1	5389	157.8	692.8
Ontario	3022	4189	1795	9007	264	1158

1 **Statistics Canada. 2006**. This is the difference between waste generated and diverted.
2 Calculated as Column 2 (t/yr) x 0.35 (t solids/t) x 0.25 (t OFMSW subject to AD/t solids). **(Ostrem, 2004)**.
(25% of the Residential waste is amenable to Anaerobic Digestion and the wastes contains 35% solids)
3 Calculated as the MSW biomass fraction that was not converted to biogas plus 50% of the ICI waste
(50% solids) and 30% of the CD waste (90% solids). Assumed the waste biomass contains 40% carbon.

Table 16. Potential RNG as a Function of Energy Production and Current Natural Gas Consumption

	Total Potential Methane Generation	Energy	Electricity	NG Consumption[1]	Total Potential Methane Generation
	(M m^3/yr)	(PJ/yr)	(GWh)	(M m3/yr)	(% of NG)
Near-Term	1372	52	14,444	24,250	5.6
Long-Term	3063	115	31,944	24,250	12.6
Total	4435	167	46,388	24,250	18.2

[1] 2010 distribution volume provided by Enbridge: 10,940 M m3; Union Gas 13,300 M m3

Table 17. GHG Reductions Due to Production of Renewable Natural Gas							
	Methane		GHG				
	Emission Reduction[1]	Fuel Substitution[2]	Emission Reduction[3]	Fuel Substitution[4]	Total[5]	Emission Reduction[6]	Fuel Substitution[6]
	(M m^3/yr)		(kt CO_2 eq/yr)			(%)	
Enbridge	403	1294	5754	2525.6	8279.6	69	31
Union Gas	320	3141	4573.8	6130.3	10704.1	43	57
Ontario Total	723	4435	10327.8	8655.9	18983.7	54	46
Near-Term	723	1372	10327.8	2677.7	13005.5	79	21
Long-Term	-	3063	-	5978.2	5978.2	0	100

1 Calculated as the CH_4 generated in landfills plus 20% of the CH_4 generated from manure through AD
2 This is the total amount of potential CH_4 generated from all wastes
3 Calculated as column 2 x 21 (GWP)
4 Calculated as column 3 (Mt CH_4/yr) x 2.87 (Mt CO_2 eq/Mt CH_4)
5 Calculated as the sum of columns 4 and 5
6 Calculated as a percent of the total GHG (column 6)

APPENDIX 2

MARKET POTENTIAL FOR SEPARATE FRANCHISE AREAS

MARKET POTENTIAL FOR SEPARATE FRANCHISE AREAS

Enbridge and Union Gas were evaluated separately for market potential based on the following approach. Population data was reviewed on a county basis and allocated to either franchise based upon their service area. The ratio of Ontario population per franchise area was used for RNG calculations for all municipal wastes since that waste stream is directly proportional to the number of people residing in the area.

The other waste materials, including agricultural and forestry residues, had RNG calculations based on Ontario government data provided on a county basis, and allocated to either franchise.

In a limited number of cases, some counties were serviced by both franchises. With these counties, the proportion of population was allocated to each franchise and this ratio was used on the waste volumes for RNG calculations.

It was also determined from the franchises' service directory that two Ontario counties (Haliburton, Manitoulin) and a few other small communities were not serviced by either franchise. As a result the population data was adjusted to remove their numbers from the total census data, including 70,000 people and representing 0.5% of the Ontario population. Statistics Canada (2006) shows census data of 12.09 M Ontario residents (adjusted to remove non-serviced communities). To evaluate the RNG potential broken out by the franchise service areas, it was determined from census data that 7.36 M residents fall within the Enbridge service area, and the remaining 4.73 M residents are within the Union Gas service area. Figure 10 shows that the Enbridge service area includes 61% of the Ontario population with the remaining 39% serviced by Union Gas.

The City of Toronto is an anomaly and represents Ontario's largest city with 2.5 M residents. Previously all solid waste had been shipped by truckload out of Ontario to Michigan. As of January 1, 2011, this waste is being shipped to a Toronto-owned landfill (Greenlane – St Thomas) which resides in Union Gas franchise area. In 2009, 44% of Toronto's residential waste was diverted from landfill through the Blue Bin, Green Bin, Yard Waste and other diversion programs, with this waste remaining within the Toronto area. However for our calculations the other 56% waste volume that was not diverted has been adjusted in the population base franchise area, representing a shift equivalent to 1.4 million Toronto residents (56% of 2.5 M residents) from Enbridge (Toronto) into the Union Gas (St. Thomas) service area, as shown in Figure 11.

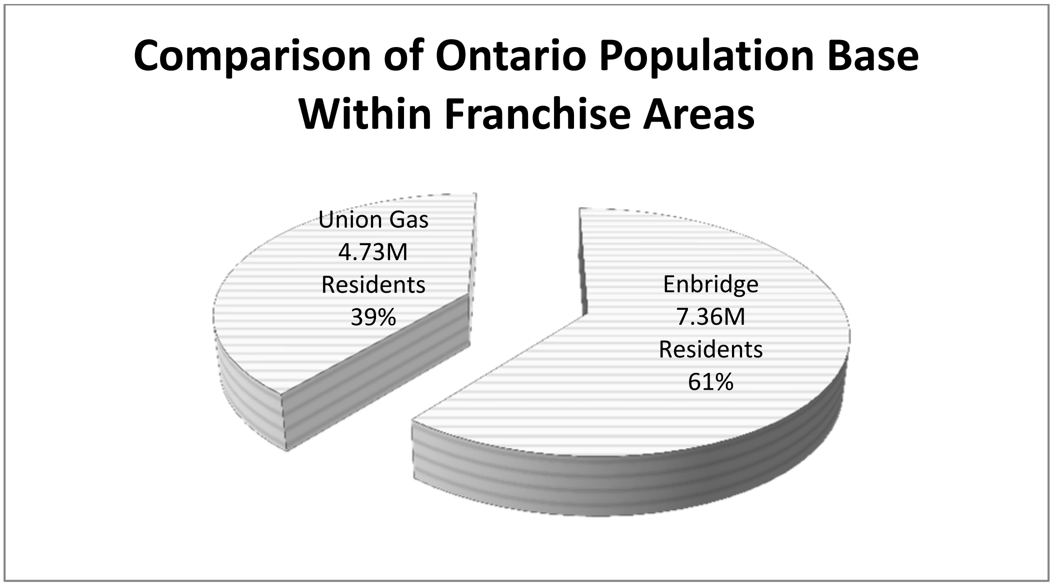

Figure 10. Comparison of Ontario Population Base within Franchise Areas.

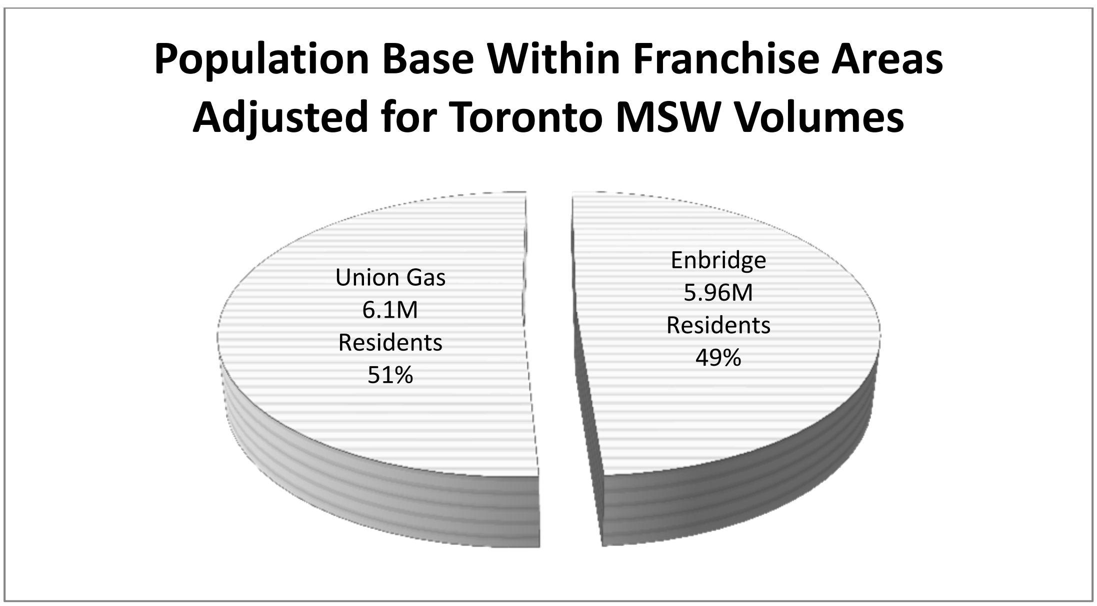

Figure 11. Population Base Within Franchise Areas Adjusted for Toronto MSW Volumes.

In order to calculate the potential RNG production in Ontario, broken out by franchise area, certain assumptions were made. It is assumed that population density is directly related to Municipal Waste volumes (MSW; LFG; Wastewater and Biosolids) and therefore Enbridge RNG will be calculated from the Ontario total RNG production by using a factor of 0.49 for MSW (adjusted population data), and 0.61 for LFG, Wastewater and Biosolids (actual population data). Union Gas RNG calculations will use a factor of 0.51 for MSW, and 0.39 for LFG, Wastewater and Biosolids.

Table 18 and Figure 12 shows that of the 4435 M m^3 RNG potentially produced in Ontario annually, the market potential for Union Gas is 71% of the total (3141 M m^3); with the remaining 29% of the market potential for Enbridge (1294 M m^3).

Table 18. Annual Potential RNG Production from Enbridge and Union Gas Franchise Areas Compared to Total Ontario Wastes

	Agriculture Wastes				Forestry Residues	Municipal Wastes					Total Methane Production
	Manure		Crops			MSW		Landfill	WW	Biosolids	
	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Near-Term (AD)	Long-Term (Gas)	
	(M m^3/yr)										
Enbridge	41.2	64	69.1	322	4.85	18.2	297	395	41.5	41.8	1294
Union Gas	156	241	309	1440	184	27.2	441	289	26.6	26.9	3141
Ontario	197	306	378	1762	188	45.6	738	684	68.1	68.7	4435

Note: AD = anaerobic digestion process; Gas = gasification process

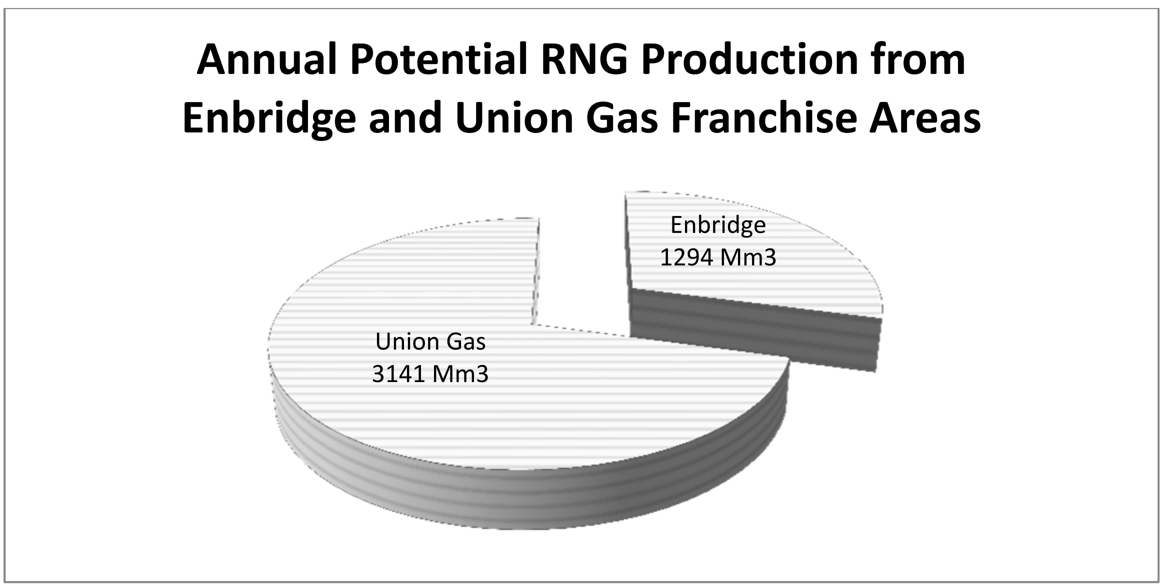

Figure 12. Annual Potential RNG Production from Enbridge and Union Gas Franchise Areas.

Results for Union Gas are broken out separately in Figures 13, 14 and 15, showing that agricultural wastes (68%) are the largest waste source for potential RNG production, followed by municipal wastes (26%) and then forestry residues (6%). The majority of the RNG produced would occur through gasification (74%), with anaerobic digestion producing the remaining 26%.

NEAR-TERM RNG POTENTIAL FOR UNION GAS

In the near-term AD processing of Ontario wastes within the Union Gas area account for 807 M m^3/yr (26%) of the total RNG within this franchise area. Of this amount 58% comes from agricultural wastes, and the remaining 42% is generated from the AD processing of municipal waste.

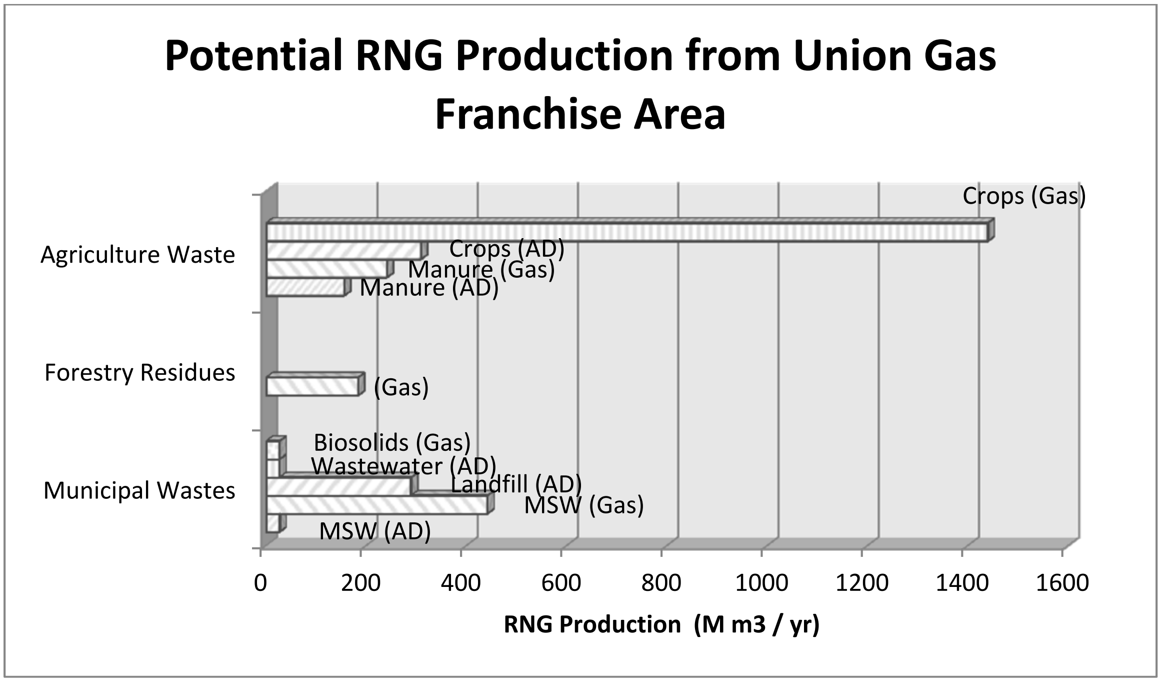

Figure 13. Potential RNG Production from Union Gas Franchise Area

LONG-TERM RNG POTENTIAL FOR UNION GAS

Over the long-term, an additional 2332 M m^3/yr (74% of total potential) could be generated in this franchise area through the development of gasification process for these waste materials. Within the Union Gas area, 72% (1681 M m^3) of this additional RNG could be generated from processing of agricultural wastes, with 20% (468 M m^3) coming from municipal waste materials, and the remaining 8% (184 M m^3) from forestry residues.

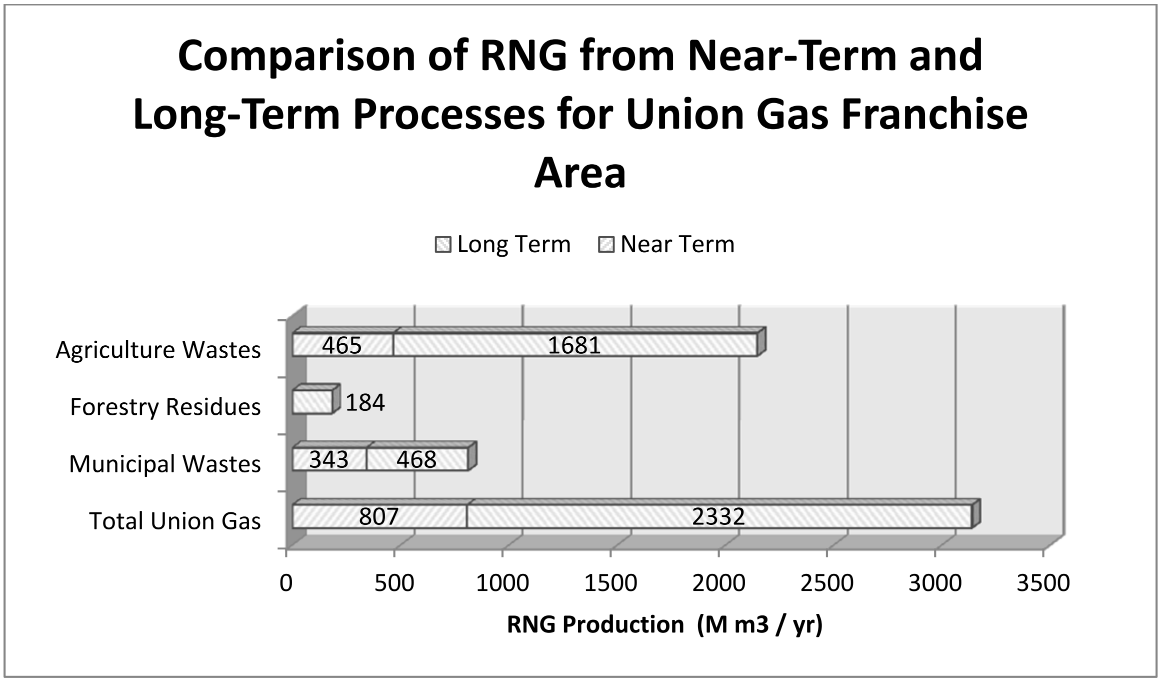

Figure 14. Comparison of RNG from Near-Term and Long-Term Processes for Union Gas Franchise Area.

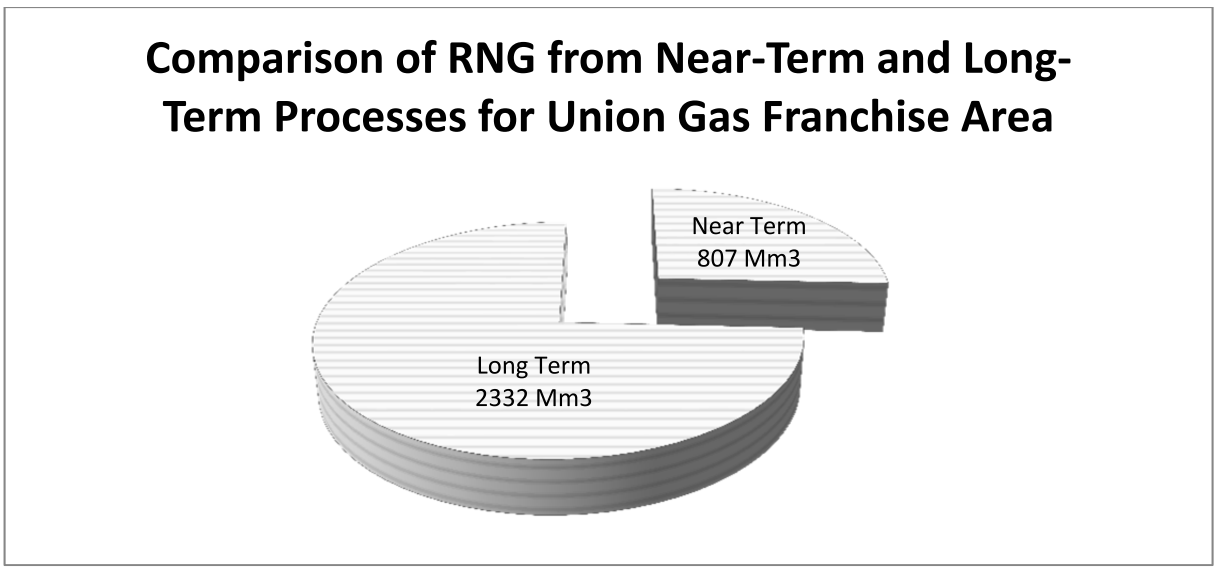

Figure 15. Comparison of RNG from Near-Term and Long-Term Processes for Union Gas Franchise Area.

Results for Enbridge are broken out separately in Figures 16, 17 and 18, showing that in this case municipal wastes (61%) are the largest waste source for potential RNG production, with the remaining RNG produced from agricultural wastes (38%) and negligible forestry residues producing RNG in this service area. Although gasification still produces the majority of the RNG (56%), the anaerobic digestion process (44%) is more significant in this service area, due in part to more landfill gas production as well as no forestry residues available for gasification.

NEAR-TERM RNG POTENTIAL FOR ENBRIDGE

In the near-term AD processing of Ontario wastes within the Enbridge area account for 565 M m^3/yr (44%) of the total RNG within this franchise area. Of this amount 80% comes from municipal wastes, and the remaining 20% is generated from the AD processing of agricultural waste.

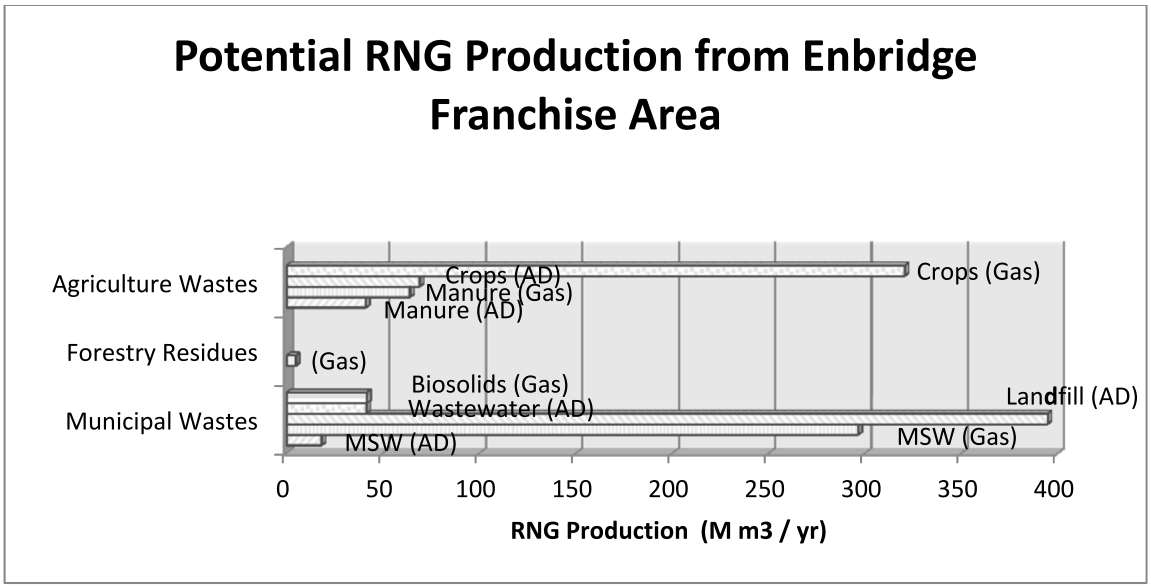

Figure 16. Potential RNG Production from Enbridge Franchise Area

LONG-TERM RNG POTENTIAL FOR ENBRIDGE

Over the long-term, an additional 729 M m^3/yr (56%) could be generated in this franchise area through the development of gasification process for these waste materials. Within the Enbridge area, 53% (387 M m^3) of this additional RNG could be generated from processing of agricultural wastes, with 46% (338 M m^3) coming from municipal waste materials.

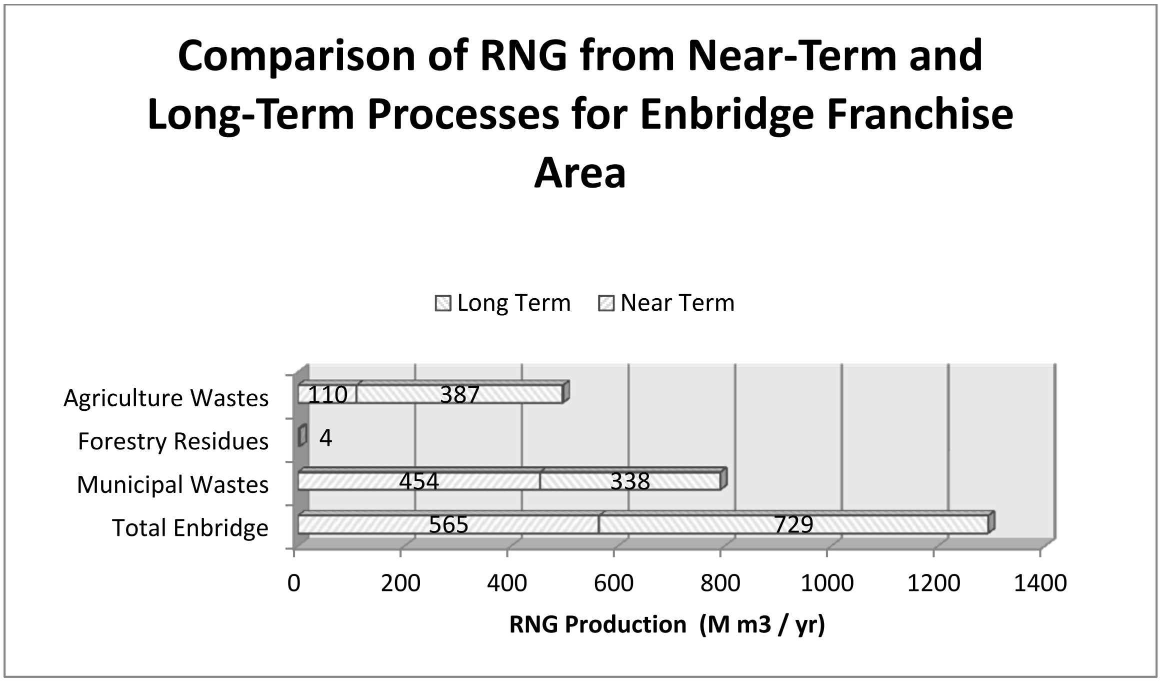

Figure 17. Comparison of RNG from Near-Term and Long-Term Processes for Enbridge Franchise Area.

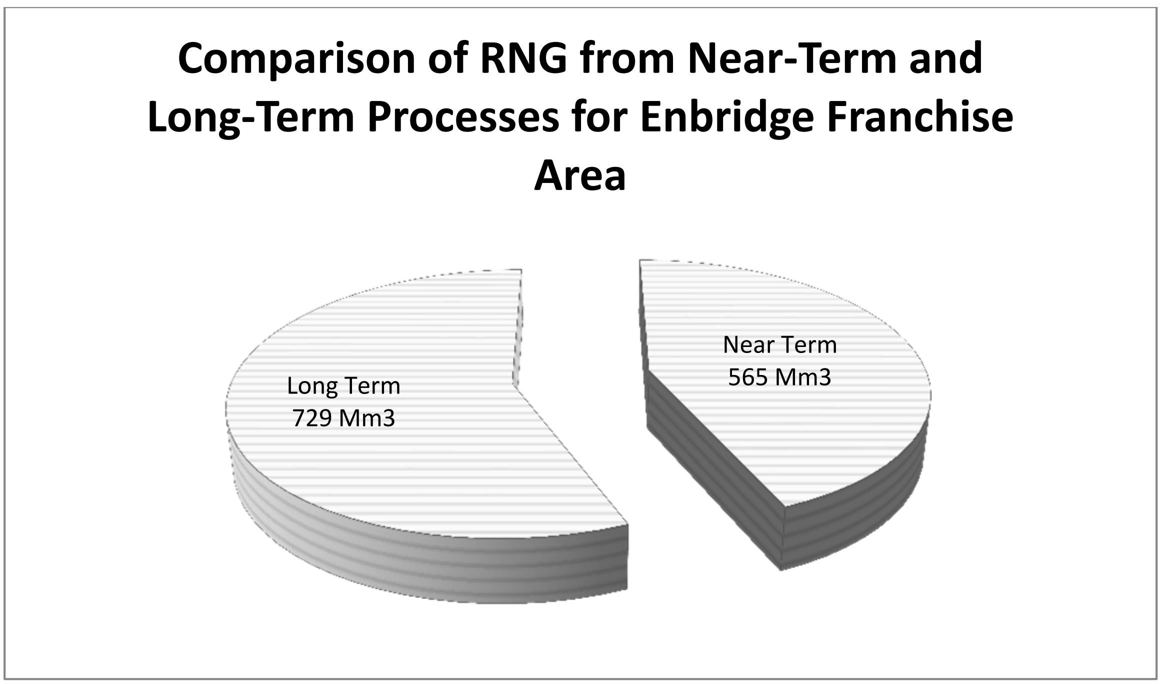

Figure 18. Comparison of RNG from Near-Term and Long-Term Processes for Enbridge Franchise Area.

Calculations for GHG reductions are provided in Table 19, Figures 19, 20 and 21 for Union Gas and Enbridge. Total GHG reductions for Ontario are 18,894 kt CO_2eq/year, with Union Gas service area accounting for 56% of this with 10,704 kt CO_2 eq./yr. Enbridge service area accounts for 44% of the total GHG reductions in Ontario with 8280 kt CO_2 eq./yr.

Table 19. GHG Reductions Due to Production of Renewable Natural Gas within the Franchise Areas

	Methane		GHG				
	Emission Reduction[1]	Fuel Substitution[2]	Emission Reduction[3]	Fuel Substitution[4]	Total[5]	Emission Reduction[6]	Fuel Substitution[6]
	(M m3/yr)		(kt CO_2 eq/yr)			(%)	
Near-Term	403	565	5754	1102.1	6856.1	84	16
Long-Term	-	729	-	1423.5	1423.5	0	100
Total Enbridge	403	1294	5754	2525.6	8279.6	69	31
Near-Term	320	807	4573.8	1575.6	6149.4	74	26
Long-Term	-	2332	-	4551.8	4551.8	0	100
Total Union Gas	320	3141	4573.8	6130.3	10704.1	43	57
Ontario	723	4435	10327.8	8655.9	18983.7	54	46

1 Calculated as the CH_4 generated in landfills plus 20% of the CH_4 generated from manure through AD
2 This is the total amount of potential CH_4 generated from all wastes
3 Calculated as column 2 x 21 (GWP)
4 Calculated as column 3 (Mt CH_4/yr) x 2.87 (Mt CO_2 eq/Mt CH_4)
5 Calculated as the sum of columns 4 and 5
6 Calculated as a percent of the total GHG (column 6)

Within each service area total GHG reductions were assessed by their constituent values for emission reduction and fuel substitution. Emission reduction values represent the potential methane capture from anaerobic digestion within landfills and from a portion of animal manure, where fuel substitution relates more broadly to the potential of displacing fossil-fuel based NG with RNG produced from all wastes.

Figures 19, 20 and 22 demonstrate that within its service area Enbridge has a proportionately higher emissions reduction potential when compared to fuel substitution. This is a function of population size with associated municipal waste volumes, in addition to factoring in limited forestry residues subject to gasification. In the near-term, Enbridge can realize GHG reductions of 6856 kt CO_2 eq/yr, representing 83% of its total potential GHG reductions. Over the long-term, an additional 1424 kt CO_2 eq/yr (17%) of its total potential can be realized with further development of gasification processing.

Figures 19, 20 and 23 demonstrate that within its service area Union Gas alternatively demonstrates higher fuel substitution potential when compared to emissions reduction. In the near-term, Union Gas can realize GHG reductions of 6149 kt CO_2 eq/yr, representing 57% of its total potential GHG reductions. Over the long-term, an additional 4552 kt CO_2/yr (43%) of its total potential can be realized with further development of gasification processing.

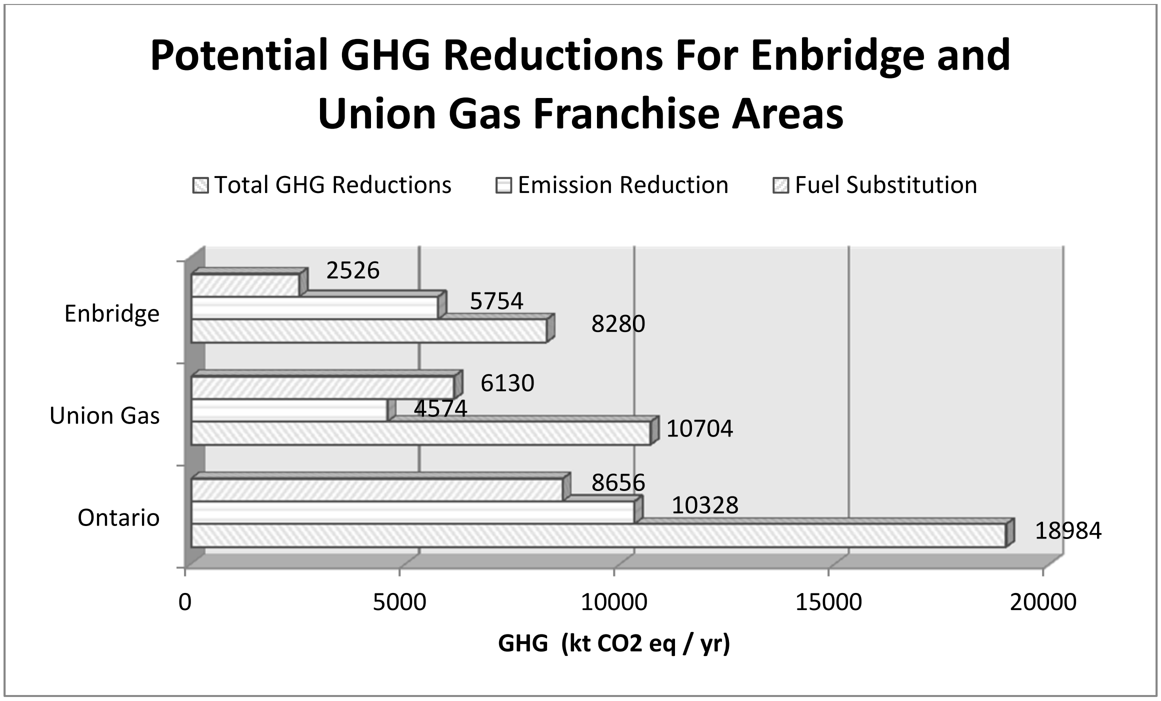

Figure 19. Potential GHG Reductions for Enbridge and Union Gas Franchise Areas

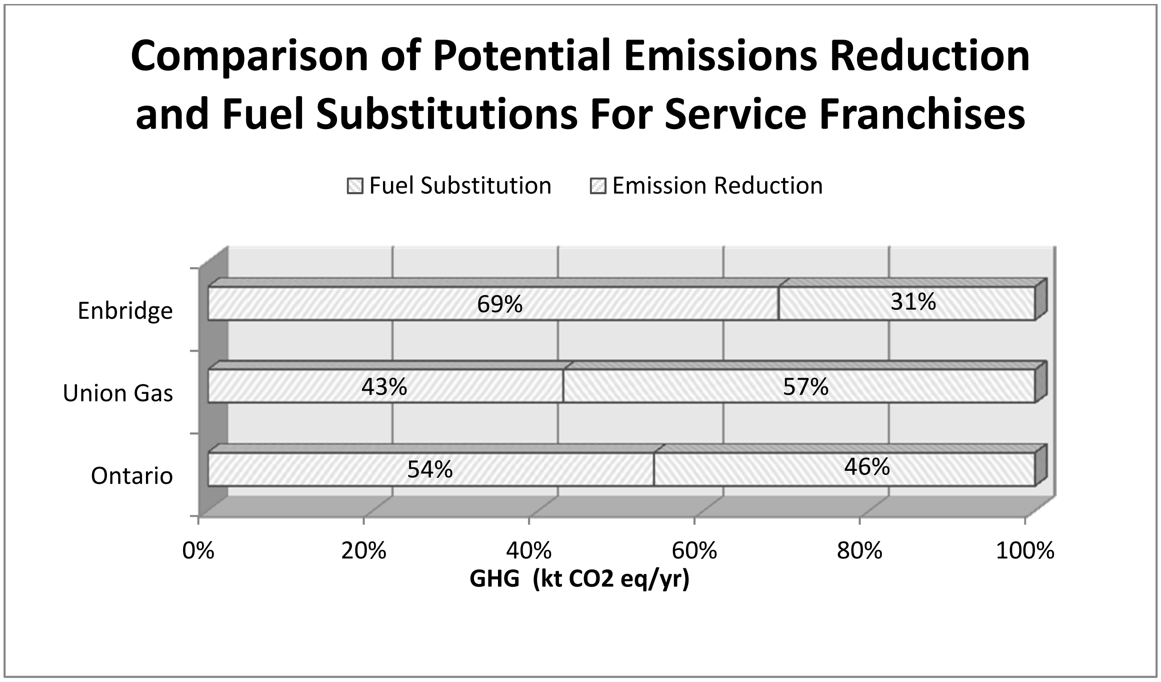

Figure 20. Comparison of Potential Emissions Reduction and Fuel Substitutions for Service Franchises.

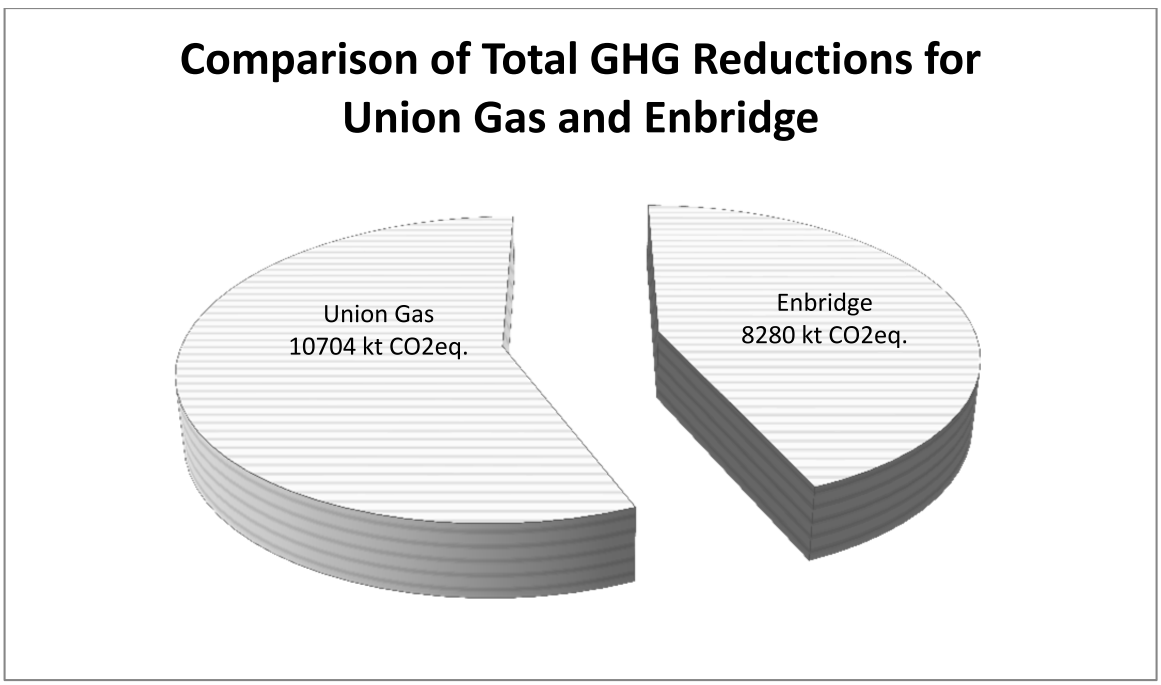

Figure 21. Comparison of Total GHG Reductions for Union Gas and Enbridge

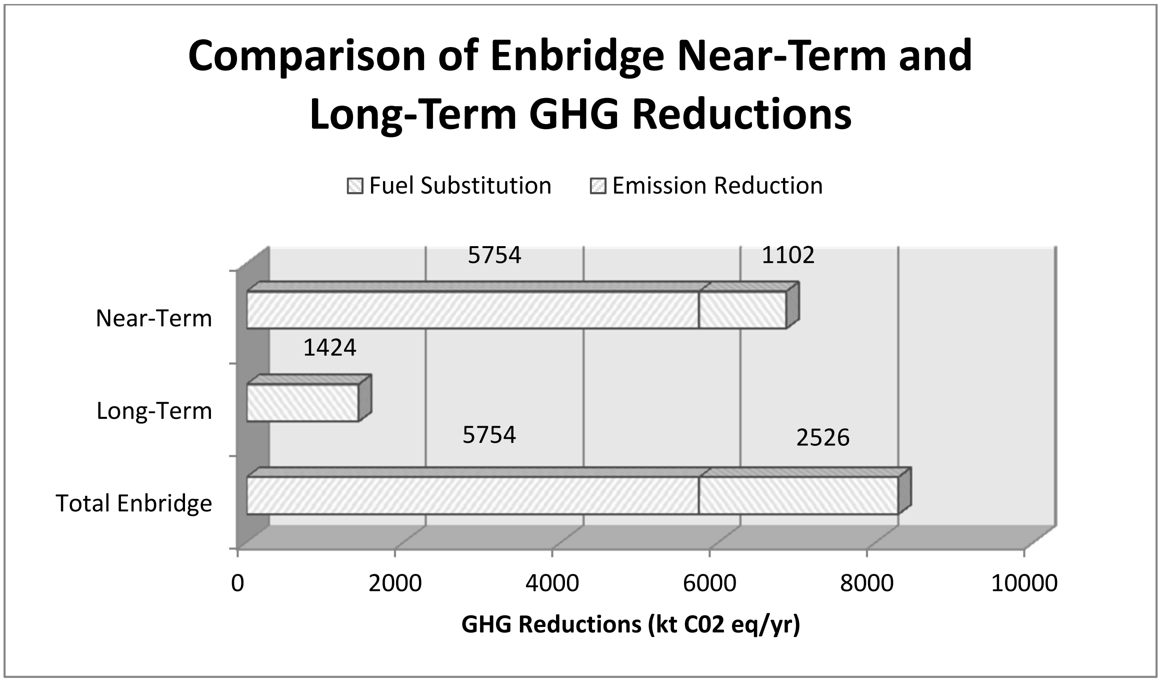

Figure 22. Comparison of Enbridge Near-Term and Long-Term GHG Reductions.

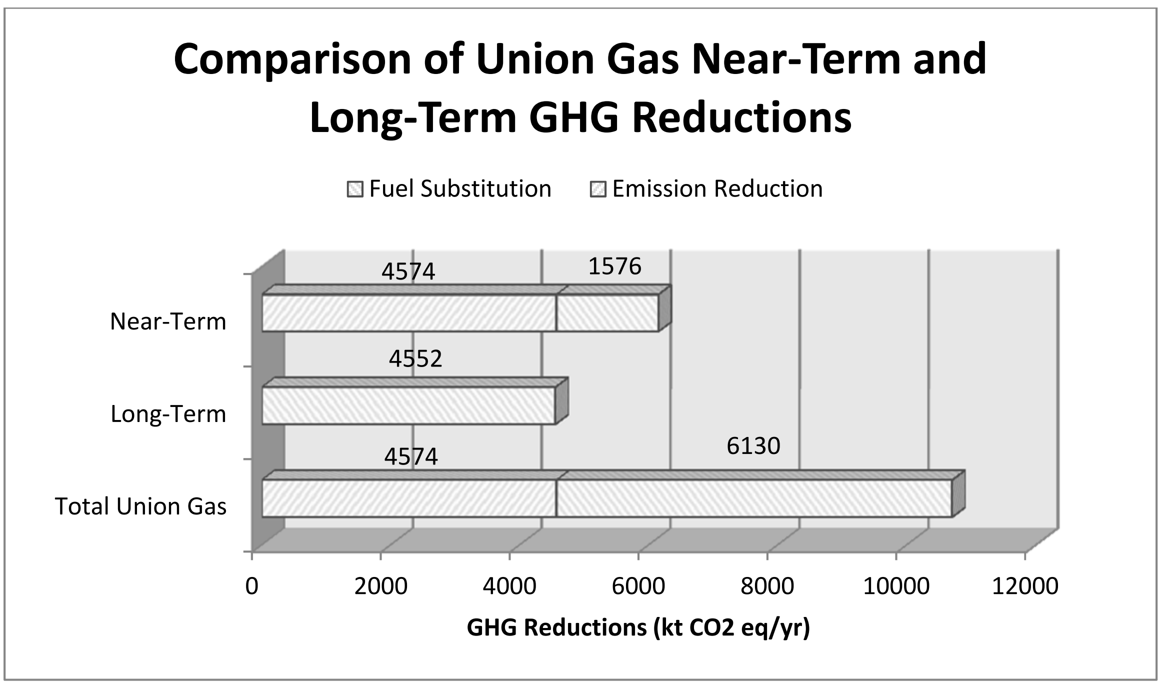

Figure 23. Comparison of Union Gas Near-Term and Long-Term GHG Reductions.

In considering the volumes of MSW generated, landfill gas is a potentially harmful emission from MSW. In addition to the greenhouse gas impact of methane capture outlined above, and converting it into a reliable energy source, the capture and use of LFG provides co-benefits of limiting odours, controlling damage to vegetation, reducing owner liability, risk from explosions, fires and asphyxiation while providing a potential source of revenue and profit. Furthermore, the combustion of landfill gas destroys volatile organic compounds, which reduces smog formation.

Methane is a potent greenhouse gas. Its contribution to global warming is 21 times that of carbon dioxide. Landfills are responsible for almost 40% of anthropogenic methane emissions in North America. The volatile organic compounds in these gases interact with nitrous oxides to form ozone, a primary cause of smog. Methane is also potentially hazardous since it is explosive in concentrations between 5 and 15 percent by volume.

UNION GAS LIMITED

Letters of Support

ALPENGLOW ENERGY

June 8, 2011

Bryan Goulden and Ed Seaward
Market Development
Union Gas Limited
P. O. Box 2001
555 Riverview Drive
Chatham, ON
N7M 5M1

RE: Biomethane Reference Price

Dear Mr. Goulden and Mr. Seaward:

Alpenglow Energy (the "Company") is please to provide this letter of support to Union Gas in its endeavour to establish a Biomethane reference price in Ontario through its application to the Ontario Energy Board.

Alpenglow Energy is a privately-held Ontario corporation and renewable energy developer, focused on biogas, landfill gas and syngas projects. The Company has specialized to provide design / build / own solutions as well as provide financing for small to medium sized power projects in Canada and the United States.

In the Ontario agri-energy sector, Alpenglow has practical development experience as a co-owner of Seacliff Energy, for which the Company has structured financing for a 3.2 MW anaerobic digestion facility in Leamington, Ontario. Recently commissioned at 1.6 MW, the Seacliff Energy facility is anticipated to be the largest electrical generator using biogas derived from anaerobic digestion in North America upon completion of its second phase in 2012.

Alpenglow Energy currently has projects in development in Ontario, the rest of Canada and the United States. The Company finds that Union Gas' Biomethane initiative is timely and may potentially be integrated into its projects as a viable alternative to electrical generation. This will be contingent on the Biomethane reference price, term of contract, timeliness of a program rollout, analysis of capital costs for gas conditioning versus power generation, amongst other factors.

Additionally, we believe that a Biomethane alternative to power generation will allow several potential projects in Ontario to be developed, which may otherwise have been plagued by the regulatory hurdles and delays, transmission constraints and uncertainty currently surrounding Ontario's Feed-In Tariff program.

Alpenglow Energy strongly supports Union Gas' initiative to establish a Biomethane reference price through the Ontario Energy Board in line with the objectives of the Green Energy Act and looks forward to working together in the future.

Yours very truly,

Jason R. Moretto, CGA, CFA
President
ALPENGLOW ENERGY LTD.

Agrienergy Producers' Association of Ontario

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

August 15, 2011

RE: Renewable Natural Gas Application by Union Gas Limited

The Agrienergy Producers' Association of Ontario is encouraged that Union Gas is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the Union's recent *Renewable Natural Gas Application*.

Anaerobic digestion is one way in which biogas can be created to in turn produce biomethane, a renewable energy that can be interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to strengthen nutrient management, protect ground and source water bodies, reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

The Agrienergy Producers' Association of Ontario is committed to moving forward on sustainable energy, climate change and air quality issues and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to approve this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

Dan Jones
President, Agrienergy Producers' Association of Ontario

AgriEnergy Producers' Association of Ontario · Association Des Producteurs d'AgriÉnergie De l'Ontario
275 Slater Street, Suite 900, Ottawa, Ontario K1P 5H9
T: 613 822-1004 www.apao.ca exec_coord@apao.ca

300 Dufferin Avenue
PO Box 5035
London ON
N6A 4L9

London
CANADA

Office of the Mayor

July 26, 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto ON   M4P 1E4

Re: Renewable Natural Gas Application by Union Gas Limited

The City of London is encouraged that Union Gas is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biomethane is a renewable energy that is created from landfill gas and other sources of biogas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewal natural gas has the added benefit of stimulating regional development.

The City of London is committed to moving forward on sustainable energy, climate change and air quality issues within its community and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

Honourable Joe Fontana
Mayor

The Corporation of the City of London
Office: 519.4920 – Fax: 519.661.5308
jfontana@london.ca / www.london.ca

FAITH · FIDELITY · PROGRESS

August 9, 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

RE: Renewable Natural Gas Application by Union Gas Limited

The City of Guelph is encouraged that Union Gas is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biomethane is a renewable energy that is created from landfill gas and other sources of biogas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Biogas has played a part of our community's energy profile for some time now. The City already has two existing biogas systems in operation and third is in development with a local private sector interest.

Incorporating Renewable Natural Gas into the existing supply stream provides us with a new opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewal natural gas has the added benefit of stimulating regional development.

Greening local energy infrastructure, reducing our per capita greenhouse gas emissions and facilitating local investment are all fundamental aspects of our Community Energy Initiative, adopted by Guelph City Council in April 2007.

The City of Guelph is committed to moving forward on sustainable energy, climate change and air quality issues within its community and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

Karen Farbridge
Mayor

Office of the Mayor

City Hall
1 Carden St
Guelph, ON
Canada
N1H 3A1

T 519-837-5643
TTY 519-826-9771
F 519-822-8277
E mayor@guelph.ca

guelph.ca

OFFICE OF THE MAYOR
CITY OF HAMILTON

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

August 4, 2011

RE: Renewable Natural Gas Application by Union Gas Limited

The City of Hamilton is encouraged that Union Gas is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biomethane is a renewable energy that is created from landfill gas and other sources of biogas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewal natural gas has the added benefit of stimulating regional development.

The City of Hamilton is committed to moving forward on sustainable energy, climate change and air quality issues within its community and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

Bob Bratina, Mayor
City of Hamilton

71 MAIN STREET WEST, 2ND FLOOR, HAMILTON, ONTARIO L8P 4Y5 PHONE: 905.546.4200 FAX: 905.546.2340

18 August 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

RE: Renewable Natural Gas Application by Union Gas Limited

Maple Reinders is encouraged that Union Gas is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system. We urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biomethane is a renewable energy that is created from the biogas of Anaerobic Digesters and landfill gas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

Maple Reinders is committed to moving forward on sustainable energy, climate change and air quality issues and we understand that renewable sources of energy must play a greater role in our future. Maple Reinders has the in-house capabilities to provide construction services to help build the infrastructure that is needed to achieve the objectives of the Renewable Natural Gas Program.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Yours sincerely,
MAPLE REINDERS CONSTRUCTORS LTD.

John H. Haanstra
Senior Vice President, Environmental

Office of the Mayor / CEO

Randy R. Hope

315 King Street West
P.O. Box 640
Chatham, Ontario
N7M 5K8

Telephone: 519.436.3219
Fax No.: 519.436.3236
Email: RandyHope@chatham-kent.ca

Municipality of Chatham-Kent

July 25, 2011

Ontario Energy Board
P.O. box 2319
2300 Yonge Street
Toronto ON M4P 1E4

RE: Renewable Natural Gas Application by Union Gas Limited

The Municipality of Chatham-Kent is encouraged that Union Gas is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent Renewable Natural Gas Application.

Biomethane is a renewable energy that is created from landfill gas and other sources of biogas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

The Municipality of Chatham-Kent is committed to moving forward on sustainable energy, climate change and air quality issues within its community and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Sincerely,

Randy R. Hope, Mayor/CEO
Municipality of Chatham-Kent

Ontario Federation of Agriculture
Ontario AgriCentre
100 Stone Road West, Suite 206, Guelph, Ontario N1G 5L3
Tel: (519) 821-8883 • Fax: (519) 821-8810 • www.ofa.on.ca

August 3, 2011

Ed Seaward, Manager
Market Opportunity Development
Union Gas Limited
P.O. Box 10
Hamilton, ON
L8N 3A5

Dear Mr. Seaward,

RE: Renewable Natural Gas Application by Union Gas Limited and Enbridge Gas Distribution Inc.

The Ontario Federation of Agriculture is encouraged that Union Gas Limited is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biomethane is a renewable energy that is created from the biogas of Anaerobic Digesters and landfill gas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

The Ontario Federation of Agriculture is committed to moving forward on sustainable energy, climate change and air quality issues and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

Bette Jean Crews

Bette Jean Crews
President

QUEST | Quality Urban Energy Systems of Tomorrow   QUEST | Systèmes d'énergie de qualité pour les villes de demain

August 22, 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

To Whom This May Concern:

RE: Support for Enbridge Gas Distribution Renewable Natural Gas Application and Union Gas Limited Renewable Natural Gas Application

QUEST – Quality Urban Energy Systems of Tomorrow – is committed to having every community in Canada operate as an integrated energy system, and utilizing local renewable energy sources, such as renewable natural gas derived from agricultural and municipal waste and organic sources is an important part of that vision.

QUEST is a collaborative network of organizations – from energy, technology and infrastructure industries, gas and electric utilities, all levels of government, civil society groups and community leaders, researchers, developers and the consulting community – actively working to make Canada a world leader in the design, development and application of integrated community energy solutions (ICES).

ICES involve taking advantage of opportunities to improve energy efficiency beyond individual buildings and houses to encompass whole communities. ICES considers how energy is supplied and consumed in all sectors including transportation, land-use planning, industry, water management, waste management and others.

Taking an integrated, community-based approach encourages the use of solutions that evaluate how energy is supplied and consumed across sectors. QUEST's practical approach to advancing ICES encourages communities, industry leaders and local natural gas and electric distribution companies (LDCs) to take advantage of cross-cutting opportunities through the integration of physical components from these sectors, including: land-use and community form; energy supply and distribution of clean fossil and renewable sources; water, waste management and other local community services; transportation; housing and buildings, and industry.

QUEST is working with community builders, such as Enbridge Gas Distribution and Union Gas Limited, to help communities in Ontario to meet their demand for energy through better planning and investment. The activities of QUEST are grounded in six technical principles that are internationally recognized for supporting ICES, including the capture and use of waste sources of energy, making use of renewable resources and using grids strategically.

QUEST is encouraged that Enbridge Gas Distribution and Union Gas Limited are undertaking to make seperate applications to utilize local community sources of renewable energy in Ontario, such as renewable natural gas – derived from biogas sources produced through anaerobic digestion of landfill gas, agricultural and municipal waste sources - an energy source that is accessible to virtually every community in Ontario in small, but significant volumes – to supplement natural gas supply.

Communities in Ontario are faced with the difficult challenge of having to capture all forms of landfill gas. The opportunity to clean up and convert biogas captured from landfills and other anaerobic digestion facilities to renewable natural gas can contribute to lowering the carbon intensity of Ontario's natural gas grid, generate local

Quality Urban Energy Systems of Tomorrow
350 Sparks St., Suite 809
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QUEST | Systèmes d'énergie de qualité pour les villes de demain

jobs and economic development in agricultural and other communities, and assist communities and the province in meeting greenhouse gas reduction objectives.

LDCs, such as Enbridge Gas Distribution and Union Gas Limited, are well placed to work with Ontario municipalities, waste management firms, energy regulators and agricultural and horticultural industries to access biogas resources to develop a supportive commercial marketplace in Ontario for renewable natural gas, making efficient use of existing natural gas infrastructure and consumer equipment.

We encourage the Ontario Energy Board to review the *Renewable Natural Gas Application* being made by Enbridge Gas Distribution and the *Renewable Natural Gas Application being made by* Union Gas Limited as opportunities to advance integrated energy systems planning across Ontario and to expand renewable energy supplies to Ontario residents and businesses.

Yours truly,

Brent Gilmour MCIP RPP
Executive Director
Quality Urban Energy Systems of Tomorrow

Cc Board of Directors, QUEST
Richard Laszlo, National Coordinator, QUEST
Tonja Leach, National Coordinator, QUEST
Ed Seaward, Union Gas Limited

Quality Urban Energy Systems of Tomorrow
350 Sparks St., Suite 809
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ENBRIDGE GAS DISTRIBUTION

Letters of Support

ALPENGLOW ENERGY

June 15, 2011

Owen W. Schneider
Manager, New Ventures
Enbridge Gas Distribution Inc.
500 Consumers Road
North York, ON
M2J 1P8

RE: Biomethane Reference Price

Dear Mr. Schneider:

Alpenglow Energy (the "Company") is please to provide this letter of support to Enbridge Gas in its endeavour to establish a Biomethane reference price in Ontario through its application to the Ontario Energy Board.

Alpenglow Energy is a privately-held Ontario corporation and renewable energy developer, focused on biogas, landfill gas and syngas projects. The Company has specialized to provide design / build / own solutions as well as provide financing for small to medium sized power projects in Canada and the United States.

In the Ontario agri-energy sector, Alpenglow has practical development experience as a co-owner of Seacliff Energy, for which the Company has structured financing for a 3.2 megawatt anaerobic digestion facility in Leamington, Ontario. Recently commissioned at 1.6 megawatts, the Seacliff Energy facility is anticipated to be the largest electrical generation project using biogas derived from anaerobic digestion in North America upon completion of its second phase in 2012.

Biogas facilities such as these benefit the environment from many perspectives including i) producing electricity from renewable sources; ii) reducing demand for landfill capacity due to waste recovery; iii) producing high-quality fertilizer; and iv) offsetting harmful greenhouse gases (over 10,000 tonnes of CO^2 per year at the Seacliff Energy facility alone).

Alpenglow Energy currently has projects in development in Ontario, the rest of Canada and the United States. The Company finds that Enbridge Gas' Biomethane initiative is timely and may potentially be integrated into its projects as a viable alternative to electrical generation. This will be contingent on the Biomethane reference price, term of contract, timeliness of a program rollout, analysis of capital costs for gas conditioning versus power generation, amongst other factors.

Additionally, we believe that a Biomethane alternative to power generation will allow several potential projects in Ontario to be developed, which may otherwise have been plagued by the regulatory hurdles, delays, transmission constraints and uncertainty currently surrounding Ontario's Feed-In Tariff program.

Alpenglow Energy strongly supports Enbridge Gas' initiative to establish a Biomethane reference price in Ontario, as we believe a program of this nature shall create a greener future for our province.

Yours very truly,

Jason R. Moretto, CGA, CFA
President
ALPENGLOW ENERGY LTD.

ALPENGLOW ENERGY LTD.
5100 RUTHERFORD ROAD, P.O. BOX 12369, VAUGHAN, ON, L4H 2T3, CANADA
TEL: (905) 605-5555 CELL: (416) 356-7179

Association of
Municipalities of Ontario

OFFICE OF THE PRESIDENT

Sent via e-mail: BoardSec@ontarioenergyboard.ca

August 26, 2011

Rosemarie T. Leclair
Chair & CEO
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Dear Rosemarie:

Re: Renewable Natural Gas Application by Enbridge Gas Distribution

I am writing to offer the Association's support for the recent Renewable Natural Gas Application submitted by Enbridge Gas Distribution and Union Gas. AMO supports the drive to make our energy system cleaner, more responsive and more efficient. Encouraging the development of biomethane is good public policy because it will help prolong the life of existing landfills and address solid waste issues as well as offering opportunities to utilize waste products from wastewater treatment plants. Developing a market for renewable natural gas has the added benefit of stimulating regional development within the agricultural and forestry sectors that so many of our communities depend upon for economic sustainability.

Biomethane is a renewable energy that is created from the biogas of Anaerobic Digesters and landfill gas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

...2/

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Yours sincerely,

Gary McNamara
President

cc: David Lindsay, Deputy Minister, Ministry of Energy

Agrienergy Producers' Association of Ontario

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

August 15, 2011

RE: Renewable Natural Gas Application by Enbridge Gas Distribution Inc.

The Agrienergy Producers' Association of Ontario is encouraged that Enbridge Gas is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support Enbridge's recent *Renewable Natural Gas Application*.

Anaerobic digestion is one way in which biogas can be created to in turn produce biomethane, a renewable energy that can be interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to strengthen nutrient management, protect ground and source water bodies, reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

The Agrienergy Producers' Association of Ontario is committed to moving forward on sustainable energy, climate change and air quality issues and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to approve this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

Dan Jones
President, Agrienergy Producers' Association of Ontario

CCI BioEnergy

Kevin P. Matthews
President

390 Davis Drive, Suite 301
Newmarket, ON L3Y 7T8
Tel: (905) 830-1160
Fax: (905) 830-0416
Cell: (416) 230-9391
e-mail:
kmatthews@canadacomposting.com

August 17, 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

RE: Renewable Natural Gas Application by Enbridge Gas Distribution

CCI is encouraged that Enbridge Gas Distribution is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application.*

Biomethane is a renewable energy that is created from the biogas of Anaerobic Digesters and landfill gas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

We are is committed to moving forward on sustainable energy, climate change and air quality issues and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

Kevin Matthews
President

Advanced Environmental Solutions

Ottawa

15 September 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

Re: **Enbridge Gas Distribution - Renewable Natural Gas Application**

To Whom It May Concern,

Please be advised that Ottawa City Council, at its meeting of 14 September 2011, approved the following resolution:

WHEREAS the recently approved Term of Council Priorities and Objectives identifies Environmental Stewardship as a Strategic Priority that includes a focus on long-term sustainability and reducing the city's environmental footprint; and

WHEREAS the City of Ottawa is committed to moving forward on renewable energy, and air quality issues; and

WHEREAS Enbridge Inc. is intending to make an application to the Ontario Energy Board to permit a program by which biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system; and

WHEREAS this utilization of methane, as opposed to discharge to the atmosphere, will reduce the discharge of harmful pollutants to the environment;

THEREFORE BE IT RESOLVED that the City of Ottawa endorses in principle this initiative and encourages the Ontario Energy Board to give it careful review.

Leslie Donnelly
Deputy City Clerk
City of Ottawa
110 Laurier Avenue West
Ottawa, ON K1P 1J1
tel.: (613) 580-2400
web: www.ottawa.ca

Leslie Donnelly
Greffière adjointe
Ville d'Ottawa
110, avenue Laurier Ouest
Ottawa, ON K1P 1J1
tél. : (613) 580-2400
web : www.ottawa.ca.

Should you require further information, please do not hesitate to contact the undersigned directly at 613-580-2400 extension 28857.

Yours truly,

Leslie Donnelly
Deputy City Clerk

cc: Councillor Maria McRae
Ms. Lyne McMarchie, Program Manager, Special Projects, Enbridge Gas, 500 Consumers Road, North York, Ontario M2J 1P8

DW/

Maple Reinders

CANADA'S 50 BEST MANAGED COMPANIES

18 August 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

RE: Renewable Natural Gas Application by Enbridge Gas Distribution Inc.

Maple Reinders is encouraged that Enbridge Gas Distribution Inc. is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system. We urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biomethane is a renewable energy that is created from the biogas of Anaerobic Digesters and landfill gas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

Maple Reinders is committed to moving forward on sustainable energy, climate change and air quality issues and we understand that renewable sources of energy must play a greater role in our future. Maple Reinders has the in-house capabilities to provide construction services to help build the infrastructure that is needed to achieve the objectives of the Renewable Natural Gas Program.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Yours sincerely,
MAPLE REINDERS CONSTRUCTORS LTD.

John H. Haanstra
Senior Vice President, Environmental

Miller Waste Systems Inc.
8050 Woodbine Avenue
Markham, Ontario L3R 2N8
E-mail: millerwaste@millergroup.ca

Tel: (905) 475-6356
Fax: (905) 475-6396

Nigel G.H. Guilford, M. Eng.

July 26th, 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario M4P 1E4

RE: Renewable Natural Gas Application by Enbridge Gas Distribution

Miller Waste Systems Inc. is encouraged that Enbridge Gas Distribution is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biomethane is a renewable energy that is created from the biogas of Anaerobic Digesters and landfill gas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

Miller Waste Systems Inc. is committed to moving forward on sustainable energy, climate change and air quality issues and we understand that renewable sources of energy must play a greater role in our future. Miller Waste presently operates a Natural Gas vehicle for collection of waste and is interested in expanding its collection fleet to include more natural gas fuelled vehicles – RNG is an excellent way to work towards a sustainable energy system.

Miller Waste is presently pursuing projects whereby Municipal and Industrial, Commercial and Institutional source separated organic waste will be collected and anaerobically digested to produce RNG in an urban setting. In addition to providing a renewable energy source this model reduces greenhouse gas effects caused by organics decomposing in landfills and provides a means to recycle nutrients back to agricultural lands in a safe sustainable manner.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

Nigel Guilford
General Manager

OFFICE OF THE REGIONAL CHAIR
GARY BURROUGHS
The Regional Municipality of Niagara
2201 St. David's Road, P.O. Box 1042
Thorold, Ontario L2V 4T7
Telephone: 905-685-1571
Fax: 905-685-6243
E-mail: gary.burroughs@niagararegion.ca

September 2, 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

RE: Renewable Natural Gas Application by Enbridge Gas Distribution

Niagara Region is encouraged that Enbridge Gas Distribution is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biomethane is a renewable energy that is created from landfill gas and other sources of biogas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewal natural gas has the added benefit of stimulating regional development.

Niagara Region is committed to moving forward on sustainable energy, climate change and air quality issues within its community and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Yours truly,

Gary Burroughs

Gary Burroughs
Regional Chair

C: Mr. Mike Trojan, CAO, Niagara Region
Mr. Brian Hutchings, Commissioner, Corporate Services, Niagara Region

GBs182-11

Ontario Federation of Agriculture
Ontario AgriCentre
100 Stone Road West, Suite 206, Guelph, Ontario N1G 5L3
Tel: (519) 821-8883 • Fax: (519) 821-8810 • www.ofa.on.ca

August 3, 2011

Rob Fennell
Director, Green Energy Strategy
Enbridge Gas Distribution Inc.
P.O. Box 650
Scarborough, ON
M1K 5E3

Dear Mr. Fennell,

RE: Renewable Natural Gas Application by Union Gas Limited and Enbridge Gas Distribution Inc.

The Ontario Federation of Agriculture is encouraged that Enbridge Gas Distribution Inc. is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biomethane is a renewable energy that is created from the biogas of Anaerobic Digesters and landfill gas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

The Ontario Federation of Agriculture is committed to moving forward on sustainable energy, climate change and air quality issues and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

Bette Jean Crews

Bette Jean Crews
President

QUEST Quality Urban Energy Systems of Tomorrow

QUEST Systèmes d'énergie de qualité pour les villes de demain

August 22, 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

To Whom This May Concern:

RE: Support for Enbridge Gas Distribution Renewable Natural Gas Application and Union Gas Limited Renewable Natural Gas Application

QUEST – Quality Urban Energy Systems of Tomorrow – is committed to having every community in Canada operate as an integrated energy system, and utilizing local renewable energy sources, such as renewable natural gas derived from agricultural and municipal waste and organic sources is an important part of that vision.

QUEST is a collaborative network of organizations – from energy, technology and infrastructure industries, gas and electric utilities, all levels of government, civil society groups and community leaders, researchers, developers and the consulting community – actively working to make Canada a world leader in the design, development and application of integrated community energy solutions (ICES).

ICES involve taking advantage of opportunities to improve energy efficiency beyond individual buildings and houses to encompass whole communities. ICES considers how energy is supplied and consumed in all sectors including transportation, land-use planning, industry, water management, waste management and others.

Taking an integrated, community-based approach encourages the use of solutions that evaluate how energy is supplied and consumed across sectors. QUEST's practical approach to advancing ICES encourages communities, industry leaders and local natural gas and electric distribution companies (LDCs) to take advantage of cross-cutting opportunities through the integration of physical components from these sectors, including: land-use and community form; energy supply and distribution of clean fossil and renewable sources; water, waste management and other local community services; transportation; housing and buildings, and industry.

QUEST is working with community builders, such as Enbridge Gas Distribution and Union Gas Limited, to help communities in Ontario to meet their demand for energy through better planning and investment. The activities of QUEST are grounded in six technical principles that are internationally recognized for supporting ICES, including the capture and use of waste sources of energy, making use of renewable resources and using grids strategically.

QUEST is encouraged that Enbridge Gas Distribution and Union Gas Limited are undertaking to make seperate applications to utilize local community sources of renewable energy in Ontario, such as renewable natural gas – derived from biogas sources produced through anaerobic digestion of landfill gas, agricultural and municipal waste sources - an energy source that is accessible to virtually every community in Ontario in small, but significant volumes – to supplement natural gas supply.

Communities in Ontario are faced with the difficult challenge of having to capture all forms of landfill gas. The opportunity to clean up and convert biogas captured from landfills and other anaerobic digestion facilities to renewable natural gas can contribute to lowering the carbon intensity of Ontario's natural gas grid, generate local

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jobs and economic development in agricultural and other communities, and assist communities and the province in meeting greenhouse gas reduction objectives.

LDCs, such as Enbridge Gas Distribution and Union Gas Limited, are well placed to work with Ontario municipalities, waste management firms, energy regulators and agricultural and horticultural industries to access biogas resources to develop a supportive commercial marketplace in Ontario for renewable natural gas, making efficient use of existing natural gas infrastructure and consumer equipment.

We encourage the Ontario Energy Board to review the *Renewable Natural Gas Application* being made by Enbridge Gas Distribution and the *Renewable Natural Gas Application being made by* Union Gas Limited as opportunities to advance integrated energy systems planning across Ontario and to expand renewable energy supplies to Ontario residents and businesses.

Yours truly,

Brent Gilmour MCIP RPP
Executive Director
Quality Urban Energy Systems of Tomorrow

Cc Board of Directors, QUEST
Richard Laszlo, National Coordinator, QUEST
Tonja Leach, National Coordinator, QUEST
Owen Schneider, Enbridge Gas Distribution

Quality Urban Energy Systems of Tomorrow
350 Sparks St., Suite 809
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VENTURE

VENTURE ENGINEERING & CONSTRUCTION
1501 REEDSDALE STREET, SUITE 505
PITTSBURGH, PA 15233

August 19, 2011

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

RE: Renewable Natural Gas Application by Enbridge Gas Distribution

Venture Engineering & Construction offers its support for Enbridge Gas Distribution's program to green Ontario's natural gas supply stream by introducing processed biogas (Renewable Natural Gas or biomethane) directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biogas is a renewable energy source that is created from the biological activity in Anaerobic Digesters and landfills. Once byproducts such as carbon dioxide have been separated, the processed gas is interchangeable with natural gas. Ontario gas utilities could readily enhance their gas supply portfolios with processed biogas. This would be a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream would reduce Ontario's carbon footprint and strengthen the network by adding sources of consistent, predictable, local supply. Added benefits include stimulating regional development and supporting Canadian enterprises that have developed technology and expertise in this area: manufacturers, academics, and analytical laboratories.

The Fuel Cell Research Center at Queen's University estimates that Ontario wastes 1.22 GWh daily from anaerobic digesters by flaring. That rate of waste is greater when landfill gas is considered. As long as this continues, a valuable resource will continue be flared instead of being used beneficially.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

DG Olmstead

Donald G. Olmstead, P.E., P.Eng.
Executive Vice President
Venture Engineering & Construction
1501 Reedsdale Street, Suite 505
Pittsburgh PA, 15233
Tel. (412) 231-5890
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YIELD

renewable energy producers

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

July 29, 2011

RE: Renewable Natural Gas Application by Enbridge Gas Distribution

Yield Energy Inc is encouraged that Enbridge Gas Distribution is taking steps to green Ontario's natural gas supply stream by developing a program where biomethane (Renewable Natural Gas) can be accepted directly into their pipeline system, and we urge the Ontario Energy Board to support the company's recent *Renewable Natural Gas Application*.

Biomethane is a renewable energy that is created from the biogas of Anaerobic Digesters and landfill gas so that it is interchangeable with natural gas. Ontario gas utilities are in a unique position, through their gas supply portfolios, to add a Renewable Natural Gas supply stream, which is a highly efficient use of a raw energy source that utilizes existing utility infrastructure and customer equipment.

Incorporating Renewable Natural Gas into the existing supply stream provides us with an opportunity to reduce Ontario's carbon footprint and minimize local waste issues, while at the same time providing a source of consistent, predictable local supply. Developing a market for renewable natural gas has the added benefit of stimulating regional development.

Yield Energy Inc is committed to moving forward on sustainable energy, climate change and air quality issues and we understand that renewable sources of energy must play a greater role in our future.

We urge the Ontario Energy Board to carefully review this important initiative so that another green energy source is available to Ontario citizens.

Respectfully,

Derek Riley, CEO
Derek.riley@yieldenergy.com
www.yieldenergy.com



Bio Methane Survey

Residential & Commercial Natural Gas Customers

November 2010

Ipsos Reid
160 Bloor Street East,
Suite 300
Toronto ON M4W 1B9
Tel: 416.324.2900
Fax: 416.324.2865/6
www.ipsos.ca

TABLE OF CONTENTS

Ipsos Ipsos Reid

1. Background and Objectives

Ipsos Reid was commissioned by Enbridge Gas Distribution to better understand the potential residential and commercial markets for biogas, its market drivers, and customer sensitivities to a range of different price points. Green bio-methane gas could be mixed with regular natural gas in order to reduce Greenhouse Gas (GHG) emissions in Ontario. In recognition of the added value of a Green gas, it is anticipated that customers may be willing to pay a premium for this product.

Enbridge wanted to assess the support for this new form of Green gas in order to determine if there would be a large enough market to generate interest in developing new supply.

In addition to gauging general awareness and support for biogas, support was also measured under different assumptions of impact on customer gas bills.

Overall objectives of the research among both the residential and commercial segment included:

- Overall environmental awareness and level of concern for the environment;
- Awareness of alternative energy sources;
- Support for alternative energy sources initiatives; and
- Price points for those initiatives.

2. Methodology

Two phases of research were conducted. The first among a sample of 1052 residential natural gas consumers in Ontario conducted online between October 12th and 18th, 2010. The second among commercial natural gas consumers using a random sample of 500 respondents drawn from a listing of Enbridge Commercial Customers provided to us by Enbridge. Commercial customers were interviewed via the telephone between October 12th and 29th, 2010.

A survey with an unweighted probability sample of this size (n=1052) and a 100% response rate would have an estimated margin of error of +/-3.1 percentage points, 19 times out of 20, of what the results would have been had the entire population of residential natural gas customers in Ontario been polled

Sub-population results have a larger error margin.

Within the residential sample of 1052 respondents, 632 were customers of Enbridge, and 420 were customers of Union. Participants for the residential survey were drawn from Ipsos Reid's iSay proprietary panel. Ipsos Reid is a pioneer in online data collection in Canada. The iSay Panel is one of Canada's largest proprietary panels with membership of over 300,000 Canadian households.

Unique reports were created for each of the residential and commercial surveys. This document presents the findings of the Residential Customer Study first followed by the findings of the Commercial Customer Study.

3. Executive Summary – Overall Results

Environmental Concern

Overall, sizeable majorities of those in both the residential and commercial studies are concerned about issues involving the environment. Across both groups, the highest level of concern is shown on the measure of the future state of the environment.

Nearly every residential and nine in ten commercial respondents have taken steps to reduce energy consumption. Among those who have taken steps to reduce energy, the use of energy efficient lighting is cited most often followed by participation in recycling programs.

Biogas Awareness and Support

While awareness of biogas is higher among commercial respondents than residential respondents, it is not particularly high in either group.

Once respondents are provided with some information regarding biogas creation and capture, strong majorities in both groups support utilities investing in and purchasing biogas.

In both groups, support for the purchase of biogas is based on the perception that doing so will benefit the environment, followed by it saving money or lowering costs. Any opposition to the inclusion of biogas centred on the perceived cost increase of doing so.

Biogas Pricing

Both residential and commercial respondents exhibit fairly high tolerance for a price increase based on their utility purchasing biogas to meet customer needs. Of the four pricing scenarios tested (bill increases of 4%, 2%, 1% or 0.5%), respondents express the highest support for an increase of 0.5% (76% residential, 71% commercial). Even at 4%, the highest proposed increase, a majority in both groups (57% residential, 53% commercial) still express support for their utility purchasing biogas.

Carbon Offsets

A majority of both residential and commercial customers have not heard of carbon offsets. When provided with additional information about carbon offsets (what they are, how they work) only a slight majority in each group favours their purchase.

Provided with a choice, residential and commercial customers indicate they are most likely to purchase a renewable energy program. About half as many would purchase an offset program. Within each group, significant portions would not purchase either of these options.



Residential Report

Ipsos Reid

4. Key Findings – Residential Survey

Environmental Concern

Overall, a sizeable majority of respondents are concerned about issues involving the environment. Particularly high levels of concern are found on the measures of the current state of the environment, the future state of the environment and the loss of oxygen producing forests.

Nearly every respondent surveyed has undertaken steps in their homes to reduce energy consumption. The activities mentioned most often include the use of energy efficient lighting and efforts at reducing, re-using and recycling.

Biogas Awareness and Support

While only a minority of residential natural gas customers have heard of biogas, once some information about biogas is provided, large majorities of residential natural gas customers support their utility both investing in and purchasing biogas.

Support for utilities purchasing biogas is based primarily on the view that doing so is good for the environment, followed by biogas offering the potential to save money. Opposition is centered on the perceived cost increase of doing so.

Biogas Pricing

Residential natural gas customers exhibit fairly high tolerance for a price increase based on the inclusion of biogas. Of the four pricing scenarios tested (residential bill increases of 4%, 2%, 1% and 0.5%), residential natural gas customers express the highest support for an increase of 0.5% (76%). Even at 4%, the highest proposed increase, a majority of residential natural gas customers (57%) still express support for their utility purchasing biogas.

Carbon Offsets

Awareness of carbon offsets is split. When provided with additional information about carbon offsets (what they are, how they work) only a small majority says they are likely to purchase them.

Given a choice, the plurality of respondents say they would purchase a renewable energy program, similar portions would purchase either an offset program or neither.

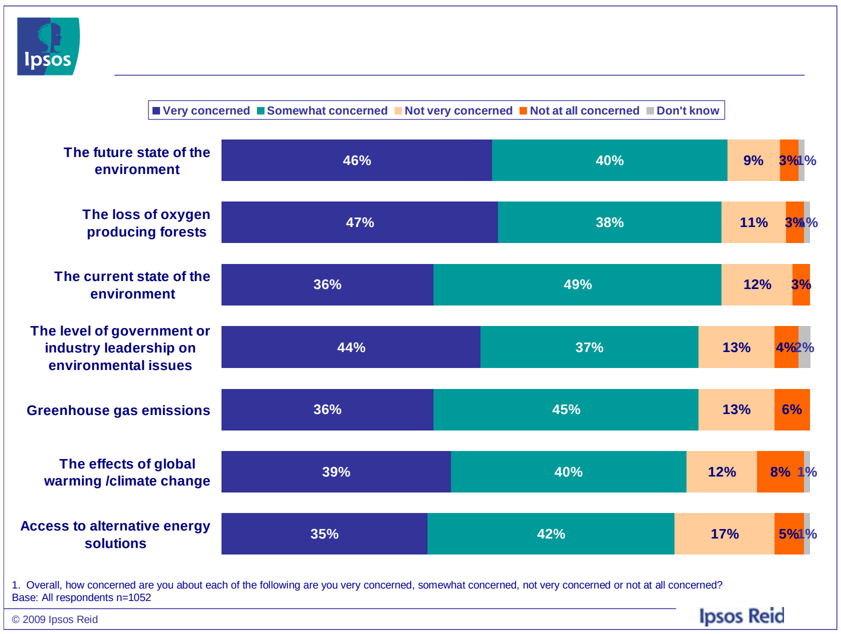
5. Detailed Findings

5.1 Environmental Concern

Overall, a sizeable majority of consumers are concerned with issues involving the environment. This includes both general concerns about the current and future state of the environment, as well as more specific issues such as the loss of forests, government leadership and greenhouse gases.

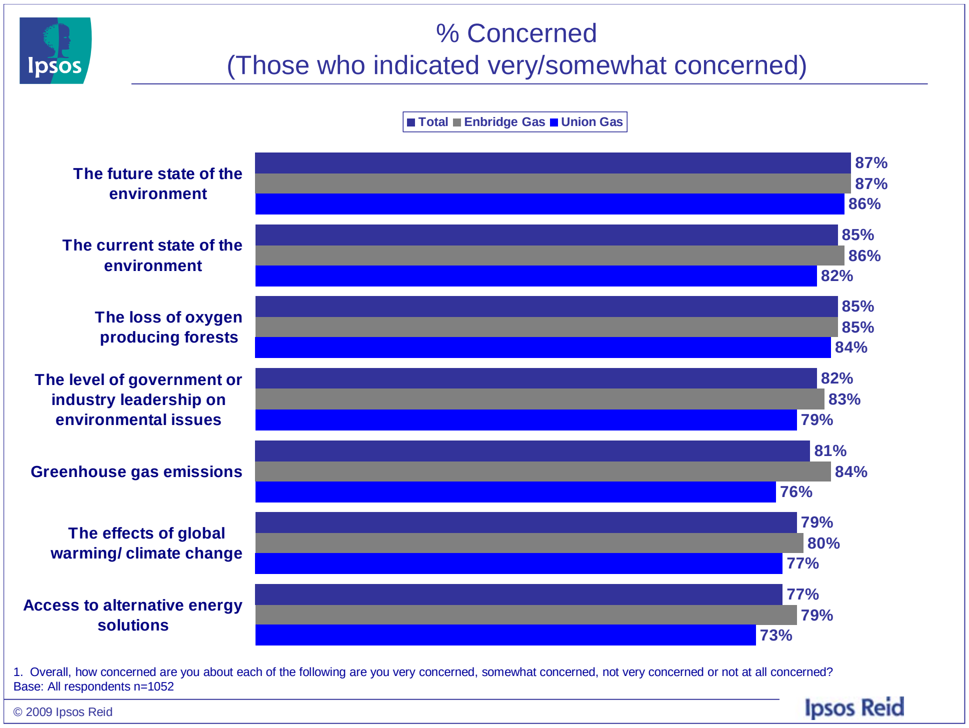
Particularly high levels of concern are found on: the future state of the environment (86% at least somewhat concerned), the loss of oxygen producing forests (85% at least somewhat concerned) and the current state of the environment (85% at least somewhat concerned). Still strong, but slightly lower levels of concern, are found on: the level of government/industry leadership on environmental issues (81% at least somewhat concerned), greenhouse gas emissions (81% at least somewhat concerned), the effects of global warming/climate change (79% at least somewhat concerned) and access to alternative energy solutions (77% at least somewhat concerned).

Concern with the Environment



Only slight differences are present between the two customer groups with Enbridge Gas residential customers, more concerned with greenhouse gas emissions (84%) and access to alternative energy solutions (79%), than Union Gas customers (76% and 73% respectively). There is no difference between the two customer groups on the key measures of: concern for the future state of the environment, the current state of the environment, the loss of oxygen producing forests and the level of government and industry leadership on environmental issues.

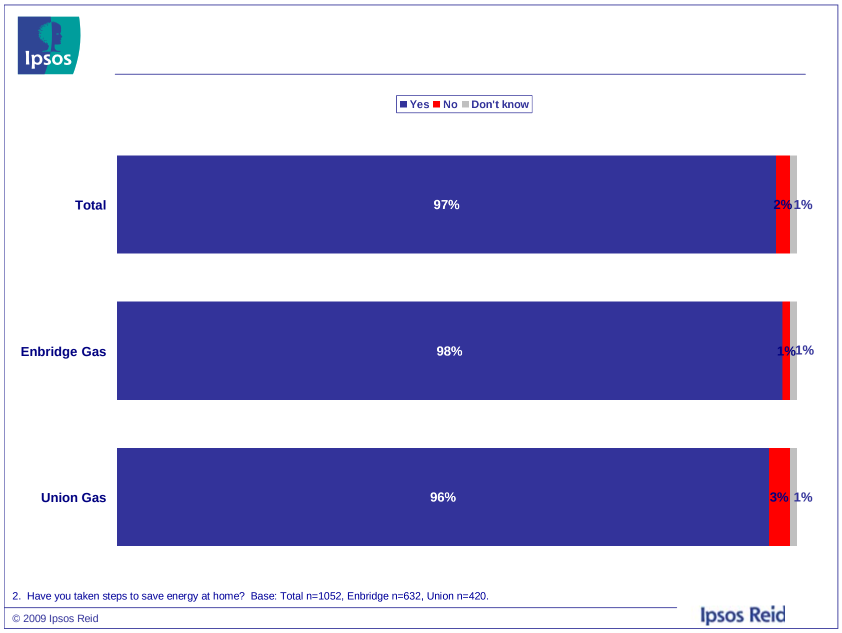
Concern with the Environment by Company



5.2 Activities Undertaken to Save Energy

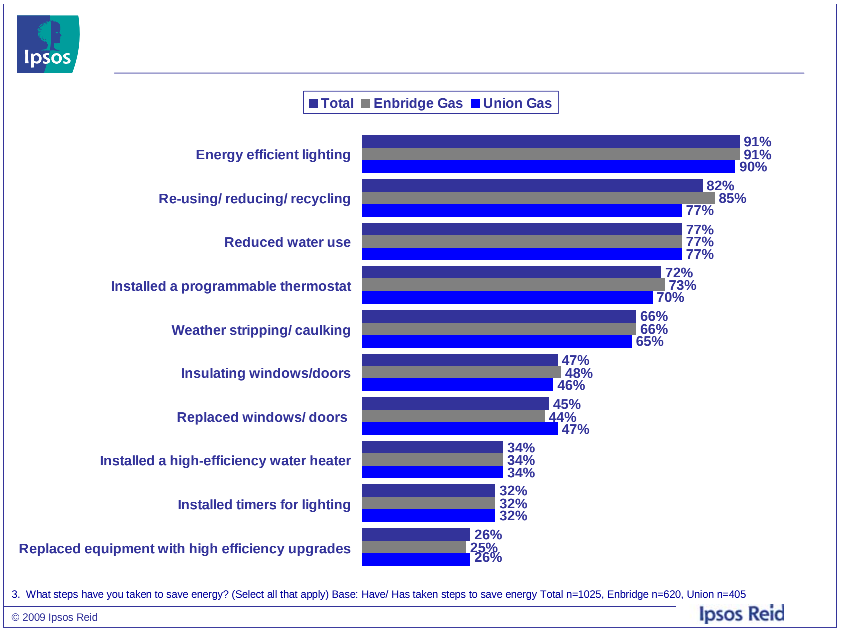
Customers show a strong desire to actively save energy in their homes. When asked, virtually all (97%) residential natural gas customers have taken steps to save energy at home. There is no variation on this measure by customer group.

Whether Taken Steps to Save Energy



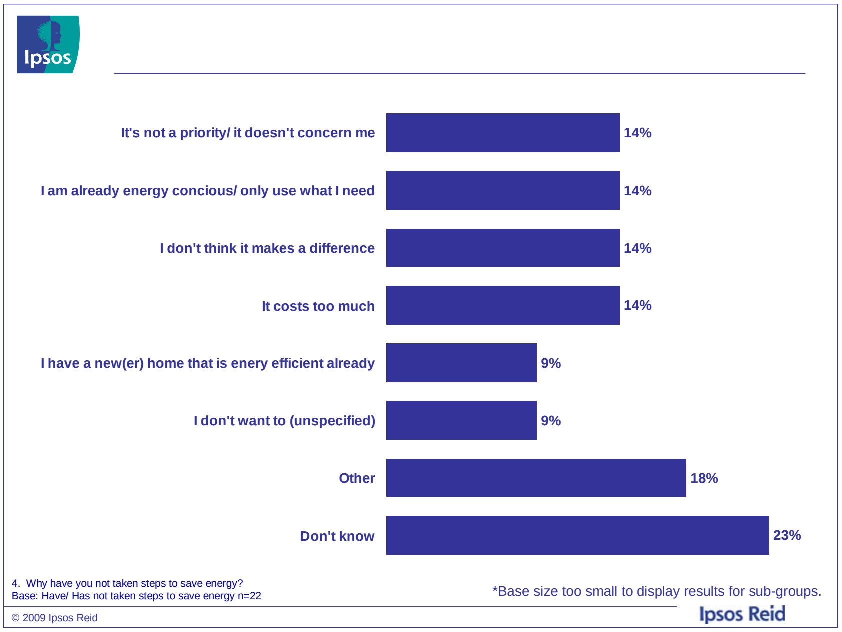
Respondents indicate using energy efficient lighting (91%) is the energy saving activity that has been undertaken most often. This is followed by respondents reducing/re-using/recycling (82%) along with efforts at reducing water use (77%). Almost three quarters have installed a programmable thermostat (72%), weather stripping/caulking (66%), insulating windows/doors (47%), replaced windows/doors (45%), installed high efficiency water heater (34%), installed timers for lighting (32%), and replaced equipment with high efficiency upgrades (26%).

Steps Taken to Save Energy



Among the very few respondents (3% or N = 22) who indicate they have not taken steps to save energy, 14% say each of: it is not a priority, they were already conscious of their energy use, they don't think it will make a difference or that actively taking steps to save energy costs too much. Other mentions include: their home is already energy efficient (9%), they have no interest in saving energy (9%), and other mentions (18%). Close to one quarter (23%) indicate they don't know why they haven't taken steps to save energy.

Reasons Given for Not Saving Energy



Looking at the questions in this section on a demographic basis, shows that overall women are more environmentally aware than men. The vast majority of women are concerned about the current state of the environment (91%), greenhouse gas emissions (87%), and access to alternative energy solutions (84%).

Environmental Concerns: Gender, Age, Education and Income Results

	Total	Gender and Age				
		Men	Women	18 – 34	35 – 54	55+
	%	%	%	%	%	%
Concern for current state of the environment	85	79	91	79	86	85
Concern with greenhouse gas emissions	81	74	87	74	80	82
Concern with access to alternative energy solutions	77	70	84	69	78	77
Taken steps to save energy at home	97	96	99	99	96	98

	Total	Education			Income			
		High school or less	College	University	Less $40K	$40-60K	$60-100K	$100K +
	%	%	%	%	%	%	%	%
Concern for current state of the environment	85	80	86	86	86	82	83	87
Concern with greenhouse gas emissions	81	79	79	82	80	76	81	84
Concern with Access to alternative energy solutions	77	73	79	77	74	77	78	76
Taken steps to save energy at home	97	98	98	97	96	100	97	97

Higher than average Lower than average

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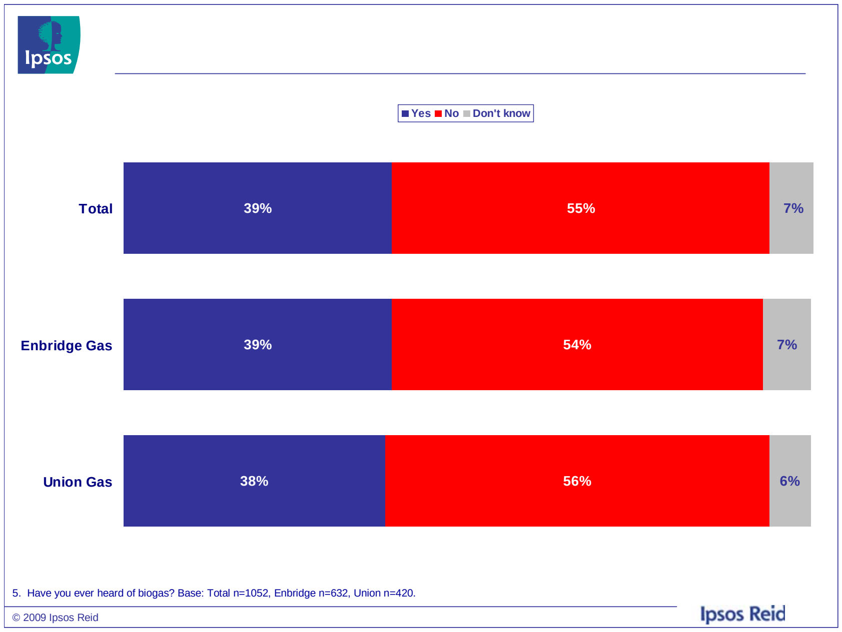
5.3 Biogas Awareness and Support

Only a minority of residential natural gas customers (39%) indicate they have previously heard of the term biogas. The majority (55%) have not heard of biogas.

Heard of Biogas



Respondents were then provided with a description of biogas:

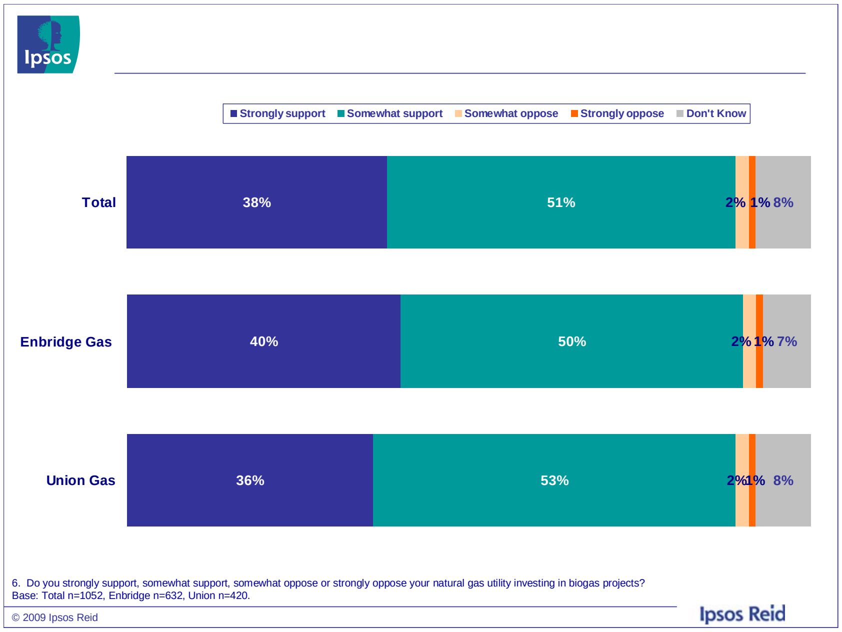
Bio methane gas or biogas is produced in landfills and waste water treatment plants and from animal manure and organic waste. It is a by-product of materials breaking down and rotting. The gas occurs naturally and is released into the atmosphere. It is possible to collect biogas. Once it is captured the biogas can then be cleaned and delivered to the market and used to heat homes and businesses <u>*thereby reducing greenhouse gas emissions.*</u>

Your natural gas utility is exploring the purchase of biogas to assist in meeting the overall gas supply needs of their customers. Biogas can then become a viable, renewable energy source for your region.

After being provided with this information, they were asked to indicate their support or opposition to their gas utility investing in biogas projects.

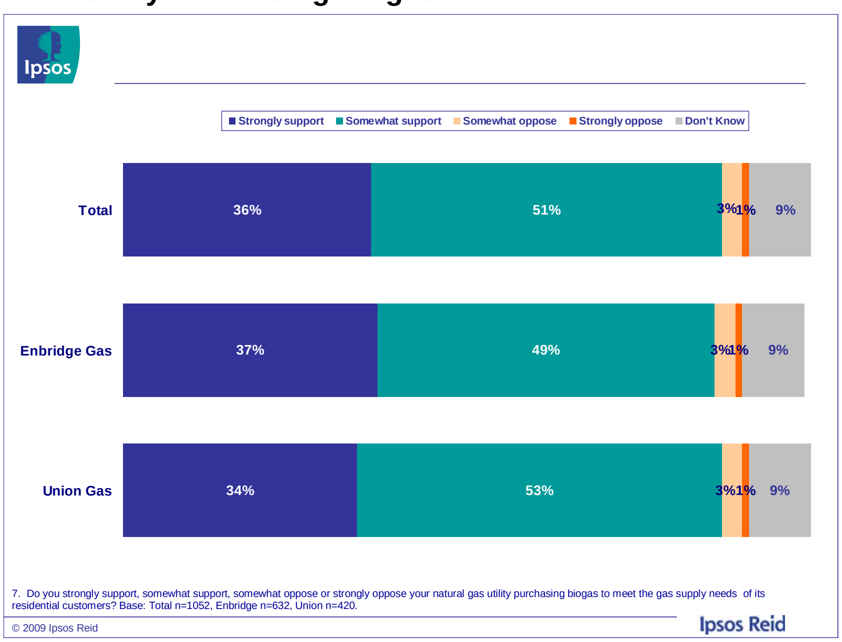
As the table below indicates, with 89% agreeing, strong support exists among residential natural gas customers for gas companies to invest in biogas projects. Very few, only three percent, expressed opposition, with a further eight percent indicating they did not know

Support for Utility Investing in Biogas



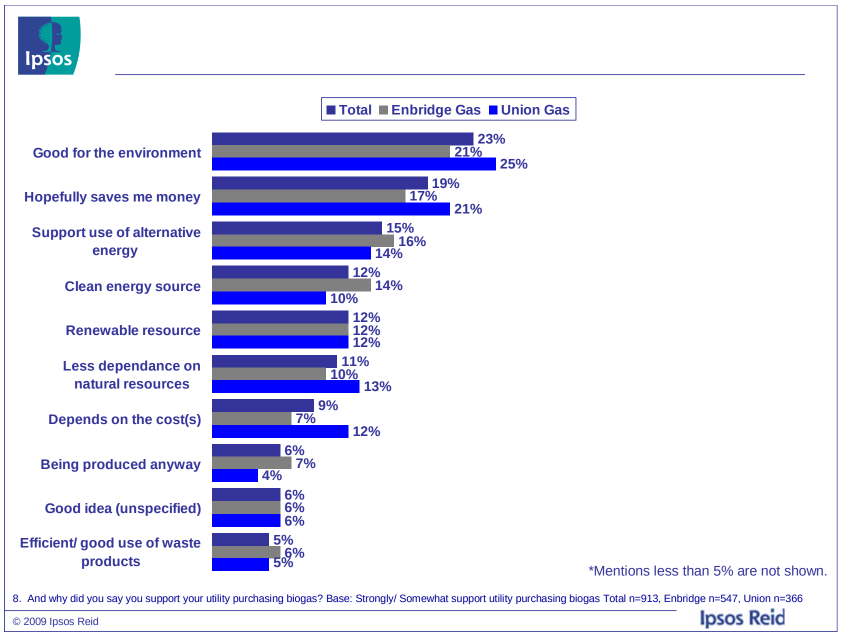
Similarly, strong support exists among residential natural gas customers for natural gas utilities purchasing biogas to meet the gas supply needs of residential customers. When asked 87% of respondents support their natural gas utility purchasing biogas. Only four percent are opposed to this, with nine percent indicating they do not know.

Support for Utility Purchasing Biogas



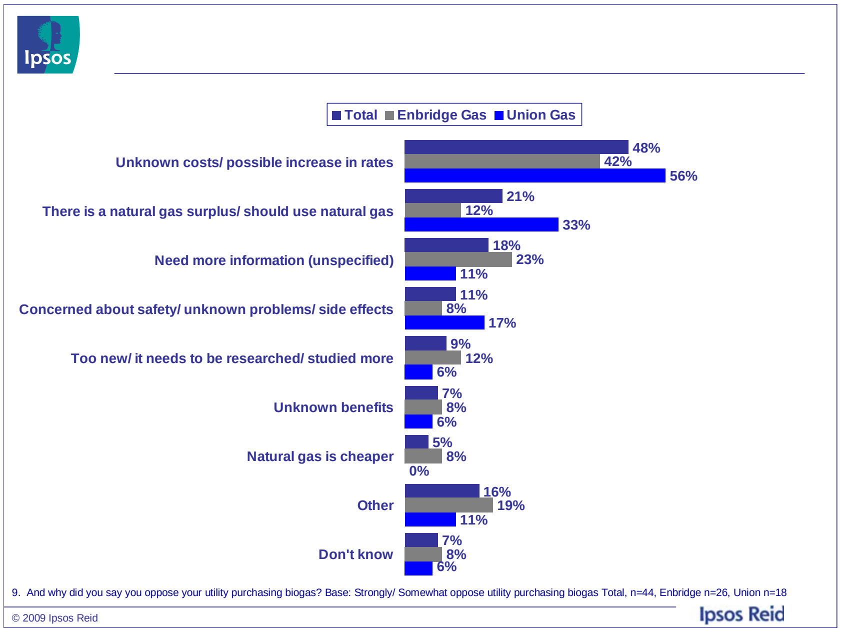
Of those who support natural gas utilities purchasing biogas, most indicate they do so because they feel it is good for the environment (23%). This is followed by the inclusion of biogas will help them save money (19%), or they support the use of alternative energy (15%). Other reasons include: biogas is a clean (12%), or renewable (12%) energy source, they want less dependence on natural resources (11%), that it depends on the cost(s) (9%), that biogas is being produced anyway (6%), or generally it is a good idea (6%) and it is an efficient use of waste products (5%). Union Gas customers are more likely to state it depends on the cost (12%) as a reason for their support.

Reasons for Support of Biogas



Among the four percent (N of 44) of respondents who oppose gas utilities purchasing biogas, the unknown cost of doing so is stated as the top concern (48%). This is followed by 21% who say there is a current surplus of natural gas and 18% who say they have a lack of information. Other mentions for not supporting biogas include: concerns about safety (11%), biogas is too new and needs to be researched more (9%), the benefits are unknown (7%), natural gas is cheaper (5%), other reasons (16%), and don't know (7%).

Reasons to Oppose Biogas



Looking at the biogas awareness and support questions across the demographics shows that men and those with a university education are more likely to have heard of biogas (52% and 48% respectively), compared to those with a high school (25%), and college education (31%) and those with a household income of less than $40,000 (29%).

Biogas Awareness and Support: Gender, Age, Education and Income Results

	Total	Gender and Age				
		Men	Women	18 – 34	35 – 54	55+
	%	%	%	%	%	%
Heard of biogas	39	52	26	38	36	41
Support for investment in biogas	90	90	90	91	88	91
Support for purchase of biogas	87	87	86	89	85	88

	Total	Education			Income			
		High school or less	College	University	Less $40K	$40-60K	$60-100K	$100K +
	%	%	%	%	%	%	%	%
Heard of biogas	39	25	31	48	29	35	42	43
Support for investment in biogas	90	89	88	91	91	89	89	91
Support for purchase of biogas	87	85	86	88	90	86	86	87

Higher than average Lower than average

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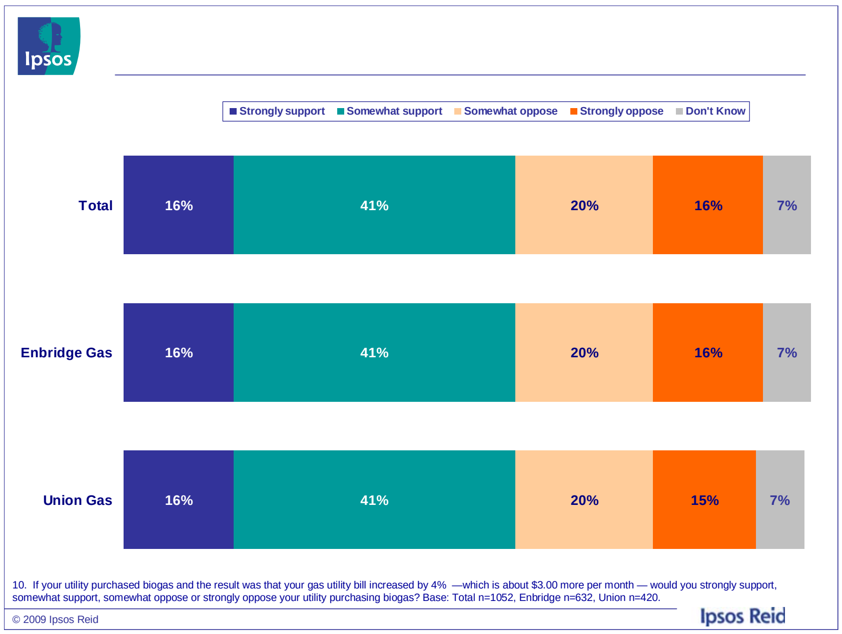
5.4 Biogas Pricing

To assess the potential for the purchase and price of biogas, residential natural gas customers were asked a series of questions related to pricing and the impact of an increase in their gas bill on support for including biogas in the natural gas delivered to their homes.

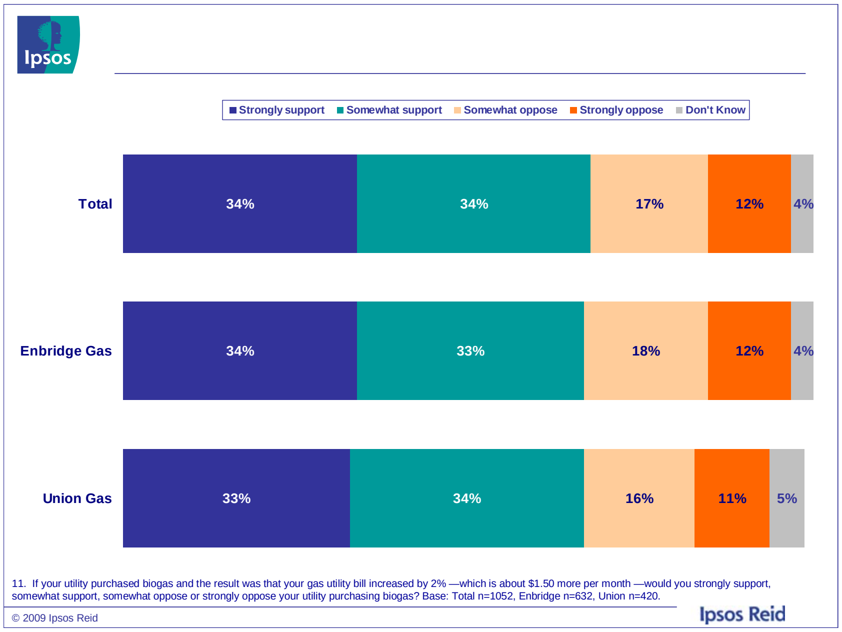
Close to six in ten residential natural gas customers (57%) support the purchase of biogas by their utility even if it means their individual natural gas bill would increase by 4%. Just over one third (36%) are opposed to the purchase of biogas if it resulted in a 4% increase in their natural gas bill.

Support Biogas if Utility Bill Increased by 4%



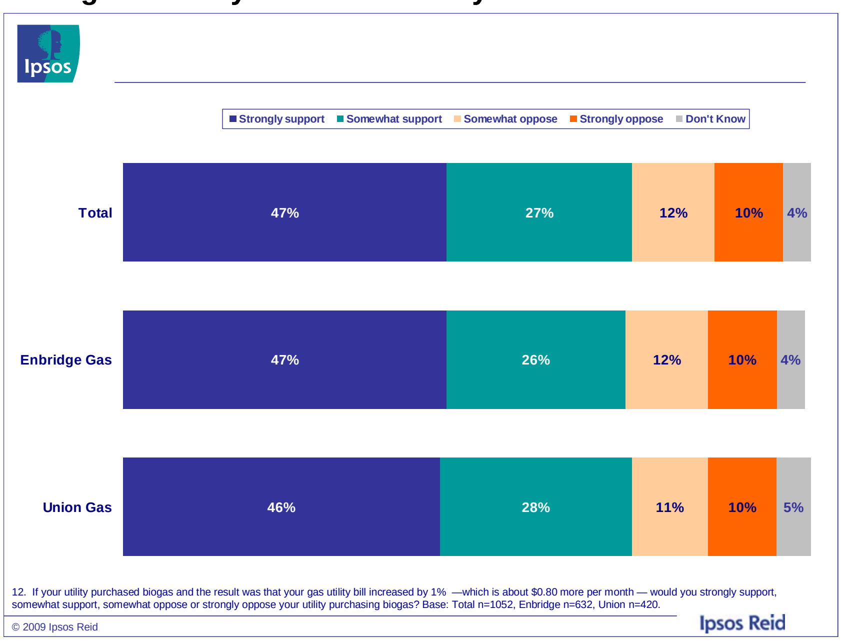
If the increase in respondents' natural gas bills was set at 2% based on the inclusion of biogas, support for the inclusion of biogas rises to just over two-thirds (68%). Opposition decreases to a level of 29%.

Support Biogas if Utility Bill Increased by 2%



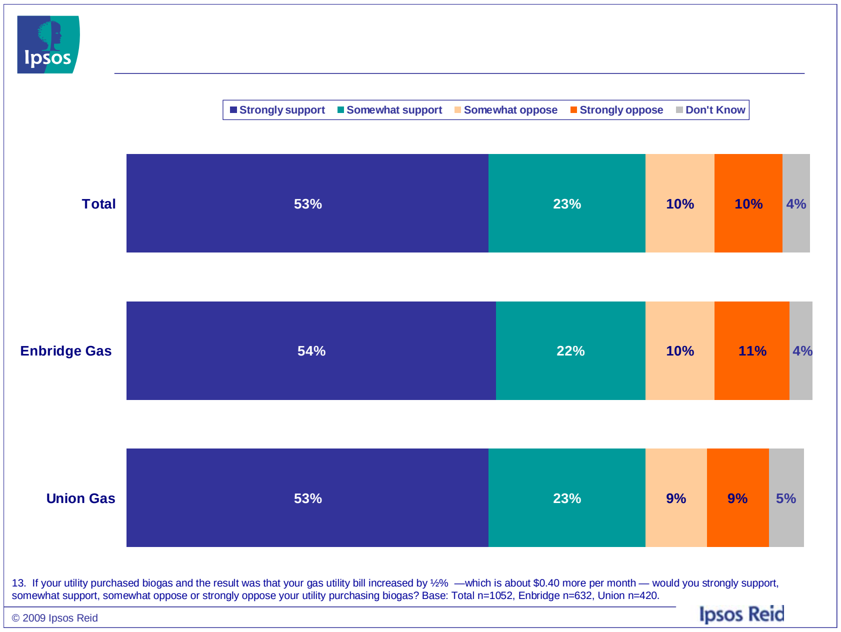
Nearly three quarters (74%) of residential natural gas customers express support for their utility purchasing biogas if the result is only a 1% increase in their residential gas bill. Just over two in ten (22%) say they are opposed to a 1% increase.

Support Biogas if Utility Bill Increased by 1%



The strongest level of support is found when residential natural gas customers are presented with the option of biogas inclusion resulting in a half of one percent increase in their utility bill. On this measure over three quarters (76%) of residential natural gas customers express support at this level. Two in ten (20%) report opposition even to a half of one percent increase in their gas bill.

Support Biogas if Utility Bill Increased by ½%



There are very few differences across the demographics assessed based on the four pricing options tested. If anything, older respondents appear to be more tolerant of a price increase to fund biogas inclusion, while younger respondents are less inclined to be supportive.

Biogas Pricing: Gender, Age, Education and Income Results

	Total	Gender and Age				
		Men	Women	18 – 34	35 – 54	55+
	%	%	%	%	%	%
Support a 4% increase	57	54	61	49	55	60
Support a 2% increase	67	62	72	63	64	70
Support a 1% increase	74	69	78	63	70	78
Support ½% increase	76	73	80	63	73	81

	Total	Education			Income			
		High school or less	College	University	Less $40K	$40-60K	$60-100K	$100K +
	%	%	%	%	%	%	%	%
Support a 4% increase	57	57	50	61	58	50	58	61
Support a 2% increase	67	67	60	70	71	62	68	68
Support a 1% increase	74	76	69	76	80	69	74	72
Support ½% increase	76	78	72	78	82	72	77	75

Higher than average   Lower than average

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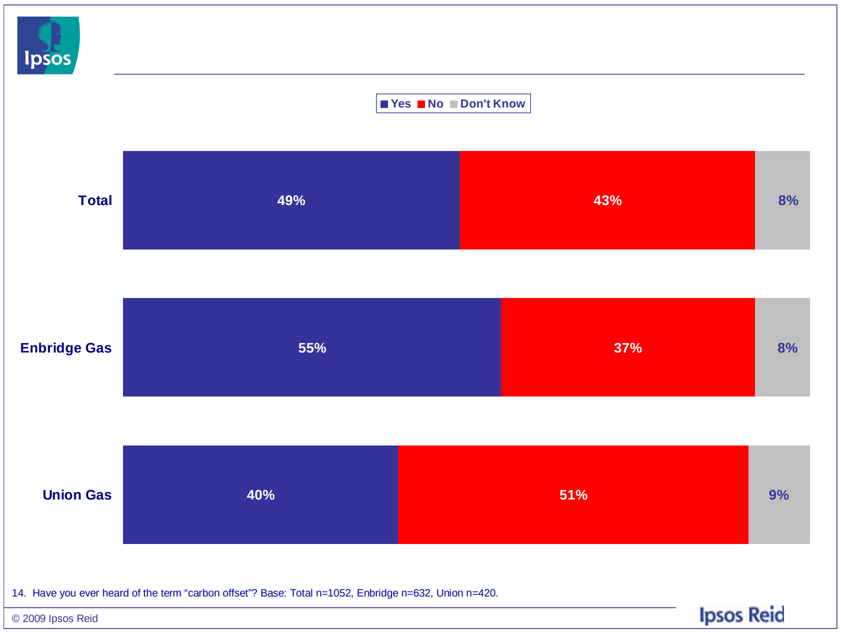
5.5 Carbon Offsets

Awareness of carbon offsets is split. Forty nine percent of residential natural gas customers say they have heard of the term "carbon offset" while 43% say they have not. Enbridge Gas customers (55%) report higher awareness than do Union Gas customers (40%).

Heard of Carbon Offsets



To better understand the likelihood of purchasing a carbon offset, residential natural gas customers were provided with the following description:

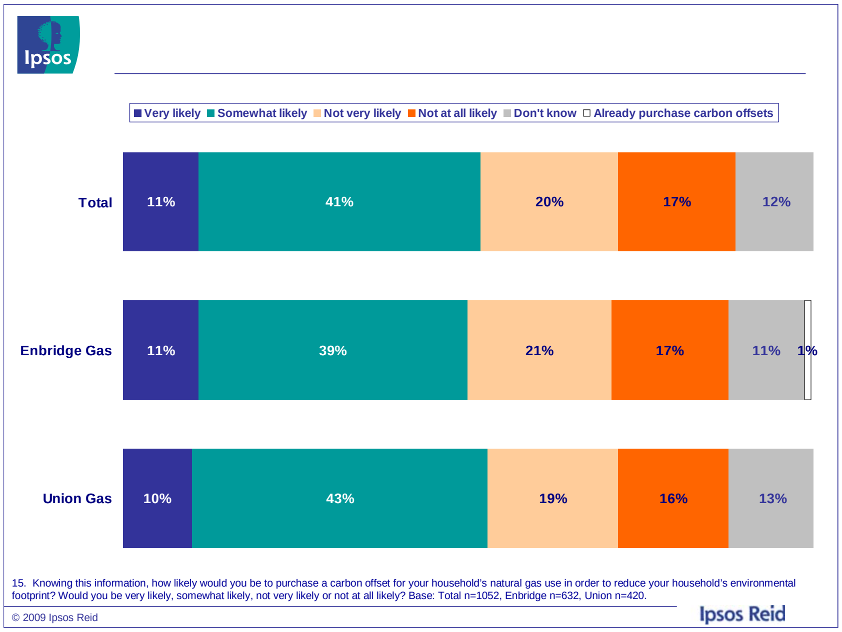
A carbon offset is a reduction in emissions of carbon or greenhouse gases made in order to compensate for or to offset an emission made elsewhere. In the case of a gas customer, the customer would receive a carbon offset in exchange for supporting a project that reduces the emission of greenhouse gases into the environment.

The customer benefits because their purchase of a carbon offset balances out greenhouse gases that they may release through activities such as home heating.

Offset projects support reduction in greenhouse gases by the planting of trees or the development of clean renewable energy projects such as biogas, wind and solar energy, etc.

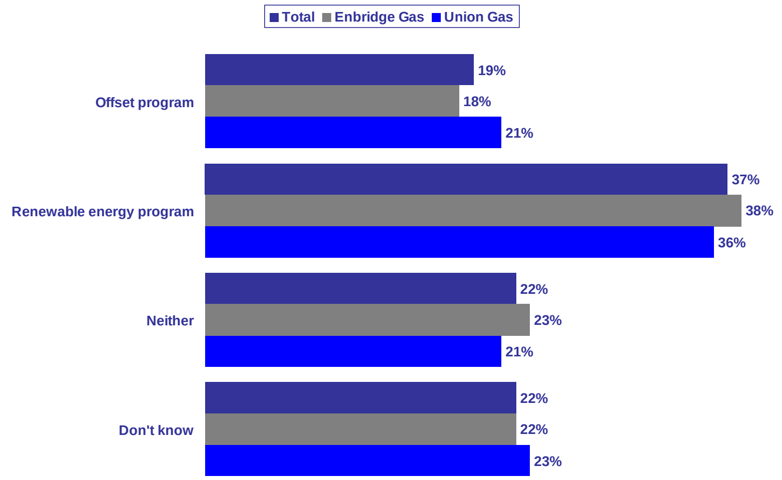
They were then asked to indicate the likelihood of purchasing a carbon offset in order to reduce their household's environmental footprint. As the table below shows, just over half (52%) of the residential natural gas customers surveyed say they are at least somewhat likely to purchase a carbon offset for their residence. Thirty seven percent are unlikely to do so.

Likelihood to Purchase Carbon Offsets



Given the choice, residential natural gas customers are more likely to support (37%) a renewable energy program (questionnaire wording -- In a renewable energy program, customers pay a premium for a portion of their natural gas to be supplied from a utility investing in renewable energy projects such as biogas) than they are an offset program (19%) (Questionnaire wording -- In an offset program, customers are offered the option to offset their home natural gas use by purchasing carbon offsets through the utility). Two in ten report they would support neither option (22%) or that they don't know (22%).

Program Support



16. Which of these two programs would you be most likely to support? Base: Total n=1052,Enbridge n=632, Union n=420.

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While men are more likely to have heard of carbon offsets (59%) than women (39%), women are more likely to support the purchase of carbon offsets (57%) than men (45%). Those who are university educated (61%) or have a household income of more than $100,000 (57%) are also more likely to have heard the term carbon offset.

Carbon Offsets: Gender, Age, Education and Income Results

	Total	Gender and Age				
		Men	Women	18 – 34	35 – 54	55+
	%	%	%	%	%	%
Heard of carbon offset	49	59	39	58	47	49
Likely to purchase	51	45	57	30	48	57
Support renewable energy program	37	38	36	47	37	35
Support offset program	19	17	22	13	17	22

	Total	Education			Income			
		High school or less	College	University	Less $40K	$40-60K	$60-100K	$100K +
	%	%	%	%	%	%	%	%
Heard of carbon offset	49	31	38	61	30	47	52	57
Likely to purchase	51	53	54	49	56	48	54	47
Support renewable energy program	37	25	33	44	26	35	41	40
Support offset program	19	23	21	17	26	16	21	15

Higher than average
Lower than average

Ipsos Reid



Commercial Report

Ipsos Reid

6. Key Findings – Commercial Study

Environmental Concern

Overall, a sizeable majority of commercial natural gas customers are concerned about issues involving the environment. Particularly high levels of concern are found on the measure of the future state of the environment.

Nearly nine in ten commercial natural gas customers have undertaken steps in their businesses to reduce energy consumption. The activities mentioned most often include the use of energy efficient lighting and efforts at reducing, re-using and recycling. Among those who have not taken steps to save energy, most say they are not sure what to do.

Biogas Awareness and Support

Commercial natural gas customers are essentially split on their awareness of the term biogas. Forty six percent have heard of biogas, while 53% have not.

Strong support exists for gas utilities to both invest in biogas projects and purchase biogas to meet customer gas supply needs.

Support for utilities purchasing biogas is based primarily on the view that doing so is good for the environment. Opposition is centered on the perceived cost increase of doing so.

Biogas Pricing

Commercial natural gas customers exhibit fairly high tolerance for a price increase based on the utility purchasing biogas to meet their gas supply needs. Of the four pricing scenarios tested (commercial bill increases of 4%, 2%, 1% and 0.5%), commercial natural gas customers express the highest support for an increase of 0.5% (71%). Even at 4%, the highest proposed increase, a majority of commercial natural gas customers (53%) still express support for their utility purchasing biogas.

Carbon Offsets

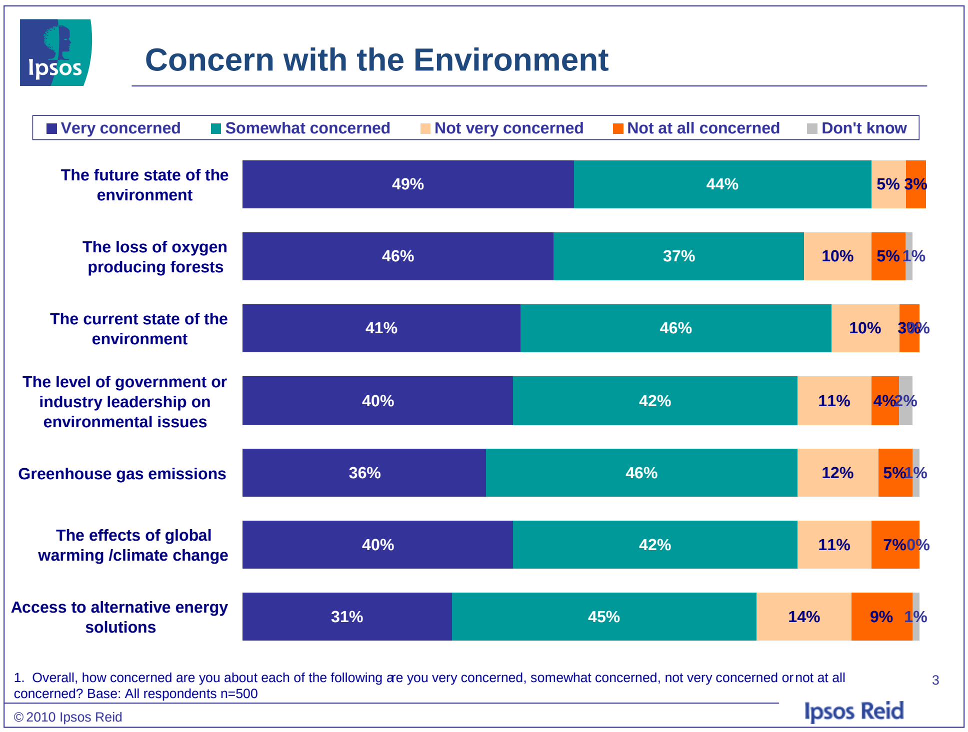
A majority of commercial natural gas customers have not heard of carbon offsets. When provided with additional information about carbon offsets (what they are, how they work) only a slight majority says they are likely to purchase them.

Given a choice, the plurality of commercial natural gas customers say they would likely purchase a renewable energy program. Two in ten would purchase an offset and one third would not purchase either option.

7. Detailed Findings

7.1 Environmental Concern

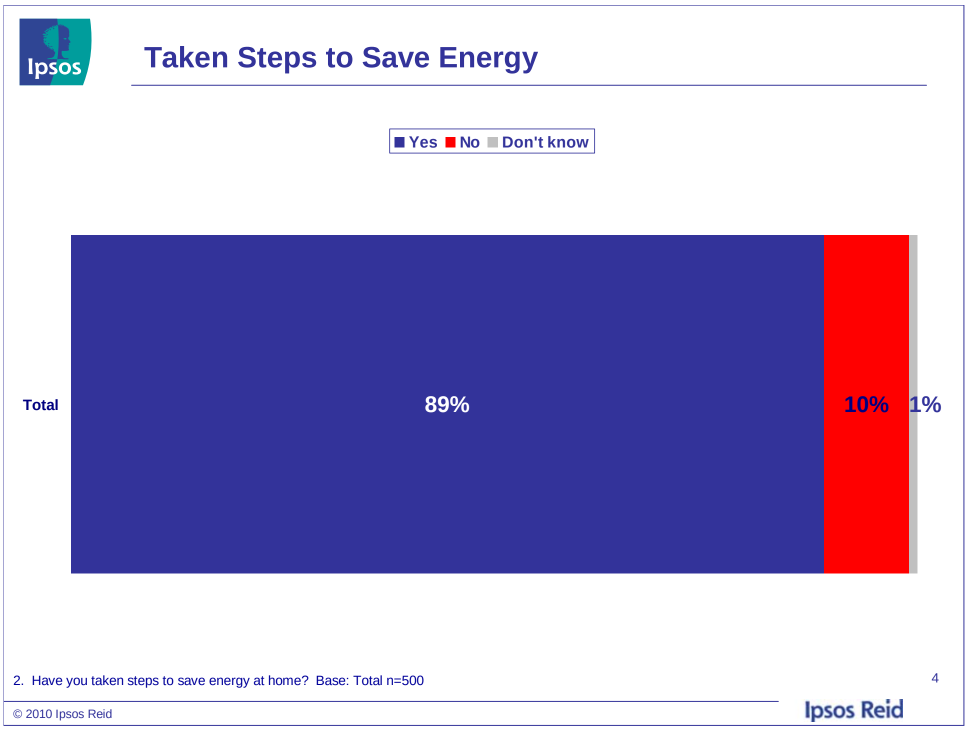
Overall, a sizeable majority of commercial natural gas customers are concerned with issues involving the environment. This includes both general concerns about the current and future state of the environment, as well as more specific issues such as the loss of forests, the level of government and industry leadership and greenhouse gases. Particularly high levels of concern are found on the future state of the environment (93% at least somewhat concerned).



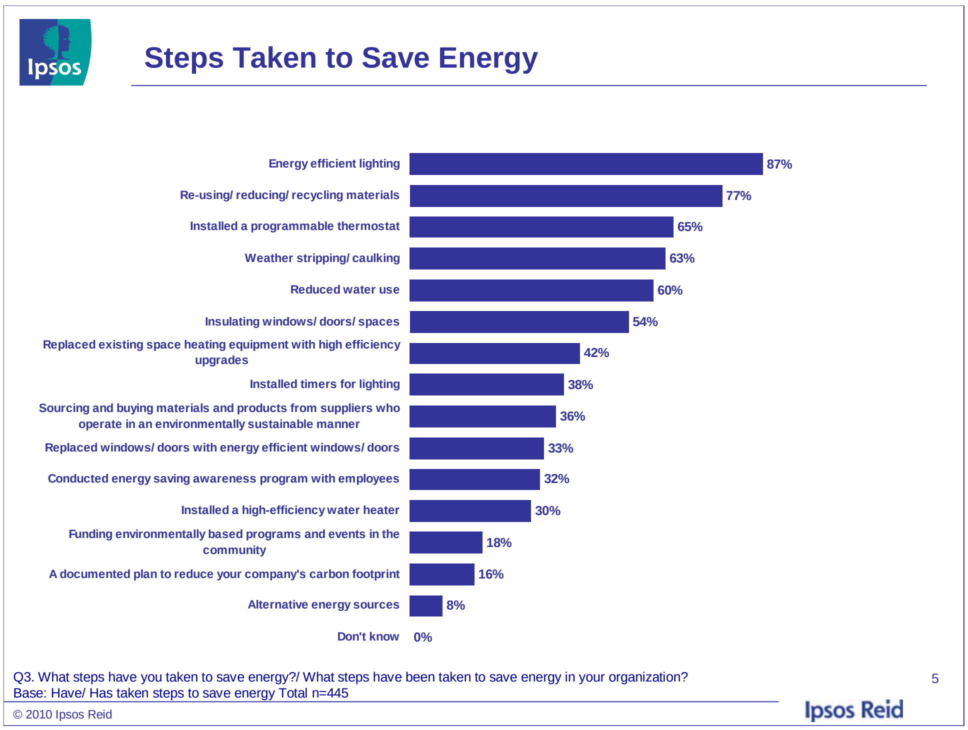
Still substantial, but slightly lower levels of concern are found on: the loss of oxygen producing forests (83% at least somewhat concerned), the current state of the environment (87% at least somewhat concerned), the level of government and industry leadership (82% at least somewhat concerned), greenhouse gas emissions (82% at least somewhat concerned) and the effects of global warming/climate change (82% at least somewhat concerned). Three quarters of respondents (76%) say they are concerned about access to alternative sources of energy.

7.2 Activities Undertaken to Save Energy

Commercial customers show a strong desire to actively save energy within their locations. Nearly nine in ten (89%) commercial natural gas customers have taken steps to save energy within their company. One in ten (10%) indicate they have not undertaken energy saving measures.

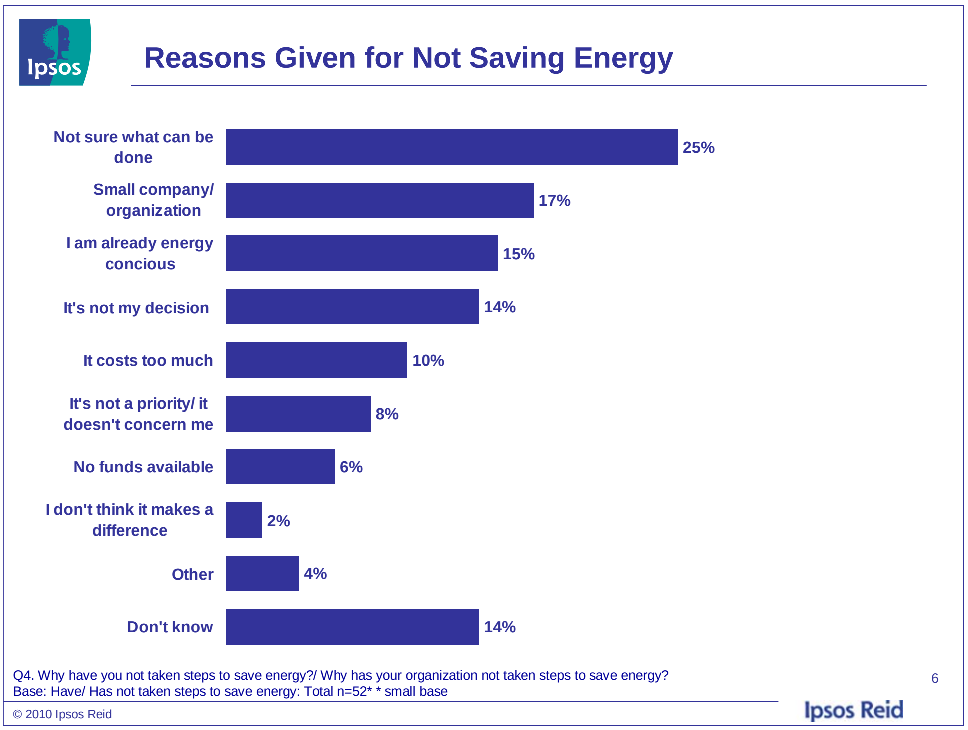


Commercial customers indicate using energy efficient lighting (87%) is the energy saving activity that has been undertaken most often. This is followed by respondents undertaking reducing/re-using/recycling (77%). About two thirds say each of installing a programmable thermostat (65%) or weather stripping (63%). Six in ten (60%) have reduced water use, and 54% have insulated windows/doors or spaces. Fewer have done each of replacing/upgrading heating equipment (42%), installing timers for lighting (38%), sourcing products from suppliers who work in an environmentally responsible manner (36%), replacing windows and doors (33%), conducting energy awareness programs with employees (32%), installing a high efficiency water heater (30%), funding environmental programs in the community (18%), drafting a plan to reduce the company's carbon footprint (16%) or looking at alternative energy sources (8%).



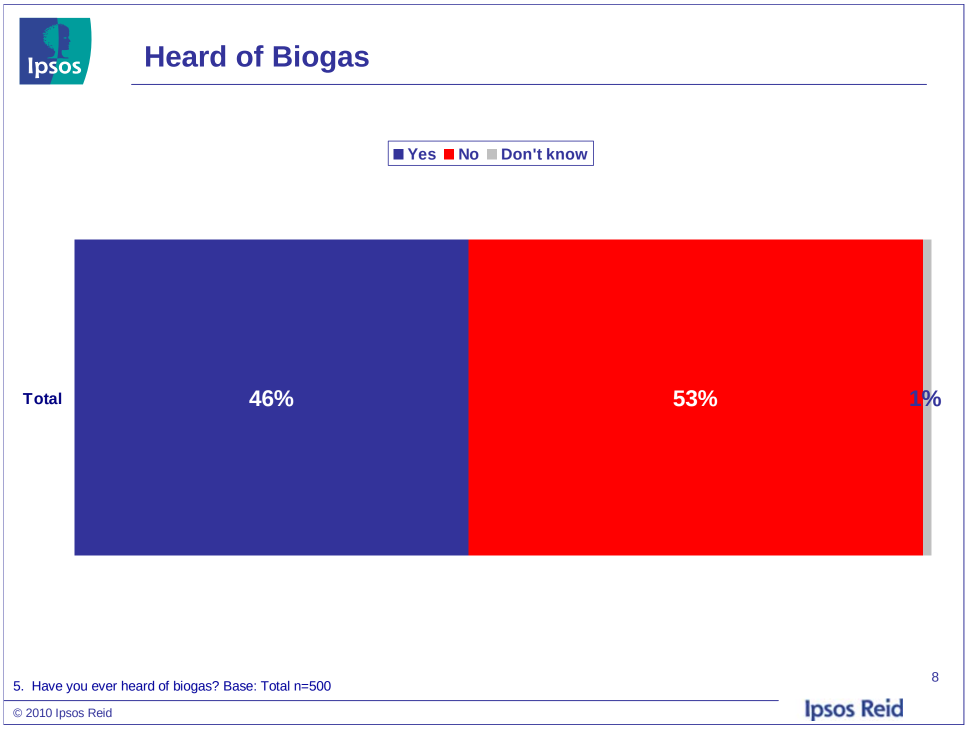
Among the few commercial respondents (10% or N = 52) who indicate they have not taken steps to save energy, a quarter (25%) say they are not sure what can be done. This is followed by 17% who say they are a small company, 15% who say they are already energy conscious and 14% who say saving energy is not their decision. About one in ten (10%) say it costs too much or that it is not a priority (8%). Six percent say there is no money available to fund energy saving programs. Two percent do not think energy saving programs will make a difference.

Fourteen percent say they don't know why they haven't taken steps to save energy.



7.3 Biogas Awareness and Support

Commercial natural gas customers are essentially split on their awareness of the term biogas. Forty six percent have heard of biogas, while 53% indicate they have not heard of biogas.



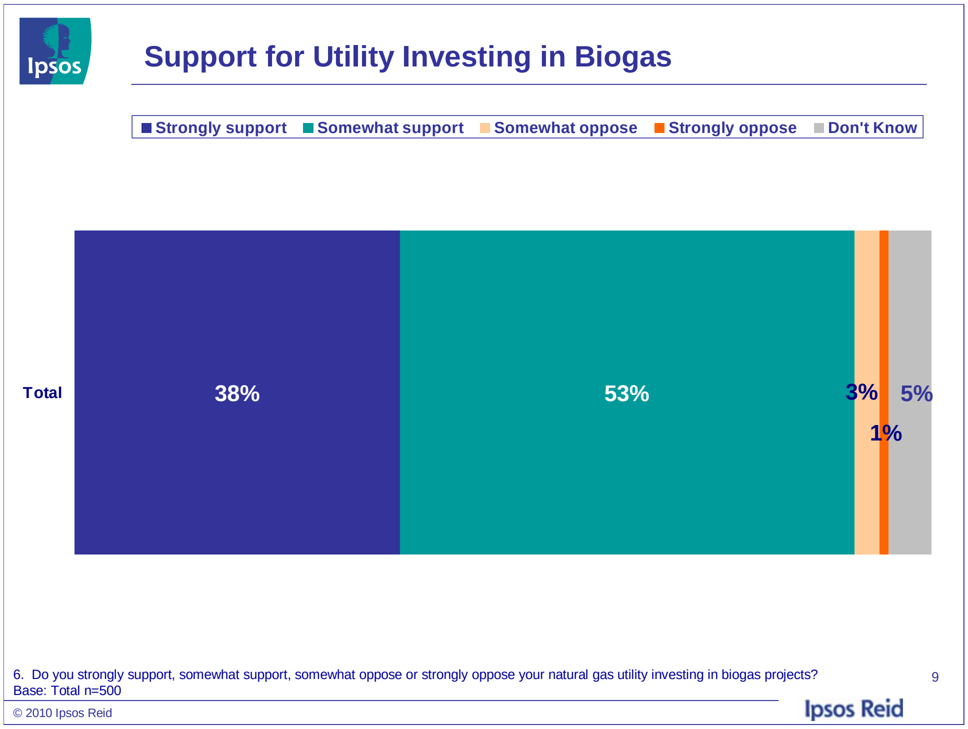
To better understand biogas, respondents were provided with the following description:

Bio methane gas or biogas is produced in landfills and waste water treatment plants and from animal manure and organic waste. It is a by-product of materials breaking down and rotting. The gas occurs naturally and is released into the atmosphere. It is possible to collect biogas. Once it is captured the biogas can then be cleaned and delivered to the market and used to heat homes and businesses <u>thereby reducing greenhouse gas emissions.</u>

Your natural gas utility is exploring the purchase of biogas to assist in meeting the overall gas supply needs of their commercial customers. Biogas can then become a viable, renewable energy source for your region.

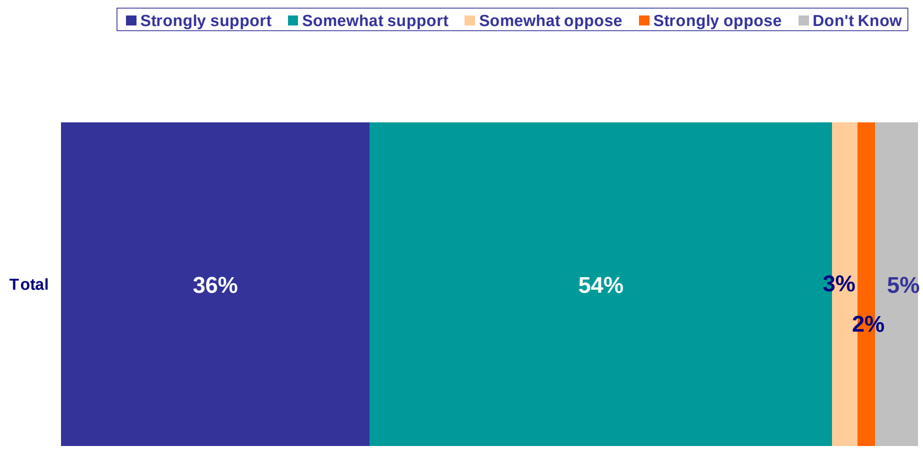
After being provided with this information, they were asked to indicate their company's support or opposition to their gas utility investing in biogas projects.

As the table below indicates with 91% agreeing, strong support exists among commercial natural gas customers for gas companies to invest in biogas projects. Very few, only four percent, expressed opposition, with a further five percent indicating they did not know.



Similarly, strong support exists among commercial natural gas customers for natural gas utilities purchasing biogas to meet the gas supply needs of business customers. When asked 90% of commercial natural gas customers support their natural gas utility purchasing biogas. Only five percent are opposed to this, with five percent indicating they do not know.

Support for Utility Purchasing Biogas



Q7. Do you strongly support, somewhat support, somewhat oppose or strongly oppose your natural gas utility purchasing biogas to meet the gas supply needs of its residential customers?/ Do strongly support, somewhat support, somewhat oppose or strongly oppose your natural gas utility purchasing biogas to meet the gas supply needs of its commercial customers? Base: All Respondents – Total n=500

10

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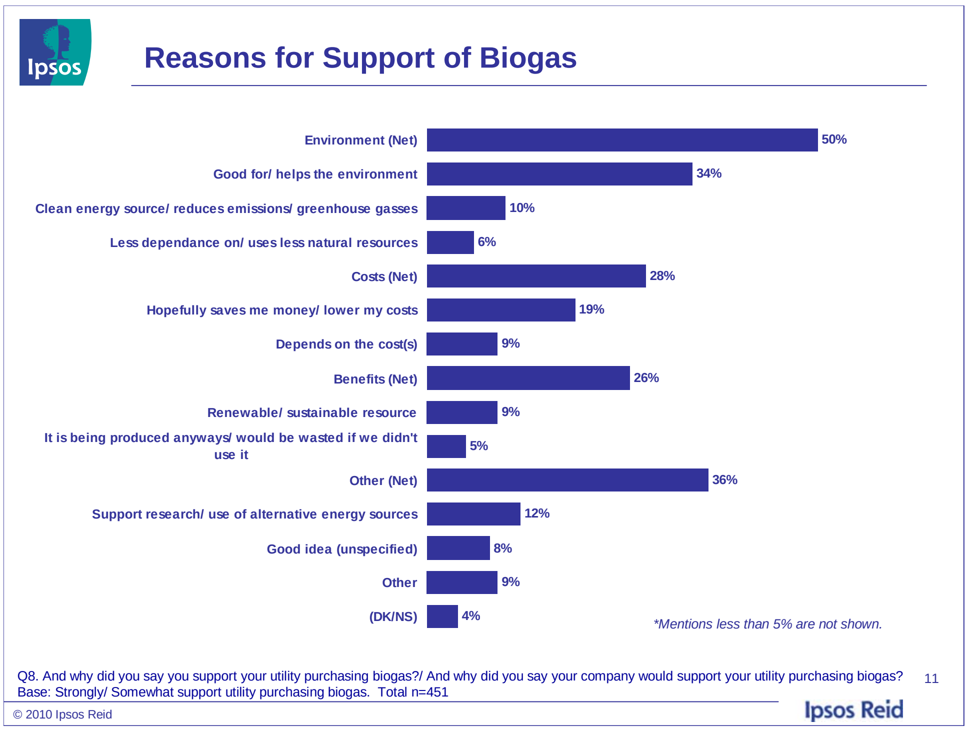
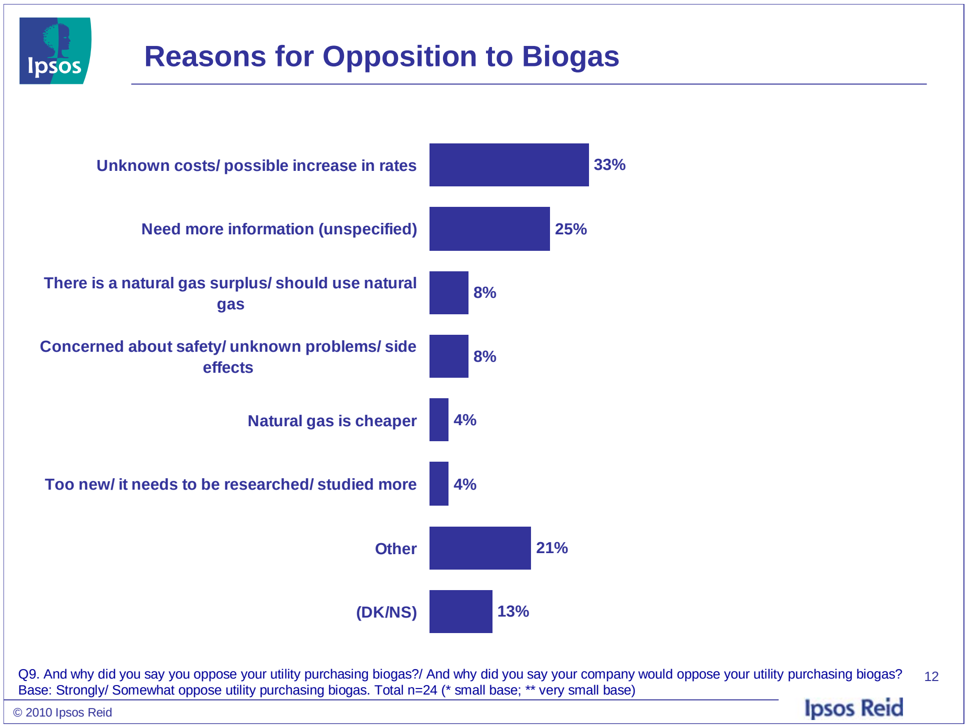
Of those who support natural gas utilities purchasing biogas, most indicate they do so out of a combination of responses related to it being good for the environment (50%), this includes; good for/helps the environment (34%), clean energy source/reduce emissions/greenhouse gases (10%) and less dependence on natural resources (6%). About one quarter (28%) indicate factors related to cost including; the inclusion of biogas will help them save money (19%), or that it depends on the cost (9%). Twenty six percent cite general benefits including; that it is renewable/sustainable (9%) and is being produced anyway (5%).

Over one third (36%) commercial natural gas customers provide other reasons for their support of the purchase of biogas.



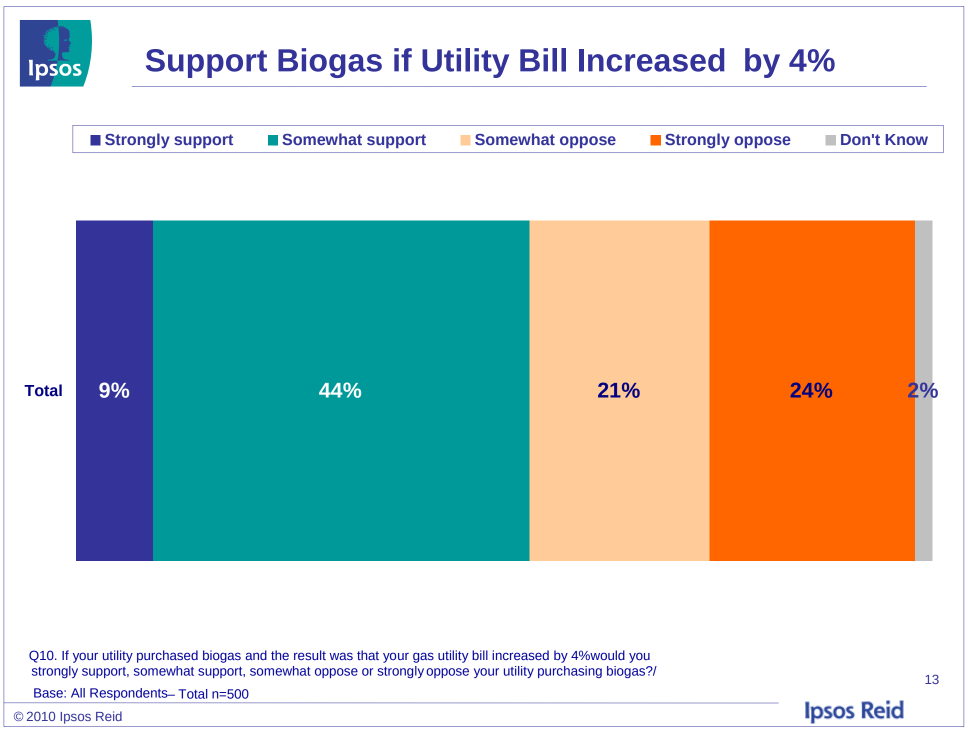
Among the five percent or N of 24 of respondents who oppose gas utilities purchasing biogas, the unknown cost of doing so is stated as the top concern (33%). This is followed by 25% who say they have a lack of information. Other mentions for not supporting biogas include: there is a natural gas surplus (8%), concerns about safety (8%), natural gas is cheaper (4%) and biogas is too new and needs to be researched more (4%).



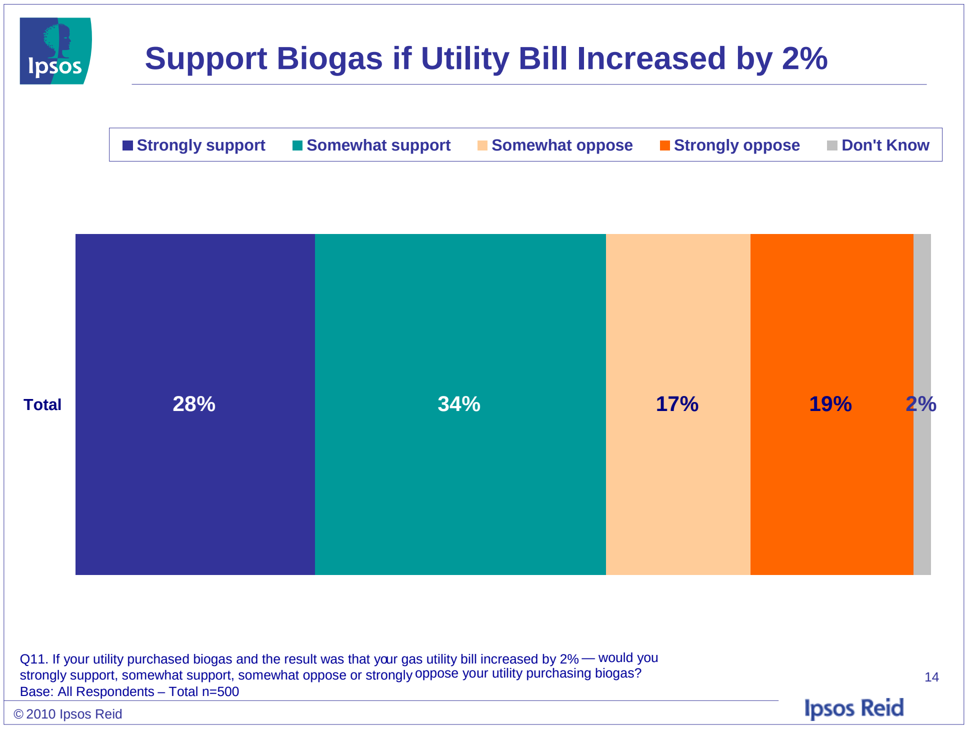
7.4 Biogas Pricing

Commercial natural gas customers were asked a series of questions related to pricing and the impact of an increase in their gas bill on support for including biogas in the natural gas delivered to their businesses.

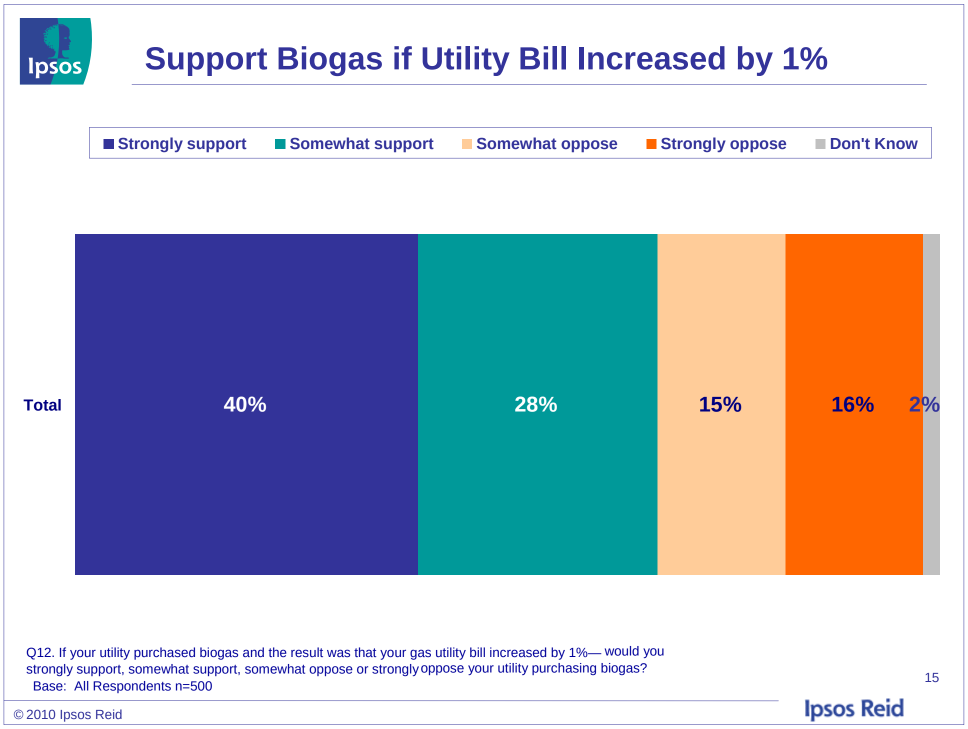
Just over half of commercial natural gas customers (53%) support the purchase of biogas by their utility even if it means their commercial natural gas bill would increase by 4%. Just under one half (45%) are opposed to the purchase of biogas if it resulted in a 4% increase in their natural gas bill.



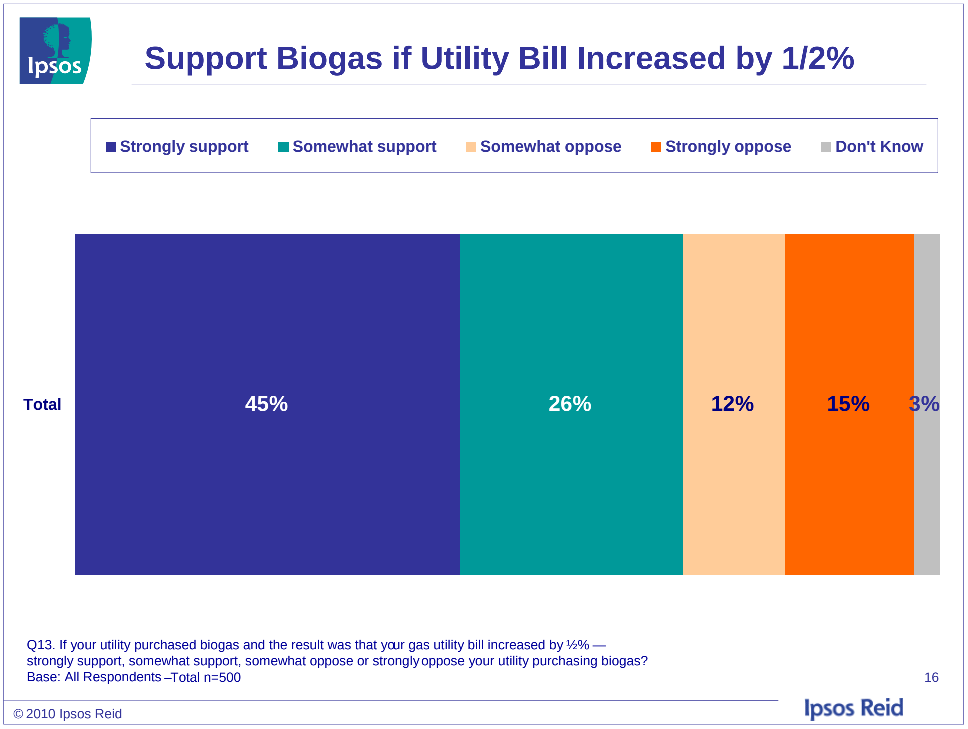
If the increase in the business's natural gas bills was set at 2% based on the inclusion of biogas, support for the inclusion of biogas rises to just over six in ten (62%). Opposition decreases somewhat to 36%.



Just over two thirds (68%) of commercial natural gas customers express support for their utility purchasing biogas if the result is only a 1% increase in their corporate gas bill. Just over three in ten (31%) say they are opposed to a 1% increase.

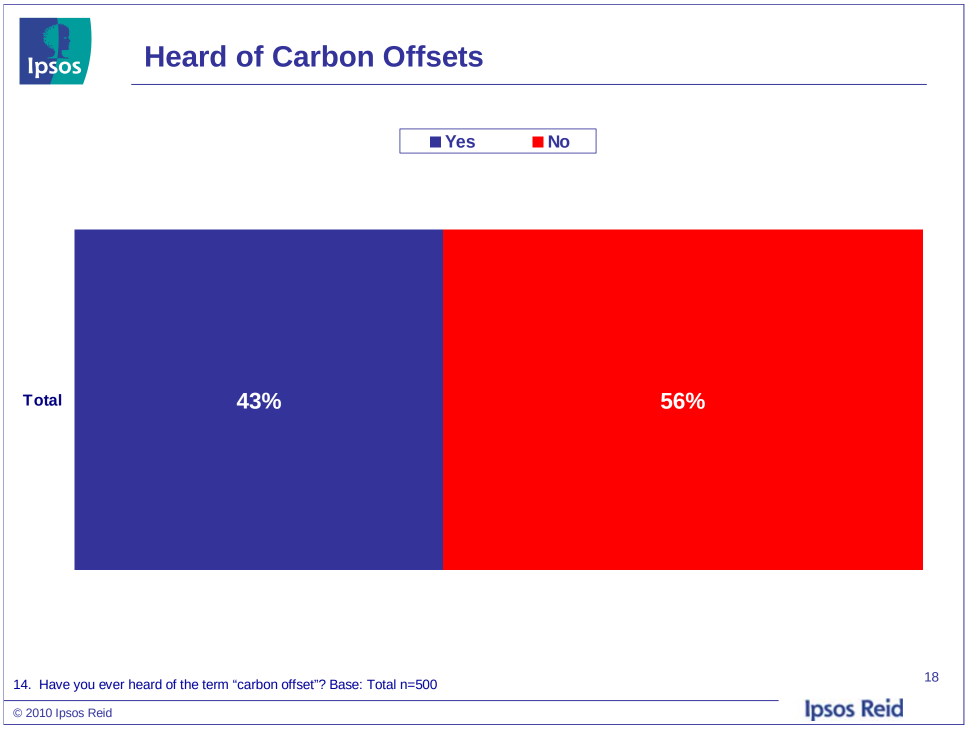


The strongest level of support is found when commercial natural gas customers are presented with the option of biogas inclusion resulting in a one half of one percent increase in their utility bill. On this measure just over seven in ten (71%) commercial natural gas customers express support at this level. Twenty seven percent report opposition even to a one half of one percent increase in their gas bill.



7.5 Carbon Offsets

A majority (56%) of commercial natural gas customers indicate they have not heard of carbon offsets. Just over four in ten (43%) of commercial customers have heard of carbon offsets.



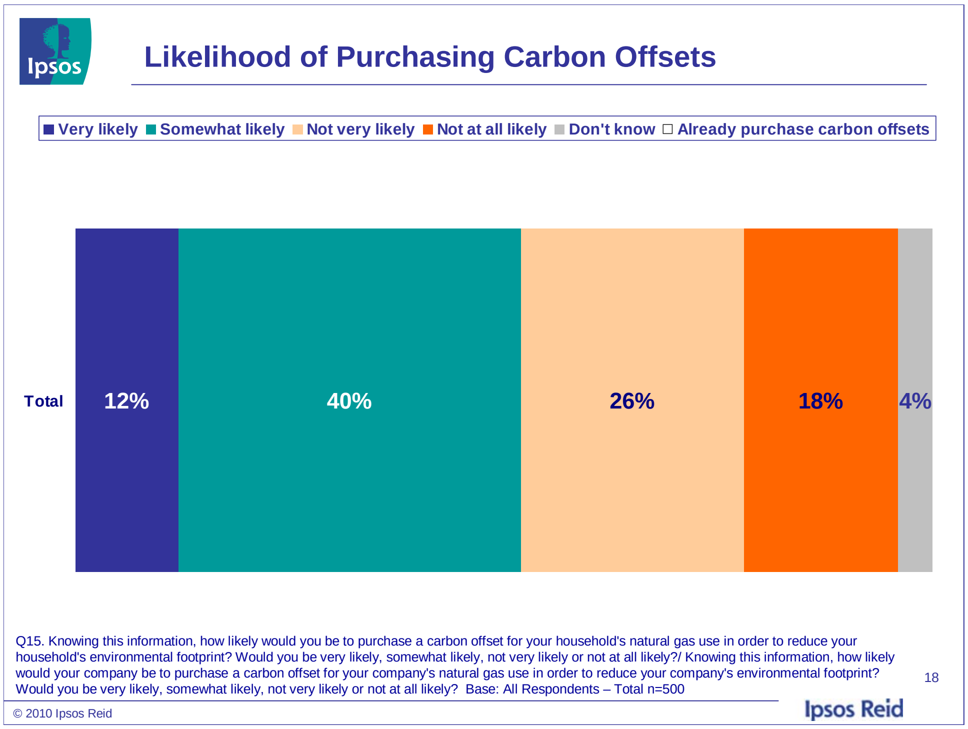
To better understand the likelihood of purchasing a carbon offset, commercial natural gas customers were provided with the following description:

A carbon offset is a reduction in emissions of carbon or greenhouse gases made in order to compensate for or to offset an emission made elsewhere. In the case of a gas customer, the customer would receive a carbon offset in exchange for supporting a project that reduces the emission of greenhouse gases into the environment.

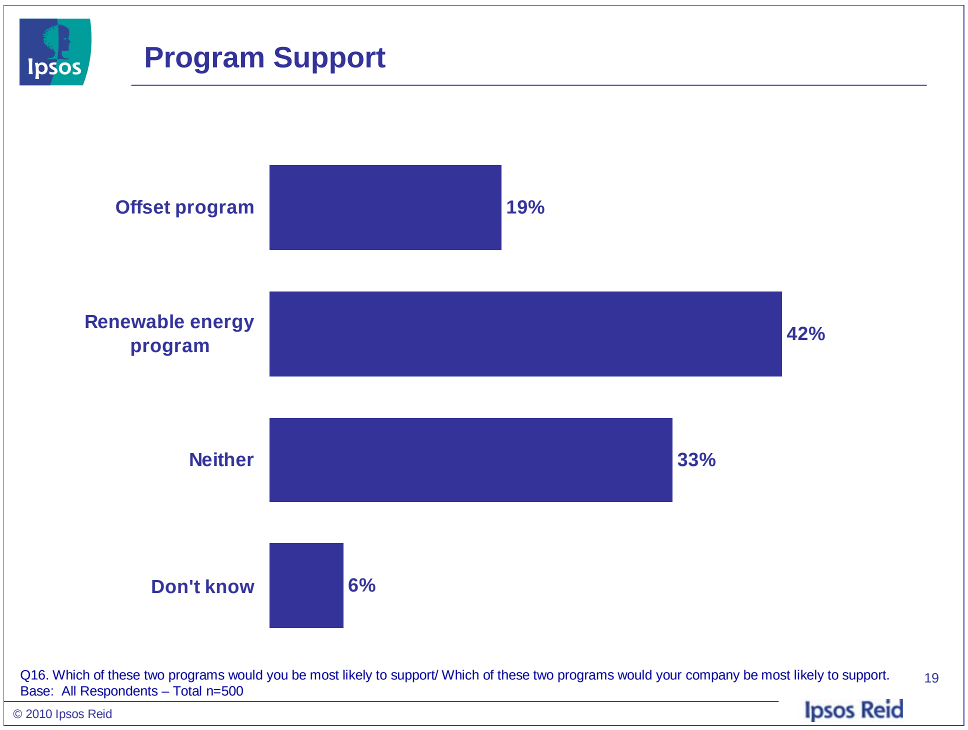
The commercial customer benefits because their purchase of a carbon offset balances out greenhouse gases that they may release through activities such as office and facility heating.

Offset projects support reduction in greenhouse gases by the planting of trees or the development of clean renewable energy projects such as biogas, wind and solar energy, etc.

They were then asked to indicate the likelihood of purchasing a carbon offset in order to reduce their company's environmental footprint. As the table below shows, just over half (52%) of the commercial natural gas customers surveyed say they are at least somewhat likely to purchase a carbon offset for their business. One third (44%) say they would not purchase carbon offsets.



Provided with a choice, commercial natural gas customers are more likely to support (42%) a renewable energy program (questionnaire wording -- In a renewable energy program, commercial customers pay a premium for a portion of their natural gas to be supplied from a utility investing in renewable energy projects such as biogas) than they are an offset program (19%) (Questionnaire wording -- In an offset program, commercial customers are offered the option to offset their corporate natural gas use by purchasing carbon offsets through the utility). One third (33%) say they would not support either option, while 6% say they don't know.



8. Appendix I – Residential Questionnaire

Ipsos Reid Public Affairs

INTRODUCTION

SCREENING

A. Do you or does anyone in your household work in any of the following areas?

Advertising or Public Relations
Market Research
The media, that is TV, radio or newspaper
Energy providers (e.g. natural gas, oil, electricity, propane)
None of the above
[IF CODE 1-4 THEN TERMINATE]

B. Are you… (Select one)

Male
Female

C. In what year were you born? PLEASE RECORD YEAR.

[INSERT SMALL TEXT BOX]
RANGE 1900-2010 [TERMINATE IF >1992]
(Resulting Codes – 18-24, 25-29, 30-34, 35-39, 40-44, 45-49, 50-54, 55-59, 60-64, 65-69, 70/older)

D. Are you the person in your household who is fully or jointly responsible for decisions about utility services?
Yes
No
[IF YES AT D CONTINUE, IF NO TERMINATE]

E. Which of the following energy sources do you use in your home? (SELECT/RECORD ALL THAT APPLY)
Natural Gas
Electricity

Other (specify)

[IF YES HAVE NATURAL GAS AT E CONTINUE, ELSE TERMINATE]

F1. Do you receive your natural gas bill from Enbridge, Union Gas or someone else?
Enbridge Gas
Union Gas
Someone else
Don't know
[IF 3 OR 4 THEN TERMINATE]

F2. Which company do you purchase your natural gas supply from?
Your natural gas distributor e.g. Enbridge or Union Gas
Or
A marketer or broker that provides a separate charge on your utility bill for the supply of natural gas

G. Are you enrolled in the [ENBRIDGE CUSTOMER: Budget Billing Plan/ UNION CUSTOMER: Equal Billing Plan]?
Yes
No
DON'T KNOW

Overall, how concerned are you about each of the following are you very concerned, somewhat concerned, not very concerned or not at all concerned?

[RANDOMIZE]
[COLUMNS]
The current state of the environment
The future state of the environment
The effects of global warming /climate change
Greenhouse gas emissions
The loss of oxygen producing forests
The level of government or industry leadership on environmental issues
Access to alternative energy solutions

[ROWS]
Very concerned
Somewhat concerned
Not very concerned
Not at all concerned
Don't know

Have you taken steps to save energy at home?

Yes
No
Don't know
[IF Q2 IS YES CONTINUE, IF Q2 IS NO SKIP TO Q4, ELSE SKIP TO Q5]

What steps have you taken to save energy? (Select all that apply)

Reduced water use (e.g., aerators, water-conserving faucets)
Energy efficient lighting
Installed timers for lighting
Installed a programmable thermostat
Weather stripping / caulking
Insulating windows / doors / spaces
Replaced windows / doors with energy efficient windows / doors
Re-using / reducing / recycling materials
Replaced existing space heating equipment with high efficiency upgrades
Installed a high-efficiency water heater
Alternative energy sources (e.g., heat pumps, solar panels)
Other (Specify)

Why have you not taken steps to save energy?
(RECORD RESPONSE)

[UNAIDED]
Don't know

BIO METHANE GAS

[ASK ALL]

Have you ever heard of biogas?
Yes
No
Don't know

Bio methane gas or biogas is produced in landfills and waste water treatment plants and from animal manure and organic waste. It is a by-product of materials breaking down and rotting. The gas occurs naturally and is released into the atmosphere. It is possible to collect biogas. Once it is captured the biogas can then be cleaned and delivered to the market and used to heat homes and businesses thereby reducing greenhouse gas emissions.

Your natural gas utility is exploring the purchase of biogas to assist in meeting the overall gas supply needs of their customers. Biogas can then become a viable, renewable energy source for your region.

Do you strongly support, somewhat support, somewhat oppose or strongly oppose your natural gas utility investing in biogas projects?

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose

Don't Know

Do you strongly support, somewhat support, somewhat oppose or strongly oppose your natural gas utility purchasing biogas to meet the gas supply needs of its residential customers?

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose
Don't Know

[IF STRONGLY/SOMEWHAT SUPPORT AT Q7 ASK Q8, IF STRONGLY/SOMEWHAT OPPOSE AT Q7 ASK Q9]

And why did you say you support your utility purchasing biogas? (RECORD RESPONSE)

____

And why did you say you oppose your utility purchasing biogas ? (RECORD RESPONSE)

____

If your utility purchased biogas and the result was that your gas utility bill increased by 4% —which is about $3.00 more per month — would you strongly support, somewhat support, somewhat oppose or strongly oppose your utility purchasing biogas?

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose
DON'T KNOW

If your utility purchased biogas and the result was that your gas utility bill increased by 2% —which is about $1.50 more per month —would you strongly support, somewhat support, somewhat oppose or strongly oppose your utility purchasing biogas?

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose
DON'T KNOW

If your utility purchased biogas and the result was that your gas utility bill increased by 1% —which is about $0.80 more per month — would you strongly support, somewhat support, somewhat oppose or strongly oppose your utility purchasing biogas?

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose
DON'T KNOW

If your utility purchased biogas and the result was that your gas utility bill increased by ½% —which is about $0.40 more per month — would you strongly support, somewhat support, somewhat oppose or strongly oppose your utility purchasing biogas?

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose
DON'T KNOW

CARBON OFFSET

Changing topics slightly…

Have you ever heard of the term "carbon offset"?

Yes
No
Don't know

A carbon offset is a reduction in emissions of carbon or greenhouse gases made in order to compensate for or to offset an emission made elsewhere. In the case of a gas customer, the customer would receive a carbon offset in exchange for supporting a project that reduces the emission of greenhouse gases into the environment.
The customer benefits because their purchase of a carbon offset balances out greenhouse gases that they may release through activities such as home heating.
Offset projects support reduction in greenhouse gases by the planting of trees or the development of clean renewable energy projects such as biogas, wind and solar energy, etc.

Knowing this information, how likely would you be to purchase a carbon offset for your household's natural gas use in order to reduce your household's environmental footprint? Would you be very likely, somewhat likely, not very likely or not at all likely?

Very likely
Somewhat likely
Not very likely
Not at all likely
Don't know
Already purchase carbon offsets

There are potentially two types of pricing programs utilities could offer in relation to reducing residential environmental footprints. One is called an offset program and the other is called a renewable energy program.

In an offset program, customers are offered the option to offset their home natural gas use by purchasing carbon offsets through the utility.

In a renewable energy program, customers pay a premium for a portion of their natural gas to be supplied from a utility investing in renewable energy projects such as biogas.

Which of these two programs would you be <u>most</u> likely to support
(Select one only)

Offset program
Renewable energy program
Neither
Don't know

DEMOGRAPHICS

[ACTIVISM INDEX]
In the last year which of the following have you done?

[ROWS - RANDOMIZE ITEMS]
a. Written a letter or email to or called a newspaper, radio or TV station, an elected official, company or any other organization
b. Been a volunteer, donor or member of a community service organization, charity, political party or other organization like an environmental group
c. Regularly talked with friends or relatives about political or social issues and tried to convince them to see things your way

[COLUMNS]
Yes
No

What is the highest level of schooling that you have completed? (Select one)

Less than elementary school
Elementary School
High School
Community College
Some University
Completed University
Graduate Degree

Which of the following income groups would best represent your annual HOUSEHOLD income? (Select one)

Less than $20,000
$20,000 to less than $40,000
$40,000 to less than $60,000
$60,000 to less than $80,000
$80,000 to less than $100,000
$100,000 to less than $120,000
$120,000 or more

Do you own or rent your home?

Own
Rent
Don't Know

What type of home do you live in?

Single Detached House
Semi- Detached House
An attached row or townhouse
A duplex
A triplex
A four-plex
A six plex
An apartment condominium
An apartment
A condominium bungalow
Other

Including yourself, how many people live in your household?

One
Two
Three
Four
Five
Six
Seven or more
Decline

How many children 17 years of age or under, if any, do you have living in your household?

[DROP DOWN MENU – 0 TO 15]

9. Appendix II – Commercial Questionnaire

Ipsos Reid Public Affairs

INTRODUCTION

SCREENING

My name is __________ and I am calling on behalf of Ipsos Reid a Canadian based market research and public opinion company. May I please speak with the person in an accounting/accounts receivable decision making role who is responsible for selecting office space, rental rates, paying large corporate bills including utilities.
We are speaking with senior staff across a number of Ontario based companies on issues related to energy, energy supply and the environment. The study is being sponsored by Enbridge Gas and it takes about ten minutes to complete. All of your answers are confidential. Is now a good time to conduct the interview or would you prefer that I schedule an appointment with you?

Now is fine (CONTINUE)
Schedule a callback on the following date and time ______________________

[INTERVIEWER: RECORD GENDER]
[DO NOT ASK]

Male
Female

D. Are you the person in your organization who is fully or jointly responsible for decisions about utility services?
Yes
No
[IF YES AT D CONTINUE, IF NO TERMINATE]

E. Which of the following energy sources do you use in your organization? (SELECT/RECORD ALL THAT APPLY)
(READ LIST)
Natural Gas
Electricity
Oil
Propane
Wood
Solar
Other (specify)

[IF YES HAVE NATURAL GAS AT E ASK F1, IF NO/DON'T KNOW/REFUSE TO NATURAL GAS AT E TERMINATE]
F1. Do you receive your natural gas bill from Enbridge, Union Gas or someone else?
Enbridge Gas
Union Gas
Broker/Marketer
Someone else

F2. Which company do you purchase your natural gas supply from?
(READ LIST)
Your natural gas distributor e.g. Enbridge or Union Gas
Or
A marketer or broker that provides a separate charge on your utility bill for the supply of natural gas

Overall, how concerned is your organization about each of the following are you very concerned, somewhat concerned, not very concerned or not at all concerned? (READ SCALE AS NECESSARY)

[RANDOMIZE]
The <u>current</u> state of the environment
The <u>future</u> state of the environment
The effects of global warming /climate change
Greenhouse gas emissions
The loss of oxygen producing forests
The level of government or industry leadership on environmental issues
Access to alternative energy solutions

Very concerned
Somewhat concerned
Not very concerned
Not at all concerned

Has your organization taken steps to save energy at its location(s)?

Yes
No
Don't know

[IF Q2 IS YES CONTINUE, IF Q2 IS NO/DON'T KNOW SKIP TO Q4, ELSE SKIP TO Q5]

What steps have been taken to save energy in your organization?
(Select all that apply)
(READ LIST)
Reduced water use (e.g., aerators, water-conserving faucets)

Energy efficient lighting
Installed timers for lighting
Installed a programmable thermostat
Weather stripping / caulking
Insulating windows / doors / spaces
Replaced windows / doors with energy efficient windows / doors
Re-using / reducing / recycling materials
Replaced existing space heating equipment with high efficiency upgrades
Installed a high-efficiency water heater
Alternative energy sources (e.g., heat pumps, solar panels)
Conducted energy saving awareness program with employees
Sourcing and buying materials and products from suppliers who operate in an environmentally sustainable manner
A documented plan to reduce your company's carbon footprint
Funding environmentally based programs and events in the community
Other (Specify)

[IF NO AT Q2 ASK Q4, OTHERWISE SKIP TO Q5]
Why has your organization not taken steps to save energy?
(UNAIDED, ACCEPT TWO RESPONSES – PROBE FOR DETAIL)

BIO METHANE GAS

[ASK ALL]

Have you ever heard of bio gas?
Yes
No

As you may know, bio methane gas or biogas is produced in landfills and waste water treatment plants and from animal manure and organic waste. It is a by-product of materials breaking down and rotting. The gas occurs naturally and is released into the atmosphere. It is possible to collect biogas. Once it is captured the biogas can then be cleaned and delivered to the market and used to heat homes and businesses <u>thereby reducing greenhouse gas emissions.</u>

Your natural gas utility is exploring the purchase of biogas to assist in meeting the overall gas supply needs of their commercial customers. Biogas can then become a viable, renewable energy source for your region.

(READ IF NECESSARY: IF RESPONDENT ASKS WHAT GREENHOUSE GASES ARE SAY 'GREENHOUSE GASES ARE THOSE GASES THAT RESULT FROM THE BURINING OF FOSSIL FUELS AND MAY BE A CAUSE OF GLOBAL WARMING.')

Do you strongly support, somewhat support, somewhat oppose or strongly oppose <u>your natural gas utility investing in biogas projects</u>?

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose

Do strongly support, somewhat support, somewhat oppose or strongly oppose <u>your natural gas utility purchasing biogas to meet the gas supply needs of its commercial customers</u>?

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose

[IF STRONGLY /SOMEWHAT SUPPORT AT Q7 ASK Q8, IF SOMEWHAT / STRONGLY OPPOSE AT Q7 ASK Q9]

And why did you say your company would <u>support</u> your utility purchasing biogas? (UNAIDED – PROBE FOR DETAIL)

____

And why did you say your company would <u>oppose</u> your utility purchasing biogas? (UNAIDED – PROBE FOR DETAIL)

____

If your utility purchased biogas and the result was that your company's utility bill increased by 4%, would you strongly support, somewhat support, somewhat oppose or strongly oppose your utility purchasing biogas?

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose

And how about if your company's utility bill increased by 2%...
(READ IF NECESSARY: If your utility purchased biogas and the result was that your company's utility bill increased by 2%, would you strongly support, somewhat support, somewhat oppose or strongly oppose your utility purchasing biogas?)

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose

And how about if your company's utility bill increased by 1%...

(READ IF NECESSARY: If your utility purchased biogas and the result was that your company's utility bill increased by 1%, would you strongly support, somewhat support, somewhat oppose or strongly oppose your utility purchasing biogas?)

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose

And how about if your company's utility bill increased by half a percent...
(READ IF NECESSARY: If your utility purchased biogas and the result was that your company's utility bill increased by half a percent, would you strongly support, somewhat support, somewhat oppose or strongly oppose your utility purchasing biogas?)

Strongly support
Somewhat support
Somewhat oppose
Strongly oppose

CARBON OFFSET

Changing topics slightly…

Have you ever heard of the term "carbon offset"?

Yes
No

As you may know, a carbon offset is a reduction in emissions of carbon or greenhouse gases made in order to compensate for or to offset an emission made elsewhere. In the case of a gas commercial customer, the commercial customer would receive a carbon offset in exchange for supporting a project that reduces the emission of greenhouse gases into the environment.
The commercial customer benefits because their purchase of a carbon offset balances out greenhouse gases that they may release through activities such as office and facility heating. Offset projects support reduction in greenhouse gases by the planting of trees or the development of clean renewable energy projects such as biogas, wind and solar energy, etc.

Knowing this information, how likely would your company be to purchase a carbon offset for your company's natural gas use in order to reduce your company's environmental footprint? Would you be very likely, somewhat likely, not very likely or not at all likely?

Very likely
Somewhat likely
Not very likely
Not at all likely

(DO NOT READ: VOLUNTEERED) Already purchase carbon offsets

There are potentially two types of pricing programs utilities could offer in relation to reducing commercial environmental footprints. One is called an offset program and the other is called a renewable energy program.

In an offset program, commercial customers are offered the option to offset their corporate natural gas use by purchasing carbon offsets through the utility.

In a renewable energy program, commercial customers pay a premium for a portion of their corporate natural gas to be supplied from a utility investing in renewable energy projects such as biogas.

Which of these two programs would your company be most likely to support
(Select one only)

(READ LIST)
Offset program
Renewable energy program
Neither

Which of the following policies or programs does your company have in place at present?

Programs that seek ways to minimize our consumption of resources, including energy, paper and water
Programs that reduce our generation of waste and emissions
Office recycling
Sourcing and buying materials and products from suppliers who operate in an environmentally sustainable manner
A documented plan to reduce your company's carbon footprint
Funding environmentally based programs and events in the community.

Yes
No

Finally we would like to ask you a few questions about your organization. Please be assured that whatever you say will be kept entirely anonymous and absolutely confidential.

Approximately how many employees, including yourself, does your company presently employ at this location? [RANGE 1-999999]

What sector or industry does your company operate in? (UNAIDED, DO NOT READ LIST, ACCEPT ONE RESPONSE)

Hospitality industry
Real estate

Restaurant/food service
Property management
Retail
Services
Manufacturing
Financial services/insurance/banking
Natural resources (i.e. Mining, oil and gas, lumber, forestry, agriculture)
Engineering
Telecommunications/information/technology
Media
Government/Crown Corporation
Transportation
Pharmaceuticals/medical
Consumer products
Automotive
Aerospace
Other (specify) ___________________

Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario

-Biogas plant costing report

Prepared for:

Enbridge Gas Distribution Inc.

Union Gas Limited

Prepared by:

Electrigaz Technologies Inc.

September 2011

Executive summary

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (UGL) are the largest natural gas distribution utilities in Ontario. They are investigating technical and economic challenges of establishing a Renewable Natural Gas (RNG) program that would allow both utilities to provide their customers renewable natural gas. Electrigaz Technologies Inc. (Electrigaz) was hired by EGD and UGL to provide biogas engineering expertise to determine project costing necessary to perform financial modeling and price evaluation for this RNG program.

Current biogas market developments in Ontario and discussions with EGD and UGL enabled Electrigaz to develop nine scenarios that cover a wide range of potential biogas projects with different substrates, biogas flow rates, and biogas quality levels.

Three scenarios use landfill gas (LFG) with various biogas flow rates (small, medium, and large). The remaining six scenarios are anaerobic digestion (AD) processes. Three AD scenarios are from the agricultural sector and one from the industrial sector. Municipal source separated organics (SSO) AD process and a wastewater treatment plant (WWTP) are also evaluated.

In this report, capital and operational costs were estimated for each scenario using the best available Ontario biogas market information. These costs form the basis for an appropriate pricing mechanism which can be found in the *Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario—RNG program pricing report*.

Glossary

Biogas	Gas produced from anaerobic digestion, mostly composed of CH_4 and CO_2
Biomethane	Methane extracted from a biogas upgrading system, also called Renewable Natural Gas (RNG)
Digestate	Nutrient rich material left following AD consisting of indigestible material and dead micro-organisms
Renewable Natural Gas	Biomethane interchangeable with natural gas
Substrate	Material uploaded into digesters

Abbreviations and units

AD	Anaerobic digestion
CGA	Canadian Gas Association
CH_4	Methane
CO_2	Carbon dioxide
C:N	Carbon/Nitrogen ratio
CSTR	Complete stirred tank reactor
d	Day
EPC	Engineering, Procurement and Construction
FIT	Feed in tariff
GHG	Greenhouse gases
GJ	Energy unit (Gigajoule)
H_2O	Water
HP injection pressure	High pressure (200 psig)
hr	Time unit (Hour)
H_2S	Hydrogen sulphide
IDC	Interest during construction
IP injection pressure	Intermediate pressure (60 psig)
kg	Mass unit (Kilogram)

kWe	Power unit (Kilowatt electrical)
kWh	Energy unit (Kilowatt-hour)
l	Volume unit (Litre)
LFG	Landfill gas
m^3	Volume unit (Cubic meter)
mg	Mass unit (Milligram)
MJ	Energy unit (MegaJoule)
MSW	Municipal solid waste
%mol	Concentration unit (molar percentage)
N_2	Nitrogen
N/D	Not defined
Nm^3	Volume unit (Normal cubic meter)
O_2	Oxygen
OPA	Ontario Power Authority
OPA FIT	Ontario Power Authority feed in tariff program
ppm	Concentration unit (part per million)
PSA	Pressure swing adsorption
psig	Pressure unit (pound square inch gauge)
RNG	Renewable natural gas
ROE	Return on equity
S	Sulphur
SSO	Source separated organics
t	Mass unit (Tonne)
TS	Total solids
VS	Volatile solids
WWTP	Wastewater treatment plant
XHP injection pressure	Extra high pressure (500 psig)
Yr	Year
°C	Temperature unit (Celsius degree)

Acknowledgments

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Stéphane Guay, Michael Brown	Biomethatec
Sven Almqvist	Purac
Charlie Anderson	Air Liquide
Louis Barré	Mabarex

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1. Introduction

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (UGL) are the largest natural gas distribution utilities in Ontario. They are investigating technical and economic challenges of establishing a Renewable Natural Gas (RNG) program that would allow both utilities to provide their customers renewable natural gas.

Electrigaz Technologies Inc. (Electrigaz) was hired by EGD and UGL to provide biogas engineering expertise to provide the inputs and scenarios required to determine project costing necessary to perform financial modeling and price evaluation for this RNG program.

Electrigaz is the only engineering firm in Canada specialised exclusively in biogas engineering (Corporate Profile in Appendix 7). Electrigaz differentiates itself by providing complete biogas project development services, including capital and operating cost review, economic projections, price sensitivity analysis, financing and permitting documentation development, contract negotiations (equipment vendors, utilities, GHG, etc.), plant commissioning and operator training services. Over the years, Electrigaz has gained a deep understanding of Ontario's energy and environmental policy framework and how it impacts the development of a viable biogas industry.

1.1 Study objectives

The main objective of the study is to develop plausible biogas plant scenarios and establish their capital and operational cost.

1.2 Methodology

Nine biogas production scenarios were developed to reflect a wide spectrum of potential biogas projects. Capital and operational costs were obtained for each scenario using the best available Ontario biogas market information.

2. RNG production scenarios

Current biogas market developments in Ontario and discussions with EGD and UGL enabled Electrigaz to develop nine scenarios that cover a wide spectrum of potential biogas projects spanning different substrates, biogas flow rates, and biogas quality levels.

Three scenarios use landfill gas (LFG) with various biogas flow rates (small, medium, and large). The remaining six scenarios are AD processes. Three AD scenarios are from the agricultural sector and one from the industrial sector. Municipal source separated organics (SSO) and a wastewater treatment plant (WWTP) AD processes are also evaluated.

2.1 Anaerobic digestion scenarios

Six AD scenarios were developed:

- Baseline agricultural
- Large agricultural
- Agricultural cooperative;
- Source separated organics (SSO);
- Industrial;
- WWTP.

2.1.1 Agricultural scenarios

Farms have access to large amount of contaminant-free organic waste usable for RNG production. Moreover, the possibility of diversifying farm revenues generates significant interest throughout agricultural communities.

For the purpose of this study it is assumed that all three agricultural scenarios are dairy farms that will use manure generated by the farm. Additionally, 25% of substrate used for AD will be off-farm material in the form of grease trap fat. Such assumption is made as this material is readily available, contaminant-free, generates gate fees and has a good biogas yield.

The chosen agricultural scenarios have the following specifications:

Baseline agricultural (350kWe equivalent)
Number of heads (dairy cows): 1,315
Annual manure: 25,000 t
Annual off-farm waste: 8,000 t

Large agricultural (700 kWe equivalent)
Number of heads (dairy cows): 2,615
Annual manure: 49,700 t
Annual off-farm waste: 16,600 t

Agricultural cooperative (1 MWe equivalent)
Number of heads (dairy cows): 3,950
Annual manure: 75,000 t
Annual off-farm waste: 25,000 t

Note that these agricultural scenarios were chosen to reflect technical and economic realities of on-farm RNG production. These RNG projects require capital investment and are unlikely to happen on small singular farms (<1000 heads).

An agricultural cooperative means a centralized digester procuring manure from several farms. In this scenario, transportation cost and regulatory challenges were not analysed.

Biogas production process description

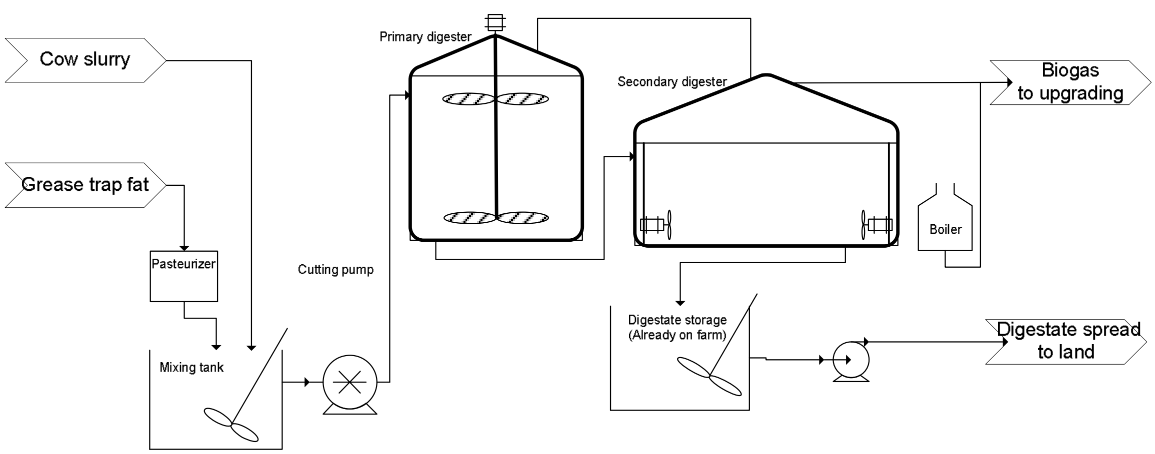

Figure 1. Agricultural AD process schematic

Manure and pasteurized off-farm waste are processed in state-of-the-art proven primary and secondary anaerobic digesters. Digestate generated by the system is assumed to be stored and land spread during allowable season. More process details are available in Appendix 1.

95% of the biogas produced is directed to the upgrading system, the remaining 5% is used to heat the process. Volumes of raw biogas (untreated) sent to the upgrading system for each scenario are as follows:

Baseline agricultural: 150m^3/hr
Large agricultural: 300m^3/hr
Agricultural cooperative: 450m^3/hr

Biogas upgrading and injection

It is assumed that upgraded biogas (RNG) will be injected to IP grid (60 psig), which is a typical pressure for distribution networks. The upgrading system outputs the RNG at the IP injection pressure, which means that no additional compression system is required.

An injection station is installed after the upgrading process for metering, quality control and odorization. An injection pipe connects the injection station to the existing natural gas distribution grid. The injection station and interconnection pipe are operated and maintained by the utilities.

Biogas upgrading mass balance was computed and details are available in Appendix 1. Mass balances were computed assuming a 100% availability of equipment. For the purpose of this study a 95% availability of upgrading equipment was assumed.

Flow rates of RNG to be injected to the grid (considering the availability of the upgrading process) are as follows:

Baseline agricultural: 77m^3/hr
Large agricultural: 158m^3/hr
Agricultural cooperative: 239m^3/hr

2.1.2 SSO scenario

Municipalities consider AD of source separated organics (SSO) as an attractive alternative to reduce the waste sent to landfill.

This scenario assumes that the facility treats 60,000 t of SSO from a 3-stream collection, contaminated with plastic, metal, sand and glass. The scenario is representative of a municipal AD facility serving a large population (300,000+). This scenario could apply to eight municipalities in Ontario [28].

Biogas production process description

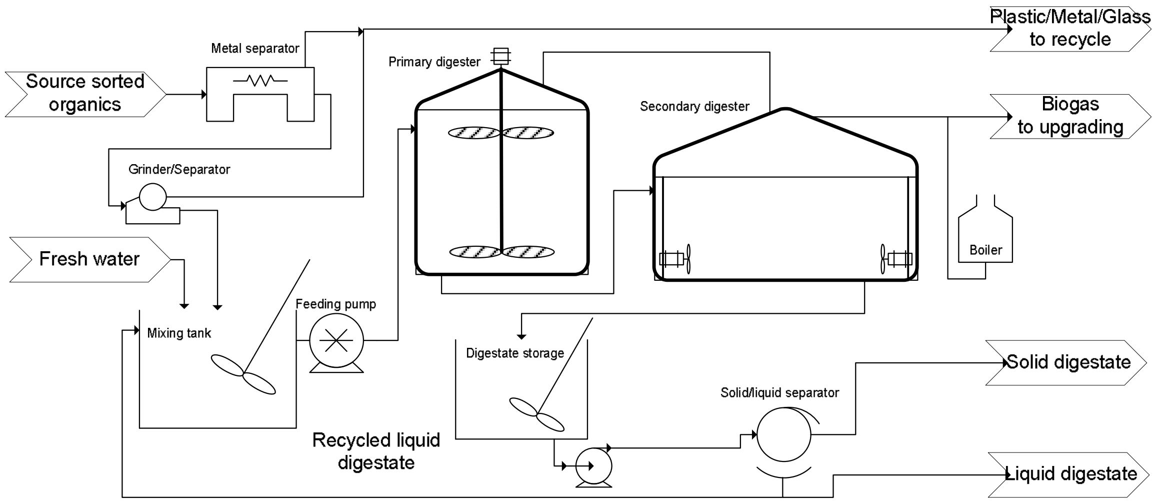

Figure 2. SSO AD process schematic

Reception and pre-treatment processes are required to pre-treat contaminated organics. To avoid odour issues, the reception area includes an airtight building with odour treatment and ventilation units. It is considered that a minimum two-lane reception hall is required to avoid odours generated by trucks waiting. The trucks would dump their loads in reception pits connected to the pre-treatment system.

The pre-treatment process removes contaminants such as plastic, sand, glass and metal, which are assumed to represent 10% of the SSO mass. The contaminants are disposed of in a landfill or recycling facility (disposal fees apply).

The organic fraction of the substrate is processed in state-of-the-art proven primary and secondary AD system. Approximately 700 m^3/hr of raw biogas (untreated) is sent to the upgrading system. This represent 95% of the total amount of biogas produced; the other 5% is used to heat the process.

The digestate is sent to a solid/liquid separation unit. The solid part of digestate is disposed of at a composting facility or sent to a landfill with a disposal cost. The liquid fraction of digestate is sent to an adjacent municipal WWTP also with a disposal cost considered. A small part of liquid digestate is recycled to the mixing tank to bring the substrate into slurry. Note that a total of 47,100 t of digestate (18,900 tonnes of solids and 28,200 tonnes of liquid) must be disposed of per year. More process details are available in Appendix 2

Biogas upgrading and injection

It is assumed that upgraded biogas (RNG) will be injected to IP grid (60 psig), which is a typical pressure for distribution networks. The upgrading system outputs the RNG at the IP injection pressure which means that no additional compression system is required.

An injection station is installed after the upgrading process for metering, quality control and odorization. An injection pipe connects the injection station to the existing natural gas distribution grid. The injection station and interconnection pipe are operated and maintained by the utilities.

Biogas upgrading mass balance was computed and details are available in Appendix 2. Mass balances were computed assuming a 100% availability of equipment. For the purpose of this study a 95% availability of upgrading equipment was assumed.

It is estimated that the flow of RNG to be injected to the grid is 366 m^3/hr (considering the availability of the upgrading process).

2.1.3 Industrial scenario

Food processing and manufacturing industries such as slaughterhouses, breweries or dairy product manufacturing have organic wastes to dispose of. Instead of sending this waste to landfill, it can be fed to anaerobic digester to produce biogas. The current scenario evaluates the possibility of such projects.

Contaminant-free substrates used for this scenario are 65,500 t/y of fruits and vegetable residues and 65,500 t/y of slaughterhouse waste.

Industrial processors generate large quantity of contaminant-free organic wastes which are suitable for AD.

Biogas production process description

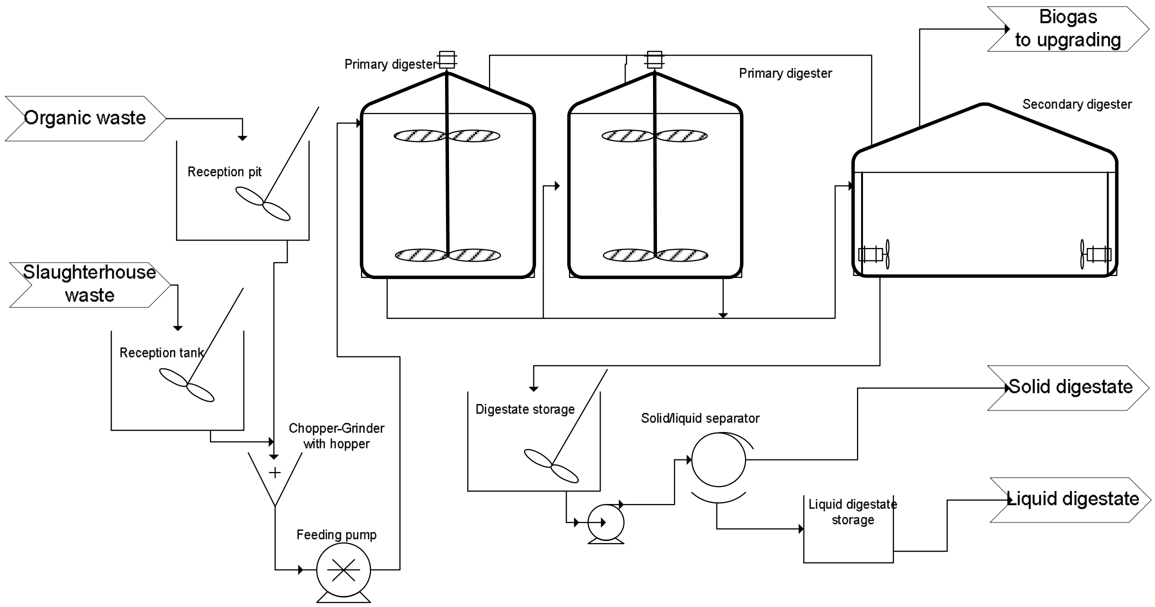

Figure 3. Industrial AD process schematic

The substrate is received in a two-lane reception hall equipped with an odour management system. The organic waste is dumped into a reception pit and the slaughterhouse waste is put into a reception tank.

It is assumed that the substrates used in this scenario are free of contaminants, and no pre-treatment is needed. To ensure that the particle size entering the digesters is homogeneous, the substrate passes through a grinder before it is sent to the digester by a feeding pump.

The organic fraction of the substrate is processed in state-of-the-art multiple tank AD system. Approximately 900 m^3/hr of raw biogas (untreated) is sent to the upgrading system. This represent 95% of the total amount of biogas produced; the other 5% is used to heat the process.

After the digestion process, the digestate is sent to solid/liquid separation unit. The solid part of the digestate is either disposed of at a composting facility or sent to landfill with a disposal cost. The liquid fraction of the digestate must be sent to an adjacent municipal WWTP or to agricultural lands also with a disposal cost. Note that a total of 119,560 t of digestate must be disposed of per year, in which approximately 40,410 t/yr is solid and 79,150 t/yr is liquid. More process details are available in Appendix 3.

Biogas upgrading and injection

It is assumed that upgraded biogas (RNG) will be injected to IP grid (60 psig), which is a typical pressure for distribution networks. The upgrading system outputs the RNG at the IP injection pressure which means that no additional compression system is required.

An injection station is installed after the upgrading process for metering, quality control and odorization. An injection pipe connects the injection station to the existing natural gas distribution grid. The injection station and interconnection pipe are operated and maintained by the utilities.

Biogas upgrading mass balance was computed and details are available in Appendix 3. Mass balances were computed assuming a 100% availability of equipment. For the purpose of this study a 95% availability of upgrading equipment was assumed.

RNG would be injected into the distribution grid at a flow rate of 471 m^3/hr (considering the availability of the upgrading process).

2.1.4 WWTP scenario

Wastewater treatment plants (WWTP) use AD to reduce effluent sludge quantities and produce biogas. In this scenario, biogas is upgraded and injected into the natural gas distribution grid.

For this scenario, it is assumed that the AD process is already operating and producing biogas. The biogas is considered as untreated and free of charge.

To establish the average WWTP size, data on WWTP using AD process in Ontario was analysed. A WWTP sludge digester was considered with a flow rate of raw biogas (untreated) of 127 m3/hr, equivalent to a 300 kWe biogas plant.

Since it is assumed that the digestion process is already in place, schematic and mass balances have not been prepared for the digestion process of this scenario. However, a mass balance of the upgrading system is presented in Appendix 4.

Biogas upgrading and injection

It is assumed that upgraded biogas (RNG) will be injected to IP grid (60 psig), which is a typical pressure for distribution networks. The upgrading system outputs the RNG at the IP injection pressure which means that no additional compression system is required.

An injection station is installed after the upgrading process for metering, quality control and odorization. An injection pipe connects the injection station to the existing natural gas distribution grid. The injection station and interconnection pipe are operated and maintained by the utilities.

Biogas upgrading mass balance was computed and details are available in Appendix 4. Mass balances were computed assuming a 100% availability of equipment. For the purpose of this study a 95% availability of upgrading equipment was assumed.

RNG would be injected to the distribution grid at a flow rate of 66.6 m^3/hr (considering the availability of the upgrading process).

2.2 Landfill scenarios

Landfills are uncontrolled anaerobic digesters producing large quantities of low quality biogas from the anaerobic degradation of the organic fraction of municipal solid waste (MSW) buried in them.

To establish representative biogas flow rates, Electrigaz analysed information on the land filling capacity of the 32 largest landfills in Ontario [4]. Other landfills were not taken into consideration because they are considered small. Three landfill scenarios were modeled to represent the complete spectrum of potential biogas flow rates.

These three landfill capacities were used to perform a LandGEM simulation [7] to calculate the annual biogas production. LandGEM simulations predict that biogas production increases each year of landfill operation. Annual capacity and raw biogas (untreated) production of each landfill are as follow:

Small landfill: 60,000 t/yr of MSW producing 475 m^3/hr of biogas
Medium landfill: 140,000 t/yr of MSW producing 1,110 m^3/hr of biogas
Large landfill: 500,000 t/yr of MSW producing 3,960 m^3/hr of biogas

In the small landfill scenario, it is assumed that the RNG will be injected in the IP grid (60 psig), which is a typical pressure for distribution networks. The upgrading system output already brings the biomethane to the IP injection pressure, which means that no additional compression system is required.

In the medium landfill scenario, it is assumed that the RNG will be injected in the HP grid (200 psig). The volume of RNG to be injected is assumed to be too large for local distribution network and interconnection must be performed upstream in the network. Therefore, an additional compression station is needed to bring the biomethane to the required pressure.

In the large landfill scenario, it is assumed that the RNG will be injected in the XHP grid (500 psig), The volume of RNG to be injected is assumed to be too large for the local distribution network and interconnection must be done in the extra high pressure distribution network. Therefore, an additional compression station is needed to bring the biomethane to the required pressure.

An injection station is installed after the upgrading and compression process for metering, quality control and odorization. An injection pipe connects the injection station to the existing natural gas distribution grid. The injection station and interconnection pipe are operated and maintained by the utilities.

RNG volumes to be injected into the distribution grid are as follow:

Small landfill: 243 m^3/hr
Medium landfill: 569 m^3/hr
Large landfill: 1,896 m^3/hr

Biogas upgrading mass balance was computed and details are available in Appendix 5. Mass balances were computed assuming a 100% availability of equipment. For the purpose of this study a 95% availability of upgrading equipment was assumed.

3. Economic data

Electrigaz independently collected all economic and technical data and information for this study. Electrigaz estimated AD process capital and operational costs.

To obtain current market information on upgrading systems, quotes from five companies supplying the Canadian market have been requested. These suppliers are as follows:

- Flotech/Greenlane
- Xebec
- Purac
- Haase
- Air Liquide

Only Air Liquide declined to provide budgetary quotes for their system.

In this study no specific biogas upgrading technology is favoured. All quotes received from aforementioned suppliers were used to obtain capital and operational costs of biogas upgrading.

3.1 General assumptions

The study economic and technical battery limits and assumptions were reviewed and approved by EGD and UGL.

Assumptions are supported by Ontario market information or Electrigaz experience. These assumptions were used to create the best snapshot of present Ontario biogas market.

3.1.1 Study battery limits[1]

EGD and UGL have established ownership and responsibility battery limits of RNG production to interconnect to their natural gas distribution grid. The following schematics (Figure 4) represent the battery limits of the study.

According to these limits, the producer is required to pay the utilities capital (aid to construct) for RNG quality monitoring, odorization and injection point (pipe). However, ownership, operation and maintenance of these systems are the responsibility of the utility. Capital and operational costs for the length of pipe to connect to the grid must be absorbed by the producer as well. This will have an impact on the RNG price since these costs will be integrated in the RNG producer economic model.

[1] Battery limits are defined as boundaries of analysis. Technical and economic parameters beyond these boundaries are not taken into consideration in this study.

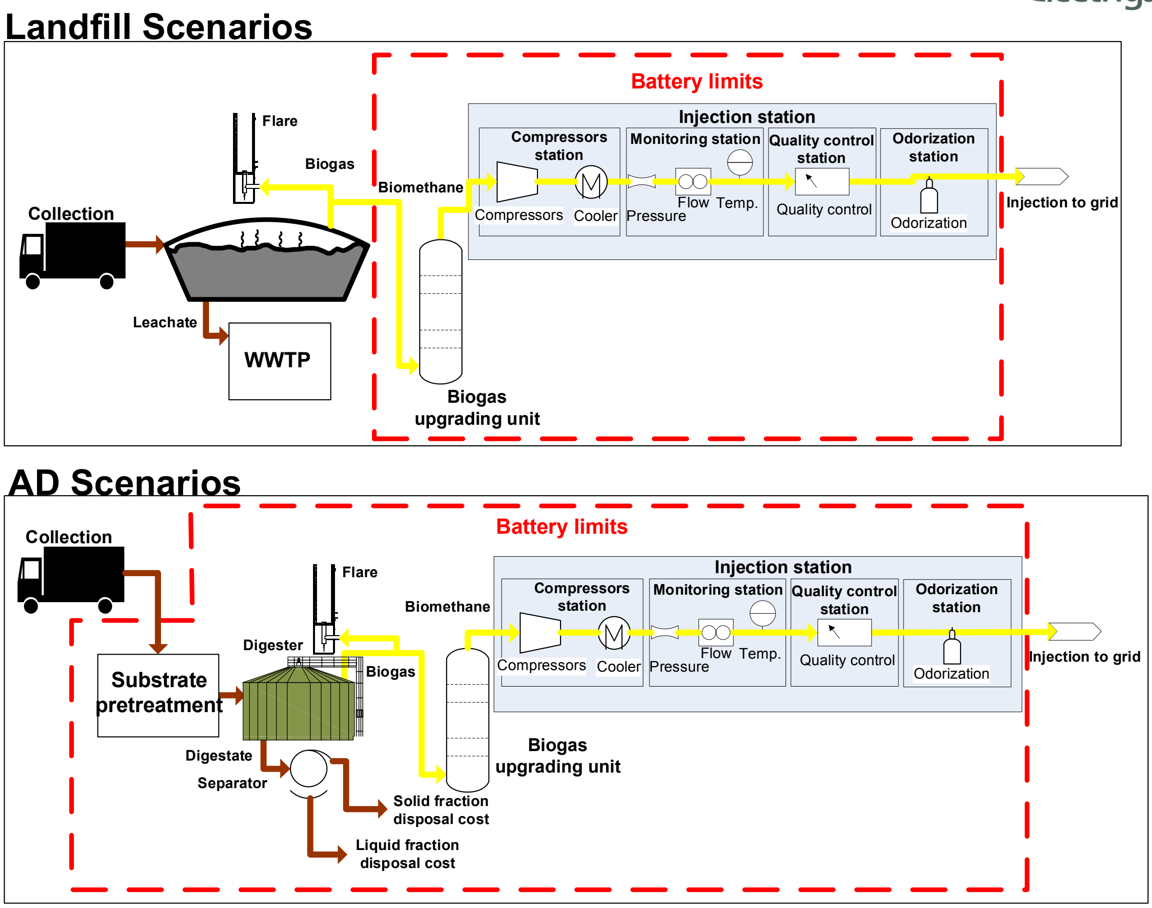

Figure 4: Battery limits of the economic evaluation

The schematics above show the differences between the battery limits of landfill and AD scenarios. For both scenarios, waste collection cost is not considered in this study. Therefore, the purchase and operation of collection trucks and bins are not included in capital or operational costs.

In landfill scenarios, it is assumed that the landfill already exists, collecting biogas and treating leachate. Therefore, no cost or investment is considered for the collection of the biogas and the treatment of the leachate. It is assumed, however, that the project would be developed by a third-party promoter. Therefore, a cost for the supply of the landfill gas is considered as a royalty payment.

In all AD scenarios, except WWTP, the substrate is organic waste brought to the plant, and a gate fee is considered as project revenue.

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The WWTP AD scenario differs from other AD scenarios as it is considered that the biogas is already produced and flared. Therefore, it is assumed that the raw biogas is available free of charge.

3.2 RNG specifications

The following RNG specifications (from Union Gas' gas quality requirement for Ontario gas Producers) were used to establish necessary biogas upgrading equipment capital and operational costs.

Table 1: RNG specification requirements considered in this study

Physical Properties	Upper Content Limit	Units
Heating Value (MJ/m3 101.325 kPa, 15C, Dry)	*36.0 to 40.2*	*MJ/M3*
Carbon monoxide	*0.5*	*mol%*
Carbon Dioxide	2	mol%
Oxygen	0.4	mol%
Hydrogen Sulphide	7	mg/M3
Sulpher (in total)	100	mg/M3
Mercaptans or Methyl Mercaptan	5	mg/M3
Water Content	80	mg/M3
Hydrocarbon Dew Point	-10	°C
Gas Interchangeability	YT, flashback, lifting factors range of permiting according to AGA Research bulletin No.36	
Temperature	43	°C
Particulates	shall be commercially free of	
Bacteria	shall be commercially free of	
Hydrogen	Trace	
Ammonia	shall be commercially free of	
Chlorinated & Fluorinated Compounds	shall be commercially free of	
Heavy Metals	shall be commercially free of	
Siloxanes	shall be commercially free of	
Aromatics	shall be commercially free of	
Sand, dust, gums, crude oils, lub. Oils, liquids, chemicals or compounds used in the production, treatment, compression or deshydratation of the gas or any other objectable substance present in sufficient quantity so as to render the Gas toxic, unmerchantable or cause injury to or interference with the Gas pipelines, regulators, meter or other appliances through which it flows, or their operation		

3.2.1 Macro-economic assumptions

Capital and operational costs for each scenario are calculated and introduced into the economic model as presented in the following chapters. Macro-economic assumptions were set to represent as accurately as possible current Ontario biogas market conditions and establish projects viability.

Some assumptions were informed by the Ontario Power Authority (OPA) feed in tariff (FIT). [9]

The following macro-economic assumptions were used as a basis for all scenarios:

Macro-economic references

- Operating labour salary: $40/hour. [13] [14]
- Electricity price: $110/MWh. [8]
- Process water price: \$1.15/m^3.[15] [17] [18] [18]
- Administration costs: 10% of labour costs. [2]
- Plant overhead costs: 15% of total maintenance, supervision and operating labour costs. [2]
- Supervision operation costs: 15% of operating labours costs. [2]
- Marketing costs: 1% of total operational cost. [2]

Macro-economic assumptions

- Maintenance and repair cost: Electrigaz estimated AD system cost from experience; costs of upgrading system are based on quotations obtained from suppliers.
- Operating supplies: Electrigaz estimated AD system cost from experience; costs of upgrading system are based on quotations obtained from suppliers
- Insurance costs: 1.0% of the fixed capital investment.
- Property taxes: 1.0% of the fixed capital investment.
- No revenue on carbon credit sales is considered.

3.3 Anaerobic digestion scenarios assumptions

3.3.1 Agricultural scenarios assumptions

The assumptions for the agricultural scenarios are the following:

Input substrates (Baseline agricultural scenario)

- 25,000 t/yr of cow manure at 8% dry matter
- 8,000 t of grease trap fat free of contaminants at 12% dry matter.
- A gate fee of $35/t is considered only for the grease trap substrate.
- The substrate is considered clean and no pre-treatment is required
- All feedstock is in slurry form.
- Off-farm feedstock is delivered in tanker trucks.

Input substrates (Large agricultural scenario)

- 49,700 t/yr of cow manure at 8% dry matter.
- 16,600 t of grease trap fat free of contaminants at 12% dry matter.
- A gate fee of $35/tonne is considered only for the grease trap substrate.
- The substrate is considered clean and no pre-treatment is required.
- All feedstock is in slurry form.
- Off-farm feedstock is delivered in tanker trucks.

Input substrates (Agricultural cooperative scenario)

- 75,000 t/yr of cow manure at 8% dry matter
- 25,000 t of grease trap fat free of contaminants at 12% dry matter.
- A gate fee of $35/tonne is considered only for the grease trap substrate.
- The substrate is considered clean and no pre-treatment is required.
- All feedstock in is slurry form.
- Off-farm feedstock is delivered in tanker trucks.

General assumptions

- No cost for collection and transport of the substrate is considered.
- No additional land must be bought.
- Construction management approach is used.
- Operating labour hours: 3 hours per day 365 days per year.
- It is considered that the digestate is spread on farm land
- Parasitic electricity of AD process represents 5% of total biogas production.
- The AD system is a CSTR.
- Land owned by farmer, no development costs.
- No secondary containment required.

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- Laboratory charges for the RNG quality control are estimated from quotes obtained for this study. It is estimated that one complete gas analysis will be needed every year.
- Laboratory charges for the AD process are equal to 8% of operating labours costs.
- Pressure to injection point is 60 psig. *(Pressure required by UGL and EGD)*

Biogas specifications

- CH_4: 55%
- CO_2: 45%
- H_2S: 1500ppm
- Siloxane: 0 ppm
- H_2O: saturated
- O_2: 0%

3.3.2 SSO scenario assumptions

Here are the assumptions for this specific scenario.

Input substrates

- 60,000 t/yr of SSO from a 3-stream collection, contaminated with plastic, metal, sand and glass.
- Assumed contamination is 10% of mass and must be pre-treated prior to digester feeding. [20]
- 54,000 t/yr of contaminant-free SSO (after pre-treatment) at 25% dry matter, are processed in the digesters.
- A gate fee of $60/t is considered. [21] [22] [23]
- The inflation factor is used on gate fees of the SSO scenario.

General assumptions

- No cost for collection and transport of the substrate is considered. *(It is assumed that the biogas producer is not responsible for substrate collection)*
- Construction approach: full EPC.
- Operating labour hours: 33 hours per day 365 days per year.
- Solid part of digestate must be disposed to landfill or to a composting facility, with a disposal cost of $10/t. [19]
- Liquid part of digestate must be sent to a municipal waste water treatment plant, with a disposal cost of $1.10/t.
- Substrate's contaminant disposal cost: $60/t. [21] [22] [23]
- Parasitic electricity of the AD process represents: 5% of total biogas production.
- The AD system is a CSTR.
- Plant is adjacent to an existing WWTP with adequate land base to add AD process. Minimal site development is required.
- Laboratory charges for the RNG quality control are estimated from quotes; it is assumed that two complete gas analysis will be needed every year
- Laboratory charges for the AD process are equal to 8% of operating labour costs.
- Pressure to injection point is 60 psig. *(Pressure required by UGL and EGD)*

Economic assumptions for the SSO AD scenario differ from the agricultural and industrial scenarios because it is assumed that a municipality will generally disburse less equity for a project and that the interest rate on debt is lower than in the private sector.

It is assumed that the gate fees are higher than in other AD scenarios, since the SSO is contaminated and must be pre-treated. Moreover, it is considered as a waste disposal cost saving for a municipality. No deflation on the gate fees is foreseen; instead, an inflation rate is applied.

Biogas characterisation

- CH_4: 55%
- CO_2: 45%
- H_2S: 1500ppm
- Siloxane: 0 ppm
- H_2O: saturated
- O_2: 0%

3.3.3 Industrial scenario assumptions

The assumptions for this specific scenario are as follows.

Input substrates

- 65,500 t/yr of vegetables residues free of contaminants at 23% dry matter.
- 65,500 t/yr of slaughterhouse waste, free of contaminant, at 10% dry matter.
- Gate fee is $35/t.

General assumptions

- No cost for collection and transport of the substrate is considered.
- Construction approach: full EPC.
- Operating labour hours: 33 hours per day 365 days per year.
- Solid part of digestate must be disposed of at a landfill or a composting facility with a disposal cost of $10/t. [19]
- Liquid part of digestate is sent to a municipal WWTP or to surrounding agricultural lands, with a disposal cost of $3/t.
- The AD system is a CSTR.
- Parasitic electricity of the AD process is 5% of total biogas production.
- Laboratory charges for the RNG quality control are estimated from quotes obtained for this study. It is estimated that two complete gas analyses will be necessary every year.
- Laboratory charges for the AD process are equal to 8% of operating labour cost.
- Pressure to injection point is 60 psig. *(Pressure required by UGL and EGD)*

Biogas characterisation

- CH_4: 55%
- CO_2: 45%
- H_2S: 1500ppm
- Siloxane: 0 ppm
- H_2O: saturated
- O_2: 0%

3.3.4 WWTP scenario assumptions

Here are the assumptions for this specific scenario.

Input substrate

- No organic waste input.
- Biogas is available but not upgraded.
- Raw biogas is the only input.
- Biogas is free of charge.

General assumptions

- No cost for collection and transport of the substrate is considered.
- Construction approach: full EPC.
- Operating labour hours: 3 hours per day 365 days per year.
- It is assumed that the AD process already exists.
- No cost for digestate disposal is considered since it is an existing operating system.
- Laboratory charges for the RNG quality control are estimated from quotes. It is estimated that two complete gas analyses will be needed every year.
- Pressure to injection point is 60 psig. *(Pressure required by UGL and EGD)*

It is important to note that the economic assumptions for the WWTP scenario are similar to the SSO scenario. This is because it is considered that WWTPs are operated by municipalities. Therefore, the equity/debt ratio and the interest rate on debt are identical to those in the SSO scenario.

Biogas characterisation

- CH_4: 55%
- CO_2: 45%
- H_2S: 250ppm
- Siloxane: 15 ppm
- H_2O: saturated
- O_2: 0%

3.4 Landfill scenarios assumptions

Economic assumptions are the same in all three landfill scenarios.

It is assumed that the landfill project would be developed by a third party and not by a landfill operator. As a result, it is assumed that the developer would pay a royalty for the landfill gas.

Moreover, since a third party developer is considered, no cost is estimated for operation of the biogas collection system and the treatment of leachate. However, the gas royalty, which act as a raw material cost, should cover these costs.

General landfill assumptions

- Landfill is open for 40 years, while only the 20 median years are taken into account.
- No cost for collection and transport of the waste is considered.
- Construction approach: full EPC.
- Landfill gas royalty: $2/GJ. [23] [24] [25]
- No gate fee is considered for waste input.
- No capital or operational cost for the biogas collection equipment.
- No capital or operational cost is assumed for the treatment of the leachate.
- Operating labour for the biogas upgrading system: 8 hours per day 260 days per year.
- Methane generation constant, k (yr^{-1}): 0.045 [3]
- Potential methane generation capacity, L_0 (m^3/tonne): 83 [5]
- Methane content: 55%.
- Methane collection efficiency: 75% [6]
- Laboratory charges for the RNG quality control are estimated from quotes. It is assumed that three complete gas analyses will be required every year.
- Pressure to injection point *(Pressure required by UGL and EGD)*
    - Small landfill: 60 psig.
    - Medium landfill: 200 psig.
    - Large landfill: 500 psig.

3.4.1 Small and medium landfill assumptions

The biogas characterization for this scenario is as follows:

Biogas characterisation

- Small landfill first year biogas flow rate: 475 m^3/hr
- Medium landfill first year biogas flow rate: 1110m^3/hr
- CH_4: 55%
- CO_2: 40%
- H_2S: 200 ppm
- Siloxane: 18 ppm
- H_2O: saturated
- O_2: 1%
- N_2: 4%

These scenarios assumed optimal gas collection operation to minimize air infiltration.

3.4.2 Large landfill assumptions

The biogas characterization for this scenario is as follows:

Biogas characterisation

- First year biogas flow rate: 3960 m^3/hr
- CH_4: 55%
- CO_2: 40.4%
- H_2S: 200 ppm
- Siloxane: 18 ppm
- H_2O: saturated
- O_2: 0.6%
- N_2: 4%

The large landfill scenario assumed biogas specification differs slightly from other landfill scenarios because such project would require very stringent gas collection operation to minimize air infiltration and cost prohibitive oxygen removal processes.

3.5 Operational costs calculation

Assumptions presented in the previous section and process mass balances of each scenario were used to estimate the operational costs. The costs generated on the first year of the project are presented in the appendices. These costs will change over time due to inflation.

3.6 Capital costs calculation

Electrigaz used its proprietary biogas production estimating techniques, models, experience and Ontario biogas market information to calculate projects capital cost. Upgrading equipment quotes were obtained from suppliers to estimate capital costs of each scenario. Equipment installation and integration costs were estimated by Electrigaz. A compression station is required only in the medium and large landfill scenarios. These capital costs were evaluated by Electrigaz. All capital cost estimation details and equipment lists are available in project details of Appendix 1 to 5.

The injection station and pipe capital costs were estimated and provided by EGD and UGL. The costs are provided by EGD and UGL and are available in Appendix 6. The following tables shows the total capital costs estimated for every scenario. Four groups of capital costs are presented: AD process, upgrading process, injection, pipe, compression and interest on capital incurred during construction time (IDC).

Table 2. Total capital costs for agricultural scenarios

Scenario name	Baseline Farm	Large Farm	Coop Farm
	IP	IP	IP
AD process	$ 2,252,000	$ 3,055,000	$ 4,579,000
Upgrading process	$ 1,561,000	$ 2,030,000	$ 2,896,000
Injection, pipe, compression	$ 529,930	$ 529,930	$ 529,930
IDC	$ 105,989	$ 137,032	$ 195,359
Total capital costs	$ 4,448,919	$ 5,751,962	$ 8,200,289

Table 3. Total capital costs for SSO, industrial and WWTP scenarios

Scenario name	SSO	Industrial	WWTP
	IP	IP	IP
AD process	$ 26 093 000	$ 23 278 000	$ -
Upgrading process	$ 3 713 000	$ 4 163 000	$ 1 977 000
Injection, pipe, compression	$ 464 930	$ 487 305	$ 464 930
IDC	$ 1 253 323	$ 1 354 038	$ 51 005
Total capital costs	$ 31 524 253	$ 29 282 343	$ 2 492 935

Table 4. Total capital costs for landfill scenarios[2]

Scenario name	Small landfill	Medium landfill	Large landfill
	IP	HP	XHP
AD process	$ -	$ -	$ -
Upgrading process	$ 4 405 000	$ 6 773 000	$ 13 542 492
Injection, pipe, compression	$ 551 680	$ 2 117 080	$ 3 364 205
IDC	$ 120 967	$ 216 961	$ 575 409
Total capital costs	$ 5 077 647	$ 9 107 041	$ 17 482 106

[2] Large landfill capital cost consolidates first year capital cost and inflated year-12 re-investment.

4. Conclusion

Electrigaz used its biogas engineering expertise and best available Ontario biogas market information to obtain each scenario capital and operational cost.

These costs will be used to obtain RNG production cost and to formulate optimal pricing for this RNG program.

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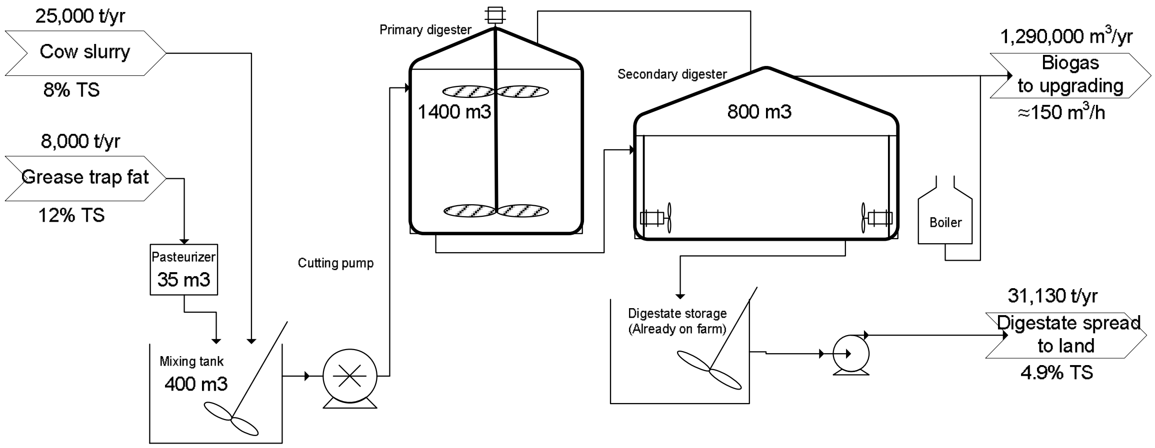
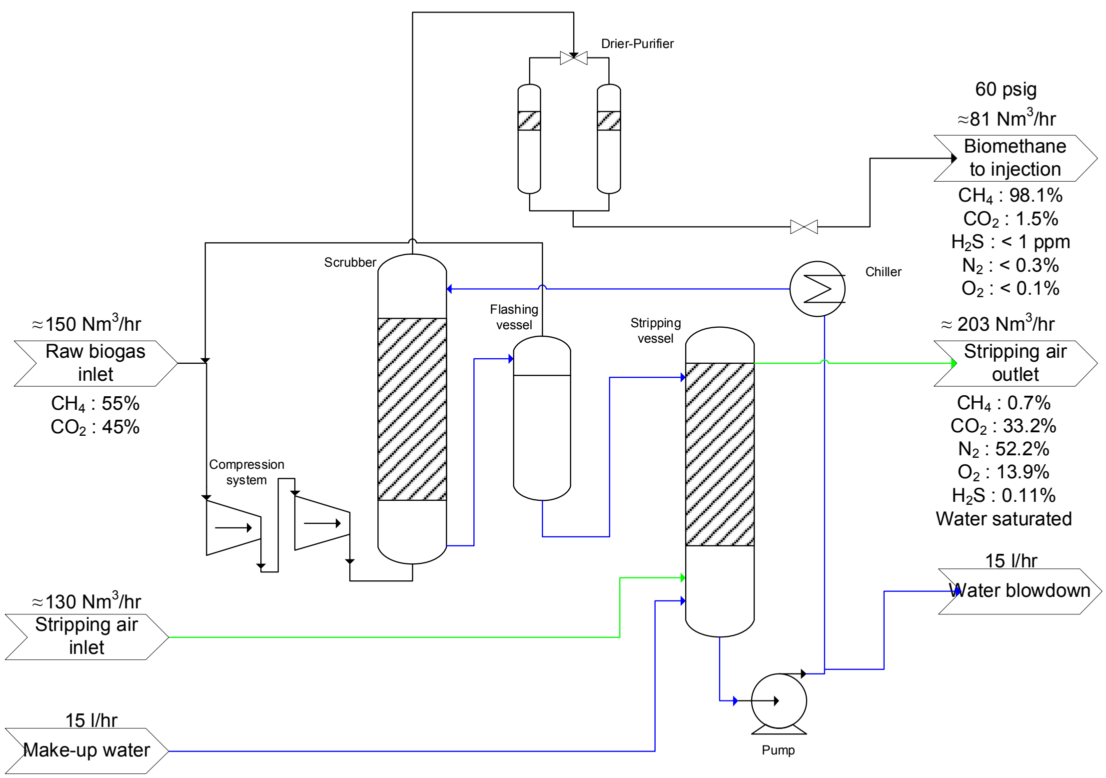
Appendix 1: Agricultural scenario details

Baseline agricultural scenario

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the AD unit of the Baseline agricultural scenario



Simplified schematic and mass balance of the Baseline agricultural scenario upgrading unit

Capital cost details

Capital cost of the AD of the Baseline agricultural scenario

Capital costs (Anaerobic digestion)		
Categories	**Items**	**Total including installation**
Pre-treatment and reception tanks		**$ 117,000**
	Pasteurizer	
	Mixing tank	
	Mixer (2)	
	Chopper pump	
Anaerobic digestion equipment		**$ 1,191,000**
	Primary digester tank	
	Top mounted mixer	
	Secondary digester	
	Submersible mixers (2)	
	Double membrane roof (gas storage)	
	Digestate pump	
Heating equipment		**$ 336,000**
	Heat exchanger	
	Boiler	
	Hot water pump	
Biogas management equipment		**$ 84,000**
	Flare	
	Gas blower	
Indirect costs		**$ 273,000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Contractor profit (Construction management approach)		**$ 90,000**
Contingency		**$ 161,000**
Total cost		**$ 2,252,000**

Capital cost of the upgrading unit of the Baseline agricultural scenario

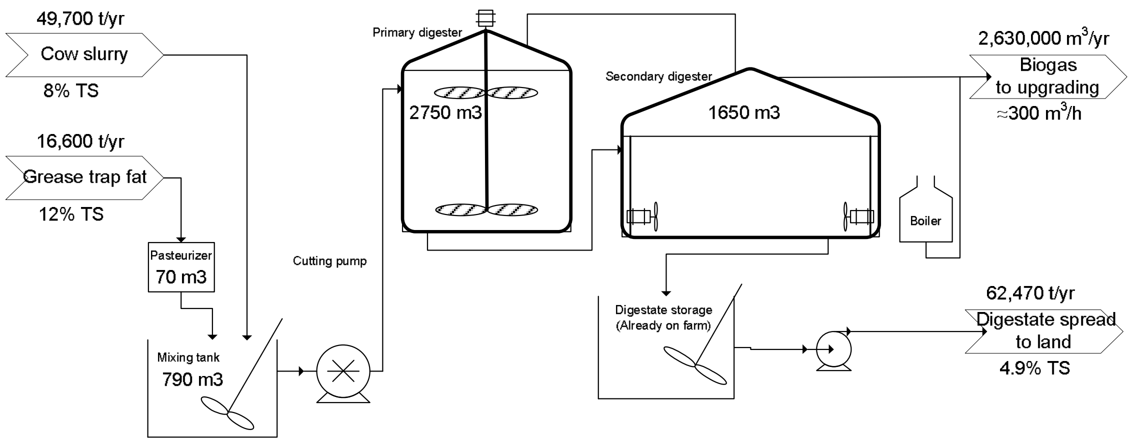
Capital costs (Upgrading)		
Categories	**Items**	**Total including intallation**
Upgrading		**$ 1,187,000**
	Compressor	
	Scrubber	
	Drying column	
	Stripper	
	Water pump	
	Flashing column	
	Air blower	
	Auxiliaries	
Indirect costs		**$ 197,000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 59,000**
Contingency		**$ 118,000**
Total cost		**$ 1,561,000**

First year operational costs of the baseline agricultural scenario

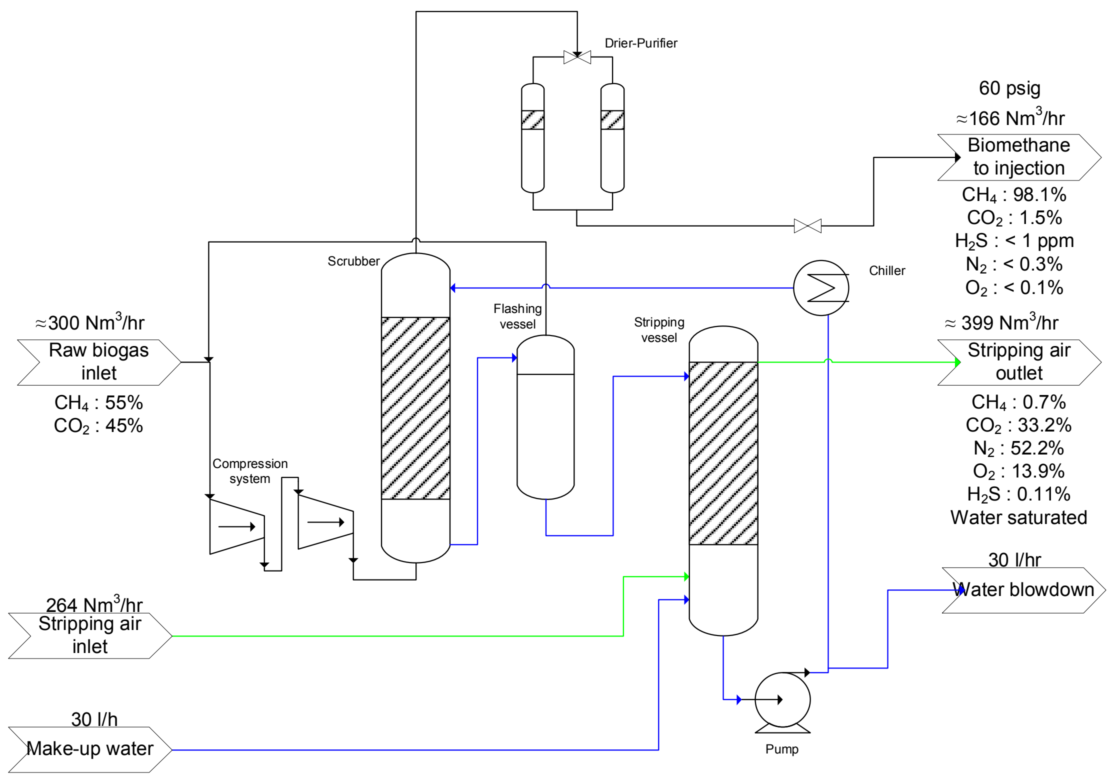
Operational costs		
Operating labor	$	43 800
Operating supervision	$	6 570
Process Water	$	151
Electricity	$	124 874
Waste water disposal cost	$	867
Solid digestate disposal cost	$	-
Contaminant diposal cost	$	-
Injection station O&M	$	5 299
Maintenance and repair	$	36 570
Operating supplies	$	29 523
Laboratory charges	$	7 836
Taxes (property)	$	43 429
Insurance	$	43 429
General expenses	$	21 019
Total operational cost	$	363 368

Large agricultural scenario

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the AD unit of the large agricultural scenario



Simplified schematic and mass balance of the large agricultural scenario upgrading unit

Capital costs details

Capital cost of the AD of the large agricultural scenario

Capital cost (Anaerobic digestion)			
Categories	Items		Total including installation
Reception and pre-treatment		$	146 000
	Pasteurizer		
	Mixing tank		
	Mixers		
	Feeding pump		
Anaerobic digestion		$	1 683 000
	Primary digester		
	Secondary digester		
	Biogas storage		
Heating system		$	420 000
	Heat exchanger		
	Boiler		
	Hydronic system		
Biogas management		$	100 000
	Flare		
	Gas safety equipment		
	Gas blower		
Indirect costs		$	365 000
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		$	122 000
Contingency		$	219 000
Total cost		$	3 055 000

Capital cost of the upgrading unit of the large agricultural scenario

Capital cost (Upgrading)			
Categories	Items		Total including installation
Upgrading		$	1 551 000
	Compressor		
	Scrubber		
	Drying column		
	Stripper		
	Water pump		
	Flashing column		
	Air blower		
	Auxiliaries		
Indirect costs		$	248 000
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		$	77 000
Contingency		$	154 000
Total cost		$	2 030 000

First year operational costs of the large agricultural scenario

Operational costs		
Operating labor	$	43,800
Operating supervision	$	6,570
Process Water	$	302
Electricity	$	174,121
Waste water disposal cost	$	1,183
Solid digestate disposal cost	$	-
Contaminant diposal cost	$	-
Injection station O&M	$	5,299
Maintenance and repair	$	42,593
Operating supplies	$	34,943
Laboratory charges	$	7,836
Taxes (property)	$	56,149
Insurance	$	56,149
General expenses	$	22,797
Total operational cost	$	451,743

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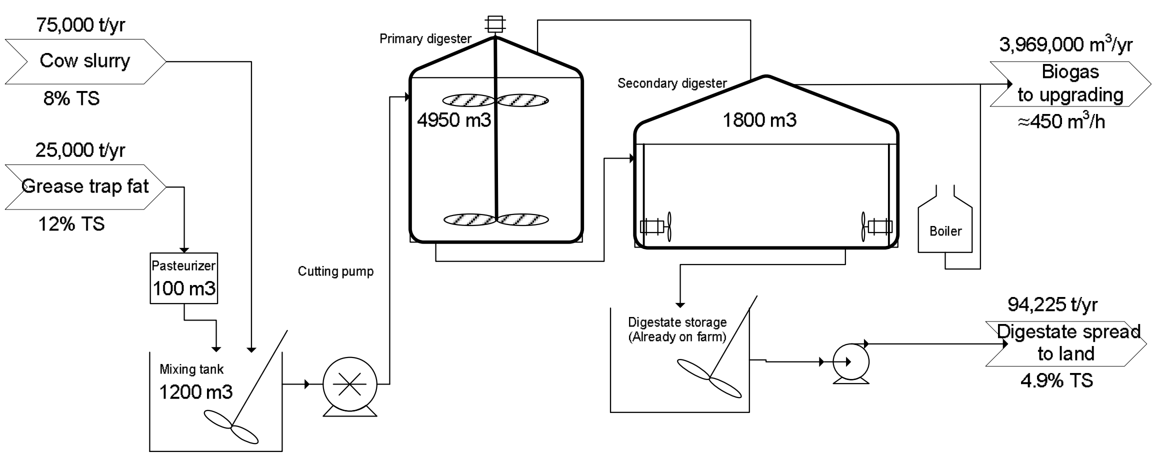
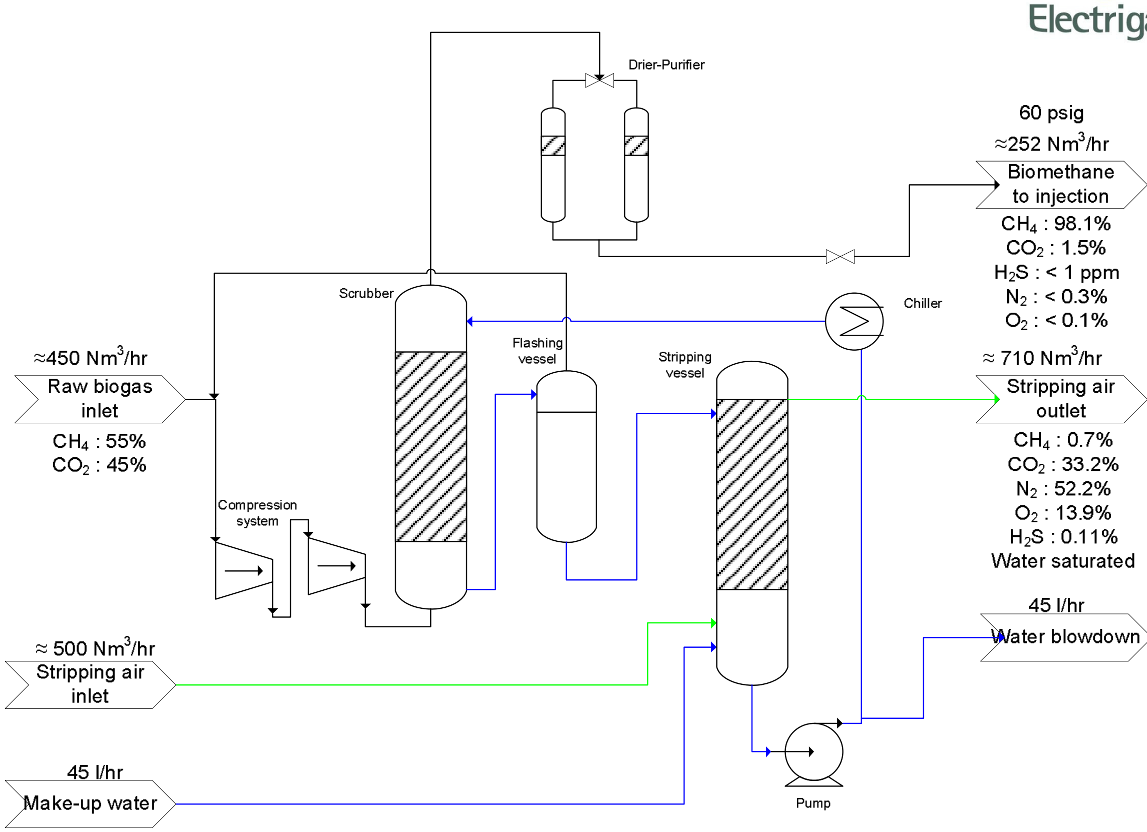
Cooperative agricultural scenario

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the AD unit of the Cooperative agricultural scenario



Simplified schematic and mass balance of the Cooperative agricultural scenario upgrading unit

Capital cost details

Capital cost of the AD of the Cooperative agricultural scenario

Capital costs (Anaerobic digestion)		
Categories	**Items**	**Total including installation**
Pre-treatment and reception tanks		**$ 188,000**
	Pasteurizer	
	Mixing tank	
	Mixer (2)	
	Chopper pump	
Anaerobic digestion equipment		**$ 2,640,000**
	Primary digester tank	
	Top mounted mixer	
	Secondary digester	
	Submersible mixers (2)	
	Double membrane roof (gas storage)	
	Digestate pump	
Heating equipment		**$ 482,000**
	Heat exchanger	
	Boiler	
	Hot water pump	
Biogas management equipment		**$ 128,000**
	Flare	
	Gas blower	
Indirect costs		**$ 575,000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Contractor profit (Construction management approach)		**$ 202,000**
Contingency		**$ 364,000**
Total cost		**$ 4,579,000**

Capital cost of the upgrading unit of the Cooperative agricultural scenario

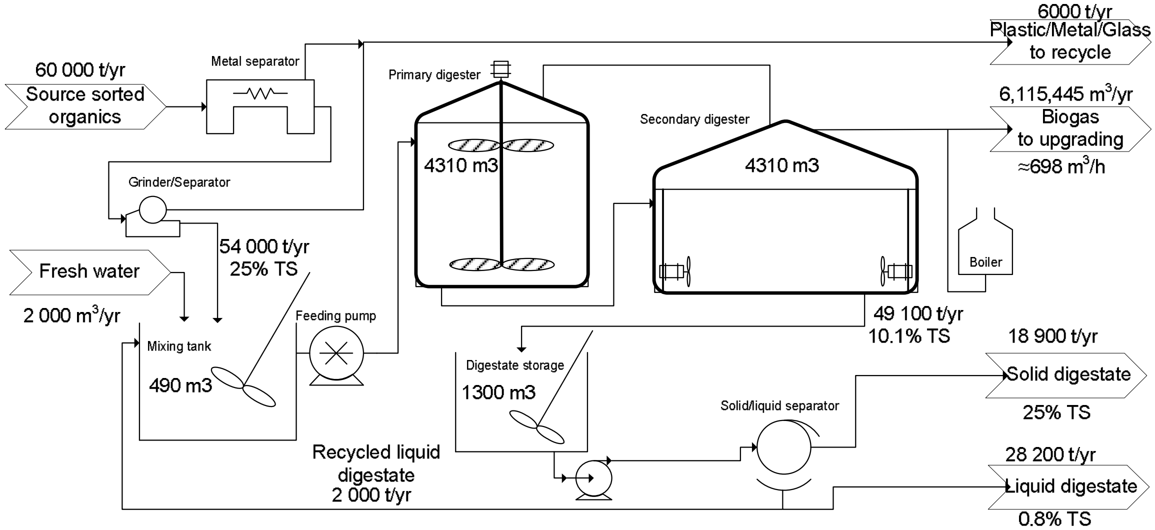
Capital costs (Upgrading)		
Categories	**Items**	**Total including intallation**
Upgrading		**$ 2,209,000**
	Compressor	
	Scrubber	
	Drying column	
	Stripper	
	Water pump	
	Flashing column	
	Air blower	
	Auxiliaries	
Indirect costs		**$ 357,000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 110,000**
Contingency		**$ 220,000**
Total cost		**$ 2,896,000**

First year operational costs of the Cooperative agricultural scenario

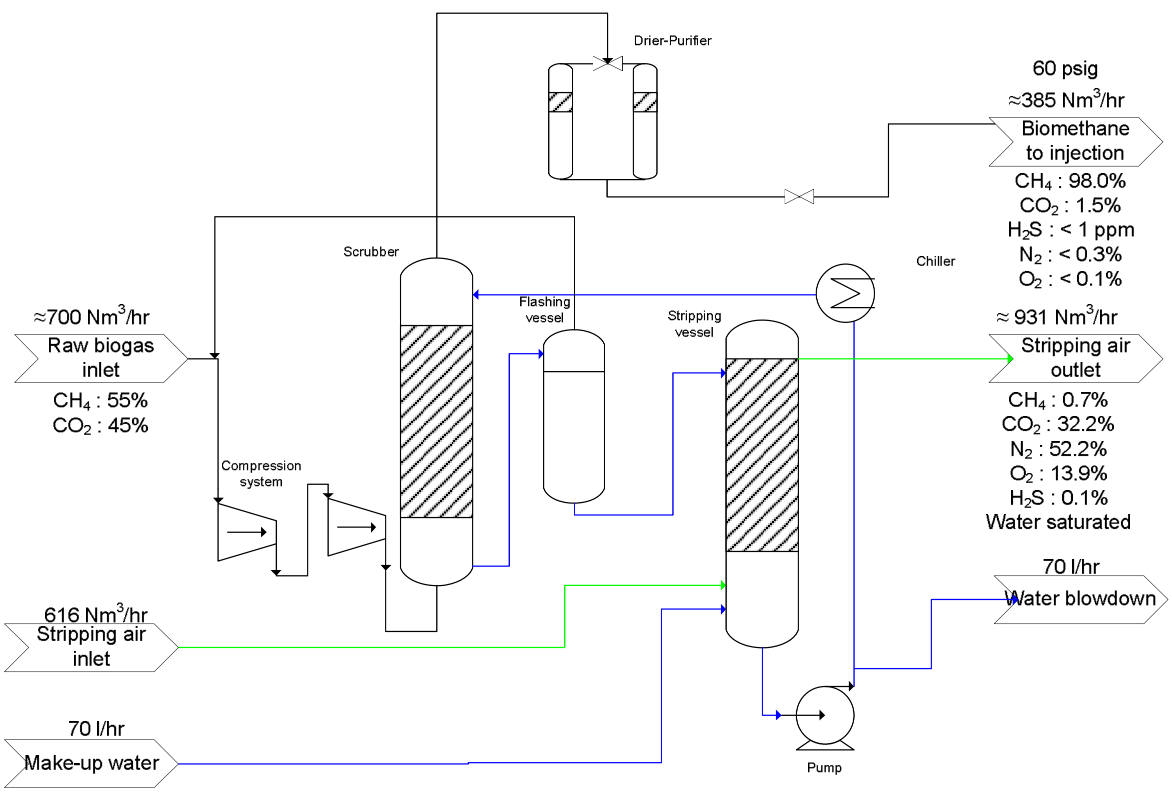
Operational costs	
Operating labor	$ 43,800
Operating supervision	$ 6,570
Process Water	$ 453
Electricity	$ 222,978
Waste water disposal cost	$ 1,577
Solid digestate disposal cost	$ -
Contaminant diposal cost	$ -
Injection station O&M	$ 5,299
Maintenance and repair	$ 54,023
Operating supplies	$ 45,230
Laboratory charges	$ 7,836
Taxes (property)	$ 80,049
Insurance	$ 80,049
General expenses	$ 25,718
Total operational cost	$ 573,583

Appendix 2: SSO scenario details

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the AD unit of the SSO scenario



Simplified schematic and mass balance of the upgrading unit of the SSO scenario

Capital costs details

Capital cost of the AD unit of the SSO scenario

Capital cost (Anaerobic digestion)			
Categories	**Items**		**Total including installation**
Building and Land		**$**	**3 750 000**
	Reception building		
	Administration building		
	Pump house		
	Digestate management building		
	Land		
Reception and pre-treatment		**$**	**8 242 000**
	Truck scale		
	Reception pits		
	Shredder		
	Conveyors		
	Plastic + metal remover		
	Mixing tank		
	Mixers		
	Feeding pump		
Odour treatment		**$**	**2 203 000**
	Ventillation equipment		
	Acid scrubber + facilities		
	Biofilter + facilities		
Anaerobic digestion		**$**	**2 724 000**
	Primary digesters		
	Secondary digester		
	Biogas storage		
Heating		**$**	**840 000**
	Heat exchanger		
	Boiler		
	Hydronic system		
Digestate management		**$**	**659 000**
	Digestate pump		
	Digestate storage		
	Solid/Liquid separator		
	Solid handling system		
Biogas management		**$**	**389 000**
	Flare		
	Gas safety equipment		
	Gas blower		
Indirect costs		**$**	**2 820 000**
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		**$**	**2 424 000**
Contingency		**$**	**2 042 000**
Total cost		**$**	**26 093 000**

Capital cost of the upgrading unit of the SSO scenario

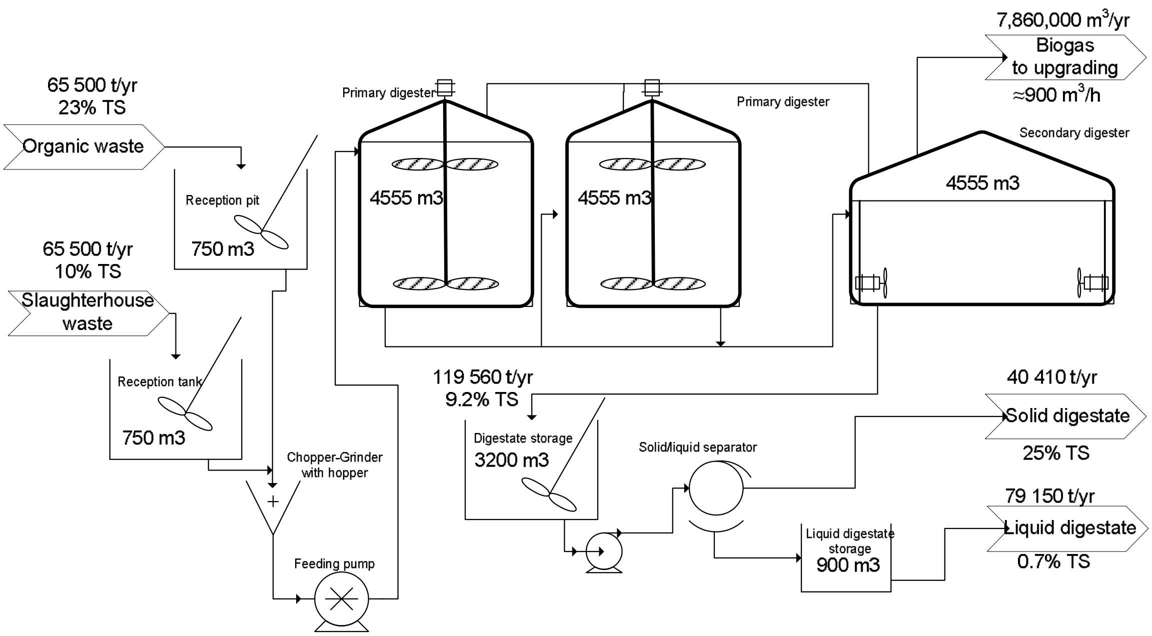
Capital cost (Upgrading)		
Categories	**Items**	**Total including installation**
Upgrading		**$ 2 732 000**
	Compressor	
	Scrubber	
	Drying column	
	Stripper	
	Water pump	
	Flashing column	
	Air blower	
	Thermal oxidizer	
	Auxiliaries	
Indirect costs		**$ 429 000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 276 000**
Contingency		**$ 276 000**
Total cost		**$ 3 713 000**

First year operational costs of the SSO scenario

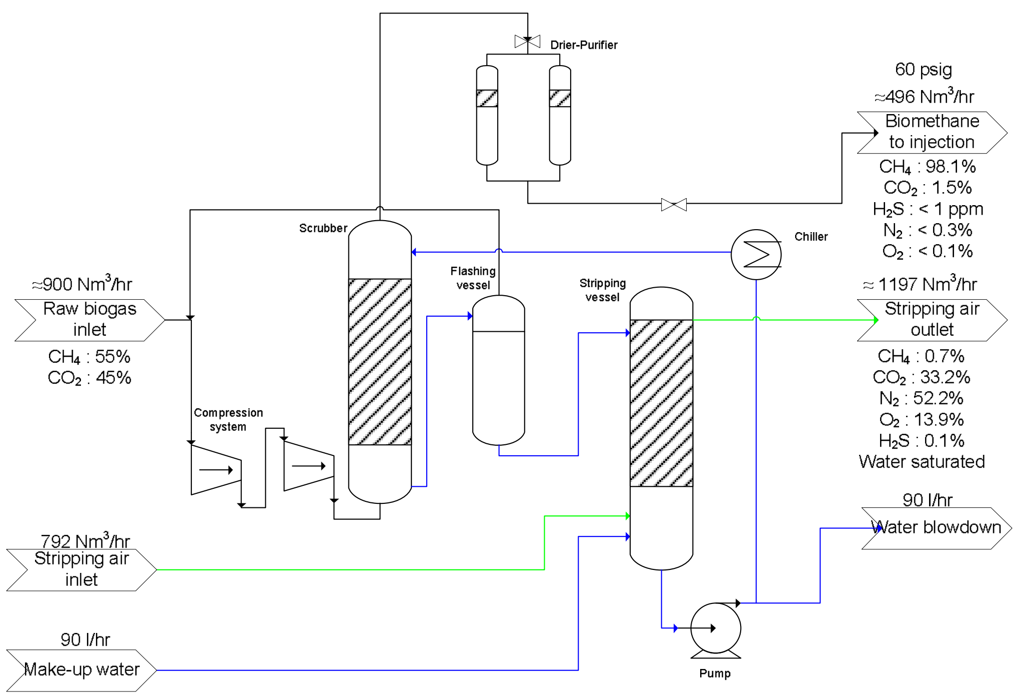
Operational costs	
Operating labor	$ 481,800
Operating supervision	$ 72,270
Process Water	$ 3,005
Electricity	$ 369,526
Waste water disposal cost	$ 32,033
Solid digestate disposal cost	$ 188,994
Contaminant diposal cost	$ 360,000
Injection station O&M	$ 4,649
Maintenance and repair	$ 215,378
Operating supplies	$ 191,200
Laboratory charges	$ 48,376
Taxes (property)	$ 302,709
Insurance	$ 302,709
General expenses	$ 190,960
Total operational cost	$ 2,763,609

Appendix 3: Industrial scenario details

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the AD unit of the industrial scenario



Simplified schematic and mass balance of the upgrading unit of the industrial scenario

Electrigaz

Capital cost details

Capital cost of the AD unit of the industrial scenario

Capital cost (Anaerobic digestion)		
Categories	**Items**	**Total including installation**
Building and Land		**$ 4 950 000**
	Reception building	
	Administration building	
	Pump house	
	Digestate management building	
	Land	
Pre-treatment and reception tanks		**$ 1 997 000**
	Truck scale	
	Reception pits	
	Shredder	
	Reception tanks	
	Mixers	
	Feeding pumps	
Odour treatment		**$ 2 377 000**
	Ventillation equipment	
	Acid scrubber + facilities	
	Biofilter + facilities	
Anaerobic digestion		**$ 4 748 000**
	Primary digesters	
	Secondary digester	
	Biogas storage	
Heating		**$ 1 226 000**
	Heat exchanger	
	Boiler	
	Hydronic equipment	
Digestate mangement		**$ 1 253 000**
	Digestate pump	
	Digestate storage	
	Solid/Liquid separator	
	Solid handling equipment	
	Liquid digestate additionnal storage	
Biogas management		**$ 471 000**
	Flare	
	Gas safety equipment	
	Gas blower	
Indirect costs		**$ 2 425 000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 2 099 000**
Contingency		**$ 1 732 000**
Total cost		**$ 23 278 000**

Capital costs of the upgrading unit of the industrial scenario

Capital cost (Upgrading)		
Categories	**Items**	**Total including installation**
Upgrading		**$ 3 175 000**
	Compressor	
	Scrubber	
	Drying column	
	Stripper	
	Flashing column	
	Air blower	
	Thermal oxidizer	
	Auxiliaries	
Indirect costs		**$ 414 000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 287 000**
Contingency		**$ 287 000**
Total cost		**$ 4 163 000**

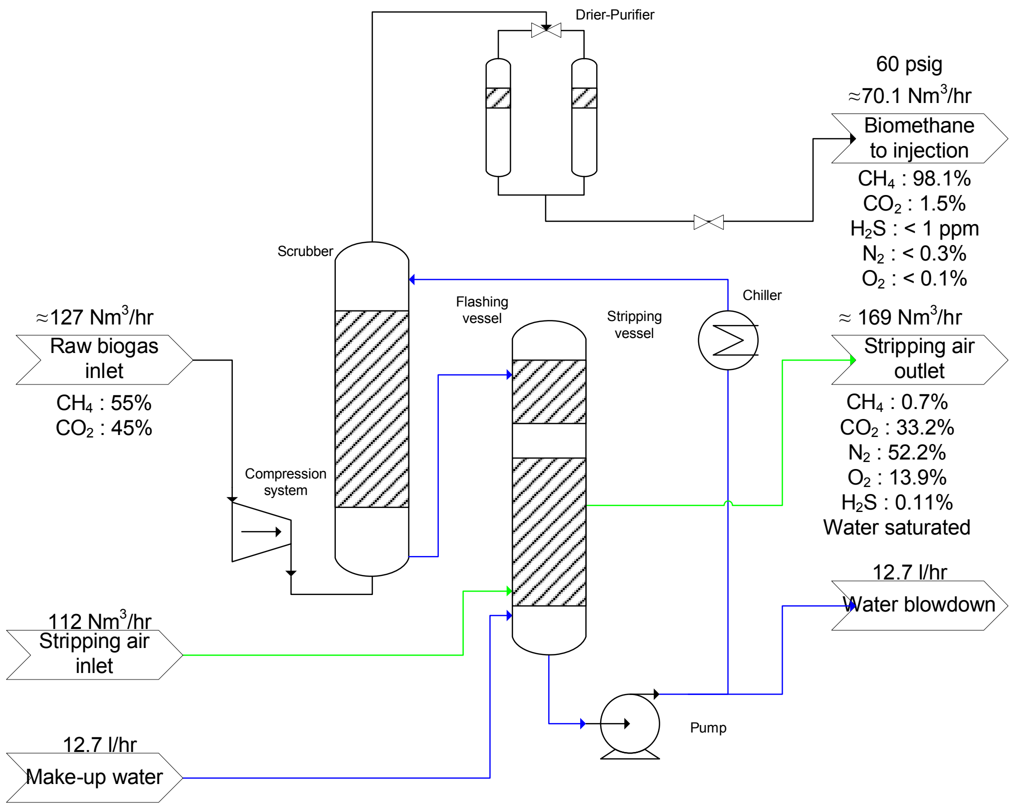
First year operational costs of the industrial scenario

Operational costs	
Operating labor	$ 481,800
Operating supervision	$ 72,270
Process Water	$ 907
Electricity	$ 461,193
Waste water disposal cost	$ 241,005
Solid digestate disposal cost	$ 404,091
Contaminant diposal cost	$ -
Injection station O&M	$ 4,873
Maintenance and repair	$ 195,765
Operating supplies	$ 173,199
Laboratory charges	$ 48,376
Taxes (property)	$ 279,283
Insurance	$ 279,283
General expenses	$ 188,682
Total operational cost	$ 2,830,727

Appendix 4: WWTP scenario details

Electrigaz

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the upgrading unit of the WWTP scenario

Capital cost details

Capital cost of the upgrading unit of the WWTP scenario

Capital cost (Upgrading)			
Categories	**Items**		**Total including installation**
Upgrading		**$**	**1 593 000**
	Compressor		
	Scrubber		
	Drying column		
	Stripper		
	Water pump		
	Flashing column		
	Thermal oxidizer		
	Air blower		
	Auxiliaries		
Indirect costs		**$**	**176 000**
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		**$**	**99 000**
Contingency		**$**	**109 000**
Total cost		**$**	**1 977 000**

First year operational costs of the WWTP scenario

Operational costs		
Operating labor	$	43,800
Operating supervision	$	6,570
Process Water	$	128
Electricity	$	38,640
Waste water disposal cost	$	-
Solid digestate disposal cost	$	-
Contaminant diposal cost	$	-
Injection station O&M	$	4,649
Maintenance and repair	$	21,180
Operating supplies	$	5,772
Laboratory charges	$	11,000
Taxes (property)	$	24,419
Insurance	$	24,419
General expenses	$	17,069
Total operational cost	$	197,647

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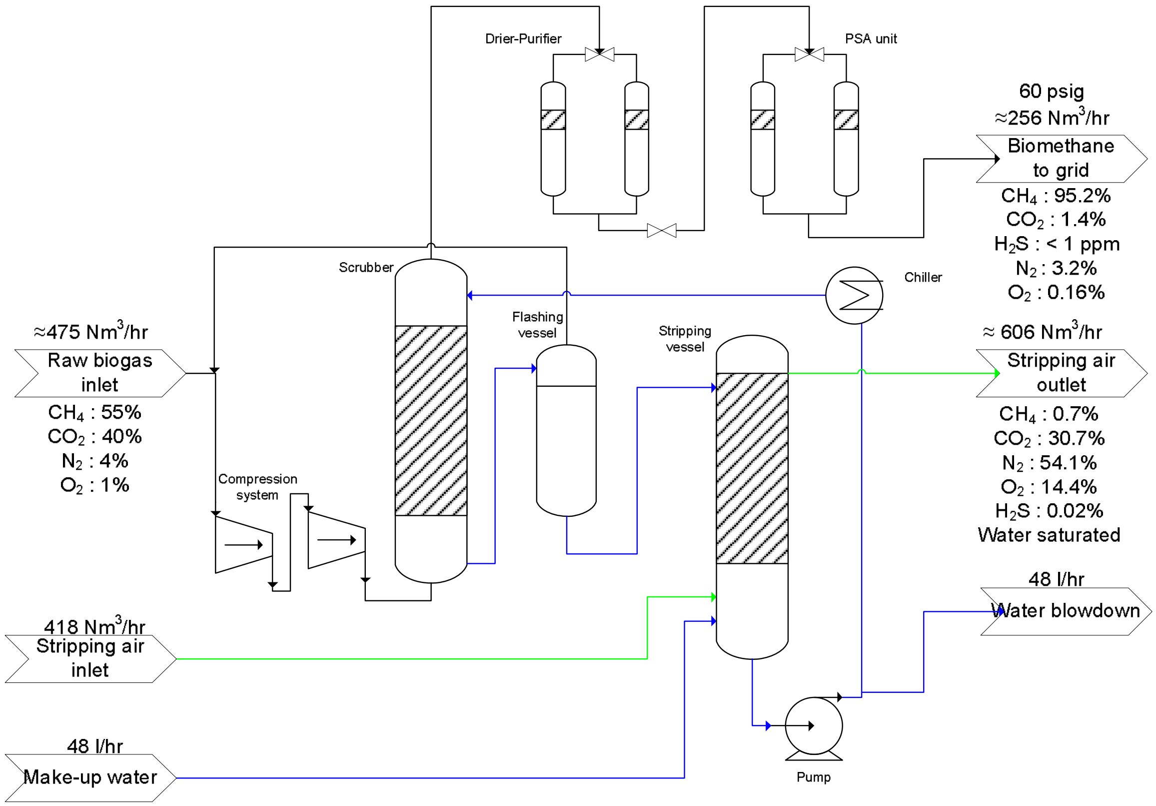
Appendix 5: Landfill scenario details

Small landfill scenario details

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the upgrading unit of the small landfill scenario

Electrigaz

Capital costs details

Table Capital cost of the upgrading unit of the small landfill scenario

Capital cost (Upgrading)		
Categories	**Items**	**Total including installation**
Upgrading		**$ 3 392 000**
	Compressor	
	Scrubber	
	Drying column	
	Stripper	
	Water pump	
	Flashing column	
	Air blower	
	PSA process (O2/N2 removal)	
	Thermal oxidizer	
	Auxiliaries	
Indirect costs		**$ 421 000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 296 000**
Contingency		**$ 296 000**
Total cost		**$ 4 405 000**

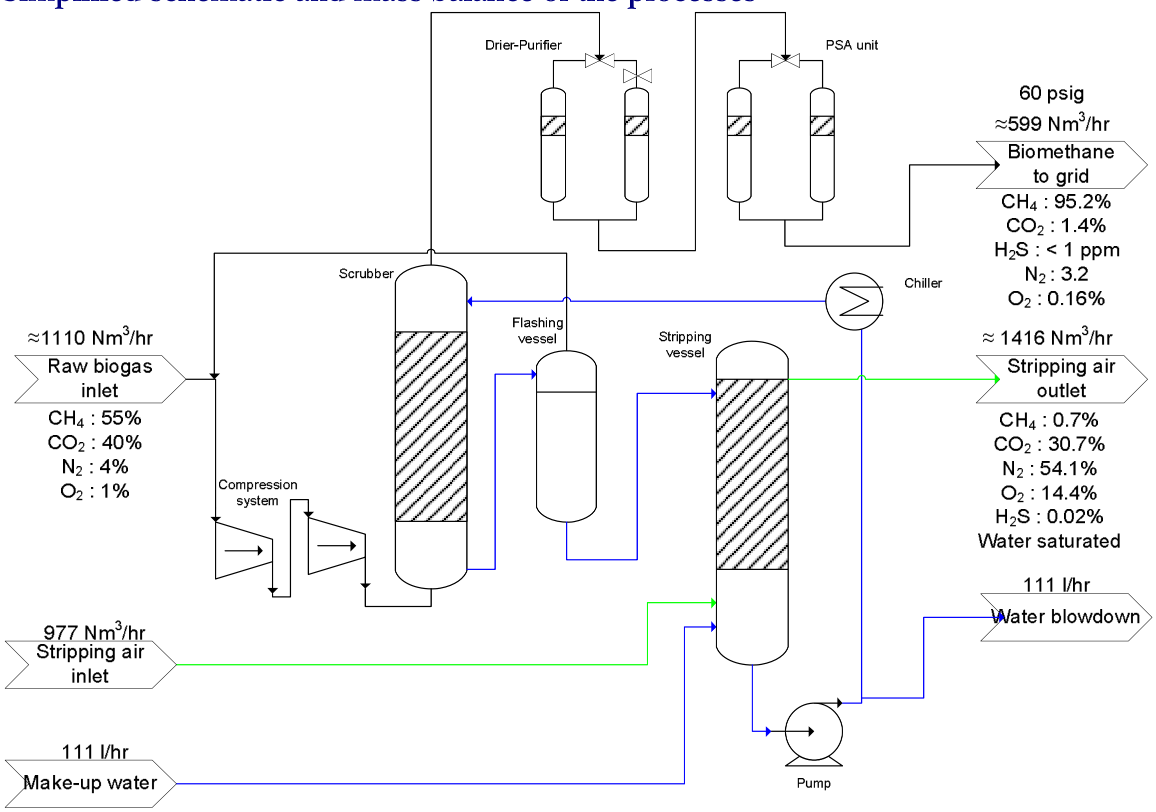
First year operational costs of the small landfill scenario

Operational costs	
Operating labor	$ 83,429
Operating supervision	$ 12,514
Process Water	$ 484
Electricity	$ 113,416
Waste water disposal cost	$ 1,892
Landfill gas royalty	$ 161,878
Injection station O&M	$ 5,517
Maintenance and repair	$ 19,680
Operating supplies	$ 15,072
Laboratory charges	$ 16,500
Taxes (property)	$ 49,567
Insurance	$ 49,567
General expenses	$ 31,238
Total product cost	$ 560,753

Electrigaz

Medium landfill scenario details

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the upgrading unit of the medium landfill scenario

Capital Cost details

Capital cost of the upgrading unit of the medium landfill scenario

Capital cost (Upgrading)		
Categories	**Items**	**Total including installation**
Upgrading		**$ 5 203 000**
	Compressor	
	Scrubber	
	Drying column	
	Stripper	
	Water pump	
	Flashing column	
	Air blower	
	PSA process (O2/N2 removal)	
	Thermal oxidizer (2)	
	Auxiliaries	
Indirect costs		**$ 672 000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 449 000**
Contingency		**$ 449 000**
Total cost		**$ 6 773 000**

Capital cost of the HP compression station for the Medium landfill scenario

Capital cost (Compression station HP, Medium landfill scenario)	
Categories	**Total including intallation**
Compressor (110kW)	**$ 664,000**
Indirect costs	**$ 93,000**
Engineering, supervision, project management	
Legal expenses	
Start-up, commissioning	
Temporary services (trailers, utilities, etc.)	
Contractor profit (EPC construction)	**$ 67,000**
Contingency	**$ 67,000**
Total cost	**$ 891,000**

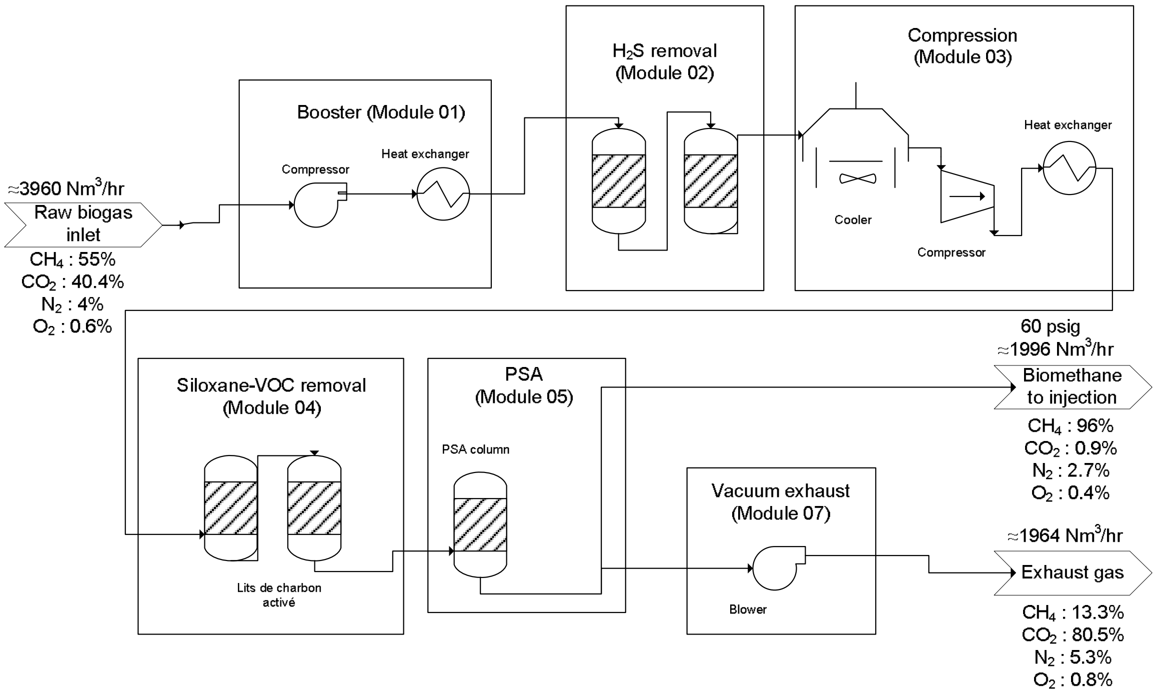
Electrigaz

First year operational costs of the medium landfill scenario

Operational costs	
Operating labor	$ 83,429
Operating supervision	$ 12,514
Process Water	$ 1,118
Electricity	$ 297,427
Waste water disposal cost	$ 4,389
Landfill gas royalty	$ 377,716
Injection station O&M	$ 12,261
Maintenance and repair	$ 24,663
Operating supplies	$ 28,386
Laboratory charges	$ 16,500
Taxes (property)	$ 88,901
Insurance	$ 88,901
General expenses	$ 37,060
Total product cost	$ 1,073,264

Large landfill scenario details

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the upgrading unit of the large landfill scenario

Capital cost details

Capital cost of the upgrading unit of the large landfill scenario

Capital cost (Upgrading)		
Categories	**Items**	**Total including installation**
Module 1: Booster		$ 8 028 000
	Compressor	
	Heat exchanger	
Module 2: H2S removal		
	Adsorption column	
Module 3: Compression		
	Compressor	
	Cooler	
Module 4: Siloxane/VOC removal		
	Adsorption column	
Module 5: PSA		
	PSA column	
Module 7: Vacuum exhaust		
	Blower	
	Thermal oxidizer (2)	
Indirect costs		$ 895 000
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		$ 670 000
Contingency		$ 670 000
Total cost		$ 10 263 000

Capital cost of the XHP compression station for the Large landfill scenario

Capital cost (Compression station HP, Large landfill scenario)	
Categories	**Total including intallation**
Compressor (400kW)	$ 1,550,000
Indirect costs	$ 217,000
Engineering, supervision, project management	
Legal expenses	
Start-up, commissioning	
Temporary services (trailers, utilities, etc.)	
Contractor profit (EPC construction)	$ 155,000
Contingency	$ 155,000
Total cost	$ 2,077,000

Year 12 capital cost of the XHP compression station for the Large landfill scenario

Equipment list Upgrading		
Categories	**Items**	**Total including installation**
Module 1: Booster		**$ 1 922 000**
	Compressor	
	Heat exchanger	
Module 2: H2S removal		
	Adsorption column	
Module 3: Compression		
	Compressor	
	Cooler	
Module 4: Siloxane/VOC removal		
	Adsorption column	
Module 5: PSA		
	PSA column	
Module 7: Vacuum exhaust		
	Blower	
Indirect costs		**$ 273 000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Contractor profit (EPC construction)		**$ 158 000**
Contingency		**$ 158 000**
Total cost		**$ 2 511 000**
Total cost 2024 (inflation included)		**$ 3 279 492**

First year operational costs of the large landfill scenario

Operational costs	
Operating labor	$ 83,429
Operating supervision	$ 12,514
Process Water	$ -
Electricity	$ 912,223
Waste water disposal cost	$ -
Landfill gas royalty	$ 1,270,313
Injection station O&M	$ 12,872
Maintenance and repair	$ 139,658
Operating supplies	$ 125,692
Laboratory charges	$ 16,500
Taxes (property)	$ 136,272
Insurance	$ 136,272
General expenses	$ 72,577
Total product cost	$ 2,918,321

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Appendix 6: EGD and UGL estimated capital and operational costs of the injection stations

Capital and operational costs of the injection stations for all scenarios

Capital Cost Summary

Scenario		Enbridge & UGL - Station and Interconnect Costs						
		Station ($)	Pipe ($)	O&M ($/year)	Pipe Length (m)	Pipe Material	Pipe Size (NPS)	Pressure (IP/HP)
1	Aggregated AD	$ 374,305	$ 113,000	$ 4,873	500	Plastic	4	IP
2	Farm AD	$ 351,930	$ 178,000	$ 5,299	1,500	Plastic	4	IP
3	SSO AD	$ 351,930	$ 113,000	$ 4,649	500	Plastic	4	IP
4	WWTP AD	$ 351,930	$ 113,000	$ 4,649	500	Plastic	4	IP
5	Small Landfill	$ 373,680	$ 178,000	$ 5,517	1,500	Plastic	4	IP
6	Medium Landfill	$ 376,080	$ 850,000	$ 12,261	5,000	Steel	8	HP (200 psi)
7	Large Landfill	$ 437,205	$ 850,000	$ 12,872	5,000	Steel	8	XHP (500psi)

Appendix 7: Corporate profile

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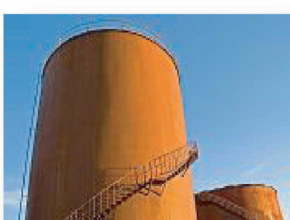
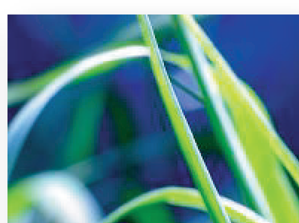
Exhibit B
Tab 1
Appendix 4





Electrigaz

Biogas Engineering

CORPORATE PROFILE

Electrigaz profile

Electrigaz is the only engineering firm in Canada specialized exclusively in biogas engineering. We don't sell equipment; we sell unbiased biogas engineering expertise.

Electrigaz services

Electrigaz differentiates itself by providing complete biogas project development services including:

- Feasibility studies
- Complete biogas plant engineering (construction plans and specifications)
- Anaerobic digestion process design
- Cost assessments and economic projections
- Price sensitivity analysis
- Financial modeling
- Biogas lab testing
- Financial and permitting documentation development
- Project planning
- Contract negotiations (equipment vendors, utilities, GHG, etc.)
- Project management
- Site supervision
- Plant commissioning
- Process optimization

Electrigaz clients

- Agricultural producers
- Industrials
- Energy developers
- Plant builders
- Engineering firms
- Governments
- Municipalities
- Universities, etc.

Electrigaz team

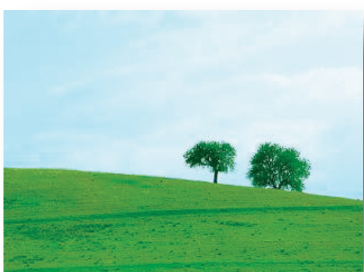
The main strength of Electrigaz is its dynamic and passionate team of professionals dedicated to find solutions to the 21st century energy and environmental challenges.

Eric Camirand, Eng., President

Mr. Camirand holds a degree in Electrical Engineering from McGill University in Montreal. Throughout his junior years Mr. Camirand piloted various engineering projects for corporations such as Petro-Canada, Hong Kong Airport Authorities and Canadian Airlines.

As founder and CEO of Cinax Designs, a Vancouver based video compression software development firm, Mr. Camirand led the company through steady growth that culminated with the merger with Ravisent Technologies of Pennsylvania.

Since then, Mr. Camirand has been active in the renewable energy sector as member of the Quebec caucus for the Canadian Wind Energy Association and more recently as founder-president of the Biogaz Quebec Association. Being an active biogas promoter, Mr. Camirand frequently participates in national and international conferences dedicated to green technologies and bioenergy.



Nathalie Garceau, VP Marketing
Nathalie completed a Bachelor's degree in Civil Engineering at Laval University and a Master's degree in Applied Science at UBC. For several years, Nathalie worked at Sandwell Engineering where she acquired valuable design, project management and site supervision experience. Over the years, Nathalie has pursued her practical education in the fields of agriculture and green marketing.

François Handfield, Jr. Eng., Project Manager
François holds a degree in bio-resources engineering from McGill University in Montreal. With a strong background in farming, François offers down-to-earth practical biogas engineering solutions to biogas engineering challenges.

Raphaël Duquette, Jr. Eng., Project Manager
Raphael holds a degree in chemical engineering from Université de Sherbrooke. Raphael brings to Electrigaz considerable process engineering experience acquired while working for Xstrata Cuivre and Ultramar (refinery).

Natalia Bourenane, MBA, Data analyst
Natalia is a MBA graduate from Université du Québec à Trois-Rivières. In 2010 she joined Electrigaz where she used her expertise in research to develop a methodology of organic waste data collection applicable to every technology of bioenergy production from biomass.

Patrick Simard, Mechanical Engineering Technician
Patrick is a certified mechanical engineering technician bringing hands on solutions to Electrigaz engineering team and clients. Patrick is also an accomplished CAD draftsman.

Liesl Fischer, Jr. Eng., Project Manager
Liesl holds a masters degree in chemical engineering, specialized in environment, from the University of Waterloo. Her master's thesis is about biogas cleaning in biomethanation systems.

Electrigaz partners

Electrigaz and its engineering partners offer over 20 years of applied experience in the field of biogas plant engineering, biogas utilization (heat, electricity, pipeline & vehicles) and general biogas project planning and realization. With over a hundred biogas plants built worldwide our group completely understands the challenges of developing biogas plants in emerging markets.

Krieg & Fischer is an experienced engineering firm specialized in the design and engineering of biogas systems. K&F have designed, built and commissioned hundreds of biogas plants worldwide.
www.kriegfischer.de

BioMil AB is a Swedish engineering company with over 30 years of experience in providing sustainable solutions for the biogas industry. BioMil offers technical consulting services, environmental and economic analyses of biogas and biomethane systems. BioMil cumulates numerous reference projects including a wide range of engineering mandates from preliminary studies and design to construction supervision and project commissioning.
www.biomil.se

Macleod Agronomics provides practical, agri-environmental support for Canadian agricultural development projects. Moreover, the firm offers considerable expertise for the quantification of greenhouse gas reduction projects. While decreasing the overall environment footprint of Canadian agriculture is a major goal for MacLeod Agronomics, a strong focus is also placed on assisting agri-producers and agri-businesses in growing farm-gate revenues with the adoption of sustainable production practices and systems.
www.macleodagronomics.com

Acesa is an infrastucture and energy consulting group based in Rio de Janeiro, Brazil. Acesa is focused on the development of bio-refineries and the energetic applications of biogas in urban and agricultural sectors of the Latin America.
www.acesabioenergia.com

Realizations

2011

> Waste-to-Resources development group (López-Cáceres Eco-Farm), Puerto Rico, USA
Preliminary engineering design report for a co-digestion biogas plant (manure, dairy residues) producing electricity for net metering at the López-Cáceres Eco-Farm.

> Waste-to-Resources development group (Nidco), Puerto Rico, USA
Preliminary engineering design report for a biogas plant producing electricity for a partially off grid quarry and using processed source separated organic residues as feedstock.

> Powerbase, Carleton Place, ON, Canada
Due diligence and troubleshooting of six (6) existing biogas plants.

> Gaz Métro (Project II) Montreal/Riviere-du-Loup, QC
Technical and economic due dilligence of a SSO municipal biogas project in Rivière-du-Loup.

> Stars' Energy Mexico, Baja California Sur, Mexico
Preliminary engineering design and economic analysis for an anaerobic digestion process treating fish processing residues, cheese, and farm waste.

> Innoventé, St-Patrice-de-Beaurivage, QC, Canada
Technical and economic study on integration and operation of an anaerobic digestion plant to a patented composting facility.

> L'Oréal, Montréal, QC, Canada
AD biogas production laboratory testing on pharmaceutical waste.

> Community Energy Partnership Program, Toronto, ON
Analysis and feasibility study for various biogas projects.

2010

> Nouveau-Brunswick Community College, Edmundston, NB, Canada
Design and implementation of a small scale biogas plant for SSO and farm waste.

> BC Ministry of Agriculture, Victoria, BC, Canada
Development and validation of a biomass survey methodology applicable to different bioenergy technologies.

> Earthrenu, Vancouver, BC, Canada, 2009/2011
Feasibility analysis and design of anaerobic digestion plant using 60, 000 t/y of industrial and agricultural organic waste. - $16 millions

> Enfouissement Champlain, Champlain, QC, Canada
Expert witness in the evaluation of the biogas production potential of a landfill.

> Régie Intermunicipale d'élimination de déchets solides de Brome-Missisquoi (R.I.E.D.S.B.M.), QC
Technical and economic due diligence of different anaerobic digestion technologies.

> Municipalité de Chambord, QC, Canada
Technical and economic feasibility study of the anaerobic digestion potential of organic waste for the municipality of Chambord.

> Investeco, Toronto, ON, Canada
Technical and economic due diligence on biogas technologies and business model viability.

> Gaz Métro, Montréal, QC, Canada
Analysis of all potential biomethane projects in Quebec. Recommendation of approach to qualify and answer potential biomethane producer concerns.

Realizations

2009

> Happy Acres, Eastsound, WA
Preliminary design of an anaerobic digestion process for wastewater sludge and grease trap treatment.

> BC Bioenergy Network, Vancouver, BC
Feasibility study – due diligence review: Agricultural waste to green energy and fertilizer project.

> City of Repentigny, QC
Study on the co-digestion of food processing residues of Lebel Island station's methanisers.

> Archibald Dairy Farm, Fredericton, NB
Anaerobic digestion of dairy cattle manure and biosolids for electricity generation at Archibald dairy farm.

> Acton Farms, Fredericton, NB
Anaerobic digestion of beef cattle manure for electricity generation.

> McLeod Agronomics, Fredericton, NB
Study for the development of an ethanol pilot plant using biogas energy in the distillation process.

> Electrigaz (internal project)
Research and development of proprietary online software for preliminary evaluation of biogas projects. (http://www.electrigaz.com/kefir/index.php)

> Zhang Project, Hebei Province, Chinea
Organic waste survey and analysis for the construction of a centralized biogas plant. On site visit of waste producers and operator. Preliminary design of an anaerobic digestion plant.

2008

> BC Innovation Council, Vancouver, CB
Technical review and economic analysis of biogas upgrading technologies to meet natural gas pipeline specifications.

> Concordia University, Montreal, QC
Preliminary engineering and cost assessment of an anaerobic digester to be located downtown Montreal on the University campus.

> Centre Local de Développement, Repentigny, QC
Conceptual, environmental and economic analysis for the construction of a coop food waste treatment plant where biogas is being reused on site.

Realizations

2007 > HSF Foods (MacLeod Agronomics), Frédéricton, NB
Economic analysis and preliminary engineering of an anaerobic digester for potatoes process industry.

> Fromagerie Champêtre, Repentigny,QC
Technical and economic feasibility study for a lactoserum digester and usage possibility of biogas produced.

> BC Bioproducts Association, Vancouver, CB
Evaluation of the potential for a biogas industry in BC and development of policy recommendations to enable its development in the Fraser Valley.

> Ferme Ashworth, Frédéricton, NB
Preliminary engineering and economic analysis for a farm based anaerobic digester using manure and silage as feedstock.

2006 > BLT Farms, Ste-Catherine, ON
Technical and economic comparative study of anaerobic digestion systems for a poultry producer.

> Frito-Lay, Amérique du Nord
Preliminary evaluation of waste management of potatoes chips plant sludge using anaerobic digestion.

> Mobilogaz, Harrington, QC
Design and construction of a 3 m^3 mobile biogas plant (10kW).

> Ferme Messier, Ham Nord, QC
Technical research to convert heating system " LB White " to use raw biogas.

2005 > Geonomic BT, Bangalore, Inde
Research and development of a waste treatment solution for a southern India temple housing 100 elephants.

> C3FE Corp, Maine, Etats-Unis
Comparative study of various technologies for treatment of manure for a 4.5 millions chicken egg layers farm.

> Global Advisors Ltd, New Delhi, Inde
Carbon financing study for 7,500 family digesters in rural India.

> Katani Ltd, Tanzanie, Afrique
Research for the implementation of an R & D pilot plant for the production of bio-hydrogen from Sisal fiber plant waste.

Selected biogas plants

FALKENSTEIN Biogas Plant , Germany
Feedstock: corn silage, wheat silage, sweet sorghum
Digester: steel tank 2 x 3,126 m^3
Energy: gas engine 2 x 726 kW
Specials: gas holder above secondary digester, thermophilic operation, heat usage
Services provided: design, preplanning, detailed and final construction plans, supervision of construction, start-up

INLAND EMPIRE Biogas Plant, USA
Feedstock: manure, waste
Digester: steel tank, 2 x 4,500 m^3
Co-generator: supplied by the gas distribution systems
Specials: biogas feeding into the gas distribution systems
Services provided: detailed final construction plans, tenders, start-up

BIOENERGIE HEHLEN Biogas Plant, Germany
Feedstock: cornsilage
Digester: concrete tank 2,000 m^3
Co-generator: gas engine 536 kW
Specials: gas holder above secondary digester, energy recovery heat, thermophilic operation
Services provided: design, preplanning, permission, detailed final construction plans, tenders, supervision of construction, start-up

Mobile Biogas Plant, Quebec, Canada
Feedstock: manure
Digester: fiberglass tank, 2.65 m^3
Energy: modified diesel engine 3kW
Specials: mobile pilot plant, can be used to test agricultural, industrial and municipal organic waste
Services provided: design, preplanning, detailed and final construction plans, construction, erection & start-up

Selected biogas plants

SCHORNBUSCHER BIOGAS GMBH Biogas Plant , Germany
Feedstock: corn, organic industrial waste
Digester: concrete tank, 1.500m³
Co-generator: gas engine, 500 kW
Specials: process water recycling, complete pasteurization
Services provided: design, permission, detailed final construction plans, supervision of construction, start-up, operation

WIETZENDORF Biogas Plant / Anaerobic WWTP , Germany
Feedstock: potato starch, potato residues
Digester: 4 steel tanks, 2500 m³ each
Co-generator: gas engine, 4 x 2,1 MW
Specials: protein recovery, reverse osmosis, retention of biomass through decanter
Services provided: planning of complete biological treatment, gas holder, dewatering, safety measuring, controlling devices

Biogas Plant, Saskatoon, Canada
Feedstock: manure, potatoes
Digester: steel tank, 2 000 m³
Co-generator: micro turbine, 4 x 30kW
Specials: gas bag above dual purpose tank
Services provided: design, preplanning, permission planning, detailed and final plannings, supervision of erection, start-up

WIESENAU II Biogas Plant , Germany
Feedstock: cattle manure, dung, wheat, corn silage
Digester: steel tank 4,300 m³
Co-generator: gas engine, 2 x 526 kW
Specials: extension of existing biogas plant
Services provided: design, preplanning, permission, detailed and final construction plans, supervision of construction, start-up

Conferences & Publications

> *Upgrade of organic wastes in food processing industry as energy efficiency measure.*
Annual congress, AQME (Association Québécoise pour la maîtrise de l'énergie) Drummondville, QC, Canada, 2011.

> *Favourable conditions for the development of the biomethane industry in Quebec.*
Americana, Montréal, QC, Canada, 2011.

> *Perspectives of biogas energy in Quebec.*
AQPER (Association québécoise de la production d'énergie renouvelable), Québec, QC, Canada, 2011.

> *Bioenergy feedstock surveying techniques.*
Agri-Energy Forum, Pacific Agriculture Show, Abbotsford, BC, Canada, 2011.

> *Biomethane production cost from various sources.*
Biocycle, Des Moines, IA, USA, 2010.

> *Biogas project development cycle.*
Biogas USA, San Francisco, CA, USA, 2010.

> *Sector future: biogas energy.*
Expo Energie, Montreal, QC, Canada, 2010.

> *Production of biomethane from organic waste.*
Efficacité énergétique. St-Hyacinthe, QC, Canada, 2010.

> *Eastern Canada biogas policy development: myths and reality.*
International Bioenergy Conference, Prince George, BC, Canada, 2010.

> *Panorama of bioenergy solutions.*
Forum Bioénegie, Montreal, QC, Canada, 2010.

> *Electric cars economic analysis as a solution for renewable energy in Quebec.*
Salon TEQ, Quebec, Canada, 2010.

> *Mandatory biomethane mix in the Canadian natural gas network.*
Growing the margins, London, ON, Canada, 2010.

> *Technical and economic challenges of building a mobile biogas plant.*
Biocycle, California, CA, USA, 2009.

> *Economic viability of upgrading farm biogas to sell energy directly to consumers over the natural gas grid.*
Growing the margins, London, ON, Canada, 2008.

> *Prospects of anaerobic digestion potential of organic materiel and biogas energy valorization for various Canadian markets.*
Salon TEQ, Quebec, QC, Canada, 2008.

> *Anaerobic digestion technologies.*
Quebec Liberal Party congress, 2008.

> *Perspectives for biomethane production and resell in the Fraser Valley.*
BC Agricultural show, BC, Canada, 2008.

> *Farm based biogas projects in Ontario.*
Toronto International Agricultural show, ON, Canada, 2008.

> *Biogas investment opportunities.*
Biofinance conference, Toronto, ON, Canada, 2008.

> *On farm energy production.*
Conférence énergie à la ferme, St-Jean-Richelieu, QC, Canada, 2008.

> *Economic viability of upgrading farm biogas for thermal or automotive applications.*
Biocycle conference, WI, USA, 2008.

> *Biogas principles.*
CRAAQ, Methanisation day, QC, Canada, 2007.

> *Climate change and anaerobic digestion.*
APCAS, Air et changements climatiques, Montreal, QC, Canada, 2007.

Electrigaz Clients

Stars Energy Mexico
Earth Renu Energy Corp.
BC Bioproducts
City of Repentigny
Concordia University
Municipality of Chambord
Province of British Columbia
Investeco
Innoventé
CLD de la MRC de l'Assomption
Collège communautaire du Nouveau-Brunswick
L'Oréal
British Columbia Innovation Council
Powerbase energy systems
Gaz Métro
Champêtre Cheesery
Massachusetts Institute of Technology
BC Bioenergy Network
MacLeod Agronomics
Community Energy Partnerships Program
Frito Lay
WTR Development group
R.I.E.D.S.B.M.
Kimminic Corporation
Kindele
Enfouissement Champlain
Happy Acres Company

Electrigaz

Biogas Engineering

Electrigaz Technologies inc.

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Trois-Rivieres (Quebec)
Canada G9B 6M6

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E: info@electrigaz.com
W: www.electrigaz.com

Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario

-RNG program pricing report

Prepared by:

Electrigaz Technologies Inc.

In conjunction with:

Enbridge Gas Distribution Inc.

Union Gas Limited

September 2011

Executive summary

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (UGL) are the largest natural gas distribution utilities in Ontario. They are investigating technical and economic challenges of establishing a Renewable Natural Gas (RNG) program that would allow both utilities to provide their customers renewable natural gas. Electrigaz Technologies Inc. (Electrigaz) was hired by EGD and UGL to provide biogas engineering expertise to perform financial modeling and price evaluation for this RNG program.

Capital and operational costs were estimated for each scenario using the best available Ontario biogas market information. These can be found in the Electrigaz *Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario—Biogas plant costing report*. These were used as a basis to evaluate and develop an appropriate pricing mechanism in this report.

A standardized financial model was developed to evaluate the Return on Equity (ROE) for each scenario under various RNG price points. EGD and UGL recommended an RNG price ceiling to balance the need to minimize the impacts on their customer's bills with the need of RNG producers to earn a reasonable return on the incremental capital and operating costs required to enable the market. Simulations were performed to establish the optimal RNG price points and energy volume thresholds to yield a target 11% ROE.

Based on the analysis performed, two distinct RNG price schedules, one for AD and one for landfills, are recommended. Within each schedule, two RNG prices are proposed around a specified energy volume threshold. This means that energy delivered below a set energy threshold will be paid at a higher price per gigajoule than the energy delivered above that energy threshold. This two-tiered approach was chosen to address the distinct characteristics of the anaerobic digestion (AD) and landfill gas (LFG) segments while facilitating the overarching objectives of simplicity and broad adoptability.

The following table presents recommended energy volume threshold and RNG price points.

RNG pricing			
AD Energy Volume Threshold		50 000	GJ/yr
AD RNG price below threshold	$	17.00	$/GJ
AD RNG price above threshold	$	11.00	$/GJ
LFG Energy Volume Threshold		150 000	GJ/yr
LFG RNG price below threshold	$	13.00	$/GJ
LFG RNG price above threshold	$	6.00	$/GJ

The following table presents expected ROE value for each scenario.

Results	Project Cost	ROE
AD scenarios		
Baseline Farm	$ 4,448,919	-
Large Farm	$ 5,751,962	10.0%
Coop Farm	$ 8,200,289	11.1%
SSO (Municipal)	$ 31,524,253	1.3%
Industrial	$ 29,282,343	-
WWTP	$ 2,492,935	-
Landfill scenarios		
Small landfill	$ 5,077,647	10.5%
Medium landfill	$ 9,107,041	13.4%
Large landfill	$ 17,482,106	13.6%

The summary results above represent returns for each segment under the developed scenarios. In certain cases, the application of the model to a production scenario resulted in a negative ROE, indicating that production would not be viable at that price level. Where ROEs are negative, no figure is included in the table. Individual biogas projects returns will vary depending on prevailing market conditions and proponents' specific operational characteristics.

Glossary

Biogas	Gas produced from anaerobic digestion, mostly composed of CH_4 and CO_2
Biomethane	Methane extracted from a biogas upgrading system, also called Renewable Natural Gas (RNG)
Digestate	Nutrient rich material left following AD consisting of indigestible material and dead micro-organisms
Renewable Natural Gas	Biomethane interchangeable with natural gas
Substrate	Material uploaded into digesters

Abbreviations and units

AD	Anaerobic digestion
CGA	Canadian Gas Association
CH_4	Methane
CO_2	Carbon dioxide
C:N	Carbon/Nitrogen ratio
CSTR	Complete stirred tank reactor
d	Day
EPC	Engineering, Procurement and Construction
FIT	Feed in tariff
GHG	Greenhouse gases
GJ	Energy unit (Gigajoule)
H_2O	Water
HP injection pressure	High pressure (200 psig)
hr	Time unit (Hour)
H_2S	Hydrogen sulphide
IDC	Interest during construction
IP injection pressure	Intermediate pressure (60 psig)
kg	Mass unit (Kilogram)
kWe	Power unit (Kilowatt electrical)

kWh	Energy unit (Kilowatt-hour)
l	Volume unit (Litre)
LFG	Landfill gas
m^3	Volume unit (Cubic meter)
mg	Mass unit (Milligram)
MJ	Energy unit (MegaJoule)
MSW	Municipal solid waste
%mol	Concentration unit (molar percentage)
N_2	Nitrogen
N/D	Not defined
Nm^3	Volume unit (Normal cubic meter)
O_2	Oxygen
OPA	Ontario Power Authority
OPA FIT	Ontario Power Authority feed in tariff program
ppm	Concentration unit (part per million)
PSA	Pressure swing adsorption
psig	Pressure unit (pound square inch gauge)
RNG	Renewable natural gas
ROE	Return on equity
S	Sulphur
SSO	Source separated organics
t	Mass unit (Tonne)
TS	Total solids
VS	Volatile solids
WWTP	Wastewater treatment plant
XHP injection pressure	Extra high pressure (500 psig)
Yr	Year
°C	Temperature unit (Celsius degree)

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1 Introduction

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (UGL) are the largest natural gas distribution utilities in Ontario. They are investigating technical and economic challenges of establishing a Renewable Natural Gas (RNG) program that would allow both utilities to provide their customers renewable natural gas. Electrigaz Technologies Inc. (Electrigaz) was hired by EGD and UGL to work with the utilities to perform financial modeling and price evaluation for this RNG program.

In the first phase of this study named: *Biogas plant costing report,* nine (9) scenarios were developed and capital and operational costs were obtained for each scenario using the best available Ontario biogas market information.

These costs are now used in this study to model an optimal RNG program.

1.1 Study objectives

The main objective of the study is to establish an appropriate RNG pricing model that would enable a viable RNG market in Ontario. The pricing model should balance the need for RNG producer requirements of a reasonable return on the incremental capital and operating costs to develop the supply stream and the utilities' customer need for minimal bill impact.

1.2 Methodology

Electrigaz developed capital and operational costs for each scenario (found in Electrigaz's report titled *Biogas Plant Costing Report*) and developed a preliminary financial model. The financial model was reviewed, expanded and validated by the Utilities and input was provided on pricing constraints. This updated financial model was then used by Electrigaz, working together with the Utilities, to evaluate projects Return on Equity (ROE). An ROE of 11% was chosen as an appropriate target informed by the OPA FIT program.

Various RNG price points were applied to landfill and AD financial models to evaluate projects potential ROE. RNG pricing simulations were used to determine the optimal pricing model.

For the purpose of financial modeling, a 20 years project life has been assumed.

2 Financial model

A financial model was developed to evaluate project return on equity (ROE) given a set of economic assumptions and RNG pricing model.

The return is calculated using a standard discounted cash flow model. The model takes into consideration multiple revenues, operating expenses, depreciation, and tax modeling such a Capital Cost Allowance (CCA). The Ontario tax information was provided by EGD and UGL. The model calculations were reviewed and approved by EGD and UGL. See Appendix 1: pro-formas for calculation details.

2.1 Economic assumptions

The following economic assumptions were taken into consideration for the financial modeling of all scenarios:

Macro-economic references

- Global inflation: 2.25%. [1] [2]
- Capital Cost Allowance (CCA) Class 1 rate: 6%. [3]
- Capital Cost Allowance (CCA) Class 8 rate: 20%. [3]
- Capital Cost Allowance (CCA) Class 43.2 rate: 50%. [4]
- RNG price escalation factor: 30% of inflation. [2]
- Equity cash flow payable as dividends: 100%.
- Straight-line depreciation on 20 years. [5] [6]

Agricultural and Industrial scenarios assumptions

- A 25% annual gate fee deflation is considered.
- Interest on loan: 7%. [7] [8]
- Equity: 40%. [10]
- Debt: 60%. [10]

SSO and WWTP scenarios assumptions

- No gate fee deflation is considered.
- Interest on loan: 4.5% [9]
- Equity: 20%.
- Debt: 80%.

All landfill scenarios assumptions

- Interest on loan: 7% [7] [8]
- Equity: 40%. [10]
- Debt: 60%. [10]

2.2 Revenues

Two potential revenues were considered:

1. Gate fees: Revenue collected by the project to treat other people's organic waste. Gate fees are proportional to amount of substrates processed. Moreover, gate fees are prone to waste disposal market fluctuations. In some scenarios gate fee deflation was considered. See each scenario economic assumptions.
2. RNG: Revenue collected for the selling of RNG. Note that there is an above set energy threshold revenue and a below energy threshold revenue

2.3 Depreciation

Linear twenty (20) years depreciation was assumed for the entire project capital cost.

2.4 Tax modeling

Capital cost allowance for Class 1, Class 8 and Class 43.2 were taken into consideration for the accelerated depreciation of assets. Moreover, tax modeling was performed to accurately represent benefits of CCA, tax loss carry forward, future tax expenses, etc.

Note that land purchase and site work are not included in CCA calculations.

2.5 Return on equity

ROE was calculated using dividends to equity and tax modeling benefits.

3 RNG Program and Findings

In the first phase of this study, *Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario—Biogas plant costing report*, capital and operational costs were estimated for each scenario using the best available Ontario biogas market information. Working together with the Utilities, ROE for each scenario under various RNG price points was evaluated with the financial model. EGD and UGL recommended an RNG price ceiling to minimize the impact on their respective customers.

Simulations were performed to establish optimal and acceptable RNG price points and energy volume thresholds to yield a target 11% ROE. Various RNG price points were applied to landfill and AD financial models to evaluate projects potential ROE.

Based on the analysis performed, two distinct RNG price schedules, one for anaerobic digestion and one for landfills, are recommended. Within each schedule, two RNG prices are proposed around a specified energy volume threshold. This means that, on an annual basis, energy delivered on below a set energy threshold will be paid at a higher price per gigajoule than the energy delivered above that energy threshold. This two tiered approach was chosen to address the distinct characteristics of the AD and LFG segments while facilitating the overarching objectives of simplicity and broad adoptability.

The following table presents recommended energy volume threshold and RNG price points.

Table 1: Recommended energy volume threshold and RNG prices

RNG pricing			
AD Energy Volume Threshold		50 000	GJ/yr
AD RNG price below threshold	$	17.00	$/GJ
AD RNG price above threshold	$	11.00	$/GJ
LFG Energy Volume Threshold		150 000	GJ/yr
LFG RNG price below threshold	$	13.00	$/GJ
LFG RNG price above threshold	$	6.00	$/GJ

The following table presents expected ROE value for each scenario.

Table 2: ROE for each scenario[1]

Results	Project Cost	ROE
AD scenarios		
Baseline Farm	$ 4,448,919	-
Large Farm	$ 5,751,962	10.0%
Coop Farm	$ 8,200,289	11.1%
SSO (Municipal)	$ 31,524,253	1.3%
Industrial	$ 29,282,343	-
WWTP	$ 2,492,935	-
Landfill scenarios		
Small landfill	$ 5,077,647	10.5%
Medium landfill	$ 9,107,041	13.4%
Large landfill	$ 17,482,106	13.6%

It is important to note that the blended price for larger scenarios is significantly lower than the set above threshold RNG price. For example, in the large landfill scenario the blended price is approximately $7.5/GJ because the first 150,000 GJ (paid at $13) represent a small fraction of the energy delivered throughout the year.

The ROE summary results above represent returns for each scenario. Individual biogas project returns will vary depending on prevailing market conditions and proponents' specific operational characteristics.

[1] Large landfill capital cost consolidates first year capital cost and inflated year-12 re-investment.

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Appendix 1: Pro-formas

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Exhibit B
Tab 1
Appendix 5

Baseline agricultural scenario		1	2	3	4	5	6	7	8	9	10
Revenu		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold		17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
Biomethane price above treshold		11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
Biomethane	$/GJ	$ 450,686	$ 453,728	$ 456,791	$ 459,874	$ 462,978	$ 466,103	$ 469,250	$ 472,417	$ 475,606	$ 478,816
Gate fees		$ 280,000	$ 210,000	$ 157,500	$ 118,125	$ 88,594	$ 66,445	$ 49,834	$ 37,375	$ 28,032	$ 21,024
Total revenues		$ 730,686	$ 663,728	$ 614,291	$ 577,999	$ 551,572	$ 532,549	$ 519,084	$ 509,793	$ 503,638	$ 499,840
Production costs											
Production costs		$ 363,368	$ 371,544	$ 379,903	$ 388,451	$ 397,191	$ 406,128	$ 415,266	$ 424,610	$ 434,163	$ 443,932
EBITDA		$ 367,318	$ 292,185	$ 234,387	$ 189,548	$ 154,381	$ 126,421	$ 103,818	$ 85,183	$ 69,474	$ 55,908
Depreciation		$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146
EBIT		$ 150,172	$ 75,039	$ 17,242	-$ 27,598	-$ 62,765	-$ 90,725	-$ 113,328	-$ 131,963	-$ 147,672	-$ 161,238
Total Annual Payment		$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968
Principle payment		$ 65,113	$ 69,671	$ 74,548	$ 79,767	$ 85,350	$ 91,325	$ 97,717	$ 104,558	$ 111,877	$ 119,708
Interest payment		$ 186,855	$ 182,297	$ 177,420	$ 172,201	$ 166,618	$ 160,643	$ 154,250	$ 147,410	$ 140,091	$ 132,260
Principle Balance	$ 2,669,351	$ 2,604,238	$ 2,534,567	$ 2,460,018	$ 2,380,252	$ 2,294,902	$ 2,203,577	$ 2,105,859	$ 2,001,302	$ 1,889,425	$ 1,769,717
Net Income (before tax)		-$ 36,682	-$ 107,258	-$ 160,178	-$ 199,799	-$ 229,383	-$ 251,368	-$ 267,579	-$ 279,373	-$ 287,763	-$ 293,498
CCA Class 43.2 Factor	*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible		$ 861,000	$ 1,291,500	$ 645,750	$ 322,875	$ 161,438	$ 80,719	$ 40,359	$ 20,180	$ 10,090	$ 5,045
CCA Class 8 Factor	*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible		$ 22,700	$ 40,860	$ 32,688	$ 26,150	$ 20,920	$ 16,736	$ 13,389	$ 10,711	$ 8,569	$ 6,855
CCA Class 1 Factor	*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible		$ 16,978	$ 32,937	$ 30,961	$ 29,103	$ 27,357	$ 25,716	$ 24,173	$ 22,722	$ 21,359	$ 20,077
Total Eligible CCA		$ 900,678	$ 1,365,297	$ 709,399	$ 378,129	$ 209,715	$ 123,171	$ 77,921	$ 53,613	$ 40,018	$ 31,978
Taxable Income		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax		-$ 9,354	-$ 26,631	-$ 40,045	-$ 49,950	-$ 57,346	-$ 62,842	-$ 66,895	-$ 69,843	-$ 71,941	-$ 73,374
Net Income (after tax)		-$ 27,328	-$ 80,627	-$ 120,134	-$ 149,849	-$ 172,037	-$ 188,526	-$ 200,684	-$ 209,530	-$ 215,822	-$ 220,123
Cash Distributions											
Equity Dividend	at 100%	-$ 27,328	-$ 80,627	-$ 120,134	-$ 149,849	-$ 172,037	-$ 188,526	-$ 200,684	-$ 209,530	-$ 215,822	-$ 220,123
Depreciation		$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146
Future Income Tax Expense		-$ 9,354	-$ 26,631	-$ 40,045	-$ 49,950	-$ 57,346	-$ 62,842	-$ 66,895	-$ 69,843	-$ 71,941	-$ 73,374
Debt Repayment		-$ 65,113	-$ 69,671	-$ 74,548	-$ 79,767	-$ 85,350	-$ 91,325	-$ 97,717	-$ 104,558	-$ 111,877	-$ 119,708
Equity dividend	-$ 1,779,567	**$ 115,350**	**$ 40,217**	**-$ 17,580**	**-$ 62,420**	**-$ 97,587**	**-$ 125,547**	**-$ 148,150**	**-$ 166,785**	**-$ 182,494**	**-$ 196,060**
	31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE	#DIV/0!										

Baseline agricultural scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
Biomethane price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
Biomethane	$ 482,048	$ 485,302	$ 488,578	$ 491,876	$ 495,196	$ 498,539	$ 501,904	$ 505,292	$ 508,702	$ 512,136
Gate fees	$ 15,768	$ 11,826	$ 8,869	$ 6,652	$ 4,989	$ 3,742	$ 2,806	$ 2,105	$ 1,579	$ 1,184
Total revenues	$ 497,816	$ 497,128	$ 497,447	$ 498,528	$ 500,185	$ 502,280	$ 504,710	$ 507,396	$ 510,281	$ 513,320
Production costs										
Production costs	$ 453,920	$ 464,134	$ 474,577	$ 485,255	$ 496,173	$ 507,337	$ 518,752	$ 530,424	$ 542,358	$ 554,561
EBITDA	$ 43,896	$ 32,994	$ 22,871	$ 13,273	$ 4,012	-$ 5,056	-$ 14,042	-$ 23,028	-$ 32,078	-$ 41,241
Depreciation	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146
EBIT	-$ 173,250	-$ 184,152	-$ 194,275	-$ 203,873	-$ 213,134	-$ 222,202	-$ 231,188	-$ 240,173	-$ 249,223	-$ 258,387
Total Annual Payment	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968
Principle payment	$ 128,088	$ 137,054	$ 146,648	$ 156,913	$ 167,897	$ 179,650	$ 192,225	$ 205,681	$ 220,078	$ 235,484
Interest payment	$ 123,880	$ 114,914	$ 105,320	$ 95,055	$ 84,071	$ 72,318	$ 59,743	$ 46,287	$ 31,889	$ 16,484
Principle Balance	$ 1,641,629	$ 1,504,575	$ 1,357,928	$ 1,201,015	$ 1,033,118	$ 853,468	$ 661,243	$ 455,562	$ 235,484	$ 0
Net Income (before tax)	-$ 297,131	-$ 299,066	-$ 299,596	-$ 298,928	-$ 297,205	-$ 294,521	-$ 290,931	-$ 286,460	-$ 281,113	-$ 274,871
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 2,522	$ 1,261	$ 631	$ 315	$ 158	$ 79	$ 39	$ 20	$ 10	$ 5
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 5,484	$ 4,387	$ 3,510	$ 2,808	$ 2,246	$ 1,797	$ 1,438	$ 1,150	$ 920	$ 736
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 18,873	$ 17,740	$ 16,676	$ 15,675	$ 14,735	$ 13,851	$ 13,020	$ 12,239	$ 11,504	$ 10,814
Total Eligible CCA	$ 26,879	$ 23,389	$ 20,816	$ 18,799	$ 17,139	$ 15,727	$ 14,497	$ 13,408	$ 12,434	$ 11,555
Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	-$ 74,283	-$ 74,766	-$ 74,899	-$ 74,732	-$ 74,301	-$ 73,630	-$ 72,733	-$ 71,615	-$ 70,278	-$ 68,718
Net Income (after tax)	-$ 222,848	-$ 224,299	-$ 224,697	-$ 224,196	-$ 222,904	-$ 220,890	-$ 218,198	-$ 214,845	-$ 210,835	-$ 206,153
Cash Distributions										
Equity Dividend	-$ 222,848	-$ 224,299	-$ 224,697	-$ 224,196	-$ 222,904	-$ 220,890	-$ 218,198	-$ 214,845	-$ 210,835	-$ 206,153
Depreciation	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146
Future Income Tax Expense	-$ 74,283	-$ 74,766	-$ 74,899	-$ 74,732	-$ 74,301	-$ 73,630	-$ 72,733	-$ 71,615	-$ 70,278	-$ 68,718
Debt Repayment	-$ 128,088	-$ 137,054	-$ 146,648	-$ 156,913	-$ 167,897	-$ 179,650	-$ 192,225	-$ 205,681	-$ 220,078	-$ 235,484
Equity dividend	**-$ 208,072**	**-$ 218,974**	**-$ 229,097**	**-$ 238,695**	**-$ 247,956**	**-$ 257,024**	**-$ 266,010**	**-$ 274,995**	**-$ 284,045**	**-$ 293,209**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31
Equity ROE										

Large agricultural scenario		1	2	3	4	5	6	7	8	9	10
Revenu		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RNG price sub treshold		17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
RNG price above treshold		11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
RNG		$ 896,459	$ 902,510	$ 908,602	$ 914,735	$ 920,910	$ 927,126	$ 933,384	$ 939,684	$ 946,027	$ 952,413
Gate fees		$ 581,000	$ 435,750	$ 326,813	$ 245,109	$ 183,832	$ 137,874	$ 103,406	$ 77,554	$ 58,166	$ 43,624
Total revenues		$ 1,477,459	$ 1,338,260	$ 1,235,415	$ 1,159,845	$ 1,104,742	$ 1,065,000	$ 1,036,790	$ 1,017,239	$ 1,004,193	$ 996,037
Operational costs											
Operational costs		$ 451,743	$ 461,907	$ 472,300	$ 482,927	$ 493,792	$ 504,903	$ 516,263	$ 527,879	$ 539,756	$ 551,901
EBITDA		$ 1,025,716	$ 876,353	$ 763,115	$ 676,918	$ 610,949	$ 560,097	$ 520,526	$ 489,360	$ 464,437	$ 444,136
Depreciation		$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648
EBIT		$ 745,068	$ 595,705	$ 482,467	$ 396,270	$ 330,301	$ 279,449	$ 239,878	$ 208,711	$ 183,788	$ 163,488
Debt service total annual payment		$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767
Principle payment		$ 84,184	$ 90,077	$ 96,383	$ 103,129	$ 110,348	$ 118,073	$ 126,338	$ 135,182	$ 144,644	$ 154,769
Interest payment		$ 241,582	$ 235,689	$ 229,384	$ 222,637	$ 215,418	$ 207,694	$ 199,429	$ 190,585	$ 181,122	$ 170,997
Principle Balance	$ 3,451,177	$ 3,366,993	$ 3,276,915	$ 3,180,533	$ 3,077,403	$ 2,967,055	$ 2,848,982	$ 2,722,644	$ 2,587,463	$ 2,442,818	$ 2,288,049
Net Income (before tax)		$ 503,486	$ 360,016	$ 253,083	$ 173,633	$ 114,883	$ 71,755	$ 40,450	$ 18,126	$ 2,666	-$ 7,509
CCA Class 43.2 Factor	*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible		$ 1,148,250	$ 1,722,375	$ 861,188	$ 430,594	$ 215,297	$ 107,648	$ 53,824	$ 26,912	$ 13,456	$ 6,728
CCA Class 8 Factor	*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible		$ 30,400	$ 54,720	$ 43,776	$ 35,021	$ 28,017	$ 22,413	$ 17,931	$ 14,345	$ 11,476	$ 9,180
CCA Class 1 Factor	*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible		$ 17,368	$ 33,694	$ 31,672	$ 29,772	$ 27,985	$ 26,306	$ 24,728	$ 23,244	$ 21,850	$ 20,539
Total Eligible CCA		$ 1,196,018	$ 1,810,789	$ 936,636	$ 495,386	$ 271,299	$ 156,368	$ 96,483	$ 64,501	$ 46,781	$ 36,447
Taxable Income		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax		$ 128,389	$ 87,487	$ 63,271	$ 43,408	$ 28,721	$ 17,939	$ 10,112	$ 4,532	$ 667	-$ 1,877
Net Income (after tax)		$ 375,097	$ 272,529	$ 189,812	$ 130,225	$ 86,162	$ 53,816	$ 30,337	$ 13,595	$ 2,000	-$ 5,632
Cash Distributions											
Equity Dividend	**at** 100%	$ 375,097	$ 272,529	$ 189,812	$ 130,225	$ 86,162	$ 53,816	$ 30,337	$ 13,595	$ 2,000	-$ 5,632
Depreciation		$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648
Future Income Tax Expense		$ 128,389	$ 87,487	$ 63,271	$ 43,408	$ 28,721	$ 17,939	$ 10,112	$ 4,532	$ 667	-$ 1,877
Debt Repayment		-$ 84,184	-$ 90,077	-$ 96,383	-$ 103,129	-$ 110,348	-$ 118,073	-$ 126,338	-$ 135,182	-$ 144,644	-$ 154,769
Equity dividend	-$ 2,300,785	**$ 699,950**	**$ 550,587**	**$ 437,348**	**$ 351,151**	**$ 285,183**	**$ 234,331**	**$ 194,760**	**$ 163,593**	**$ 138,670**	**$ 118,370**
	31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE	9.96%										

Large agricultural scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
RNG price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
RNG price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
RNG	$ 958,842	$ 965,314	$ 971,830	$ 978,390	$ 984,994	$ 991,642	$ 998,336	$ 1,005,075	$ 1,011,859	$ 1,018,689
Gate fees	$ 32,718	$ 24,539	$ 18,404	$ 13,803	$ 10,352	$ 7,764	$ 5,823	$ 4,367	$ 3,276	$ 2,457
Total revenues	$ 991,560	$ 989,853	$ 990,234	$ 992,193	$ 995,346	$ 999,407	$ 1,004,159	$ 1,009,442	$ 1,015,135	$ 1,021,146
Operational costs										
Operational costs	$ 564,319	$ 577,016	$ 589,999	$ 603,274	$ 616,847	$ 630,726	$ 644,918	$ 659,428	$ 674,265	$ 689,436
EBITDA	$ 427,241	$ 412,837	$ 400,235	$ 388,919	$ 378,499	$ 368,680	$ 359,242	$ 350,014	$ 340,869	$ 331,709
Depreciation	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648
EBIT	$ 146,593	$ 132,189	$ 119,587	$ 108,271	$ 97,851	$ 88,032	$ 78,593	$ 69,366	$ 60,221	$ 51,061
Debt service total annual payment	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767
Principle payment	$ 165,603	$ 177,195	$ 189,599	$ 202,871	$ 217,072	$ 232,267	$ 248,526	$ 265,923	$ 284,537	$ 304,455
Interest payment	$ 160,163	$ 148,571	$ 136,168	$ 122,896	$ 108,695	$ 93,500	$ 77,241	$ 59,844	$ 41,229	$ 21,312
Principle Balance	$ 2,122,446	$ 1,945,250	$ 1,755,651	$ 1,552,780	$ 1,335,708	$ 1,103,441	$ 854,915	$ 588,992	$ 304,455	$ 0
Net Income (before tax)	-$ 13,570	-$ 16,382	-$ 16,580	-$ 14,625	-$ 10,844	-$ 5,467	$ 1,353	$ 9,522	$ 18,992	$ 29,749
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 3,364	$ 1,682	$ 841	$ 421	$ 210	$ 105	$ 53	$ 26	$ 13	$ 7
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 7,344	$ 5,876	$ 4,700	$ 3,760	$ 3,008	$ 2,407	$ 1,925	$ 1,540	$ 1,232	$ 986
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 19,306	$ 18,148	$ 17,059	$ 16,036	$ 15,073	$ 14,169	$ 13,319	$ 12,520	$ 11,769	$ 11,062
Total Eligible CCA	$ 30,015	$ 25,705	$ 22,600	$ 20,216	$ 18,292	$ 16,681	$ 15,297	$ 14,086	$ 13,014	$ 12,055
Taxable Income	$ -	$ -	$ -	$ 189,259	$ 251,512	$ 258,500	$ 266,704	$ 276,084	$ 286,626	$ 298,343
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	-$ 3,393	-$ 4,096	-$ 4,145	-$ 3,656	-$ 2,711	-$ 1,367	$ 338	$ 2,380	$ 4,748	$ 7,437
Net Income (after tax)	-$ 10,178	-$ 12,287	-$ 12,435	-$ 10,968	-$ 8,133	-$ 4,100	$ 1,014	$ 7,141	$ 14,244	$ 22,312
Cash Distributions										
Equity Dividend	-$ 10,178	-$ 12,287	-$ 12,435	-$ 10,968	-$ 8,133	-$ 4,100	$ 1,014	$ 7,141	$ 14,244	$ 22,312
Depreciation	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648
Future Income Tax Expense	-$ 3,393	-$ 4,096	-$ 4,145	-$ 50,971	-$ 65,589	-$ 65,992	-$ 66,338	-$ 66,640	-$ 66,909	-$ 67,148
Debt Repayment	-$ 165,603	-$ 177,195	-$ 189,599	-$ 202,871	-$ 217,072	-$ 232,267	-$ 248,526	-$ 265,923	-$ 284,537	-$ 304,455
Equity dividend	**$ 101,475**	**$ 87,070**	**$ 74,468**	**$ 15,838**	**-$ 10,146**	**-$ 21,711**	**-$ 33,201**	**-$ 44,774**	**-$ 56,554**	**-$ 68,643**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

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EB-2011-0283
Exhibit B
Tab 1
Appendix 5

Coop agricultural scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
Biomethane price above treshold			11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
Biomethane	0.00 $/GJ		$ 1,198,881	$ 1,206,974	$ 1,215,121	$ 1,223,323	$ 1,231,580	$ 1,239,893	$ 1,248,263	$ 1,256,688	$ 1,265,171	$ 1,273,711
Gate fees			$ 875,000	$ 656,250	$ 492,188	$ 369,141	$ 276,855	$ 207,642	$ 155,731	$ 116,798	$ 87,599	$ 65,699
Total revenues			$ 2,073,881	$ 1,863,224	$ 1,707,308	$ 1,592,463	$ 1,508,436	$ 1,447,535	$ 1,403,994	$ 1,373,487	$ 1,352,770	$ 1,339,410
Production costs												
Production costs			$ 573,583	$ 586,488	$ 599,684	$ 613,177	$ 626,974	$ 641,080	$ 655,505	$ 670,254	$ 685,334	$ 700,754
EBITDA			$ 1,500,299	$ 1,276,735	$ 1,107,624	$ 979,286	$ 881,462	$ 806,454	$ 748,489	$ 703,233	$ 667,435	$ 638,656
Depreciation			$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364
EBIT			$ 1,098,934	$ 875,371	$ 706,259	$ 577,922	$ 480,098	$ 405,090	$ 347,125	$ 301,869	$ 266,071	$ 237,291
Total Annual Payment			$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430
Principle payment			$ 120,017	$ 128,419	$ 137,408	$ 147,027	$ 157,318	$ 168,331	$ 180,114	$ 192,722	$ 206,212	$ 220,647
Interest payment			$ 344,412	$ 336,011	$ 327,022	$ 317,403	$ 307,111	$ 296,099	$ 284,316	$ 271,708	$ 258,217	$ 243,782
Principle Balance		$ 4,920,173	$ 4,800,156	$ 4,671,737	$ 4,534,329	$ 4,387,303	$ 4,229,985	$ 4,061,654	$ 3,881,540	$ 3,688,818	$ 3,482,606	$ 3,261,959
Net Income (before tax)			$ 754,522	$ 539,360	$ 379,238	$ 260,519	$ 172,986	$ 108,991	$ 62,809	$ 30,161	$ 7,854	-$ 6,491
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 1,716,250	$ 2,574,375	$ 1,287,188	$ 643,594	$ 321,797	$ 160,898	$ 80,449	$ 40,225	$ 20,112	$ 10,056
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 39,600	$ 71,280	$ 57,024	$ 45,619	$ 36,495	$ 29,196	$ 23,357	$ 18,686	$ 14,948	$ 11,959
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 17,128	$ 33,228	$ 31,234	$ 29,360	$ 27,599	$ 25,943	$ 24,386	$ 22,923	$ 21,548	$ 20,255
Total Eligible CCA			$ 1,772,978	$ 2,678,883	$ 1,375,446	$ 718,573	$ 385,891	$ 216,038	$ 128,193	$ 81,833	$ 56,608	$ 42,270
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			$ 192,403	$ 131,067	$ 94,809	$ 65,130	$ 43,247	$ 27,248	$ 15,702	$ 7,540	$ 1,963	-$ 1,623
Net Income (after tax)			$ 562,119	$ 408,293	$ 284,428	$ 195,389	$ 129,740	$ 81,743	$ 47,107	$ 22,621	$ 5,890	-$ 4,868
Cash Distributions												
Equity Dividend	at	100%	$ 562,119	$ 408,293	$ 284,428	$ 195,389	$ 129,740	$ 81,743	$ 47,107	$ 22,621	$ 5,890	-$ 4,868
Depreciation			$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364
Future Income Tax Expense			$ 192,403	$ 131,067	$ 94,809	$ 65,130	$ 43,247	$ 27,248	$ 15,702	$ 7,540	$ 1,963	-$ 1,623
Debt Repayment			-$ 120,017	-$ 128,419	-$ 137,408	-$ 147,027	-$ 157,318	-$ 168,331	-$ 180,114	-$ 192,722	-$ 206,212	-$ 220,647
Equity dividend		-$ 3,280,116	**$ 1,035,869**	**$ 812,306**	**$ 643,194**	**$ 514,857**	**$ 417,032**	**$ 342,025**	**$ 284,059**	**$ 238,804**	**$ 203,006**	**$ 174,226**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		11.12%										

Coop agricultural scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
Biomethane price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
Biomethane	$ 1,282,308	$ 1,290,964	$ 1,299,678	$ 1,308,451	$ 1,317,283	$ 1,326,175	$ 1,335,126	$ 1,344,138	$ 1,353,211	$ 1,362,345
Gate fees	$ 49,274	$ 36,956	$ 27,717	$ 20,788	$ 15,591	$ 11,693	$ 8,770	$ 6,577	$ 4,933	$ 3,700
Total revenues	$ 1,331,583	$ 1,327,920	$ 1,327,395	$ 1,329,238	$ 1,332,874	$ 1,337,868	$ 1,343,896	$ 1,350,716	$ 1,358,144	$ 1,366,045
Production costs										
Production costs	$ 716,521	$ 732,643	$ 749,128	$ 765,983	$ 783,218	$ 800,840	$ 818,859	$ 837,283	$ 856,122	$ 875,385
EBITDA	$ 615,061	$ 595,277	$ 578,267	$ 563,256	$ 549,656	$ 537,028	$ 525,037	$ 513,432	$ 502,022	$ 490,660
Depreciation	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364
EBIT	$ 213,697	$ 193,912	$ 176,903	$ 161,891	$ 148,292	$ 135,663	$ 123,673	$ 112,068	$ 100,658	$ 89,296
Total Annual Payment	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430
Principle payment	$ 236,092	$ 252,619	$ 270,302	$ 289,223	$ 309,469	$ 331,132	$ 354,311	$ 379,113	$ 405,651	$ 434,046
Interest payment	$ 228,337	$ 211,811	$ 194,127	$ 175,206	$ 154,961	$ 133,298	$ 110,118	$ 85,317	$ 58,779	$ 30,383
Principle Balance	$ 3,025,867	$ 2,773,248	$ 2,502,945	$ 2,213,722	$ 1,904,253	$ 1,573,121	$ 1,218,810	$ 839,697	$ 434,046	$ 0
Net Income (before tax)	-$ 14,640	-$ 17,898	-$ 17,225	-$ 13,315	-$ 6,669	$ 2,365	$ 13,554	$ 26,751	$ 41,879	$ 58,913
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 5,028	$ 2,514	$ 1,257	$ 629	$ 314	$ 157	$ 79	$ 39	$ 20	$ 10
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 9,567	$ 7,654	$ 6,123	$ 4,898	$ 3,919	$ 3,135	$ 2,508	$ 2,006	$ 1,605	$ 1,284
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 19,040	$ 17,897	$ 16,823	$ 15,814	$ 14,865	$ 13,973	$ 13,135	$ 12,347	$ 11,606	$ 10,910
Total Eligible CCA	$ 33,635	$ 28,065	$ 24,203	$ 21,341	$ 19,098	$ 17,265	$ 15,721	$ 14,392	$ 13,231	$ 12,203
Taxable Income	$ -	$ -	$ -	$ 302,015	$ 375,597	$ 386,465	$ 399,197	$ 413,723	$ 430,013	$ 448,074
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	-$ 3,660	-$ 4,475	-$ 4,306	-$ 3,329	-$ 1,667	$ 591	$ 3,389	$ 6,688	$ 10,470	$ 14,728
Net Income (after tax)	-$ 10,980	-$ 13,424	-$ 12,918	-$ 9,986	-$ 5,002	$ 1,774	$ 10,166	$ 20,064	$ 31,409	$ 44,185
Cash Distributions										
Equity Dividend	-$ 10,980	-$ 13,424	-$ 12,918	-$ 9,986	-$ 5,002	$ 1,774	$ 10,166	$ 20,064	$ 31,409	$ 44,185
Depreciation	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364
Future Income Tax Expense	-$ 3,660	-$ 4,475	-$ 4,306	-$ 78,833	-$ 95,567	-$ 96,025	-$ 96,411	-$ 96,743	-$ 97,033	-$ 97,290
Debt Repayment	-$ 236,092	-$ 252,619	-$ 270,302	-$ 289,223	-$ 309,469	-$ 331,132	-$ 354,311	-$ 379,113	-$ 405,651	-$ 434,046
Equity dividend	**$ 150,632**	**$ 130,847**	**$ 113,838**	**$ 23,322**	**-$ 8,673**	**-$ 24,018**	**-$ 39,192**	**-$ 54,428**	**-$ 69,911**	**-$ 85,788**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

SSO scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
Biomethane price above treshold			11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
Biomethane	$/GJ		$ 1,675,708	$ 1,687,019	$ 1,698,406	$ 1,709,870	$ 1,721,412	$ 1,733,031	$ 1,744,729	$ 1,756,506	$ 1,768,363	$ 1,780,299
Gate fees			$ 3,240,000	$ 3,312,900	$ 3,387,440	$ 3,463,658	$ 3,541,590	$ 3,621,276	$ 3,702,754	$ 3,786,066	$ 3,871,253	$ 3,958,356
Total revenues			$ 4,915,708	$ 4,999,919	$ 5,085,846	$ 5,173,528	$ 5,263,002	$ 5,354,307	$ 5,447,484	$ 5,542,573	$ 5,639,616	$ 5,738,655
Production costs												
Production costs			$ 2,763,609	$ 2,825,790	$ 2,889,370	$ 2,954,381	$ 3,020,854	$ 3,088,824	$ 3,158,322	$ 3,229,384	$ 3,302,046	$ 3,376,342
EBITDA			$ 2,152,099	$ 2,174,129	$ 2,196,476	$ 2,219,147	$ 2,242,147	$ 2,265,483	$ 2,289,162	$ 2,313,188	$ 2,337,570	$ 2,362,314
Depreciation			$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225
EBIT			$ 650,874	$ 672,904	$ 695,251	$ 717,922	$ 740,922	$ 764,258	$ 787,936	$ 811,963	$ 836,345	$ 861,088
Total Annual Payment			$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770
Principle payment			$ 803,897	$ 840,073	$ 877,876	$ 917,380	$ 958,662	$ 1,001,802	$ 1,046,883	$ 1,093,993	$ 1,143,223	$ 1,194,668
Interest payment			$ 1,134,873	$ 1,098,698	$ 1,060,894	$ 1,021,390	$ 980,108	$ 936,968	$ 891,887	$ 844,777	$ 795,548	$ 744,103
Principle Balance		$ 25,219,402	$ 24,415,505	$ 23,575,432	$ 22,697,556	$ 21,780,176	$ 20,821,513	$ 19,819,711	$ 18,772,828	$ 17,678,834	$ 16,535,612	$ 15,340,944
Net Income (before tax)			-$ 483,999	-$ 425,794	-$ 365,643	-$ 303,468	-$ 239,186	-$ 172,710	-$ 103,951	-$ 32,814	$ 40,797	$ 116,986
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 6,066,563	$ 9,099,844	$ 4,549,922	$ 2,274,961	$ 1,137,480	$ 568,740	$ 284,370	$ 142,185	$ 71,093	$ 35,546
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 107,000	$ 192,600	$ 154,080	$ 123,264	$ 98,611	$ 78,889	$ 63,111	$ 50,489	$ 40,391	$ 32,313
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 103,048	$ 199,913	$ 187,918	$ 176,643	$ 166,044	$ 156,082	$ 146,717	$ 137,914	$ 129,639	$ 121,861
Total Eligible CCA			$ 6,276,610	$ 9,492,357	$ 4,891,920	$ 2,574,868	$ 1,402,136	$ 803,711	$ 494,198	$ 330,588	$ 241,123	$ 189,720
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			-$ 123,420	-$ 104,029	-$ 91,411	-$ 75,867	-$ 59,796	-$ 43,177	-$ 25,988	-$ 8,204	$ 10,199	$ 29,246
Net Income (after tax)			-$ 360,579	-$ 321,766	-$ 274,233	-$ 227,601	-$ 179,389	-$ 129,532	-$ 77,963	-$ 24,611	$ 30,598	$ 87,739
Cash Distributions												
Equity Dividend	**at**	100%	-$ 360,579	-$ 321,766	-$ 274,233	-$ 227,601	-$ 179,389	-$ 129,532	-$ 77,963	-$ 24,611	$ 30,598	$ 87,739
Depreciation			$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225
Future Income Tax Expense			-$ 123,420	-$ 104,029	-$ 91,411	-$ 75,867	-$ 59,796	-$ 43,177	-$ 25,988	-$ 8,204	$ 10,199	$ 29,246
Debt Repayment			-$ 803,897	-$ 840,073	-$ 877,876	-$ 917,380	-$ 958,662	-$ 1,001,802	-$ 1,046,883	-$ 1,093,993	-$ 1,143,223	-$ 1,194,668
Equity dividend		-$ 6,304,851	**$ 213,329**	**$ 235,358**	**$ 257,706**	**$ 280,377**	**$ 303,377**	**$ 326,713**	**$ 350,391**	**$ 374,418**	**$ 398,800**	**$ 423,543**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		1.32%										

SSO scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
Biomethane price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
Biomethane	$ 1,792,316	$ 1,804,414	$ 1,816,594	$ 1,828,856	$ 1,841,201	$ 1,853,629	$ 1,866,141	$ 1,878,737	$ 1,891,419	$ 1,904,186
Gate fees	$ 4,047,419	$ 4,138,486	$ 4,231,602	$ 4,326,813	$ 4,424,166	$ 4,523,710	$ 4,625,494	$ 4,729,567	$ 4,835,982	$ 4,944,792
Total revenues	$ 5,839,735	$ 5,942,900	$ 6,048,196	$ 6,155,669	$ 6,265,367	$ 6,377,339	$ 6,491,634	$ 6,608,305	$ 6,727,401	$ 6,848,978
Production costs										
Production costs	$ 3,452,309	$ 3,529,986	$ 3,609,411	$ 3,690,623	$ 3,773,662	$ 3,858,569	$ 3,945,387	$ 4,034,158	$ 4,124,927	$ 4,217,738
EBITDA	$ 2,387,426	$ 2,412,914	$ 2,438,785	$ 2,465,046	$ 2,491,705	$ 2,518,770	$ 2,546,248	$ 2,574,146	$ 2,602,475	$ 2,631,240
Depreciation	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225
EBIT	$ 886,201	$ 911,689	$ 937,560	$ 963,821	$ 990,480	$ 1,017,545	$ 1,045,022	$ 1,072,921	$ 1,101,249	$ 1,130,015
Total Annual Payment	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770
Principle payment	$ 1,248,428	$ 1,304,607	$ 1,363,315	$ 1,424,664	$ 1,488,774	$ 1,555,768	$ 1,625,778	$ 1,698,938	$ 1,775,390	$ 1,855,283
Interest payment	$ 690,342	$ 634,163	$ 575,456	$ 514,107	$ 449,997	$ 383,002	$ 312,992	$ 239,832	$ 163,380	$ 83,488
Principle Balance	$ 14,092,516	$ 12,787,909	$ 11,424,594	$ 9,999,930	$ 8,511,157	$ 6,955,389	$ 5,329,611	$ 3,630,673	$ 1,855,283	-$ 0
Net Income (before tax)	$ 195,858	$ 277,526	$ 362,104	$ 449,714	$ 540,483	$ 634,543	$ 732,030	$ 833,089	$ 937,869	$ 1,046,528
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 17,773	$ 8,887	$ 4,443	$ 2,222	$ 1,111	$ 555	$ 278	$ 139	$ 69	$ 35
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 25,850	$ 20,680	$ 16,544	$ 13,235	$ 10,588	$ 8,471	$ 6,777	$ 5,421	$ 4,337	$ 3,470
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 114,549	$ 107,676	$ 101,216	$ 95,143	$ 89,434	$ 84,068	$ 79,024	$ 74,283	$ 69,826	$ 65,636
Total Eligible CCA	$ 158,173	$ 137,243	$ 122,203	$ 110,600	$ 101,133	$ 93,094	$ 86,078	$ 79,843	$ 74,232	$ 69,140
Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,492,021	$ 2,364,862	$ 2,478,612
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	$ 48,965	$ 69,381	$ 90,526	$ 112,429	$ 135,121	$ 158,636	$ 183,007	$ 208,272	$ 234,467	$ 261,632
Net Income (after tax)	$ 146,894	$ 208,144	$ 271,578	$ 337,286	$ 405,363	$ 475,907	$ 549,022	$ 624,817	$ 703,402	$ 784,896
Cash Distributions										
Equity Dividend	$ 146,894	$ 208,144	$ 271,578	$ 337,286	$ 405,363	$ 475,907	$ 549,022	$ 624,817	$ 703,402	$ 784,896
Depreciation	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225
Future Income Tax Expense	$ 48,965	$ 69,381	$ 90,526	$ 112,429	$ 135,121	$ 158,636	$ 183,007	-$ 164,733	-$ 356,748	-$ 358,021
Debt Repayment	-$ 1,248,428	-$ 1,304,607	-$ 1,363,315	-$ 1,424,664	-$ 1,488,774	-$ 1,555,768	-$ 1,625,778	-$ 1,698,938	-$ 1,775,390	-$ 1,855,283
Equity dividend	**$ 448,656**	**$ 474,144**	**$ 500,015**	**$ 526,276**	**$ 552,935**	**$ 579,999**	**$ 607,477**	**$ 262,371**	**$ 72,489**	**$ 72,817**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

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Appendix 5

Industrial scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
Biomethane price above treshold			11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
Biomethane	$/GJ		$ 2,070,667	$ 2,084,644	$ 2,098,715	$ 2,112,881	$ 2,127,143	$ 2,141,501	$ 2,155,957	$ 2,170,509	$ 2,185,160	$ 2,199,910
Gate fees			$ 4,585,000	$ 3,438,750	$ 2,579,063	$ 1,934,297	$ 1,450,723	$ 1,088,042	$ 816,031	$ 612,024	$ 459,018	$ 344,263
Total revenues			$ 6,655,667	$ 5,523,394	$ 4,677,777	$ 4,047,178	$ 3,577,866	$ 3,229,543	$ 2,971,988	$ 2,782,533	$ 2,644,178	$ 2,544,173
Production costs												
Production costs			$ 2,830,727	$ 2,894,418	$ 2,959,542	$ 3,026,132	$ 3,094,220	$ 3,163,840	$ 3,235,026	$ 3,307,815	$ 3,382,240	$ 3,458,341
EBITDA			$ 3,824,940	$ 2,628,976	$ 1,718,235	$ 1,021,046	$ 483,646	$ 65,703	-$ 263,038	-$ 525,282	-$ 738,062	-$ 914,167
Depreciation			$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191
EBIT			$ 2,470,749	$ 1,274,785	$ 364,044	-$ 333,145	-$ 870,545	-$ 1,288,487	-$ 1,617,229	-$ 1,879,472	-$ 2,092,253	-$ 2,268,358
Total Annual Payment			$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428
Principle payment			$ 428,569	$ 458,569	$ 490,669	$ 525,016	$ 561,767	$ 601,090	$ 643,167	$ 688,188	$ 736,362	$ 787,907
Interest payment			$ 1,229,858	$ 1,199,859	$ 1,167,759	$ 1,133,412	$ 1,096,661	$ 1,057,337	$ 1,015,261	$ 970,239	$ 922,066	$ 870,521
Principle Balance		$ 17,569,406	$ 17,140,837	$ 16,682,268	$ 16,191,599	$ 15,666,583	$ 15,104,816	$ 14,503,726	$ 13,860,559	$ 13,172,370	$ 12,436,009	$ 11,648,102
Net Income (before tax)			$ 1,240,891	$ 74,926	-$ 803,714	-$ 1,466,556	-$ 1,967,206	-$ 2,345,824	-$ 2,632,490	-$ 2,849,711	-$ 3,014,319	-$ 3,138,879
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 5,039,617	$ 7,559,425	$ 3,779,713	$ 1,889,856	$ 944,928	$ 472,464	$ 236,232	$ 118,116	$ 59,058	$ 29,529
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 91,400	$ 164,520	$ 131,616	$ 105,293	$ 84,234	$ 67,387	$ 53,910	$ 43,128	$ 34,502	$ 27,602
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 139,719	$ 271,055	$ 254,792	$ 239,504	$ 225,134	$ 211,626	$ 198,928	$ 186,993	$ 175,773	$ 165,227
Total Eligible CCA			$ 5,270,736	$ 7,995,000	$ 4,166,120	$ 2,234,653	$ 1,254,296	$ 751,477	$ 489,070	$ 348,237	$ 269,334	$ 222,358
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			$ 316,427	$ 12,527	-$ 200,929	-$ 366,639	-$ 491,801	-$ 586,456	-$ 658,122	-$ 712,428	-$ 753,580	-$ 784,720
Net Income (after tax)			$ 924,464	$ 62,399	-$ 602,786	-$ 1,099,917	-$ 1,475,404	-$ 1,759,368	-$ 1,974,367	-$ 2,137,283	-$ 2,260,739	-$ 2,354,159
Cash Distributions												
Equity Dividend	at	100%	$ 924,464	$ 62,399	-$ 602,786	-$ 1,099,917	-$ 1,475,404	-$ 1,759,368	-$ 1,974,367	-$ 2,137,283	-$ 2,260,739	-$ 2,354,159
Depreciation			$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191
Future Income Tax Expense			$ 316,427	$ 12,527	-$ 200,929	-$ 366,639	-$ 491,801	-$ 586,456	-$ 658,122	-$ 712,428	-$ 753,580	-$ 784,720
Debt Repayment			-$ 428,569	-$ 458,569	-$ 490,669	-$ 525,016	-$ 561,767	-$ 601,090	-$ 643,167	-$ 688,188	-$ 736,362	-$ 787,907
Equity dividend		-$ 11,712,937	**$ 2,166,512**	**$ 970,548**	**$ 59,807**	**-$ 637,382**	**-$ 1,174,782**	**-$ 1,592,724**	**-$ 1,921,466**	**-$ 2,183,709**	**-$ 2,396,490**	**-$ 2,572,595**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		#DIV/0!										

Industrial scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
Biomethane price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
Biomethane	$ 2,214,759	$ 2,229,709	$ 2,244,760	$ 2,259,912	$ 2,275,166	$ 2,290,524	$ 2,305,985	$ 2,321,550	$ 2,337,220	$ 2,352,997
Gate fees	$ 258,197	$ 193,648	$ 145,236	$ 108,927	$ 81,695	$ 61,271	$ 45,954	$ 34,465	$ 25,849	$ 19,387
Total revenues	$ 2,472,957	$ 2,423,357	$ 2,389,996	$ 2,368,839	$ 2,356,861	$ 2,351,795	$ 2,351,938	$ 2,356,015	$ 2,363,069	$ 2,372,383
Production costs										
Production costs	$ 3,536,154	$ 3,615,717	$ 3,697,071	$ 3,780,255	$ 3,865,310	$ 3,952,280	$ 4,041,206	$ 4,132,133	$ 4,225,106	$ 4,320,171
EBITDA	-$ 1,063,197	-$ 1,192,360	-$ 1,307,075	-$ 1,411,416	-$ 1,508,449	-$ 1,600,485	-$ 1,689,268	-$ 1,776,118	-$ 1,862,037	-$ 1,947,788
Depreciation	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191
EBIT	-$ 2,417,387	-$ 2,546,550	-$ 2,661,265	-$ 2,765,606	-$ 2,862,639	-$ 2,954,675	-$ 3,043,459	-$ 3,130,309	-$ 3,216,228	-$ 3,301,978
Total Annual Payment	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428
Principle payment	$ 843,061	$ 902,075	$ 965,220	$ 1,032,785	$ 1,105,080	$ 1,182,436	$ 1,265,206	$ 1,353,771	$ 1,448,535	$ 1,549,932
Interest payment	$ 815,367	$ 756,353	$ 693,208	$ 625,642	$ 553,347	$ 475,992	$ 393,221	$ 304,657	$ 209,893	$ 108,495
Principle Balance	$ 10,805,041	$ 9,902,966	$ 8,937,746	$ 7,904,961	$ 6,799,881	$ 5,617,445	$ 4,352,238	$ 2,998,467	$ 1,549,932	$ -
Net Income (before tax)	-$ 3,232,754	-$ 3,302,903	-$ 3,354,473	-$ 3,391,249	-$ 3,415,987	-$ 3,430,667	-$ 3,436,680	-$ 3,434,965	-$ 3,426,120	-$ 3,410,474
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 14,765	$ 7,382	$ 3,691	$ 1,846	$ 923	$ 461	$ 231	$ 115	$ 58	$ 29
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 22,082	$ 17,665	$ 14,132	$ 11,306	$ 9,045	$ 7,236	$ 5,789	$ 4,631	$ 3,705	$ 2,964
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 155,313	$ 145,994	$ 137,235	$ 129,001	$ 121,261	$ 113,985	$ 107,146	$ 100,717	$ 94,674	$ 88,994
Total Eligible CCA	$ 192,159	$ 171,042	$ 155,058	$ 142,152	$ 131,228	$ 121,682	$ 113,165	$ 105,463	$ 98,436	$ 91,986
Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	-$ 808,189	-$ 825,726	-$ 838,618	-$ 847,812	-$ 853,997	-$ 857,667	-$ 859,170	-$ 858,741	-$ 856,530	-$ 852,618
Net Income (after tax)	-$ 2,424,566	-$ 2,477,177	-$ 2,515,855	-$ 2,543,436	-$ 2,561,990	-$ 2,573,000	-$ 2,577,510	-$ 2,576,224	-$ 2,569,590	-$ 2,557,855
Cash Distributions										
Equity Dividend	-$ 2,424,566	-$ 2,477,177	-$ 2,515,855	-$ 2,543,436	-$ 2,561,990	-$ 2,573,000	-$ 2,577,510	-$ 2,576,224	-$ 2,569,590	-$ 2,557,855
Depreciation	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191
Future Income Tax Expense	-$ 808,189	-$ 825,726	-$ 838,618	-$ 847,812	-$ 853,997	-$ 857,667	-$ 859,170	-$ 858,741	-$ 856,530	-$ 852,618
Debt Repayment	-$ 843,061	-$ 902,075	-$ 965,220	-$ 1,032,785	-$ 1,105,080	-$ 1,182,436	-$ 1,265,206	-$ 1,353,771	-$ 1,448,535	-$ 1,549,932
Equity dividend	**-$ 2,721,624**	**-$ 2,850,787**	**-$ 2,965,502**	**-$ 3,069,843**	**-$ 3,166,877**	**-$ 3,258,912**	**-$ 3,347,696**	**-$ 3,434,546**	**-$ 3,520,465**	**-$ 3,606,215**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

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WWTP scenario			1	2	3	4	5	6	7	8	9	10
Biomethane price sub treshold			17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
Biomethane price above treshold			11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
Biomethane	$/GJ		$ 388,118	$ 390,738	$ 393,376	$ 396,031	$ 398,704	$ 401,395	$ 404,105	$ 406,833	$ 409,579	$ 412,343
Total revenues			$ 388,118	$ 390,738	$ 393,376	$ 396,031	$ 398,704	$ 401,395	$ 404,105	$ 406,833	$ 409,579	$ 412,343
Production costs			$ 197,647	$ 202,094	$ 206,641	$ 211,291	$ 216,045	$ 220,906	$ 225,876	$ 230,959	$ 236,155	$ 241,469
EBITDA			$ 190,471	$ 188,644	$ 186,734	$ 184,740	$ 182,659	$ 180,489	$ 178,228	$ 175,874	$ 173,424	$ 170,875
Depreciation			$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197
EBIT			$ 71,274	$ 69,447	$ 67,537	$ 65,543	$ 63,462	$ 61,293	$ 59,032	$ 56,677	$ 54,227	$ 51,678
Total Annual Payment			$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318
Principle payment			$ 63,572	$ 66,433	$ 69,422	$ 72,546	$ 75,811	$ 79,222	$ 82,787	$ 86,513	$ 90,406	$ 94,474
Interest payment			$ 89,746	$ 86,885	$ 83,895	$ 80,771	$ 77,507	$ 74,095	$ 70,530	$ 66,805	$ 62,912	$ 58,844
Principle Balance		$ 1,994,348	$ 1,930,776	$ 1,864,343	$ 1,794,921	$ 1,722,374	$ 1,646,563	$ 1,567,341	$ 1,484,553	$ 1,398,041	$ 1,307,635	$ 1,213,160
Net Income (before tax)			-$ 18,471	-$ 17,438	-$ 16,358	-$ 15,228	-$ 14,044	-$ 12,803	-$ 11,499	-$ 10,128	-$ 8,685	-$ 7,166
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 434,250	$ 651,375	$ 325,688	$ 162,844	$ 81,422	$ 40,711	$ 20,355	$ 10,178	$ 5,089	$ 2,544
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 13,100	$ 23,580	$ 18,864	$ 15,091	$ 12,073	$ 9,658	$ 7,727	$ 6,181	$ 4,945	$ 3,956
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 13,948	$ 27,059	$ 25,435	$ 23,909	$ 22,475	$ 21,126	$ 19,859	$ 18,667	$ 17,547	$ 16,494
Total Eligible CCA			$ 461,298	$ 702,014	$ 369,987	$ 201,844	$ 115,970	$ 71,496	$ 47,941	$ 35,026	$ 27,581	$ 22,995
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			-$ 4,710	-$ 4,267	-$ 4,089	-$ 3,807	-$ 3,511	-$ 3,201	-$ 2,875	-$ 2,532	-$ 2,171	-$ 1,791
Net Income (after tax)			-$ 13,761	-$ 13,171	-$ 12,268	-$ 11,421	-$ 10,533	-$ 9,602	-$ 8,624	-$ 7,596	-$ 6,514	-$ 5,374
Cash Distributions												
Equity Dividend	at	100%	-$ 13,761	-$ 13,171	-$ 12,268	-$ 11,421	-$ 10,533	-$ 9,602	-$ 8,624	-$ 7,596	-$ 6,514	-$ 5,374
Depreciation			$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197
Future Income Tax Expense			-$ 4,710	-$ 4,267	-$ 4,089	-$ 3,807	-$ 3,511	-$ 3,201	-$ 2,875	-$ 2,532	-$ 2,171	-$ 1,791
Debt Repayment			-$ 63,572	-$ 66,433	-$ 69,422	-$ 72,546	-$ 75,811	-$ 79,222	-$ 82,787	-$ 86,513	-$ 90,406	-$ 94,474
Equity dividend		-$ 498,587	**$ 37,153**	**$ 35,326**	**$ 33,416**	**$ 31,422**	**$ 29,341**	**$ 27,172**	**$ 24,911**	**$ 22,556**	**$ 20,106**	**$ 17,557**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		#NUM!										

WWTP scenario	11	12	13	14	15	16	17	18	19	20
Biomethane price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
Biomethane price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
Biomethane	$ 415,127	$ 417,929	$ 420,750	$ 423,590	$ 426,449	$ 429,328	$ 432,226	$ 435,143	$ 438,080	$ 441,037
Total revenues	$ 415,127	$ 417,929	$ 420,750	$ 423,590	$ 426,449	$ 429,328	$ 432,226	$ 435,143	$ 438,080	$ 441,037
Production costs	$ 246,902	$ 252,457	$ 258,137	$ 263,945	$ 269,884	$ 275,957	$ 282,166	$ 288,514	$ 295,006	$ 301,643
EBITDA	$ 168,225	$ 165,472	$ 162,613	$ 159,644	$ 156,565	$ 153,371	$ 150,060	$ 146,629	$ 143,074	$ 139,394
Depreciation	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197
EBIT	$ 49,028	$ 46,275	$ 43,416	$ 40,448	$ 37,368	$ 34,174	$ 30,863	$ 27,432	$ 23,878	$ 20,197
Total Annual Payment	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318
Principle payment	$ 98,726	$ 103,168	$ 107,811	$ 112,662	$ 117,732	$ 123,030	$ 128,566	$ 134,352	$ 140,398	$ 146,716
Interest payment	$ 54,592	$ 50,150	$ 45,507	$ 40,656	$ 35,586	$ 30,288	$ 24,751	$ 18,966	$ 12,920	$ 6,602
Principle Balance	$ 1,114,435	$ 1,011,267	$ 903,456	$ 790,794	$ 673,061	$ 550,031	$ 421,465	$ 287,113	$ 146,716	-$ 0
Net Income (before tax)	-$ 5,564	-$ 3,875	-$ 2,091	-$ 208	$ 1,782	$ 3,887	$ 6,112	$ 8,466	$ 10,958	$ 13,595
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 1,272	$ 636	$ 318	$ 159	$ 80	$ 40	$ 20	$ 10	$ 5	$ 2
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 3,165	$ 2,532	$ 2,026	$ 1,620	$ 1,296	$ 1,037	$ 830	$ 664	$ 531	$ 425
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 15,505	$ 14,574	$ 13,700	$ 12,878	$ 12,105	$ 11,379	$ 10,696	$ 10,054	$ 9,451	$ 8,884
Total Eligible CCA	$ 19,942	$ 17,742	$ 16,043	$ 14,657	$ 13,481	$ 12,456	$ 11,546	$ 10,728	$ 9,987	$ 9,311
Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 93,133
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	-$ 1,391	-$ 969	-$ 523	-$ 52	$ 446	$ 972	$ 1,528	$ 2,117	$ 2,739	$ 3,399
Net Income (after tax)	-$ 4,173	-$ 2,906	-$ 1,568	-$ 156	$ 1,337	$ 2,915	$ 4,584	$ 6,350	$ 8,218	$ 10,196
Cash Distributions										
Equity Dividend	-$ 4,173	-$ 2,906	-$ 1,568	-$ 156	$ 1,337	$ 2,915	$ 4,584	$ 6,350	$ 8,218	$ 10,196
Depreciation	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197
Future Income Tax Expense	-$ 1,391	-$ 969	-$ 523	-$ 52	$ 446	$ 972	$ 1,528	$ 2,117	$ 2,739	-$ 19,885
Debt Repayment	-$ 98,726	-$ 103,168	-$ 107,811	-$ 112,662	-$ 117,732	-$ 123,030	-$ 128,566	-$ 134,352	-$ 140,398	-$ 146,716
Equity dividend	**$ 14,907**	**$ 12,154**	**$ 9,295**	**$ 6,327**	**$ 3,247**	**$ 53**	**-$ 3,258**	**-$ 6,689**	**-$ 10,243**	**-$ 37,207**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

Small LF scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			13.00	13.09	13.18	13.27	13.35	13.44	13.54	13.63	13.72	13.81
Biomethane price above treshold			6.00	6.04	6.08	6.12	6.16	6.21	6.25	6.29	6.33	6.37
Biomethane	$/GJ		$1,052,209	$1,088,947	$1,124,821	$1,159,866	$1,194,117	$1,227,607	$1,260,368	$1,292,431	$1,323,826	$1,354,581
Total revenues			$1,052,209	$1,088,947	$1,124,821	$1,159,866	$1,194,117	$1,227,607	$1,260,368	$1,292,431	$1,323,826	$1,354,581
Production costs												
Production costs			$560,753	$581,436	$602,403	$623,664	$645,231	$667,113	$689,321	$711,868	$734,763	$758,019
EBITDA			$491,455	$507,511	$522,418	$536,202	$548,886	$560,494	$571,046	$580,563	$589,062	$596,562
Depreciation			$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917
EBIT			$247,538	$263,594	$278,501	$292,285	$304,969	$316,577	$327,129	$336,646	$345,145	$352,645
Total Annual Payment			$287,576	$287,576	$287,576	$287,576	$287,576	$287,576	$287,576	$287,576	$287,576	$287,576
Principle payment			$74,315	$79,517	$85,083	$91,039	$97,412	$104,231	$111,527	$119,334	$127,687	$136,625
Interest payment			$213,261	$208,059	$202,493	$196,537	$190,164	$183,345	$176,049	$168,242	$159,889	$150,951
Principle Balance		$3,046,588	$2,972,273	$2,892,756	$2,807,672	$2,716,633	$2,619,221	$2,514,990	$2,403,463	$2,284,129	$2,156,442	$2,019,816
Net Income (before tax)			$34,277	$55,535	$76,008	$95,748	$114,805	$133,231	$151,080	$168,403	$185,256	$201,694
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$995,925	$1,493,888	$746,944	$373,472	$186,736	$93,368	$46,684	$23,342	$11,671	$5,835
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$22,200	$39,960	$31,968	$25,574	$20,460	$16,368	$13,094	$10,475	$8,380	$6,704
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$16,550	$32,108	$30,181	$28,370	$26,668	$25,068	$23,564	$22,150	$20,821	$19,572
Total Eligible CCA			$1,034,675	$1,565,955	$809,093	$427,417	$233,864	$134,804	$83,342	$55,967	$40,872	$32,112
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			$8,741	$13,712	$19,002	$23,937	$28,701	$33,308	$37,770	$42,101	$46,314	$50,423
Net Income (after tax)			$25,536	$41,822	$57,006	$71,811	$86,104	$99,923	$113,310	$126,302	$138,942	$151,270
Cash Distributions												
Equity Dividend	at	100%	$25,536	$41,822	$57,006	$71,811	$86,104	$99,923	$113,310	$126,302	$138,942	$151,270
Depreciation			$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917
Future Income Tax Expense			$8,741	$13,712	$19,002	$23,937	$28,701	$33,308	$37,770	$42,101	$46,314	$50,423
Debt Repayment			-$74,315	-$79,517	-$85,083	-$91,039	-$97,412	-$104,231	-$111,527	-$119,334	-$127,687	-$136,625
Equity dividend		-$2,031,059	**$203,879**	**$219,935**	**$234,842**	**$248,626**	**$261,310**	**$272,918**	**$283,470**	**$292,987**	**$301,486**	**$308,986**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		10.52%										

Small LF scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	13.90	14.00	14.09	14.19	14.28	14.38	14.48	14.58	14.67	14.77
Biomethane price above treshold	6.42	6.46	6.50	6.55	6.59	6.64	6.68	6.73	6.77	6.82
Biomethane	$1,384,725	$1,414,284	$1,443,284	$1,471,748	$1,499,702	$1,527,168	$1,554,168	$1,580,723	$1,606,855	$1,632,582
Total revenues	$1,384,725	$1,414,284	$1,443,284	$1,471,748	$1,499,702	$1,527,168	$1,554,168	$1,580,723	$1,606,855	$1,632,582
Production costs										
Production costs	$781,647	$805,659	$830,067	$854,882	$880,118	$905,786	$931,900	$958,473	$985,518	$1,013,905
EBITDA	$603,078	$608,625	$613,217	$616,866	$619,584	$621,382	$622,267	$622,250	$621,337	$618,677
Depreciation	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917
EBIT	$359,161	$364,708	$369,300	$372,949	$375,667	$377,464	$378,350	$378,333	$377,420	$374,760
Total Annual Payment	$287,576	$287,576	$287,576	$287,576	$287,576	$287,576	$287,576	$287,576	$287,576	$287,576
Principle payment	$146,189	$156,422	$167,372	$179,088	$191,624	$205,038	$219,391	$234,748	$251,180	$268,763
Interest payment	$141,387	$131,154	$120,204	$108,488	$95,952	$82,538	$68,186	$52,828	$36,396	$18,813
Principle Balance	$1,873,627	$1,717,204	$1,549,832	$1,370,744	$1,179,120	$974,082	$754,691	$519,943	$268,763	-$0
Net Income (before tax)	$217,774	$233,554	$249,095	$264,461	$279,715	$294,926	$310,164	$325,505	$341,024	$355,946
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$2,918	$1,459	$729	$365	$182	$91	$46	$23	$11	$6
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$5,363	$4,291	$3,433	$2,746	$2,197	$1,757	$1,406	$1,125	$900	$720
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$18,398	$17,294	$16,256	$15,281	$14,364	$13,502	$12,692	$11,930	$11,215	$10,542
Total Eligible CCA	$26,679	$23,043	$20,418	$18,391	$16,743	$15,351	$14,143	$13,078	$12,126	$11,267
Taxable Income	$ -	$126,548	$472,595	$489,986	$506,889	$523,492	$539,938	$556,344	$572,815	$588,596
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	$54,443	$58,388	$62,274	$66,115	$69,929	$73,731	$77,541	$81,376	$85,256	$88,987
Net Income (after tax)	$163,330	$175,165	$186,821	$198,345	$209,786	$221,194	$232,623	$244,128	$255,768	$266,960
Cash Distributions										
Equity Dividend	$163,330	$175,165	$186,821	$198,345	$209,786	$221,194	$232,623	$244,128	$255,768	$266,960
Depreciation	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917	$243,917
Future Income Tax Expense	$54,443	$26,751	-$55,875	-$56,381	-$56,794	-$57,142	-$57,443	-$57,710	-$57,948	-$58,163
Debt Repayment	-$146,189	-$156,422	-$167,372	-$179,088	-$191,624	-$205,038	-$219,391	-$234,748	-$251,180	-$268,763
Equity dividend	**$315,502**	**$289,412**	**$207,492**	**$206,793**	**$205,286**	**$202,932**	**$199,707**	**$195,588**	**$190,557**	**$183,952**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

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EB-2011-0242
EB-2011-0283
Exhibit B
Tab 1
Appendix 5

Medium LF scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			13.00	13.09	13.18	13.27	13.35	13.44	13.54	13.63	13.72	13.81
Biomethane price above treshold			6.00	6.04	6.08	6.12	6.16	6.21	6.25	6.29	6.33	6.37
Biomethane	$/GJ		$ 2,183,148	$ 2,229,800	$ 2,275,569	$ 2,320,493	$ 2,364,610	$ 2,407,957	$ 2,450,568	$ 2,492,477	$ 2,533,716	$ 2,574,317
Total revenues			$ 2,183,148	$ 2,229,800	$ 2,275,569	$ 2,320,493	$ 2,364,610	$ 2,407,957	$ 2,450,568	$ 2,492,477	$ 2,533,716	$ 2,574,317
Production costs												
Production costs			$ 1,073,264	$ 1,116,205	$ 1,159,689	$ 1,203,739	$ 1,248,375	$ 1,293,621	$ 1,339,500	$ 1,386,033	$ 1,433,245	$ 1,481,158
EBITDA			$ 1,109,884	$ 1,113,595	$ 1,115,880	$ 1,116,755	$ 1,116,235	$ 1,114,336	$ 1,111,068	$ 1,106,444	$ 1,100,471	$ 1,093,159
Depreciation			$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152
EBIT			$ 664,732	$ 668,443	$ 670,728	$ 671,603	$ 671,083	$ 669,184	$ 665,916	$ 661,292	$ 655,319	$ 648,007
Total Annual Payment			$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784
Principle payment			$ 133,288	$ 142,619	$ 152,602	$ 163,284	$ 174,714	$ 186,944	$ 200,030	$ 214,032	$ 229,014	$ 245,045
Interest payment			$ 382,496	$ 373,166	$ 363,182	$ 352,500	$ 341,070	$ 328,840	$ 315,754	$ 301,752	$ 286,770	$ 270,739
Principle Balance		$ 5,464,225	$ 5,330,936	$ 5,188,318	$ 5,035,716	$ 4,872,432	$ 4,697,718	$ 4,510,774	$ 4,310,744	$ 4,096,712	$ 3,867,697	$ 3,622,652
Net Income (before tax)			$ 282,236	$ 295,278	$ 307,546	$ 319,102	$ 330,013	$ 340,343	$ 350,162	$ 359,540	$ 368,550	$ 377,268
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 1,560,500	$ 2,340,750	$ 1,170,375	$ 585,188	$ 292,594	$ 146,297	$ 73,148	$ 36,574	$ 18,287	$ 9,144
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 32,700	$ 58,860	$ 47,088	$ 37,670	$ 30,136	$ 24,109	$ 19,287	$ 15,430	$ 12,344	$ 9,875
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 63,512	$ 123,214	$ 115,821	$ 108,872	$ 102,340	$ 96,199	$ 90,427	$ 85,002	$ 79,902	$ 75,107
Total Eligible CCA			$ 1,656,712	$ 2,522,824	$ 1,333,284	$ 731,730	$ 425,070	$ 266,605	$ 182,863	$ 137,006	$ 110,533	$ 94,126
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 320,805
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			$ 71,970	$ 72,408	$ 76,886	$ 79,776	$ 82,503	$ 85,086	$ 87,541	$ 89,885	$ 92,137	$ 94,317
Net Income (after tax)			$ 210,266	$ 222,870	$ 230,659	$ 239,327	$ 247,510	$ 255,258	$ 262,622	$ 269,655	$ 276,412	$ 282,951
Cash Distributions												
Equity Dividend	at	100%	$ 210,266	$ 222,870	$ 230,659	$ 239,327	$ 247,510	$ 255,258	$ 262,622	$ 269,655	$ 276,412	$ 282,951
Depreciation			$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152
Future Income Tax Expense			$ 71,970	$ 72,408	$ 76,886	$ 79,776	$ 82,503	$ 85,086	$ 87,541	$ 89,885	$ 92,137	$ 14,116
Debt Repayment			-$ 133,288	-$ 142,619	-$ 152,602	-$ 163,284	-$ 174,714	-$ 186,944	-$ 200,030	-$ 214,032	-$ 229,014	-$ 245,045
Equity dividend		-$ 3,642,816	**$ 594,100**	**$ 597,811**	**$ 600,096**	**$ 600,970**	**$ 600,451**	**$ 598,552**	**$ 595,284**	**$ 590,660**	**$ 584,687**	**$ 497,173**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		13.44%										

Medium LF scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	13.90	14.00	14.09	14.19	14.28	14.38	14.48	14.58	14.67	14.77
Biomethane price above treshold	6.42	6.46	6.50	6.55	6.59	6.64	6.68	6.73	6.77	6.82
Biomethane	$ 2,614,310	$ 2,653,723	$ 2,692,585	$ 2,730,923	$ 2,768,762	$ 2,806,128	$ 2,843,045	$ 2,879,536	$ 2,915,624	$ 2,951,330
Total revenues	$ 2,614,310	$ 2,653,723	$ 2,692,585	$ 2,730,923	$ 2,768,762	$ 2,806,128	$ 2,843,045	$ 2,879,536	$ 2,915,624	$ 2,951,330
Production costs										
Production costs	$ 1,529,797	$ 1,579,186	$ 1,629,350	$ 1,680,313	$ 1,732,102	$ 1,784,740	$ 1,838,256	$ 1,892,676	$ 1,948,026	$ 2,004,285
EBITDA	$ 1,084,512	$ 1,074,536	$ 1,063,235	$ 1,050,609	$ 1,036,660	$ 1,021,388	$ 1,004,789	$ 986,860	$ 967,598	$ 947,046
Depreciation	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152
EBIT	$ 639,360	$ 629,384	$ 618,083	$ 605,457	$ 591,508	$ 576,236	$ 559,637	$ 541,708	$ 522,446	$ 501,894
Total Annual Payment	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784
Principle payment	$ 262,199	$ 280,552	$ 300,191	$ 321,204	$ 343,689	$ 367,747	$ 393,489	$ 421,034	$ 450,506	$ 482,041
Interest payment	$ 253,586	$ 235,232	$ 215,593	$ 194,580	$ 172,095	$ 148,037	$ 122,295	$ 94,751	$ 65,278	$ 33,743
Principle Balance	$ 3,360,454	$ 3,079,901	$ 2,779,710	$ 2,458,506	$ 2,114,817	$ 1,747,070	$ 1,353,581	$ 932,547	$ 482,041	-$ 0
Net Income (before tax)	$ 385,775	$ 394,153	$ 402,490	$ 410,878	$ 419,413	$ 428,198	$ 437,342	$ 446,958	$ 457,168	$ 468,151
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 4,572	$ 2,286	$ 1,143	$ 571	$ 286	$ 143	$ 71	$ 36	$ 18	$ 9
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 7,900	$ 6,320	$ 5,056	$ 4,045	$ 3,236	$ 2,589	$ 2,071	$ 1,657	$ 1,325	$ 1,060
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 70,601	$ 66,365	$ 62,383	$ 58,640	$ 55,122	$ 51,814	$ 48,706	$ 45,783	$ 43,036	$ 40,454
Total Eligible CCA	$ 83,073	$ 74,971	$ 68,582	$ 63,256	$ 58,643	$ 54,546	$ 50,848	$ 47,476	$ 44,379	$ 41,523
Taxable Income	$ 747,854	$ 764,334	$ 779,060	$ 792,773	$ 805,922	$ 818,805	$ 831,646	$ 844,634	$ 857,940	$ 871,780
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	$ 96,444	$ 98,538	$ 100,622	$ 102,719	$ 104,853	$ 107,050	$ 109,335	$ 111,739	$ 114,292	$ 117,038
Net Income (after tax)	$ 289,331	$ 295,615	$ 301,867	$ 308,158	$ 314,560	$ 321,149	$ 328,006	$ 335,218	$ 342,876	$ 351,113
Cash Distributions										
Equity Dividend	$ 289,331	$ 295,615	$ 301,867	$ 308,158	$ 314,560	$ 321,149	$ 328,006	$ 335,218	$ 342,876	$ 351,113
Depreciation	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152
Future Income Tax Expense	-$ 90,520	-$ 92,545	-$ 94,143	-$ 95,474	-$ 96,627	-$ 97,652	-$ 98,576	-$ 99,419	-$ 100,193	-$ 100,907
Debt Repayment	-$ 262,199	-$ 280,552	-$ 300,191	-$ 321,204	-$ 343,689	-$ 367,747	-$ 393,489	-$ 421,034	-$ 450,506	-$ 482,041
Equity dividend	**$ 381,765**	**$ 367,669**	**$ 352,686**	**$ 336,632**	**$ 319,396**	**$ 300,902**	**$ 281,093**	**$ 259,918**	**$ 237,329**	**$ 213,317**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

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Exhibit B
Tab 1
Appendix 5

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Exhibit B
Tab 1
Appendix 5

Large LF scenario			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold			13.00	13.09	13.18	13.27	13.35	13.44	13.54	13.63	13.72	13.81	13.90	14.00	14.09	14.19	14.28	14.38	14.48	14.58	14.67	14.77
Biomethane price above treshold			6.00	6.04	6.08	6.12	6.16	6.21	6.25	6.29	6.33	6.37	6.42	6.46	6.50	6.55	6.59	6.64	6.68	6.73	6.77	6.82
Biomethane	$/GJ		$ 4,860,938	$ 5,001,088	$ 5,034,845	$ 5,068,830	$ 5,103,045	$ 5,137,490	$ 5,172,169	$ 5,207,081	$ 5,242,228	$ 5,277,614	$ 5,313,237	$ 5,349,102	$ 6,365,631	$ 6,476,409	$ 6,585,389	$ 6,692,653	$ 6,798,283	$ 6,902,356	$ 7,004,947	$ 7,106,127
Total revenues			$ 4,860,938	$ 5,001,088	$ 5,034,845	$ 5,068,830	$ 5,103,045	$ 5,137,490	$ 5,172,169	$ 5,207,081	$ 5,242,228	$ 5,277,614	$ 5,313,237	$ 5,349,102	$ 6,365,631	$ 6,476,409	$ 6,585,389	$ 6,692,653	$ 6,798,283	$ 6,902,356	$ 7,004,947	$ 7,106,127
Production costs																						
Production costs			$ 2,918,321	$ 3,047,042	$ 3,115,601	$ 3,185,702	$ 3,257,380	$ 3,330,671	$ 3,405,611	$ 3,482,237	$ 3,560,588	$ 3,640,701	$ 3,722,617	$ 4,048,652	$ 4,645,376	$ 4,788,258	$ 4,947,909	$ 5,109,985	$ 5,274,566	$ 5,441,735	$ 5,611,574	$ 5,784,168
EBITDA			$ 1,942,617	$ 1,954,046	$ 1,919,245	$ 1,883,129	$ 1,845,665	$ 1,806,820	$ 1,766,558	$ 1,724,843	$ 1,681,641	$ 1,636,913	$ 1,590,621	$ 1,300,450	$ 1,720,255	$ 1,688,151	$ 1,637,479	$ 1,582,668	$ 1,523,717	$ 1,460,621	$ 1,393,373	$ 1,321,959
Depreciation			$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096
EBIT			$ 1,253,238	$ 1,264,667	$ 1,229,866	$ 1,193,750	$ 1,156,286	$ 1,117,441	$ 1,077,179	$ 1,035,465	$ 992,262	$ 947,534	$ 901,242	$ 611,071	$ 616,160	$ 584,055	$ 533,384	$ 478,572	$ 419,621	$ 356,526	$ 289,278	$ 217,864
Total Annual Payment			$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 1,137,410	$ 1,137,410	$ 1,137,410	$ 1,137,410	$ 1,137,410	$ 1,137,410	$ 1,137,410	$ 1,137,410
Principle payment			$ 206,695	$ 221,163	$ 236,645	$ 253,210	$ 270,934	$ 289,900	$ 310,193	$ 331,906	$ 355,140	$ 380,000	$ 406,600	$ 435,062	$ 661,983	$ 708,322	$ 757,905	$ 810,958	$ 867,725	$ 928,466	$ 993,458	$ 1,063,000
Interest payment			$ 593,148	$ 578,680	$ 563,198	$ 546,633	$ 528,908	$ 509,943	$ 489,650	$ 467,937	$ 444,703	$ 419,843	$ 393,243	$ 364,781	$ 475,427	$ 429,088	$ 379,506	$ 326,453	$ 269,685	$ 208,945	$ 143,952	$ 74,410
Principle Balance		$ 8,473,547	$ 8,266,853	$ 8,045,689	$ 7,809,045	$ 7,555,835	$ 7,284,901	$ 6,995,001	$ 6,684,808	$ 6,352,901	$ 5,997,762	$ 5,617,762	$ 5,211,162	$ 6,791,817	$ 6,129,834	$ 5,421,512	$ 4,663,607	$ 3,852,649	$ 2,984,924	$ 2,056,459	$ 1,063,000	$ 0
Net Income (before tax)			$ 660,090	$ 685,987	$ 666,667	$ 647,117	$ 627,378	$ 607,498	$ 587,529	$ 567,528	$ 547,559	$ 527,690	$ 507,999	$ 246,290	$ 140,732	$ 154,967	$ 153,878	$ 152,120	$ 149,936	$ 147,581	$ 145,325	$ 143,454
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible			$ 2,381,500	$ 3,572,250	$ 1,786,125	$ 893,063	$ 446,531	$ 223,266	$ 111,633	$ 55,816	$ 27,908	$ 13,954	$ 6,977	$ 3,489	$ 1,744	$ 872	$ 436	$ 218	$ 109	$ 55	$ 27	$ 14
CCA Class 43.2 Factor														*100.0000%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*
CCA Class 43.2 Eligible														$	785,916	$ 1,178,873	$ 589,437	$ 294,718	$ 147,359	$ 73,680	$ 36,840	$ 18,420
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible			$ 40,200	$ 72,360	$ 57,888	$ 46,310	$ 37,048	$ 29,639	$ 23,711	$ 18,969	$ 15,175	$ 12,140	$ 9,712	$ 7,770	$ 6,216	$ 4,973	$ 3,978	$ 3,182	$ 2,546	$ 2,037	$ 1,629	$ 1,304
CCA Class 8 Factor														*100.0000%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*
CCA Class 8 Eligible														$	9,404	$ 16,926	$ 13,541	$ 10,833	$ 8,666	$ 6,933	$ 5,546	$ 4,437
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible			$ 100,926	$ 195,797	$ 184,049	$ 173,006	$ 162,626	$ 152,868	$ 143,696	$ 135,074	$ 126,970	$ 119,352	$ 112,191	$ 105,459	$ 99,132	$ 93,184	$ 87,593	$ 82,337	$ 77,397	$ 72,753	$ 68,388	$ 64,285
CCA Class 1 Factor														*100.0000%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*
CCA Class 1 Eligible														$	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Eligible CCA			$ 2,522,626	$ 3,840,407	$ 2,028,062	$ 1,112,379	$ 646,205	$ 405,772	$ 279,040	$ 209,859	$ 170,053	$ 145,446	$ 128,880	$ 116,717	$ 902,411	$ 1,294,828	$ 694,985	$ 391,289	$ 236,077	$ 155,457	$ 112,431	$ 88,459
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 587,359	$ 1,071,624	$ 1,068,498	$ 818,952	$ 342,417	$ -	$ 527,223	$ 864,927	$ 1,017,954	$ 1,096,220	$ 1,136,990	$ 1,159,091
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			$ 168,323	$ 168,196	$ 166,667	$ 161,779	$ 156,844	$ 151,874	$ 146,882	$ 141,882	$ 136,890	$ 131,923	$ 127,000	$ 61,572	$ 35,183	$ 38,742	$ 38,469	$ 38,030	$ 37,484	$ 36,895	$ 36,331	$ 35,863
Net Income (after tax)			$ 491,767	$ 517,791	$ 500,001	$ 485,338	$ 470,533	$ 455,623	$ 440,646	$ 425,646	$ 410,669	$ 395,768	$ 380,999	$ 184,717	$ 105,549	$ 116,225	$ 115,408	$ 114,090	$ 112,452	$ 110,686	$ 108,994	$ 107,590
Cash Distributions																						
Equity Dividend	at	100%	$ 491,767	$ 517,791	$ 500,001	$ 485,338	$ 470,533	$ 455,623	$ 440,646	$ 425,646	$ 410,669	$ 395,768	$ 380,999	$ 184,717	$ 105,549	$ 116,225	$ 115,408	$ 114,090	$ 112,452	$ 110,686	$ 108,994	$ 107,590
Depreciation			$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096
Future Income Tax Expense			$ 168,323	$ 168,196	$ 166,667	$ 161,779	$ 156,844	$ 151,874	$ 146,882	$ 141,882	-$ 9,950	-$ 135,983	-$ 140,125	-$ 143,165	-$ 50,421	$ 38,742	-$ 93,336	-$ 178,202	-$ 217,005	-$ 237,160	-$ 247,916	-$ 253,909
Debt Repayment			-$ 206,695	-$ 221,163	-$ 236,645	-$ 253,210	-$ 270,934	-$ 289,900	-$ 310,193	-$ 331,906	-$ 355,140	-$ 380,000	-$ 406,600	-$ 435,062	-$ 661,983	-$ 708,322	-$ 757,905	-$ 810,958	-$ 867,725	-$ 928,466	-$ 993,458	-$ 1,063,000
Equity dividend		-$ 5,649,032	$ **1,142,774**	$ **1,154,203**	$ **1,119,402**	$ **1,083,286**	$ **1,045,822**	$ **1,006,977**	$ **966,715**	$ **925,001**	$ **734,958**	$ **569,164**	$ **523,653**	-$ **1,047,941**	$ **497,240**	$ **550,740**	$ **368,263**	$ **229,026**	$ **131,818**	$ **49,156**	-$ **28,285**	$ **105,224**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31
Equity ROE		13.56%																				

Union Gas Limited
Prefiled Evidence on
Renewable Natural Gas Application

DERIVATION OF CUSTOMER BILL IMPACT AND RELATED VOLUME

As identified in the market surveys of Union Gas Limited ("Union") and Enbridge Gas Distribution ("EGD") customers (see Exhibit B, Tab 1, Appendix 3) and outlined in Exhibit B, Tab 1, pp. 9-11, a majority of residential customers indicated they would be willing to pay approximately 2% or $18/year more on their gas bills in order to reduce greenhouse gas emissions through the Utilities' purchase of renewable natural gas ("RNG") as part of their supply portfolio. This bill impact level was used as a guideline when determining the maximum cumulative annual volume for the program.

Based on an acceptable bill impact of approximately $18/year for an average residential sales service customer, Union calculated an RNG gas supply volume limit of 2.2 PJs. Using that cumulative volume limit, Union used the current approved Quarterly Rate Adjustment Mechanism ("QRAM") methodology to review the impact of replacing existing supply with RNG.

The Ontario RNG supply price used for this analysis was based on the RNG pricing framework as provided at Exhibit B, Tab 1, Appendix 5, p. (iii) ("RNG Pricing"), and assumed 50% of the RNG volume is sourced from landfill gas and 50% of the RNG volume is sourced from anaerobic digestion. The maximum price level defined in the pricing matrix for RNG from landfill and anaerobic digestion was used in the analysis ($13 and $17/GJ respectively), resulting in a blended price of $15/GJ of RNG for the purposes of bill impact calculations.

The general service customer bill impacts for the south and the north can be found at Exhibit C, Appendix 1, Schedule 1. Rate impact calculations are found at Exhibit C, Appendix 1, Schedules 2 through 5. The supporting gas supply and deferral account balance derivation schedules as filed in the July 2011 QRAM application (EB-2011-0135) and revised for this analysis to reflect inclusion of RNG are provided at Exhibit C, Appendix 1, Schedules 6 through 9.

IMPACT OF RNG PURCHASES ON SOUTH GENERAL SERVICE CUSTOMERS

For the Southern Operations Area, when comparing to the Board-approved July 2011 QRAM filing, an RNG purchase of 1.7 PJs (1.8%) of South Sales Service Supply reduces the 12-month projected deferral amount credit in the South Purchased Gas Variance Account ("SPGVA") by $18.362 million[(1)], from $76.816 million to $58.453 million. The SPGVA tracks the difference between actual gas supply costs and the gas supply costs included in rates approved by the Board for Union's Southern Operations area. As a result, there is a decrease of $0.183/GJ in the Southern Portfolio Cost Differential ("SPCD"). The SPCD is determined by comparing the projected cost of serving south sales service customers, based on Union's south portfolio, to the cost of

[(1)] Exhibit C, Appendix 1, Schedule 6, Line 29, column f) serving south sales service customers based on the Ontario Landed Reference Price, then dividing the difference by the south sales service demand. The reduction in the SPCD results in a corresponding increase of $0.183/GJ (0.6908 cents/$m^3$)[(2)] in the south transportation rate.

Based on the increase of 0.6908 cents/m^3 in the transportation rate, a typical M1 residential customer consuming 2,600 m^3 per year will see a net bill increase of $17.96 per year (2.1% of average residential bill) when compared to current Board-approved July 2011 QRAM rates.[(3)] Bundled M1 direct purchase customers will see no bill impact.

Impact of RNG Purchases on North General Service Customers

For the Northern and Eastern Operations area, when comparing to the Board-approved July 2011 QRAM filing, an RNG purchase of 0.5 PJs (1.2%) of north system supply increases the 12-month projected deferral amounts in the North Purchased Gas Variance Account ("NPGVA") by $5.792 million[(4)] and the North Fuel deferral account by $0.003 million[(5)]. The NPGVA tracks the difference between actual gas supply costs and the gas supply costs included in rates approved by the Board for Union's Northern and Eastern Operations area. The North Fuel deferral account tracks the difference between the actual TCPL fuel costs and the TCPL fuel costs included in rates approved by the Board for Union's Northern and Eastern Operations area. The incremental

(2) Exhibit C, Appendix 1, Schedule 2, Line 13, column e) and f)
(3) Exhibit C, Appendix 1, Schedule 1, Line 12 column c)
(4) Exhibit C, Appendix 1, Schedule 7, line 29 column f)
(5) Exhibit C, Appendix 1, Schedule 8 line 29 column d)

deferral amounts are divided by the forecast north sales volume to determine the corresponding increases in the commodity & fuel price adjustment of 0.7028 cents/m^3 (6) related to NPGVA and 0.0004 cents/m^3 (7) related to North Fuel.

Based on the net increase of 0.7032 cents/m^3(8) in the commodity & fuel price adjustment rate, a typical Rate 01 Eastern Zone residential customer consuming 2,600 m^3 per year will see a net bill increase of $18.28 per year (1.7% of average residential bill) when compared to current approved July 2011 QRAM rates.[9] North Bundled Rate 01 direct purchase customers will see no bill impact.

In summary, to manage the customer bill impacts to a maximum of approximately $18/year, Union will limit RNG contracts in this program to a cumulative total of 1.7 PJs in the south and to 0.5 PJs in the north, for a total volume limit of RNG of 2.2 PJs. How quickly the RNG program will reach the maximum volume level is unknown. As a result, Union has also provided in Table 1 below the approximate bill impacts at various volume levels of RNG purchases through the program.

(6) Exhibit C, Appendix 1, Schedule 4, line 20 column g)
(7) Exhibit C, Appendix 1, Schedule 5, line 20 column g)
(8) (0.7028 cents/m^3 + 0.0004 cents/m^3 = 0.7032 cents/m^3)
(9) Exhibit C, Appendix 1, Schedule 1, line 27 column c)

Table 1

Approximate Bill Impacts at Various Volume Levels

RNG Volume (PJs)	0.5	1.0	1.5	2.2
Approximate Bill Impact($/yr)	$3.50 to $4.50	$7.50 to $8.50	$10.50 to $12.50	$18

MONTHLY FIXED CHARGE FOR PRODUCERS

The RNG producer will pay an aid to construct to recover the direct connection costs to deliver their gas into the Union system. This includes the capital cost of the customer station and pipe lateral to connect to Union's system. This is consistent with Union's treatment of M13 shippers and local producers in Ontario.

Operating and maintenance costs as well as capital related costs associated with this pipe and this station will be collected by Union through a connection charge. Union proposes to charge RNG producers the existing Board-approved monthly fixed charge per customer station as identified in the M13 Rate Schedule at page 1. As at July 1, 2011 this amount is $656.48. This charge reflects station maintenance costs such as technician call outs plus operating expenses such as valve inspections, leakage surveys, vehicle costs and sample analyses. It is also intended to recover the costs related to capital (meters, regulators, land, other allocated general costs etc). Charging the producer for these services avoids cross-subsidization by other rate classes. The commodity charges on the M13 Rate Schedule relate to M13 transport of gas to Dawn and are not applicable to RNG purchases.

LETTER OF INTENT

In addition to letters of support from a number of municipalities, industry participants and potential producers which are filed in Exhibit B, Tab 1, Appendix 2, Union received a letter of intent from Seacliff Energy Ltd. The letter is attached at Exhibit C, Appendix 2.

UNION GAS LIMITED
Southern Operations Area
General Service Customer Bill Impacts

Line No.		Rate M1 - Residential (Annual Consumption of 2,600 m³) EB-2011-0135 Approved 01-Jul-11 Total Bill ($)	EB-2011-0283 Including RNG (1) 01-Jul-11 Total Bill ($)	Annual Bill Impact ($)
		(a)	(b)	(c) = (b) - (a)
	Delivery Charges			
1	Monthly Charge	240.00	240.00	-
2	Delivery Commodity Charge	92.68	92.68	-
3	Prospective Recovery - Delivery	0.01	0.01	-
4	Storage Services	25.42	25.42	-
5	Total Delivery Charge	358.11	358.11	-
	Supply Charges			
6	Transportation to Union	144.69	162.65	17.96
7	Commodity & Fuel	388.14	388.14	-
8	Prospective Recovery - Commodity & Fuel	(30.10)	(30.10)	-
9	Subtotal	358.04	358.04	-
10	Total Gas Supply Charge	502.73	520.69	17.96
11	Total Bill	860.84	878.80	17.96
12	Annual Bill Impact - Sales Service (line 11)			17.96
13	Annual Bill Impact - Direct Purchase (line 5)			-

Notes:
(1) RNG purchase of 1.9 PJ's (1.9%) of Union South System Supply.

UNION GAS LIMITED
Northern & Eastern Operations Area
General Service Customer Bill Impacts

Line No.		(Eastern) Rate 01 - Residential (Annual Consumption of 2,600 m³) EB-2011-0135 Approved 01-Jul-11 Total Bill ($)	EB-2011-0283 Including RNG (1) 01-Jul-11 Total Bill ($)	Annual Bill Impact ($)
		(a)	(b)	(c) = (b) - (a)
	Delivery Charges			
14	Monthly Charge	240.00	240.00	-
15	Delivery Commodity Charge	193.45	193.45	-
16	Total Delivery Charge	433.45	433.45	-
	Supply Charges			
17	Transportation to Union	227.77	227.77	-
18	Prospective Recovery - Transportation	31.25	31.25	-
19	Storage Services	66.83	66.83	-
20	Prospective Recovery - Storage	-	-	-
21	Subtotal	325.85	325.85	-
22	Commodity & Fuel	388.15	388.15	-
23	Prospective Recovery - Commodity & Fuel	(51.04)	(32.76)	18.28
24	Subtotal	337.11	355.39	18.28
25	Total Gas Supply Charge	662.96	681.24	18.28
26	Total Bill	1,096.41	1,114.69	18.28
27	Annual Bill Impact - Sales (line 26)			18.28
28	Annual Bill Impact - Direct Purchase (line 16 + line 21)			-

Notes:
(1) RNG purchase of 0.5 PJ's (1.2%) of Union North System Supply.

UNION GAS LIMITED
Southern Operations Area
Calculation of Gas Supply Commodity Charges - Including RNG Purchase

Line No.	Particulars	EB-2011-0135 Effective July 1, 2011 (cents/m^3) (a)	($/GJ) (1) (b)	EB-2011-0283 Effective July 1, 2011 (cents/m^3) (c)	($/GJ) (1) (d)		RNG-Related Change Effective July 1, 2011 (cents/m^3) (e)= (c) - (a)	($/GJ) (f)= (d) - (b)
1	Alberta Border Price	14.2016	3.762	14.2016	3.762		-	-
2	Fuel Ratios	2.908%	2.908%	2.908%	2.908%		-	-
3	Compressor Fuel Charge	0.4130	0.109	0.4130	0.109		-	-
4	Administration Charge	0.3138	0.083	0.3138	0.083		-	-
5	Gas Commodity & Fuel Rate (line 1+3+4)	14.9284	3.954	14.9284	3.954		-	-
	Prospective Recovery							
6	Inventory Revaluations	0.6367	0.169	0.6367	0.169		-	-
7	Spot Gas	-	-	-	-		-	-
8	Firm PGVA	(1.7944)	(0.475)	(1.7944)	(0.475)		-	-
9	Temporary Charge/(Credit)	-	-	-	-		-	-
10	Prospective Recovery (line 6+7+8+9)	(1.1577)	(0.306)	(1.1577)	(0.306)		-	-
11	Total Commodity and Fuel Rate (line 5+10)	13.7707	3.648	13.7707	3.648		-	-
12	Transportation Tolls	5.5644	1.474	6.2552	1.657	(2)	0.6908	0.183
13	Total Commodity & Fuel & Transportation Rate (line 11+12)	19.3351	5.122	20.0259	5.305		0.6908	0.183

Notes:
(1) Conversion to GJs based on avg. heating value of Western suppliers of 37.75 GJ / 10^3m^3.
(2) Includes impact related to RNG purchase of 1.9 PJs (1.9%) of Union South System Supply.

(Compares to schedule filed in July 1,2011 QRAM EB-2011-0135, Tab 2, Schedule 1, p. 1)

UNION GAS LIMITED
Northern & Eastern Operations Area
Calculation of Gas Commodity and Fuel - Including RNG Purchase
Eastern Zone

Line No.	Description	EB-2011-0135 Effective July 1, 2011 (cents/m^3)	($/GJ) (1)	EB-2011-0283 Effective July 1, 2011 (cents/m^3)	($/GJ) (1)	RNG-Related Change Effective July 1, 2011 (cents/m^3)	($/GJ)
		(a)	(b)	(c)	(d)	(e) = (c)-(a)	(f)= (d)-(b)
	Rates 01A & 10						
1	Alberta Border Price	14.2016	3.762	14.2016	3.762	-	-
2	Fuel ratios	2.908%	2.908%	2.908%	2.908%	-	-
3	Compressor Fuel Charge	0.4130	0.109	0.4130	0.109	-	-
4	Administration Charge	0.3138	0.083	0.3138	0.083	-	-
5	Gas Commodity & Fuel Rate (line 1+3+4)	14.9284	3.954	14.9284	3.954	-	-
	Prospective Recovery						
6	Inventory Revaluations	0.6367	0.169	0.6367	0.169	-	-
7	Spot Gas	(0.1552)	(0.041)	(0.1552)	(0.041)	-	-
8	Firm PGVA	(2.5000)	(0.662)	(1.7972)	(0.476)	0.7028 (2)	0.186
9	Fuel	0.0553	0.015	0.0557	0.015	0.0004 (2)	-
10	Temporary Charge/(Credit)	-	-	-	-	-	-
11	Total Prospective Recovery (line 6+7+8+9+10)	(1.9632)	(0.520)	(1.2599)	(0.333)	0.7032	0.186
12	Total Commodity and Fuel Rate (line 5+11)	12.9652	3.435	13.6685	3.621	0.7032	0.186

Notes:

(1) Conversion to GJs based on 37.75 GJs / $10^3 m^3$.
(2) Includes deferral impact related to RNG purchase of 0.5 PJs (1.2%) of Union North System Supply.

(Compares to scheduled filed at July 1, 2011 QRAM at EB-2011-0135, Tab 2, Schedule 1. p. 5)

UNION GAS LIMITED

North Purchased Gas Variance Account (Deferral Account 179-105)

Derivation of Amounts and Unit Rates for Prospective Recovery - Including RNG Purchase

Line No.	Particulars	Units	Year 2010 Jul Q3 (a)	Year 2010 Oct Q4 (1) (b)	Year 2011 Jan Q1 (2) (c)	Year 2011 Apr Q2 (3) (d)	Year 2011 Jul Q3 (4) (e)	Including RNG Jul Q3 (5) (f)	RNG-Related Variance (g) = (f-e)
	Deferral Amounts for Recovery								
	Change in 12-month deferral account projection:								
1	12-month projection from current QRAM application	($000's)	-	-	-	-	-	5,792	5,792 (6)
2	Less: 12-month projection from previous QRAM application	($000's)	-	-	-	-	-	-	-
3	Change (Line 1 - Line 2)	($000's)	-	-	-	-	-	5,792	5,792
	Previous Quarter: True-up of deferral balances								
4	Actual deferral balances	($000's)	1,032	(15,729)	(13,243)	(6,532)	(3,265)	(3,265)	-
5	Current projected deferral amounts	($000's)	(15,990)	(8,456)	(5,542)	(1,946)	(655)	(655)	-
6	Less: Previous projection included in recovery	($000's)	(278)	(15,990)	(8,456)	(5,542)	(1,946)	(1,946)	-
7	Variance (Line 4 + Line 5 - Line 6)	($000's)	(14,680)	(8,195)	(10,329)	(2,936)	(1,974)	(1,974)	-
8	Total Deferral Amounts for Recovery (Line 3 + Line 7)	($000's)	(14,680)	(8,195)	(10,329)	(2,936)	(1,974)	3,818	5,792
9	Cumulative Deferral Amounts for Recovery	($000's)	(180,575)	(188,770)	(199,099)	(202,035)	(204,009)	(198,217)	5,792
	Previous Quarter: True-up of Prospective Recovery Amounts								
	Variance between projected and actual prospective recovery for month(s) with actual data since previous QRAM application:								
10	Forecast prospective recovery amount	($000's)	(30,670)	(7,074)	(2,568)	(8,709)	(13,720)	(13,720)	-
11	Less: Actual prospective recovery amount	($000's)	(33,914)	(7,372)	(2,782)	(9,970)	(15,620)	(15,620)	-
12	Variance (Line 10 - Line 11)	($000's)	3,244	298	214	1,262	1,900	1,900	-
13	Total Amount for Prospective Recovery (Line 8 + Line 12)	($000's)	(11,436)	(7,897)	(10,115)	(1,674)	(74)	5,718	5,792
14	Forecast - 12 month sales service volume	(10^3m^3)	790,322	790,349	790,419	789,803	824,123	824,123	-
15	Unit Rate	(cents/m^3)	(1.4471)	(0.9992)	(1.2798)	(0.2120)	(0.0090)	0.6938	0.7028
	Summary of Unit Rates								
16	Unit Rate Q1	(cents/m^3)	(1.3959)	(1.3959)	(1.2798)	(1.2798)	(1.2798)	(1.2798)	-
17	Unit Rate Q2	(cents/m^3)	(0.0786)	(0.0786)	(0.0786)	(0.2120)	(0.2120)	(0.2120)	-
18	Unit Rate Q3 Expiring rider replaced by new rider	(cents/m^3)	(1.4471)	(1.4471)	(1.4471)	(1.4471)	(0.0090)	0.6938	0.7028
19	Unit Rate Q4	(cents/m^3)	(2.1478)	(0.9992)	(0.9992)	(0.9992)	(0.9992)	(0.9992)	-
20	**Total Unit Rate - Prospective Recovery**	(cents/m^3)	**(5.0694)**	**(3.9208)**	**(3.8047)**	**(3.9381)**	**(2.5000)**	**(1.7972)**	0.7028

Notes:
(1) EB-2010-0265, Tab 2, Schedule 2, Column (a).
(2) EB-2010-0359, Tab 2, Schedule 2, Column (a).
(3) EB-2011-0029, Tab 2, Schedule 2, Column (a).
(4) EB-2011-0135, Tab 2, Schedule 2, Column (a).
(5) EB-2011-0135, Tab 2, Schedule 2, Column (a), including deferral impact related to RNG purchase of 0.5 PJs (1.2%) of Union North System Supply.
(6) EB-2011-0283, Exhibit C, Appendix 1, Schedule 7, line 27, column (f)

(Compares to schedule filed in July 1,2011 QRAM EB-2011-0135 at Tab 2 Schedule 3 page 1)

UNION GAS LIMITED

North Fuel - Northern and Eastern Operations Area (Deferral Account 179-100)

Derivation of Amounts and Unit Rates for Prospective Recovery - Including RNG Purchase

Line No.	Particulars	Units	Year 2010 Jul Q3	Year 2010 Oct Q4 (1)	Year 2011 Jan Q1 (2)	Year 2011 Apr Q2 (3)	Year 2011 Jul Q3 (4)	Including RNG Jul Q3 (5)	RNG-Related Variance
			(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-e)
	Deferral Amounts for Recovery								
	Change in 12-month deferral account projection:								
1	12-month projection from current QRAM application	($000's)	(85)	(183)	(208)	(205)	(194)	(190)	3
2	Less: 12-month projection from previous QRAM application	($000's)	(22)	(85)	(183)	(208)	(205)	(205)	-
3	Change (Line 1 - Line 2)	($000's)	(63)	(98)	(25)	3	11	15	3
	Previous Quarter: True-up of deferral balances								
4	Actual deferral balances	($000's)	731	(61)	42	(66)	251	251	-
5	Current projected deferral amounts	($000's)	(407)	(269)	(158)	(86)	(67)	(67)	-
6	Less: Previous projection included in recovery	($000's)	(19)	(407)	(269)	(158)	(86)	(86)	-
7	Variance (Line 4 + Line 5 - Line 6)	($000's)	343	77	153	6	270	270	-
8	Total Deferral Amounts for Recovery (Line 3 + Line 7)	($000's)	280	(21)	128	9	281	285	3
9	Cumulative Deferral Amounts for Recovery	($000's)	1,515	1,494	1,622	1,631	1,912	1,915	3
	Previous Quarter: True-up of Prospective Recovery Amounts								
	Variance between projected and actual prospective recovery for month(s) with actual data since previous QRAM application:								
10	Forecast prospective recovery amount	($000's)	(1,930)	(596)	(133)	37	334	334	-
11	Less: Actual prospective recovery amount	($000's)	(2,124)	(621)	(178)	11	379	379	-
12	Variance (Line 10 - Line 11)	($000's)	194	25	45	27	(45)	(45)	-
13	Total Amount for Prospective Recovery (Line 8 + Line 12)	($000's)	474	4	173	36	236	239	3
14	Forecast - 12 month sales service volume	(10^3m^3)	790,322	790,349	790,419	789,803	824,123	824,123	-
15	Unit Rate	(cents/m^3)	0.0600	0.0004	0.0218	0.0045	0.0286	0.0290	0.0004
	Summary of Unit Rates								
16	Unit Rate Q1	(cents/m^3)	(0.0667)	(0.0667)	0.0218	0.0218	0.0218	0.0218	-
17	Unit Rate Q2	(cents/m^3)	0.0116	0.0116	0.0116	0.0045	0.0045	0.0045	-
18	Unit Rate Q3 Expiring rider replaced by new rider	(cents/m^3)	0.0600	0.0600	0.0600	0.0600	0.0286	0.0290	0.0004
19	Unit Rate Q4	(cents/m^3)	(0.3198)	0.0004	0.0004	0.0004	0.0004	0.0004	-
20	**Total Unit Rate - Prospective Recovery**	(cents/m^3)	**(0.3149)**	**0.0053**	**0.0938**	**0.0867**	**0.0553**	**0.0558**	0.0004

Notes:
(1) EB-2010-0265, Tab 2, Schedule 2, Column (c).
(2) EB-2010-0359, Tab 2, Schedule 2, Column (c).
(3) EB-2011-0029, Tab 2, Schedule 2, Column (c).
(4) EB-2011-0135, Tab 2, Schedule 2, Column (c).
(5) EB-2011-0135, Tab 2, Schedule 2, Column (c), including deferral impact related to RNG purchase of 0.5 PJs (1.2%) of Union North System Supply.
(Compares to schedule filed at July 1, 2011 QRAM EB-2011-0135 at Tab 2, Schedule 3 page 3)

UNION GAS LIMITED
Deferral Account for
South Purchased Gas Variance Account
(Deferral Account 179-106)
RNG Purchase of 1.73 PJs (1.8%) of Union South System Supply (Average Price $15/GJ)

Line No.	Particulars		Purchase Cost ($000's)	Volume (GJ)	Weighted Avg. Price ($/GJ)	Reference Price ($/GJ) (1)	Unit Rate Difference ($/GJ)	Monthly Deferral Amount ($000's)	Southern Portfolio Cost Differential Adjustment ($000's)	Deferral Amount Before Interest ($000's)	Adjustments ($000's)	Total Deferral Before Interest ($000's)	Interest ($000's) (2)	Total Deferral Amount ($000's)
			(a)	(b)	(c) = (a)/(b)	(d)	(e) =(c) - (d)	(f) = (b) x (e)	(g)	(h) = (f) + (g)	(i)	(j) = (h) + (i)	(k)	(l) = (j) + (k)
1	Cumulative to end of June, 2010							$ (331,826)	$ 76,039	$ (255,787)	$ -	$ (255,787)	$ (974)	$ (256,761)
2	July, 2010	*	$ 27,898	5,204,858	$ 5.360	$ 6.121	$ (0.761)	$ (3,961)	$ 2,946	$ (1,015)		$ (1,015)	$ (20)	$ (1,035)
3	August	*	$ 28,600	5,691,342	$ 5.025	$ 6.121	$ (1.096)	$ (6,236)	$ 2,984	$ (3,252)		$ (3,252)	$ (21)	$ (3,273)
4	September	*	$ 23,068	5,062,902	$ 4.556	$ 6.121	$ (1.565)	$ (7,922)	$ 2,880	$ (5,043)	$ 8,377	$ 3,334	$ (22)	$ 3,313
5	October, 2010	*	$ 31,857	7,188,612	$ 4.432	$ 5.670	$ (1.238)	$ (8,902)	$ 2,487	$ (6,415)	$ -	$ (6,415)	$ (26)	$ (6,441)
6	November	*	$ 34,391	8,352,493	$ 4.117	$ 5.670	$ (1.553)	$ (12,967)	$ 2,723	$ (10,244)	$ (15)	$ (10,259)	$ (46)	$ (10,304)
7	December	*	$ 44,279	9,131,573	$ 4.849	$ 5.670	$ (0.821)	$ (7,497)	$ 2,804	$ (4,693)	$ -	$ (4,693)	$ (40)	$ (4,733)
8	January, 2011	*	$ 43,807	9,104,359	$ 4.812	$ 5.370	$ (0.558)	$ (5,084)	$ 3,950	$ (1,133)	$ -	$ (1,133)	$ (36)	$ (1,169)
9	February	*	$ 44,187	9,204,577	$ 4.801	$ 5.370	$ (0.569)	$ (5,241)	$ 3,568	$ (1,673)	$ (3,805) (3)	$ (5,478)	$ (15)	$ (5,492)
10	March	*	$ 47,254	10,875,166	$ 4.345	$ 5.370	$ (1.025)	$ (11,146)	$ 3,950	$ (7,196)	$ -	$ (7,196)	$ (0)	$ (7,196)
11	April, 2011		$ 40,764	8,516,353	$ 4.787	$ 5.890	$ (1.103)	$ (9,397)	$ 6,189	$ (3,208)	$ -	$ (3,208)	$ (20)	$ (3,229)
12	May		$ 40,720	8,375,772	$ 4.862	$ 5.890	$ (1.028)	$ (8,613)	$ 6,395	$ (2,218)	$ -	$ (2,218)	$ (30)	$ (2,247)
13	June		$ 40,949	8,494,886	$ 4.820	$ 5.890	$ (1.070)	$ (9,086)	$ 6,189	$ (2,897)	$ -	$ (2,897)	$ (35)	$ (2,933)
14	Total (Lines 1 to 13)		$ 447,774	95,202,893				$ (427,880)	$ 123,106	$ (304,774)	$ 4,558	$ (300,216)	$ (1,284)	$ (301,500)
	Current QRAM Period													
15	July, 2011		$ 49,853	9,208,065	$ 5.414	$ 6.114	$ (0.700)	$ (6,445)	$ 4,951	$ (1,494)	$ -	$ (1,494)	$ -	$ (1,494)
16	August		$ 42,378	7,600,642	$ 5.576	$ 6.114	$ (0.538)	$ (4,092)	$ 4,951	$ 859	$ -	$ 859	$ -	$ 859
17	September		$ 41,699	7,355,460	$ 5.669	$ 6.114	$ (0.445)	$ (3,272)	$ 4,791	$ 1,519	$ -	$ 1,519	$ -	$ 1,519
18	October, 2011		$ 49,153	9,045,940	$ 5.434	$ 6.114	$ (0.680)	$ (6,153)	$ 4,951	$ (1,203)	$ -	$ (1,203)	$ -	$ (1,203)
19	November		$ 46,405	8,682,665	$ 5.345	$ 6.114	$ (0.769)	$ (6,681)	$ 4,791	$ (1,890)	$ -	$ (1,890)	$ -	$ (1,890)
20	December		$ 49,469	8,972,086	$ 5.514	$ 6.114	$ (0.600)	$ (5,386)	$ 4,951	$ (435)	$ -	$ (435)	$ -	$ (435)
21	January, 2012		$ 46,192	8,169,391	$ 5.654	$ 6.114	$ (0.460)	$ (3,756)	$ 4,951	$ 1,195	$ -	$ 1,195	$ -	$ 1,195
22	February		$ 43,812	7,642,334	$ 5.733	$ 6.114	$ (0.381)	$ (2,913)	$ 4,632	$ 1,718	$ -	$ 1,718	$ -	$ 1,718
23	March		$ 45,660	8,169,391	$ 5.589	$ 6.114	$ (0.525)	$ (4,287)	$ 4,951	$ 663	$ -	$ 663	$ -	$ 663
24	April, 2012		$ 43,140	7,905,863	$ 5.457	$ 6.114	$ (0.657)	$ (5,196)	$ 4,791	$ (405)	$ -	$ (405)	$ -	$ (405)
25	May		$ 44,381	8,169,391	$ 5.433	$ 6.114	$ (0.681)	$ (5,567)	$ 4,951	$ (616)	$ -	$ (616)	$ -	$ (616)
26	June		$ 43,633	7,905,863	$ 5.519	$ 6.114	$ (0.595)	$ (4,703)	$ 4,791	$ 88	$ -	$ 88	$ -	$ 88
27	Total (Lines 15 to 26)		$ 545,776	98,827,091 (4)				$ (58,453)	$ 58,453	$ 0	$ -	$ 0	$ -	$ 0
28							Jul11QRAM	$ (76,816)						
29	* Reflects actual information.						**RNG Impact**	**$ 18,362**						

Notes:

(1) The reference price from July 2010 to September 2010 is as approved in EB-2010-0201.
The reference price from October 2010 to December 2010 is as approved in EB-2010-0265.
The reference price from January 2011 to March 2011 is as approved in EB-2010-0359.
The reference price from April 2011 to June 2011 is as approved in EB-2011-0029.
The reference price from July 2011 to June 2012 is as proposed in EB-2011-0135.

(2) Interest is computed on the deferral amount balance net of the actual prospective recovery amount for the quarter prior to the current QRAM period.

(3) February 2011 SPGVA deferral costs includes a credit due to excess DP Balancing Gas of 3.19 PJs transferred to the System portfolio.

(4) RNG purchase of 1.73 PJs (1.8%) of Union South System Supply (Average Price $15/GJ)
(Compares to schedule filed in July 1, 2011 QRAM EB-2011-0135 Tab 1 Schedule 3 page 4 of 6)

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Appendix 1
Schedule 7

UNION GAS LIMITED
Deferral Account for
North Purchased Gas Variance Account
(Deferral Account 179-105)
RNG purchase of 0.5 PJs (1.2%) of Union North System Supply (Average Price $15/GJ)

Line No.	Particulars	Purchase Cost ($000's)	Volume (GJ)	Weighted Avg. Price ($/GJ)	Reference Price ($/GJ) (1)	Unit Rate Difference ($/GJ)	Deferral Amount Before Interest ($000's)	Adjustments ($000's)	Total Deferral Before Interest ($000's)	Interest ($000's) (2)	Total Deferral Amount ($000's)
		(a)	(b)	(c) = (a)/(b)	(d)	(e) =(c) - (d)	(f) = (b) x (e)	(g)	(h) = (f) + (g)	(i)	(j) = (h) + (i)
1	Cumulative to end of June, 2010						$ (89,522)	$ -	$ (89,522)	$ (253)	$ (89,775)
2	July, 2010 *	$ 10,379	2,729,906	$ 3.802	$ 4.363	$ (0.561)	$ (1,532)		$ (1,532)	$ (12)	$ (1,544)
3	August *	$ 10,118	2,926,657	$ 3.457	$ 4.363	$ (0.906)	$ (2,651)		$ (2,651)	$ (14)	$ (2,666)
4	September *	$ 7,645	2,692,011	$ 2.840	$ 4.363	$ (1.523)	$ (4,100)	$ (4,919)	$ (9,019)	$ (15)	$ (9,034)
5	October, 2010 *	$ 9,490	2,884,597	$ 3.290	$ 3.920	$ (0.630)	$ (1,818)	$ -	$ (1,818)	$ (17)	$ (1,835)
6	November *	$ 12,802	4,073,544	$ 3.143	$ 3.920	$ (0.777)	$ (3,166)	$ -	$ (3,166)	$ (28)	$ (3,195)
7	December *	$ 11,509	3,313,062	$ 3.474	$ 3.920	$ (0.446)	$ (1,479)	$ -	$ (1,479)	$ (24)	$ (1,503)
8	January, 2011 *	$ 12,698	3,587,785	$ 3.539	$ 3.627	$ (0.088)	$ (315)	$ -	$ (315)	$ (25)	$ (340)
9	February *	$ 11,445	3,239,460	$ 3.533	$ 3.627	$ (0.094)	$ (305)	$ (1,268) (3)	$ (1,573)	$ (15)	$ (1,588)
10	March *	$ 11,807	3,620,676	$ 3.261	$ 3.627	$ (0.366)	$ (1,325)	$ -	$ (1,325)	$ (12)	$ (1,337)
11	April, 2011	$ 12,024	3,457,157	$ 3.478	$ 3.550	$ (0.072)	$ (249)	$ -	$ (249)	$ (10)	$ (259)
12	May	$ 11,978	3,420,782	$ 3.501	$ 3.550	$ (0.049)	$ (166)	$ -	$ (166)	$ (13)	$ (179)
13	June	$ 12,289	3,518,374	$ 3.493	$ 3.550	$ (0.057)	$ (202)	$ -	$ (202)	$ (15)	$ (217)
14	Total (Lines 1 to 13)	$ 134,182	39,464,011				$ (106,829)	$ (6,187)	$ (113,016)	$ (454)	$ (113,471)
	Current QRAM Period										
15	July, 2011	$ 13,716	3,520,574	$ 3.896	$ 3.762	$ 0.134	$ 471	$ -	$ 471	$ -	$ 471
16	August	$ 13,611	3,475,663	$ 3.916	$ 3.762	$ 0.154	$ 535	$ -	$ 535	$ -	$ 535
17	September	$ 13,351	3,354,956	$ 3.980	$ 3.762	$ 0.217	$ 730	$ -	$ 730	$ -	$ 730
18	October, 2011	$ 12,097	2,966,583	$ 4.078	$ 3.762	$ 0.316	$ 936	$ -	$ 936	$ -	$ 936
19	November	$ 12,760	3,460,023	$ 3.688	$ 3.762	$ (0.074)	$ (257)	$ -	$ (257)	$ -	$ (257)
20	December	$ 13,968	3,589,993	$ 3.891	$ 3.762	$ 0.129	$ 462	$ -	$ 462	$ -	$ 462
21	January, 2012	$ 14,329	3,580,096	$ 4.002	$ 3.762	$ 0.240	$ 860	$ -	$ 860	$ -	$ 860
22	February	$ 13,320	3,334,028	$ 3.995	$ 3.762	$ 0.233	$ 777	$ -	$ 777	$ -	$ 777
23	March	$ 14,175	3,596,621	$ 3.941	$ 3.762	$ 0.179	$ 644	$ -	$ 644	$ -	$ 644
24	April, 2012	$ 13,125	3,459,093	$ 3.794	$ 3.762	$ 0.032	$ 111	$ -	$ 111	$ -	$ 111
25	May	$ 13,700	3,589,450	$ 3.817	$ 3.762	$ 0.055	$ 196	$ -	$ 196	$ -	$ 196
26	June	$ 13,342	3,459,753	$ 3.856	$ 3.762	$ 0.094	$ 326	$ -	$ 326	$ -	$ 326
27	Total (Lines 15 to 26)	$ 161,494	41,386,834 (4)				$ 5,792	$ -	$ 5,792	$ -	$ 5,792
28						Jul11QRAM	$ -				
29	* Reflects actual information.					**RNG Impact**	**$ 5,792** (5)				

Notes:

(1) The reference price from July 2010 to September 2010 is as approved in EB-2010-0201.
The reference price from October 2010 to December 2010 is as approved in EB-2010-0265.
The reference price from January 2011 to March 2011 is as approved in EB-2010-0359.
The reference price from April 2011 to June 2011 is as approved in EB-2011-0029.
The reference price from July 2011 to June 2012 is as proposed in EB-2011-0135.

(2) Interest is computed on the deferral amount balance net of the actual prospective recovery amount for the quarter prior to the current QRAM period.

(3) February 2011 NPGVA deferral costs includes a credit due to excess DP Balancing Gas of 1.07 PJs transferred to the System portfolio.

(4) RNG purchase of 0.5 PJs (1.2%) of Union North System Supply (Average Price $15/GJ)

(5) Assumed NO TCPL Turnback therefore no offset for this cost.
(Compares to schedule filed in July 1, 2011 QRAM, EB-2011-0135, Tab1, Schedule 3, page 2 of 6

Filed 2011-09-30
EB-2011-0283
Exhibit C
Appendix 1
Schedule 8

UNION GAS LIMITED
Deferral Account for
North TCPL Tolls and Fuel - Northern and Eastern Operations Area
(Deferral Account 179-100)
RNG purchase of 0.5 PJs (1.2%) of Union North System Supply (Average Price $15/GJ)

Line No.	Particulars		North TCPL Tolls: Deferral Amount Before Interest ($000's)	North TCPL Tolls: Interest ($000's) (1)	North TCPL Tolls: Deferral Amount With Interest ($000's)	North TCPL Fuel: Deferral Amount Before Interest ($000's)	North TCPL Fuel: Interest ($000's) (1)	North TCPL Fuel: Deferral Amount With Interest ($000's)	Total Deferral Amount With Interest ($000's)
			(a)	(b)	(c) = (a) + (b)	(d)	(e)	(f) = (d) + (e)	(g) = (c) + (f)
1	Cumulative to end of June, 2010		$ (3,383)	$ 32	$ (3,351)	$ (1,810)	$ 61	$ (1,749)	$ (5,100)
2	July, 2010	*	$ 463	$ (4)	$ 459	$ 33	$ 0	$ 33	$ 492
3	August	*	$ 427	$ 3	$ 430	$ 6	$ (0)	$ 6	$ 435
4	September	*	$ 3,563	$ (2)	$ 3,561	$ 4	$ (0)	$ 4	$ 3,565
5	October, 2010	*	$ 640	$ (2)	$ 638	$ (10)	$ (0)	$ (10)	$ 628
6	November	*	$ 543	$ (3)	$ 540	$ (9)	$ (0)	$ (9)	$ 532
7	December	*	$ 337	$ 1	$ 338	$ (47)	$ (0)	$ (47)	$ 290
8	January, 2011	*	$ 443	$ 1	$ 444	$ 235	$ (0)	$ 235	$ 679
9	February	*	$ 792	$ 0	$ 792	$ 76	$ (0)	$ 76	$ 868
10	March	*	$ 3,292	$ 1	$ 3,292	$ (60)	$ (0)	$ (60)	$ 3,233
11	April, 2011		$ 772	$ 4	$ 775	$ (15)	$ 0	$ (14)	$ 761
12	May		$ 782	$ 6	$ 788	$ (24)	$ 0	$ (23)	$ 765
13	June		$ 786	$ 8	$ 794	$ (29)	$ 0	$ (29)	$ 765
14	Total (Lines 1 to 13)		$ 9,457	$ 44	$ 9,501	$ (1,649)	$ 61	$ (1,588)	$ 7,913
	Current QRAM Period								
15	July, 2011		$ 787	$ -	$ 787	$ (49)	$ -	$ (49)	$ 738
16	August		$ 787	$ -	$ 787	$ (48)	$ -	$ (48)	$ 740
17	September		$ 785	$ -	$ 785	$ (40)	$ -	$ (40)	$ 745
18	October, 2011		$ 778	$ -	$ 778	$ (28)	$ -	$ (28)	$ 751
19	November		$ 749	$ -	$ 749	$ (17)	$ -	$ (17)	$ 732
20	December		$ 750	$ -	$ 750	$ 7	$ -	$ 7	$ 758
21	January, 2012		$ 787	$ -	$ 787	$ 3	$ -	$ 3	$ 790
22	February		$ 784	$ -	$ 784	$ 4	$ -	$ 4	$ 788
23	March		$ 769	$ -	$ 769	$ 12	$ -	$ 12	$ 782
24	April, 2012		$ 772	$ -	$ 772	$ (6)	$ -	$ (6)	$ 765
25	May		$ 782	$ -	$ 782	$ (14)	$ -	$ (14)	$ 768
26	June		$ 786	$ -	$ 786	$ (15)	$ -	$ (15)	$ 771
27	Total (Lines 15 to 26)		$ 9,317	$ -	$ 9,317	$ (190)	$ -	$ (190)	$ 9,126
28		Jul11QRAM	$ 9,317		Jul11QRAM	$ (194)			
29		RNG Toll Impact	$ -	(2)	**RNG Fuel Impact**	**$ 3**	**(3)**		

* Reflects actual information.

Notes:

(1) Interest is computed on the deferral amount balance net of the actual prospective recovery amount for the quarter prior to the current QRAM period.
(2) Transportation costs decrease, but create no change to the Net Deferral as both Actual and Approved Pricing are the same.
(3) Fuel costs decrease slightly creating a very small Net Deferral caused by the Fuel Ratio percentage being applied to a changed supply cost.
(4) DP Volumes are assumed to be unchanged. Full impact of RNG purchase is offset to Sales Volumes included in Sch 7.
(Compares to schedule filed in July 1, 2011 QRAM, EB-2011-0135, Tab 1, Schedule 3, page 3 of 6)

UNION GAS LIMITED
Calculation of South Portfolio Cost Differential & South Transportation Rate
For the 12 month period ending June 30, 2012
RNG purchase of 1.7 PJs (1.8%) of Union South System Supply (Average Price $15/GJ)

Line No.	Particulars	EB-2011-0135 July 11 QRAM			EB-2011-0283 Including RNG (3)		
1	South Purchased Gas Variance Account (SPGVA) ($000's)	$	76,816	(1)	$	58,453	(3)
2	South Consumption Volumes (PJs)		99.8	(2)		99.8	
3	South Price Cost Differential (Line 1/Line 2)	$	0.769	/GJ	$	0.586	/GJ
4	TCPL Transportation EDA Toll	$	2.243	/GJ	$	2.243	/GJ
5	South Price Cost Differential (Line 3)	$	0.769	/GJ	$	0.586	/GJ
6	South Transportation Rate (Line 4 - Line 5)	$	1.474	/GJ	$	1.657	/GJ

Notes:
(1) EB-2011-0135 Tab 1, Schedule 3, page 4, Column (g), line 27.
(2) Demand Forecast for South sales service customers for the period July 2011 to June 2012.
(3) RNG purchase of 1.7 PJs (1.8%) of Union South System Supply (Average Price $15/GJ)
(Compares to schedule filed in July 1, 2011 QRAM, EB-2011-0135, Tab 1, Schedule 2)

Dennis Dick
Chief Operating Officer
Seacliff Energy Ltd.
RR#4, 1200 County Road 20,
Leamington, ON
N8V 3V7

August 9, 2011

Dear Dennis:

This letter, jointly developed by Union Gas Limited and Seacliff Energy Limited, demonstrates our mutual intent to enter into a purchase agreement for Renewable Natural Gas, also known as biomethane.

Seacliff Energy owns and operates an anaerobic digestion bio-energy facility in Leamington, Ontario. The facility accepts agricultural and commercial organic waste streams to create biogas that currently fuels a reciprocating generator to produce 1.6 megawatts of renewable energy. Commissioned in early 2011, Phase I of the project is based on power generation that is supported by an Ontario Power Authority (OPA) Renewable Energy Standard Offer Program (RESOP) contract that was rate-enhanced by an amendment for the Feed-In Tariff (FIT) program.

Phase II of the project is based on an additional 1.6 megawatts of power generation through the OPA FIT program. Upon completion of phase II, the project will have the capacity to create enough biogas to supply a further 1.6 megawatts of power generation—a potential total of 4.8 megawatts. The current FIT status for Phase II generation is positioned in queue for an upcoming OPA Economic Connection Test, which is anticipated later this year. Additionally, Seacliff Energy is interested in entering into a Renewable Natural Gas Purchase Agreement in order to supply upgraded biogas (biomethane) to Union Gas's distribution network.

It is understood by both parties that Union Gas's ability to offer a specified price and long term contract for Renewable Natural Gas is dependent upon regulatory approval by the Ontario Energy Board (OEB). Union Gas intends to file a joint application with Enbridge Gas Distribution to the OEB for regulatory approval to establish a Renewable Natural Gas Program. Based upon OEB approval for the necessary price and long term, 20 year contract required to provide sufficient business planning certainty to allow for investment in this project, Seacliff Energy intends to enter into a Renewable Natural Gas Purchase Agreement with Union Gas, provided all operational requirements can be met and the final contract pricing drives favourable project economics.

Signed

Dennis Dick
Chief Operating Officer
Seacliff Energy Ltd.

Aug. 12/2011
Date

Bryan Goulden
Manager, Market Development
Union Gas Ltd.

August 9, 2011
Date