2.85 MW LETHBRIDGE BIOGAS/COGENERATION FACILTY

PROJECT ID #G101234



FINAL REPORT
(Non-Confidential)
March 2011 – November 2013

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1. EXECUTIVE SUMMARY

Lethbridge Biogas General Partner Inc., in its capacity as managing partner of Lethbridge Biogas LP, a limited partnership between ECB Enviro North America Inc. and PlanET Biogas, has developed, built and commissioned a 2.85 MW biogas/cogeneration facility located in Section 3, Township 9, Range 21, West of the 4th Meridian, immediately east of the City of Lethbridge east boundary.

The facility is unique in its process design, technology scope and scale and is the first one of its kind in Alberta and all over Canada. It uses advanced anaerobic digester technology to extract biogas from organic feedstock (liquid & solid) in a technically controlled anaerobic environment. It is producing increasing quantities of biogas generated electricity since late August of 2013.

Since digester filling began in early June of 2013, the facility:

- Has processed more than 25,000 t of liquid and solid organic feedstock
- Has produced more than 6,000 MWh of electricity (natural gas and biogas)
- Has achieved a stable biogas production to have one of the co-generation units exclusively operating on biogas for 24/7
- Is expected to have an estimated initial reduction of GHG emissions for 2013 between 500 -1,000 t CO_2e
- Has created economic, environmental and societal benefits for the region through waste reduction, energy creation and advanced technology application

Eligible project expenses total $28,575,741 until November 30, 2013 and project contributions provided by CCEMC and the project partners are as follows:

- Agriculture Financial Services Corporation (AFSC): $ 5,000,000
- Climate Change and Emissions Management (CCEMC) Corporation: (incl. holdback) $ 8,200,000
- Department of Energy: $ 6,448,016
- PlanET: $ 8,200,000
- Lethbridge Biogas: $ 727,725

Project revenues until November 30, 2013, predominantly received from electricity sales to the AESO, total $826,327.

The implementation of the thermal hydrolysis process (THD) will be the major focus for Lethbridge Biogas in 2014. It is anticipated that the system will be delivered, installed and commissioned in Q3/Q4 of 2014.

2. BACKGROUND

2.1 Climate Change Emission Management (CCEMC) Corporation

In April 2007, Alberta became the first jurisdiction in North America to pass climate change legislation requiring large emitters to reduce emissions.

Alberta's Specified Gas Emitters Regulation (SGER) identifies that companies that emit more than 100,000 metric tonnes of carbon dioxide equivalent per year must reduce emissions intensity by 12 per cent below their 2004-2005 baseline intensity. Organizations that are unable to meet their targets have three compliance options:

- Improve the energy efficiency of their internal operations;
- Buy carbon credits from other Alberta-based organizations; or
- Pay $15 into the Climate Change and Emissions Management Fund for every tonne they exceed the allocated limit.

The Climate Change and Emissions Management (CCEMC) Corporation was created in 2009 to be a key part of Alberta's climate change strategy and movement toward a stronger and more diverse lower carbon economy. It receives money from the Climate Change and Emissions Management Fund and directs it towards innovative projects that will reduce greenhouse gas emissions.

Priority areas for funding by the CCEMC are aligned with Alberta's 2008 Climate Change Strategy and include:

- Conserving and Using Energy Efficiently (emissions target of 24MT by 2050);
- Implementing CCS (emissions target of 139MT by 2050); and
- Greening Energy Production (emissions target of 37 MT by 2050).

2.2 Lethbridge Biogas General Partner Inc. (LBGP)

LBGP, initially set up as the managing partner for a limited partnership between ECB Enviro North America Inc. (ECB NA) and StormFisher Biogas, submitted an Expression of Interest (EOI) to build a 3.2 MW biogas/ cogeneration facility under the 'Renewable Energy' category on September 30, 2009. Project objectives were to:

- Provide a safe, sutainable & cost-efficient alternative disposal option for manure, organic by-products & animal by-products that currently contribute to the release of greenhouse gas emissions (GHG)

- Generate 3.2MW of base-load green electricity & reduce GHG emission through the use of renewable sources

- Produce an organic fertilizer and offset the carbon footprint of regular fossil fuel based fertilizer production and application

On November 20, 2009 the project was selected as one of 30 out of 223 to move to the Full Project Proposal stage.

LBGP, at that time representing a limited partnership between ECB NA and ATCO Midstream (AML), submitted a Full Proposal (FP) with a final project size of 2.8 MW generation capacity on February 25, 2010. With project objectives remaining unchanged the project was approved for a $8,200,000 contribution by the CCEMC subject to various conditions. On March 28, 2011 LBGP signed a Contribution Agreement with the CCEMC.

LBGP, now acting on behalf of Lethbridge Biogas LP (LP), a limited partnership between ECB NA and PlanET Biogas, was able to successfully complete financing for the project and on June 30, 2011 LBGP received a 'Notice of Satisfaction Of Conditions' from the CCEMC confirming that all conditions as outlined in the Contribution Agreement have been satisfied.

LBGP completed partnership agreements and construction contracts and was able to start with construction activities for the Lethbridge biogas/cogeneration facility on August 12, 2011. The facility is located in the County of Lethbridge at 4456 – 8th Avenue North, Lethbridge, AB (Section 3, Township 9, Range 21, West of the 4th Meridian) immediately east of the City of Lethbridge east boundary.

The facility and its components have been commissioned, operation has started and the official Ribbon Cutting/Opening ceremony is scheduled for December 4, 2013. The progress during the construction process of the facility has been documented and reported to the CCEMC with every project milestone (see Attachment A).

2.3 ECB Enviro North America Inc. (ECB NA)

ECB Enviro North America Inc. (ECB NA), located in Fort Macleod, AB, was incorporated under the Alberta Business Corporations Act in October in 2001 as an initiative of successful Alberta businessman closely related to the agriculture business, who believed in the future of the emerging markets of bio-energy in Canada. ECB NA's management team combines successful business experience in Alberta's agricultural and industrial sectors with international technical expertise in cogeneration and renewable energy projects.

ECB NA was the owner and developer of the Lethbridge biogas/cogeneration project and has brought the project through the stages of feasibility, regulatory approval, design & engineering and financing to a shovel-ready project.

ECB NA, through its subsidiary ECB Lethbridge Co-Gen Ltd., is a limited partner in Lethbridge Biogas LP.

2.4 PlanET Biogas (PlanET)

PlanET Biogas is one of the world's leading biogas plant suppliers. Founded in 1998, the company's service portfolio covers all fields of biogas technology and component distribution: from planning, plant construction, refinement of biogas to natural gas quality and all the way to service and biological support from an in-house laboratory.

PlanET's RePowering division enables customers to increase the efficiency of their existing plants in a targeted fashion. At the same time, the modularly developed SYSTEMBIOGAS functional principle allows biogas plant operators and investors to react to new developments on the biogas market at any time.

Over 200 employees currently work at the company headquarters in the German Muensterland alone. Other employees work in the international subsidiaries in the Netherlands, France and Canada. PlanET is also represented in the United Kingdom, Italy, Spain and Japan. PlanET already has successfully realized more than 300 biogas plants worldwide on a scale from 40 kW to several megawatts.

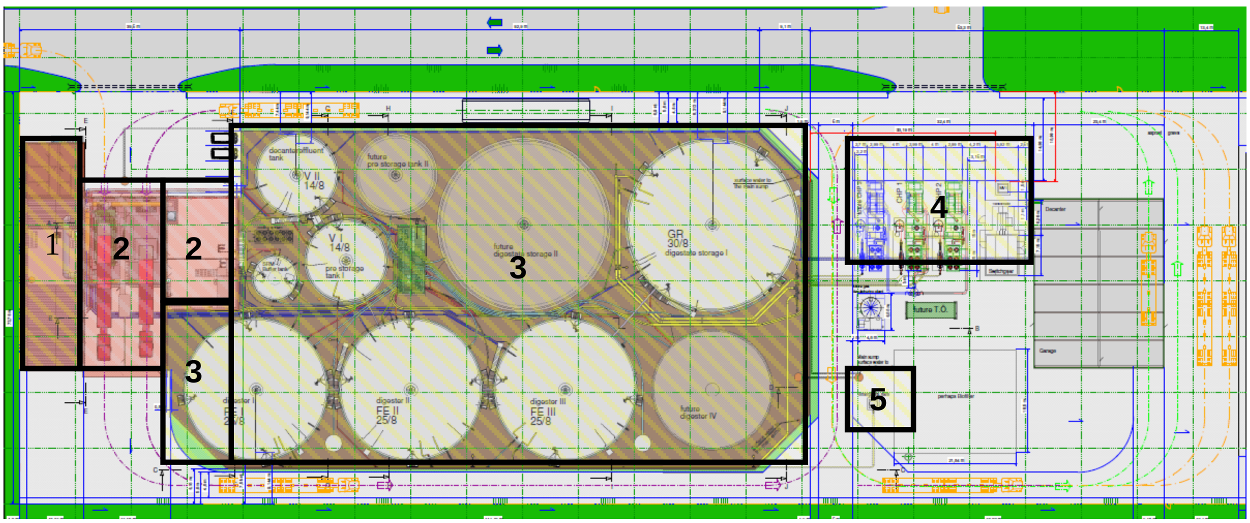
PlanET, through its subsidiary PlanET Biogas Investments Inc., is a limited partner in Lethbridge Biogas LP.

3. FINAL OUTCOMES REPORT

3.1 Project Technology

LB built and operates a biogas/cogeneration facility that uses advanced anaerobic digester technology to extract biogas from organic feedstock in a technically controlled anaerobic environment. The system is designed to produce up to 26,000 m^3 of combustible biogas (50-60% CH_4, max. 200 ppm H_2S) per day at a maximum Organic Loading Rate (OLR) of 4.0 kg VS/m^3.

The following site plan gives an overview of the current facility and its various components.



1 Scrubber Building/Biofilters
2 Receiving/Unloading & Process Building
3 Tank Farm and Secondary Containment Area (incl. 2 pre-storage tanks, 1 hydrolyzed animal by-product storage tank, 3 anaerobic digesters, 1 digestate storage tank, technical container, 4 ferric chloride tanks)
4 Cogeneration Area (incl. 2 co-generation units, exhaust stack, switchgear building, transformer, MVI, emergency generator)
5 Emergency Flare

3.1.1 Receiving/Unloading Technology

Feedstock is delivered to the site by truck, truck weights are recorded with the on-site truck scale and trucks are unloaded in the receiving building. Trucks are currently unloaded in truck bay 1 only (liquid and solid organics).

Liquid feedstock in truck bay 1 is unloaded via a pump and a manifold and is stored in dedicated storage tanks (pre-storage 1 & 2) after the unloading process. The characteristics of the two (2) pre-storage tanks located in the secondary containment area with a gross volume of approx. 1,150 m^3 (14m *8m) are:

- Reinforced, cast-in-place concrete tank (jump form system with tie-less forms)
- In-floor and in-wall hot water heating
- Man door
- Biogas protective treatment of concrete vessel (complete interior)
- Rigid high-density floor and wall insulation (double layer), protective cladding
- One (1) submersible and laterally & vertically adjustable mid-sized 'wing' agitator (7.5 kW)
- Various inlets and outputs for feeding and discharge of substrate, biogas, air, condensate, ferric chloride, etc.
- Fill level and operating sensors
- Over-/under pressure safety valves
- Access platform
- Inspection windows

The double membrane biogas storage & weather protection system allows for approximately 300 m^3 of biogas storage inside of each pre-storage tank.

Solid feedstock in truck bay 1 is dumped into an underground solid feeding system. The solid feeding system (Vario) can pump chopped energy crops, solid manure, feed remains as well as other solid co-ferments via a liquid flushing system and a progressive cavity pump directly into the anaerobic digesters. The pump is equipped with a speed regulator which adjusts the feed rate in the pipeline under constant flow pressure. The feed screw also has a speed regulator to ensure variable solids feeding in the chute. The characteristics of the solid feeding/liquid flushing system are:

- Hydraulically powered in-floor hatch
- Receiving hopper with a nominal capacity of 75 m^3
- Individually propelled stainless steel conveyor lines
- Hinged flaps for efficient conveying
- Auger system
- Liquid flushing system with progression cavity pump

Trucks that unload in truck bay 1 reload with digested slurry (digestate) from the digestate storage tank located in the secondary containment. Trucks drive onto the weigh scale for second time to record the load of digestate before leaving the facility. Digestate is stored in existing manure storage lagoons at participating dairy and/or hog operations and will be land applied at the appropriate time on agricultural land.

3.1.2 Air Cleaning Technology

All air from the receiving/process building potentially contaminated with NH_3 and other VOC's including small levels of H_2S is treated with a two stage scrubber (acid & base) followed by a 100% redundant biological bio-filtration system. The receiving/unloading & process building is constantly kept under a slight negative pressure to trap odorous air within the building. Once the trucks enter the truck bays and overhead doors start to open, the ventilation system in the building ramps up air flow to maintain negative pressure in the building.

The air treatment system is located in the scrubber building adjacent to the receiving building. The bio-filtration system uses wood material (bark from softwood) that is always kept at a certain temperature and level of moisture to biologically destroy VOC's and other odorous components. The bio-filtration system consists of two (2) fully redundant biofilter chambers each capable of treating 30,000 m^3/h. The biofilter chambers are also located adjacent to the receiving building.

3.1.3 Technical Container

The technical container located in the secondary containment is 12 m long (40 ft.) and was delivered as a pre-assembled unit to the site. All substrate pumping in and out of the system goes through the pumping manifolds in the technical container as well as the distribution of hot water process heat. Included are furthermore:

- Man doors
- Air ventilation system
- Control panels
- Air compressor unit for pneumatic valves and sealing tracks in the field, inclusive air cooling system and compressor units for the desulphurization system
- Gas analyzer (CH4: 0 -100% vol.; O2: 0 - 25% vol.; H: 0 – 4000 ppm; H2S: 0 – 5,000 ppm)

3.1.4 Anaerobic Digestion Technology

The anaerobic digestion process operates mesophilically at around 40 degree C. The facility is equipped with three (3) concrete anaerobic digesters located in the secondary containment area with a gross digester volume of approximately 3,900 m^3 each (25m *8m). The digester characteristics are:

- Reinforced, cast-in-place concrete tank (jump form system with tie-less forms)
- In-floor and in-wall hot water heating
- Man door

- Biogas protective treatment of concrete vessel in gas zone
- Rigid high-density floor and wall insulation (double layer), protective cladding
- Four (4) submersible and laterally & vertically adjustable mid-sized 'wing' agitators (7.5 kW each)
- Various inlets and outputs for feeding and discharge of substrate, biogas, air, condensate, ferric chloride, etc.
- Fill level and operating sensors
- Over-/under pressure safety valves
- Access platform
- Inspection windows

The double membrane biogas storage & weather protection system allows for approximately 1,500 m^3 of biogas storage inside of each digester. Each anaerobic digester can be fed with organic material from the pre-storage tanks, the solid feeding system and the hydrolyzed slurry storage tank. Digester feeding and digester emptying occurs at a constant rate to ensure an optimal mix and proper fill levels are maintained in the digesters.

Digestate following the anaerobic treatment is discharged into one (1) digestate storage tank located in the secondary containment area that has a gross volume of approximately 5,700 m^3 (30m *8m). The characteristics of the digestate storage tank are:

- Reinforced, cast-in-place concrete tank (jump form system with tie-less forms)
- In-floor and in-wall hot water heating
- Man door
- Biogas protective treatment of concrete vessel in gas zone
- Rigid high-density floor and wall insulation (double layer), protective cladding
- Four (4) submersible and laterally & vertically adjustable mid-sized 'wing' agitators (7.5 kW each)
- Various inlets and outputs for feeding and discharge of substrate, biogas, air, condensate, ferric chloride, etc.
- Fill level and operating sensors
- Over-/under pressure safety valves
- Access platform
- Inspection windows

The double membrane biogas storage & weather protection system allows for approximately 2,100 m^3 of biogas storage inside of the digestate storage tank.

3.1.5 Biogas Cleaning & Biogas Conditioning Technology

The composition of the biogas ranges in percent methane by weight from between 50 % to 60 %. The remainder of gas composition consists principally of carbon dioxide. The biogas also contains trace amounts of H_2S. The H_2S in the biogas is removed through a biological process within the anaerobic digesters. A newly developed desulphurization fabric is optimally stretched over the tank with tension belts. The stainless steel column in the centre of the tank provides an additional point of support and simultaneously serves to deflect the belts. The belts are fastened to the exterior wall of the tank by anchor elements made of stainless steel. The desulphurization fabric creates the surface for organic bacteria that reduce the H_2S to elemental sulfur in a reaction with small amounts of oxygen.

As a back-up system and also used for the start-up, the anaerobic digesters are equipped with a chemical H_2S cleaning system as well, that is based on dosing small amounts of ferric chloride into the system.

Prior to the combustion process in the cogeneration units (CHP's), the biogas is adjusted in moisture and temperature and passes through an activated carbon filter for a third layer of H_2S removal if required.

3.1.6 Co-Generation Technology

Initially two (2) 2G fully containerized units with an electrical generation capacity of 1,425 kW, each featuring GE-Jenbacher engines, will use the biogas to produce electricity and process heat (see Attachment B). One of the units is equipped for fuel blending (biogas/natural gas). The facility is connected to the FortisAlberta distribution system at the 25 KV level. Switchgear that is located within a small building and an on-site transformer deliver and convert the 600V electricity as produced by the engines into 25KV and connect the facility to the Alberta power grid at all times. The facility can be taken off the grid through a transfer trip system by the utilities. An automatic transfer switch that is connected to an emergency generator ensures that in case of power outages or other upset conditions the facility will be able to maintain its key electric functions.

Thermal energy recovered from the co-generation units is used within a closed loop glycol/water system to cover the thermal needs of the process.

3.1.7 Emergency Flare

The on-site emergency flare is capable of safely combusting all biogas produced on-site. The flare offers concealed combustion with an invisible flame. The flare is made up of a burner and a stainless steel flare tube, a hot-dip galvanized stand console, gas fan, gas valve line, ignition system (electric igniter and pilot plight) and switching system.

3.1.8 Control System & Visualization Software

The central control system provides the Lethbridge Biogas operator with the ability to monitor and control the process from any PC or via internet. Remote control is also possible via an auto dialer system and smart phone programming. The graphic user interface/visualization system is a touch screen system. The system also includes the main control cabinet located in the technical container, internal bus bar distribution system, network devices, circuit breakers, motor protection switches, transformers and relays, and a Siemens SPS unit.

3.1.9 Other Infrastructure

In addition to the core project technology as described above, Lethbridge Biogas had to install the following infrastructure for the project:

A) Industrial Runoff and Stormwater Retention Pond System including a composite liner system for the pond consisting of a

- minimum of 0.60 m thickness of compacted clay (constructed in lifts no more than 150 mm thick; hydraulic conductivity of 1x10-7 cm/sec or less and 98% Standard Proctor Density at 2-3% optimum moisture content)

- HDPE synthetic liner installed upon the compacted clay liner (60 mil or greater; ultraviolet light protected, capacity within the pond to store precipitation, industrial runoff and stormwater the following from a storm event; minimum of 0.5 meters of freeboard and prevent winds from driving the contents of the pond over the berm;

B) Secondary Containment System including

- a concrete wall that surrounds all of the tanks and provides secondary containment capable of containing 110% of the volume of the largest tank plus 10% of the aggregate capacity of all other tanks and the precipitation resulting from a storm event that falls within the secondary containment; and provides sufficient freeboard above the capacity in order to prevent winds from driving the contents of the secondary containment area over the concrete wall;

- a base pad within the secondary containment area that is sloped towards the east end of the area so that all precipitation falling upon or traversing that area collects in a sump so it can be transferred to the Industrial Runoff and Stormwater Retention Pond System;

- a composite liner system upon the base pad including a minimum of 0.60 m thickness of compacted clay (constructed in lifts no more than 150 mm thick; hydraulic conductivity of $1x10^{-7}$ cm/sec or less; and 98% Standard Proctor

Density at 2-3% optimum moisture content); an HDPE synthetic liner installed upon the compacted clay liner (60 mil or greater and ultraviolet light protected); and the synthetic liner in anchored and permanently sealed to the wall

- infrastructure that allows the stormwater resulting from a storm event that falls within the secondary containment to be pumped to the Industrial Runoff and Stormwater Retention Pond System

C) City Water Line

To connect with the facility to the existing water distribution system within the County of Lethbridge, Lethbridge Biogas had to install a 10 inch PVC water line from 8th Avenue North to the facility. Part of the water system was gate valves, plugs, reducers, elbows fire hydrants and road restoration work.

D) Ring Road

To allow weighing of the trucks and to facilitate truck movement on-site Lethbridge Biogas had to install a ring road around the secondary containment that connects the north side and the south side of the unloading building. A truck scale has been installed on the north side of the ring road.

3.2 Regulatory Approvals

The construction and operation of the Lethbridge biogas/cogeneration facility has been authorized through various approval processes with several regulatory agencies. The following regulatory approvals have been issued until November 30, 2013:

Regulatory Agency	Approval/Amendment	Issued
County of Lethbridge	Development Permit #2006-75 as amended	August 15,2006/July 25,2007/July 19, 2011
Alberta Environment and Sustainable Resources Development (ESRD)	001-224576-00	November 2, 2007
	001-224576-01	April 1, 2009
	001-224576-02	May 14, 2010
	001-224576-03	October 7, 2011
	001-224576-04	March 27, 2013
	001-224576-05	September 26 , 2013
Alberta Utilities Commission (AUC)	Connection Order U2010-171	May 14, 2010
	Power Plant Approval U2011-180	April 28, 2011
Natural Resources Conservation Board (NRCB)	Authorization LA 134024	November 5, 2013
Municipal Affairs	Variance No. G12.05	October 2, 2012
Superior Safety Codes Inc.	AMA B 0077 11 LT	August 16, 2011
	AMA B 0027 12 LT	April 23, 2012
	AMA D 0028 12 LT	April 24, 2012
	AMA B 0077 12 LT	August 22, 2012

3.3 Project Innovations

The Lethbridge Biogas cogeneration is unique in its process design, technology scope and scale and is the first one of its kind in Alberta and all over Canada.

A) **Process Design:** The facility is a large-scale, privately owned, commercial, off-farm biogas facility located in an industrial area close to an urban environment. It is designed to process multiple liquid and solid organic waste streams from various agricultural and agro-industrial sources (co-fermentation). The unique feedstock mix allows to maximize biogas production.

B) **Technology:** The facility is an advanced anaerobic digester system designed for high efficiency and low energy consumption. The biological gas cleaning system based on the desulphurization fabric has been used in the Lethbridge facility for the first time. No other facility has incorporated a state of the art odour control system with a combination of wet scrubbing and biological air cleaning through redundant and enclosed wood-chip based biofilters. The incorporation of the high pressure thermal hydrolysis system will be the first commercial application for that technology (see Section 5).

C) **Scope:** The facility has an integrated 'Zero-Waste'(closed-loop) approach with use of all by-products of the anaerobic digestion process. Waste heat is captured from the co-gens for process heating and the digestate is used as a nutrient enriched organic fertilizer for agricultural purposes.

D) **Size:** The facility is capable of processing up to 150,000 t/a of liquid and solid organic feedstock including up to 20,000 t/a of animal by-products (ABP) while initially generating up to 2.85 MW with the potential to increase generation capacity to 4.2MW.

3.4 Project Performance

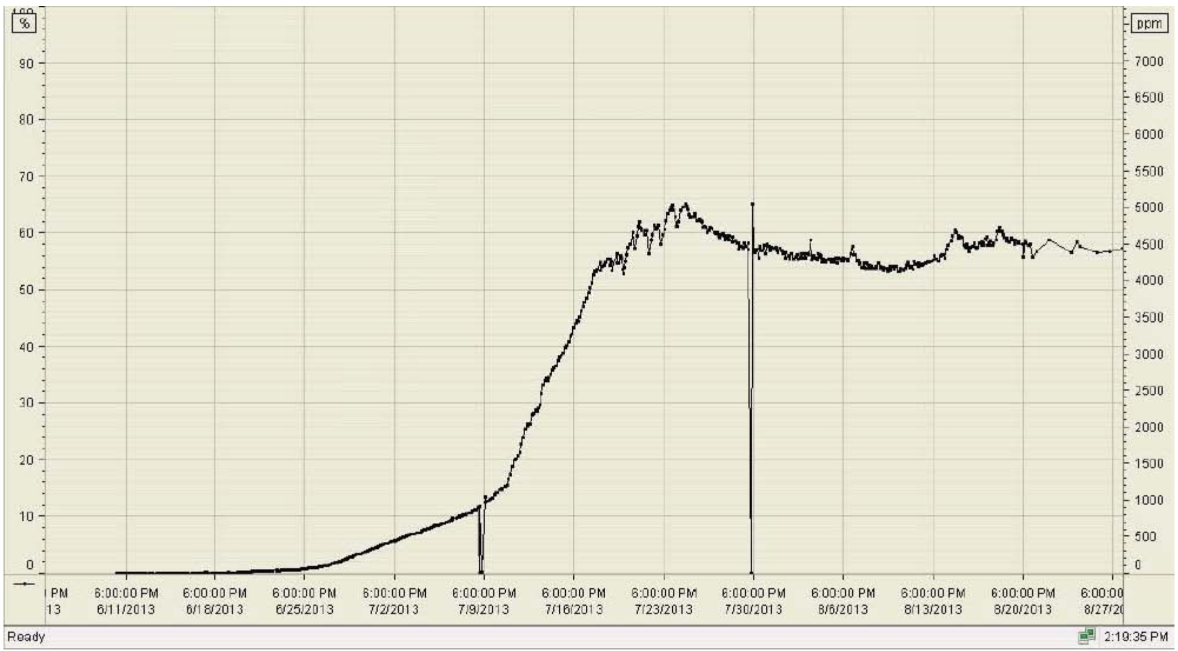
Project performance at this point can only be evaluated considering the amounts of feedstock quantities processed and electricity generated.

3.4.1 Feedstock

a) Process Start-Up

Lethbridge Biogas has started to fill the facility with organic feedstock on June 5, 2013. In the subsequent months until the end of September 2013 the facility has accepted approximately 18,000 t of organic product. Feedstock used was predominantly liquid dairy manure with some small amounts of liquid cheese whey. The main purpose during this initial period was to get the anaerobic digesters up to operating temperature and establish a healthy biological system.

During the start-up process no complications did occur and the biological process was established without any third party inoculums. Methane content (CH_4) in the biogas rose slowly but was initially not suited for use in the engines. Peaks in methane concentration of approximately 65 % did occur before the methane content was stabilized around 55 %, see Graph below.



Development of CH_4 content from digester filling to engine commissioning (Digester 1)

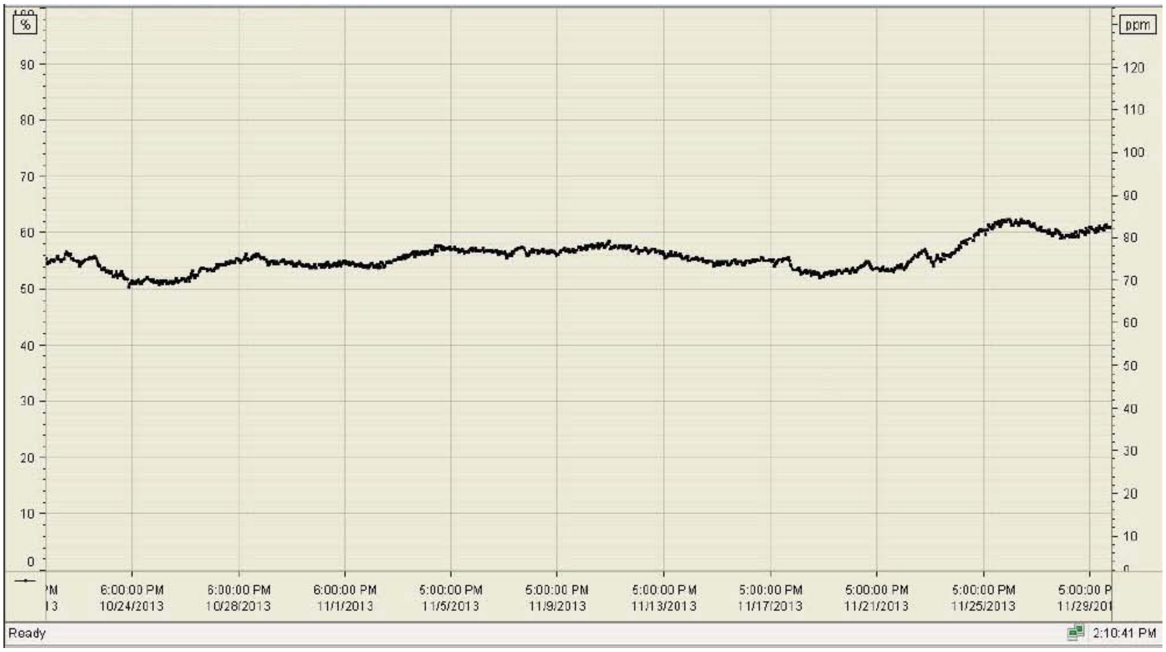
b) Commissioning of Solid Feeding System (Vario)

After the establishment of a biologically healthy process, the facility has accepted approximately 8,500 t of liquid feedstock until November 30, 2013. At the same time solid and more energy rich feedstock was introduced into the process. The solid feeding system was successfully commissioned on October 21, 2013 and more than 400 t of solid feedstock have been processed since. Solid feedstock used so far was solid separated dairy and hog manure, chicken manure, waste potatoes, grocery waste and DAF.

During the commissioning process some hardware & software adjustments have been made to the system.

c) Increased Substrate Feeding

Since November 11, 2013 substrate feeding rates (liquid & solid) have been increased and the system is operating automatically without continuous supervision. Gas quantity and gas quality have significantly improved and the methane content has currently been stabilised at around 60%, see Graph below. Feeding rates will continually be increased as more and more feedstock will be processed in the coming month.



Development of CH_4 content since commissioning of solid feeding system (Digester 1)

Overall the anaerobic digester system is biologically stable, reacting normally and performing well as expected. Attachment C shows the variety of organic feedstock that can be processed in the Lethbridge biogas/cogeneration facility.

3.4.2 Electricity Production

a) Metering Program

Lethbridge Biogas has installed 2 bi-directional meters at the plant located in the switchgear building. Both meters are manufactured by Schneider Electric, model ION 7550:

- The 'GROSS GEN' meter (serial# PI-1207A777-03) is measuring gross generation. This meter has been installed for the purpose of accounting for eligible electricity production under the Bioenergy Producer Credit Program (BPCP)

- The 'POI' meter (serial# PI-1207A776-03) is measuring export into the FortisAlberta grid at the Point of Interconnection (POI). This meter is used for settlement with the Alberta Electric System Operator (AESO)

The plant load (parasitic load) itself is not metered but can be calculated as the difference between the metered values of 'GROSS GEN' and 'POI'

Both meters have been calibrated at the factory and sealed by FortisBC Measurement – a Measurement Canada accredited meter verifier.

b) Engine Configuration

Lethbridge Biogas has currently installed 2 co-generation units packaged and delivered by 2G Energietechnik GmbH, Germany based on engines manufactured by GE/Jenbacher (Attachment B):

- CHP 1: Type JMS 420 GS-B.L (Biogas only), max. electrical output 1.426 MW_{el} (100% Biogas), serial# JN-385/1

- CHP 2: Type JMS 420 GS-B.L (Biogas/Natural Gas), max electrical output 1.426 MW (100% biogas); max. 1,248 MW_{el} (100% Natural Gas), serial# JN-385/2). This engine allows dual fuel operation with the use of either 100% biogas or 100% natural gas or any blend of biogas/natural gas.

Both engines are equipped with a gas flow meter, manufactured by Esters Elektronik GmbH, Germany. These flow meters measure the use of biogas used for electricity production. The measured flow is displayed on the engine module visualization screen with 'Gas Counter' for each engine.

CHP 1 has been commissioned for natural gas operation on April 27, 2013 and has delivered the heat for starting up and commissioning the anaerobic digestion process. Natural gas based electricity has been exported to the Alberta Power Pool since then as well. CHP 1 & CHP 2 have both been commissioned for biogas operation on August 28, 2013.

An unexpected breakdown of CHP 1 due to a mechanical failure of the crank shaft caused CHP 1 to be out of service between September 17, 2013 and October 18, 2013. The engine manufacturer replaced the engine block on a warranty claim and the engine is back in operation since October 19, 2013.

c) Electricity Generation

To-date Lethbridge Biogas has produced a total of 6,055.83 MWh of electricity (see Table below, including production until November 30, 2013). The following table shows the amounts of electricity generated (GROSS GEN) and sold (POI) to the Alberta Power Pool administered by the Alberta Electric System Operator (AESO) in 2013.

Month	GROSS GEN (as measured in MWh)	POI (as measured in MWh)	Fuel Type (% BG)	Plant Load (as calculated in MWh)	Plant Load (in % of gross generation)
Process Heating & Start-Up (04-07 2013)					
Apr	113.41	111.77	0%	1.64	1.45%
May	644.54	644.32	0%	0.22	0.03%
Jun	595.73	586.00	0%	9.73	1.63%
Jul	871.05	845.95	0%	25.10	2.88%
Start Feeding & Biogas Production (08-11 2013)					
Aug	903.98	871.89	13.8%	32.09	3.55%
Sep	952.35	912.82		39.53	4.15%
Oct	992.00	937.33	19.7%	54.67	5.51%
Nov*	982.77	926.74	20.7%	56.03	5.70%
TOTAL	**6,055.83**	**5,836.82**		**219.01**	**3.62%**

Note *: Data for November 2013 until Nov-30-2013

Due to the increased feeding rates in recent weeks and resulting increase in biogas quantity and quality the amount of electricity derived from biogas is steadily increasing. On November 30, 2013 CHP 1 produced 17.2 MWh hours (716 kW) of electricity exclusively derived from biogas which was the highest daily biogas generated electricity production in any 24 hour period since the facility came on-line. CHP 1 is running exclusively on biogas for 24/7 since November, 29 at 9.00 p.m. For December 2013 it is anticipated that the facility will produce well over 500 MWh of biogas generated electricity.

3.4.3 GHG Emission Reductions

Lethbridge Biogas has contracted Blue Source Canada to certify and register all Emission Reduction Credits arising from the Project and to represent Lethbridge Biogas in the sale or other marketing of such Emission Reduction Credits.

Initial contact with the Air and Climate Change Policy Branch within Alberta Environment and Sustainable Resource Development (ESRD) revealed the following (see Attachment D):

- ***The project can use the flagged 'Quantification Protocol for the Anaerobic Decomposition of Agricultural Materials' in its current state for the crediting of biogas energy production and use providing it can be accurately separated from the natural gas component.***

  As biogas flow and natural gas flows will be metered separately, Lethbridge Biogas will be able to use the current protocol.

BUT

- ***The landfill gas diversion model is currently being revised to address identified risks and is unable to be used until revised. Once the landfill gas diversion methodology is revised this project will be able to use it on a go forward basis.***

  Lethbridge biogas has started to divert organic material from landfill. Approximately 100 t have been diverted until November 30, 2013. In order to claim greenhouse credits under the revised protocol, it is anticipated that extensive records will have to be provided to demonstrate how long and where products have been previously land filled. The unknown status of the protocol and the anticipated requirements put some uncertainty on the evaluation of greenhouse gas credits from landfill diversion which is expected to deliver a significant amount of greenhouse gas credits over the lifetime of the project.

- ***This project will not be able to generate credit under the protocol from the natural gas cogeneration. This is a new activity that will likely require a new protocol and must complete all the required stages of protocol development within Alberta's offset system.***

  Although effectively reducing greenhouse gases by partly using natural gas for electricity generation, the project will currently not be able to generate greenhouse gas offsets under the current offset system. This is somewhat surprising as this policy contradicts all current political efforts on the Alberta power market to make a shift from coal fired power generation to more sustainable power generation based on clean natural gas within the next 10-15 years.

Because of the current uncertainty around the landfill protocol, the limited operational activities in 2013 and the high costs associated with the third party verification of GHG emission reductions, Lethbridge Biogas will likely postpone its 1st third party verification into Q1 of 2015.

Initial reduction of GHG emissions for 2013 are estimated to reach between 500 -1,000 t CO_2e.

3.5 Project Impact

In its very short operational lifetime to-date the Lethbridge facility has already made a significant impact on the local community:

A) **Employment:** Lethbridge Biogas is currently employing 6 people full-time. Once at full capacity it is anticipated that up to 10 people will work full-time at the facility.

B) **Waste Management:** Lethbridge Biogas offers the only 'green' solution for of disposal of organic waste material in the area and as a result of this Lethbridge Biogas has been approached by various waste management companies and waste haulers. A pilot program has been started with the world's largest retail organization to dispose of grocery waste from the local stores in the Lethbridge facility.

   Lethbridge Biogas was also able to lower disposal costs for one of Alberta's large hog processing facilities. By-products like peptone and DAF are now being disposed of environmentally sustainable in the Lethbridge facility.

C) **Capacity Building:** The Lethbridge facility already served as technology example for another anaerobic digestion facility that is currently under construction in the hamlet of Chin, Alberta, approximately 10 minutes east outside of Coaldale. Although significantly smaller in size, the GrowTec facility will use the same anaerobic digestion technology to process liquid and solid residues from potato processing and other organic materials to generate 633 kW of renewable electricity.

D) **Societal Benefits:** Lethbridge Biogas has been invited for round table discussions with local post secondary educational facilities and research organizations to discuss potential collaboration with industry. The close proximity of the Lethbridge biogas/cogeneration facility to several of these organizations (e.g. Lethbridge College, AAFC Lethbridge Research Centre) will allow the establishment of advanced educational opportunities as well as new research opportunities.

4. FINAL FINANCIAL REPORT

4.1 Project Expenses

Eligible project expenses total $28,575,741 until November 30, 2013 and are related to the milestones as follows:

- Phase 1 - Milestone 1: $ 4,187,775
- Phase 1 - Milestone 2: $ 3,819,680
- Phase 1 - Milestone 3A: $16,888,127
- Phase 1/2 - Milestone 3B: $ 3,185,761
- Phase 2: - Jul-Nov 2013: $ 494,399

Project expenses included in Milestone 3B did in part include operational expenses originally planned for Phase 2 of the project. When submitting expenses for Milestone 3B Lethbridge Biogas has been advised by PWC to not report these expenses in the online reporting period for Milestone 3B.

4.2 Project Contributions

Project contributions provided by CCEMC and the project partners total $28,575,741 until November 30, 2013 and are as follows:

- Agriculture Financial Services Corporation (AFSC): $ 5,000,000
- Climate Change and Emissions Management (CCEMC) Corporation: (incl. holdback) $ 8,200,000
- Department of Energy: $ 6,448,016
- PlanET: $ 8,200,000
- Lethbridge Biogas: $ 727,725

4.3 Project Revenues

Lethbridge Biogas commissioned the 1st engine on natural gas on April 27, 2013 and is producing electricity for export into the Alberta grid since that time. On August 28, 2013 both engines were commissioned on biogas and the second engine started to produce first quantities of biogas generated electricity. Project revenues until November 30, 2013, predominantly received from electricity sales to the AESO, total $826,327.

5. CONCLUSION & NEXT STEPS

The Lethbridge biogas/cogeneration has been successfully implemented between March 2011 and November 2013 through the stages of development, construction, commissioning, start-up and initial operation.

The project demonstrates the use of innovative technologies to reduce GHG emissions through the use of renewable energy sources and will directly contribute to Alberta's long-term Climate Change goals. This demonstration will greatly increase the chances of success of commercial-scale biogas development in Alberta and will result in future opportunities throughout Alberta, Canada and abroad. A direct spin-off was already achieved with the start of construction for the GrowTEC anaerobic digestion facility in Chin, AB.

The Lethbridge biogas/cogeneration is an important rural development project that already has economic, environmental and societal benefits for the region through waste reduction, energy creation and advanced technology application.

The implementation of the thermal hydrolysis process (THD) will be the major focus for Lethbridge Biogas in 2014. The first commercial application of the THD will allow animal by-products incl. Specified Risk Material (SRM) to be processed in the Lethbridge facility.

Some infrastructure for the THD process such as the process building, distribution manifolds, process piping, hydraulic floor hatch, the hydrolyzed animal by-product storage tank and the hot-oil heater system are already installed. The main components of the THD had to be delayed because the supplier originally selected could not deliver the system because. A new supplier has been chosen and a potential scope of delivery has been discussed. A purchase order could not be issued at this point because of cash flow issues within the project. It is anticipated that Lethbridge Biogas will be able to place an order for the THD system within Q1 of 2014. This would allow for the system to be delivered, installed and commissioned in Q3/Q4 of 2014.

The THD system will pre-treat animal by-products before they are pumped into the anaerobic digestion process. The thermal hydrolysis vessel and associated components will be located in the process building adjacent to the receiving building. The thermal hydrolysis will be a batch process and will employ heat and pressure to the ground up animal by-products, to break longer chain organic compounds into short-chain fragments better suited for consumption by micro-organisms. The thermal hydrolysis' operating temperature and pressure will be 180 ºC at 12 bar pressure, respectively. The cycle time, which includes loading, treatment and unloading, will be 160 minutes which includes a treatment time of 40 minutes. Following the 40 minute treatment time, the vessel will be allowed to depressurize at a controlled rate. The material will be discharged into a flash tank before outside storage of the hydrolyzed material in a 300 m^3

concrete storage tank with a fixed concrete roof located in the secondary containment area (already installed). The energy for the thermal hydrolysis process will be produced by a natural gas fired 3,000 kW hot oil heater and associated components. The heat will be delivered to the thermal hydrolysis process through indirect heating.

The operating parameters of this thermal hydrolysis process have been approved by the Canadian Food Inspection Agency (CFIA) for the safe treatment of SRM and the destruction of prions.

Because of the current uncertainty around the landfill quantification protocol a detailed assessment of the impact of the delayed implementation of the THD system is very difficult. Given the long term nature of the project, it is anticipated that a 6-9 month delay will not significantly impact the projects ability to reduce GHG emissions.

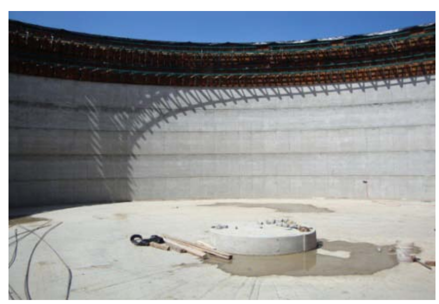
ATTACHMENT A

CONSTRUCTION & COMMISSIONING ACTIVITIES AUGUST 2011 – NOVEMBER 2013

AUGUST 12 (START OF CONSTRUCTION)		
AUGUST 22 (SITE GRADING & WEST CULVERT)		
AUGUST 30 (EXCAVATION FOR SECONDARY CONTAINMENT)		
SEPTEMBER 02 (FINISHING OF ROUGH CUTS)		

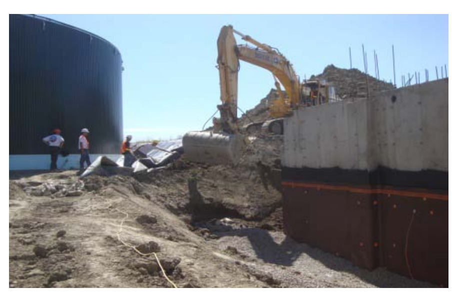
September 07 (Work on clay liner)		
September 18 (Placement of HDPE liner)		
September 22 (Partial backfill & road access to tanks)		
September 28 (Placement of insulation & rebar)		
September 30 (Start of concrete work)		

OCTOBER 04 (3RD DIGESTER FOUNDATION POURED)		
OCTOBER 05 (SITE VISIT BY PLANET DELEGATION FROM GERMANY)		
OCTOBER 14 (ALL DIGESTER & TANK FOUNDATIONS COMPLETE)		
NOVEMBER 3 (WEEPING TILE, DRAINAGE SUMPS & PARTIAL BACKFILL)		
NOVEMBER 10 (CONCRETE FOOTINGS FOR CENTER PIERS)		

NOVEMBER 11 (SITE WINTERIZED)		
APRIL 09/12 (START ON CONCRETE WORK FOR TANK WALLS)		
APRIL 16/12 (1ST WALL RING ON DIGESTER 1)		
APRIL 30/12 (6TH WALL RING ON DIGESTER 1)		
MAY 07/12 (2ND WALL RING ON PRE-STORAGE I & SITE PREP ON EAST BLDG./ PARKING AREA)		

May 15/12 (1ST DIGESTER INSULATED, 6TH WALL RING ON PRE-STORAGE I & 2ND WALL RING ON 2ND DIGESTER)		
May 22/12 (PRE-STORAGE I FINISHED, 2ND WALL RING ON PRE-STORAGE II & 4TH WALL RING ON DIGESTER 2)		
May 28/12 (CLADDING ON 1ST DIGESTER, 6TH WALL RING ON 2ND DIGESTER & 5TH WALL RING ON PRE-STORAGE II)		
June 12/12 (CLADDING ON 1ST DIGESTER AND PRE-STORAGE I & II)		
June 20/12 (1ST WALL ON SRM BUFFER TANK & START OF TANK EQUIPMENT INSTALLATION)		

JUNE 26/12 (SRM BUFFER TANK COMPLETED & 2ND DIGESTER INSULATED & CLADDED)		
JULY 03/12 (START OF EXCAVATION FOR RECEIVING/PROCESS BLDG. BASEMENT)		
JULY 06/12 (EXCAVATION PROGRESS)		
JULY 11/12 (SRM BUFFER TANK INSULATED & CLADDED & START OF BUILDING FOUNDATION)		
JULY 17/12 (BASEMENT FLOOR IN RECEIVING/PROCESS BLDG.)		

JULY 31/12 (REBAR RECEIVING/PROCESS BLDG. BASEMENT & SITE PREP FOR CO-GENS AND SWITCHGEAR BLDG.)		
AUGUST 08/12 (PROGRESS RECEIVING/PROCESS BLDG. BASEMENT & START OF RETENTION POND EXCAVATION)		
AUGUST 11/12 (1^{ST} BASEMENT WALLS POURED & 3^{RD} WALL RING ON 3^{RD} DIGESTER)		
AUGUST 16/12 (BASEMENT WALLS COMPLETED & 4^{TH} WALL RING ON 3^{RD} DIGESTER)		
AUGUST 23/12 (START OF BACKFILL FOR BASEMENT)		

AUGUST 27/12 (6th WALL RING ON 3rd DIGESTER & START OF MIXER INSTALLATIONS)	 
AUGUST 31/12 1st WALL RING ON POST-STORAGE & START OF PIPE WORK	 
SEPTEMBER 05/12 2nd WALL RING ON POST-STORAGE & MUD SLAB FOR PROCESS BLDG. FOUNDATION	 
SEPTEMBER 07/12 3rd WALL RING ON POST-STORAGE & START OF INSTALLATION OF TANK CENTER PIERS	 
SEPTEMBER 11/12 TANK CENTER PIERS INSTALLED & DRAINAGE PIPE INSTALLED IN RETENTION POND	 

September 14 / 12 5TH wall ring on post-storage & 3RD digester insulated & cladded		
September 17 / 12 6TH wall ring on post-storage & Start of shoring for floor slab of receiving bldg.		
September 20 / 12 Stairs to scrubber bldg. & Western One barbecue		
September 24 / 12 Progress in pipe work & Assembly of the hatches for floor slab of receiving bldg.		
September 25 / 12 Placement of Floor hatches for receiving bldg.		

SEPTEMBER 27 / 12 FOUNDATION FOR SWITCHGEAR BLDG. & START OF SOUTH CONTAINMENT WALL	 
OCTOBER 01 / 12 HDPE LINER INSTALLED IN RETENTION POND & ERECTION OF SWITCHGEAR BLDG.	 
OCTOBER 04 / 12 CLADDING ON POST STORAGE (LAST TANK!!) & SWITCHGEAR BLDG. POURED	 
OCTOBER 10 / 12 GRADE BEAMS FOR PROCESS BLDG. & RECEIVING BLDG. POURED	 
OCTOBER 12 / 12 REBAR IN SOUTH CONTAINMENT WALL & START OF EXCAVATION FOR WATER PIPELINE	 

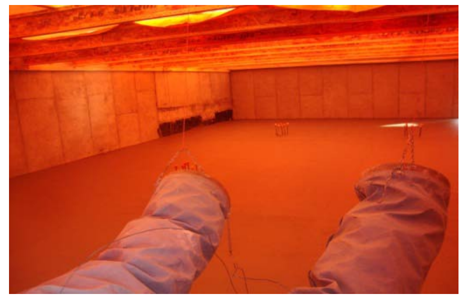
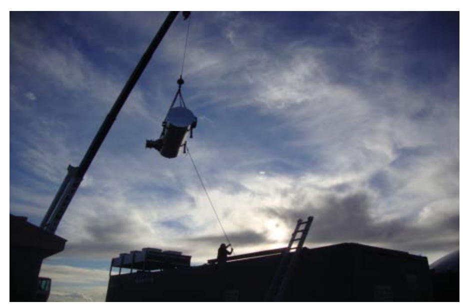
October 16/12 Start of north containment wall & footings for co-gen units	 
October 18/12 Completion of south containment wall & technical unit in place	 
October 23/12 A winter day…	 
November 02/12 Rebar in north containment wall & prep work for receiving/process bldg. floor slab	 
November 06/12 Completion of co-gen footings & start of roof installation on tanks & digesters	 

<u>November 07/12</u> <u>Start of commissioning Activities</u>		
<u>November 08/12</u> <u>Foundation for co-gen stack & roofs for pre-storage I & II commissioned</u>		
<u>November 10/12</u> <u>Arrival and placement of 1st co-gen</u>		
<u>November 13/12</u> <u>Commissioning of piping & Progress on water line</u>		
<u>November 14/12</u> <u>Roof on digester 2 commissioned & Hydrovac for water line</u>		

NOVEMBER 16/12 POURING OF FLOOR SLAB FOR RECEIVING/PROCESS BLDG & EXCAVATION FOR WEIGH SCALE		
NOVEMBER 19/12 INSTALLATION OF GRID CONNECTION & MVI & ROOF ON DIGESTER 3 COMMISSIONED		
NOVEMBER 23/12 MUD SLAB FOR WEIGH SCALE & PROGRESS ON WATER LINE		
NOVEMBER 26/12 REBAR FOR WEIGH SCALE & FOUNDATION WORK ON BIO-FILTERS		
NOVEMBER 28/12 ROOF ON DIGESTER 1 COMMISSIONED & FLOOR SLAB FOR WEIGH SCALE POURED		

December 04/12 Foundation completed for biofilter/scrubber bldg. & Repair work on liner	 
December 13/12 Drilling of groundwater monitoring wells & East wall of process Bldg.	 
December 20/12 Start of east containment wall & completion of concrete work on receiving/process bldg.	 
January 04/13 (Gas line hook up & Walls on north biofilter)	 
January 08/13 (Prep work for bldg. erection & delivery of hot oil system)	 

JANUARY 10/13 (START OF BLDG. ERECTION & WALLS ON SOUTH BIOFILTER)		
JANUARY 11/13 PROGRESS ON BLDG. ERECTION & DELIVERY OF WET SCRUBBER SYSTEM)		
JANUARY 15/13 PROGRESS ON BLDG. ERECTION & INSTALLATION OF TRANSFORMER)		
JANUARY 17/13 INSTALLATION OF SWITCHGEAR & INSTALLATION OF WEIGH SCALE DECK)		
JANUARY 23/13 LINER INSTALLATION ON BLDG. & INSTALLATION OF CATWALKS ON DIGESTERS & TANKS		

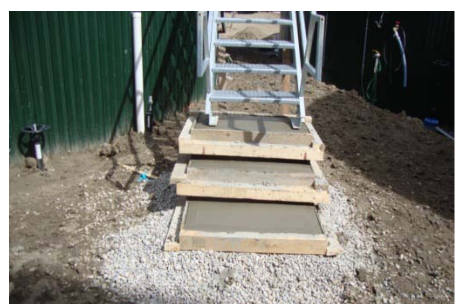
JANUARY 24/13 INSULATION & REBAR FOR NORTH BIOFILTER SLAB & PREP WORK FOR EMERGENCY FLARE FOUNDATION		
JANUARY 25/13 ROOF ON POST-STORAGE COMMISSIONED & SLAB FOR NORTH BIOFILTER		
JANUARY 26/13 ARRIVAL AND PLACEMENT OF 2ND CO-GEN		
JANUARY 28/13 START OF INSTALLATION OF AUXILIARY CO-GEN EQUIPMENT		
JANUARY 31/13 PRIMARY STEEL FOR OFFICE & ROOF INSTALLATIONS FOR CO-GENS ASSEMBLED		

February 04/13 Installation of co-gen exhaust stack & biogas cooling units		
February 07/13 Mezzanine in receiving/process bldg & emergency flare pad		
February 11/13 Start of bldg. insulation & cladding & shoring for south biofilter roof		
February 12/13 Insulation & cladding on east process bldg. wall & natural gas connect for dual-fuel engine		
February 14/13 Fencing for high voltage transformer & insulation & cladding on south process bldg. wall		

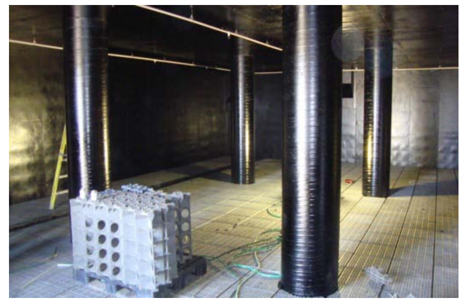
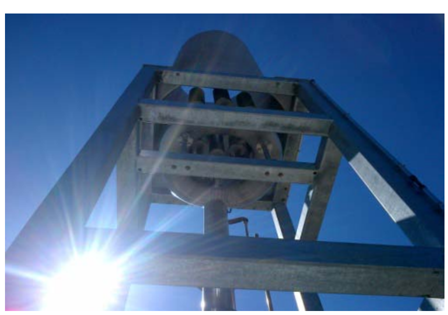
February 15 / 13 Installation of high voltage cables from co-gens to switchgear		
February 19 / 13 Insulation & cladding on North & South receiving bldg. walls		
February 20 / 13 Exhaust pipe connections from co-gens to stack & SW corner of containment wall		
February 26 / 13 NE corner of containment wall & Rebar for North & South biofilter roofs		
February 28 / 13 Installation of transformer fence & Facility overview		

MARCH 05/13 INSTALLATION OF EMERGENCY FLARE & INSTALLATION OF GAS METER		
MARCH 07/13 NW CORNER OF CONTAINMENT WALL & INSTALLATION OF BUS BAR (SWITCHGEAR TO TRANSFORMER)		
MARCH 08/13 INSTALLATION OF OVERHEAD DOORS IN RECEIVING BLDG. & INSULATION & CLADDING ON NORTH BIOFILTER/OFFICE		
MARCH 11/13 CONTAINMENT BACKFILL SOUTH SIDE & LINER ATTACHMENT TO CONTAINMENT WALL		
MARCH 13/13 START OF SCRUBBER EQUIPMENT INSTALLATION & CONTAINMENT LANDSCAPING		

March 18/13 Attachment of liner to Receiving Bldg. & Separation Wall in Receiving Bldg.	 
March 20/13 Insulation/Cladding on Receiving Bldg. & Biofilter completed & Installation of wet scrubber	 
March 25/13 Receiving Bldg. incl. biofilters and office enclosed & Commissioning of 1st engine	 
March 27/13 Completion of biogas piping & start of installation of ventilation system in Receiving Bldg.	 
April 03/13 Backfill in containment area & Finished separation wall in Receiving Bldg.	 

APRIL 08/13 POLES FOR FINAL(SE) CORNER OF CONTAINMENT WALL & INSTALLATION OF FINAL GAS OVERFLOW		
APRIL 09/13 INSTALLATION OF VENTILATION/HVAC FOR OFFICE & INSTALLATION OF STAIRS TO DIGESTERS		
APRIL 11/13 BACKFILL IN CONTAINMENT COMPLETED & INSTALLATION OF VENTILATION/HVAC FOR RECEIVING BLDG.		
APRIL 12/13 CONCRETE PAD FOR EMERGENCY GENERATOR & CONCRETE LANDING PADS FOR STAIRS TO DIGESTERS		
APRIL 18/13 INSTALLATION OF REMOVABLE PANELS IN RECEIVING BLDG. & CONCRETE LANDING PAD FOR OFFICE STAIRS		

April 26/13 Re-commissioning of 1st Engine & Successful Synchronization with FortisAlberta Grid	 
April 27/13 Facility Overview – We are producing power!	 
May 02/13 Installation of Hot Oil System & Installation of Unit Heaters in Receiving Bldg.	 
May 13/13 Last (SE) Corner of Containment Wall Closed & Installation of Sump for Digestate Pump	 
May 15/13 Installation of Office Stairs & Installation of Emergency Generator	 

May 21/13 1st Truck and Trailer Unit Ready to Roll	 
May 27/13 Installation of Perforated Biofilter Floors & Completion of Sprinkler System	 
June 05/13 First Load of Manure Hauled into the Plant (Start of Wet Commissioning)	 
June 12/13 Installation of Make-up Air Unit Heater & Installation of Solid Feeding System (Vario)	 
July 10/13 Commissioning of Emergency Flare (Facility is Producing Biogas)	 

July 26/13 Installation of gas meter for receiving bldg. & commissioning of hydraulic hatches	 
September 23/13 Graveling of Ring road (south side) & Office framing	 
September 28/13 Engine block replacement on co-gen #1	 
October 21/13 Filling of Biofilter # Commissioning of Solid feeding system (Vario)	 
October 26/13 Facility Overview	 

ATTACHMENT B

Technical Description

Cogeneration Unit-Container

JMC 420 GS-B.L

JMC 420 600V

This spec is rated for full output at an altitude of 3500ft and an air intake temperature ≤ 96.8°F. At air intake temperatures between 95°F and 113°F a derate of .67%/°F will occur. At air intake temperatures > 113°F a derate of 1.11%/°F will occur.

Electrical output	**1426 kW el.**
Thermal output	**5192 MBTU/hr**

Emission values
NOx < 1.1 g/bhp.hr (NO2)

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0.01 Technical Data (on container)

Data at:				Full load	Part Load	
Fuel gas LHV		BTU/scft		558		
				100%	75%	50%
Energy input		MBTU/hr	[2]	12,072	9,360	6,647
Gas volume		scfhr	*)	21,635	16,773	11,912
Mechanical output		bhp	[1]	1,966	1,475	983
Electrical output		kW el.	[4]	1,426	1,068	706
Recoverable thermal output						
~ Intercooler 1st stage		MBTU/hr		749		
~ Lube oil		MBTU/hr		563		
~ Jacket water		MBTU/hr		1,365		
~ Exhaust gas cooled to 356 °F		MBTU/hr		2,515		
Total recoverable thermal output		MBTU/hr	[5]	5,192		
Heat to be dissipated						
~ Intercooler 2nd stage		MBTU/hr		227		
~ Surface heat	ca.	MBTU/hr	[7]	377		
~ Balance heat		MBTU/hr		119		
Spec. fuel consumption of engine		BTU/bhp.hr	[2]	6,141		
Lube oil consumption	ca.	gal/hr	[3]	0.14		
Electrical efficiency		%		40.3%		
Thermal efficiency		%		43.0%		
Total efficiency		%	[6]	83.3%		
Hot water circuit: Internal						
Forward temperature		°F		194.0		
Return temperature		°F		158.0		
Hot water flow rate		GPM		166.7		
Hot water circuit: External						
Forward temperature		°F		185.0		
Return temperature		°F		149.0		
Hot water flow rate		GPM		287.8		

*) approximate value for pipework dimensioning
[_] Explanations: see 0.10 - Technical parameters

All heat data is based on standard conditions according to attachment 0.10. Deviations from the standard conditions can result in a change of values within the heat balance, and must be taken into consideration in the layout of the cooling circuit/equipment (intercooler; emergency cooling; ...). In the specifications in addition to the general tolerance of +/- 8% on the thermal output a further reserve of 10% is recommended for the dimensioning of the cooling requirements.

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Main dimensions and weights (on container)

Length	in	~ 490
Width	in	~ 120
Height	in	~ 110
Weight empty	lbs	~ 78,460
Weight filled	lbs	~ 82,660

Connections

Jacket water inlet and outlet	in/lbs	4"/145
Exhaust gas outlet	in/lbs	12"/145
Fuel gas connection (on container)	in	6"/232
Fresh oil connection	G	28x2"
Waste oil connection	G	28x2"
Cable outlet	in	31.5x15.7
Condensate drain	in	0.7

Output / fuel consumption

ISO standard fuel stop power ICFN	bhp	1,966
Mean effe. press. at stand. power and nom. speed	psi	232
Fuel gas type		Biogas
Based on methane number	MN d)	100
Compression ratio	Epsilon	12.50
Min./Max. fuel gas pressure at inlet to gas train	psi	1.8 - 2.9 c)
Allowed Fluctuation of fuel gas pressure	%	± 10
Max. rate of gas pressure fluctuation	psi/sec	0.145
Maximum Intercooler 2nd stage inlet water temperature	°F	131
Spec. fuel consumption of engine	BTU/bhp.hr	6,141
Specific lube oil consumption	g/bhp.hr	0.22
Max. Oil temperature	°F	185
Jacket-water temperature max.	°F	194
Filling capacity lube oil (refill)	gal	~ 115

c) Lower gas pressures upon inquiry
d) based on methane number calculation software AVL 3.1

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0.02 Technical data of engine

Manufacturer		GE Jenbacher
Engine type		J 420 GS-A81
Working principle		4-Stroke
Configuration		V 70°
No. of cylinders		20
Bore	in	5.71
Stroke	in	7.28
Piston displacement	cu.in	3,728
Nominal speed	rpm	1,800
Mean piston speed	in/s	437
Length	in	148
Width	in	62
Height	in	80
Weight dry	lbs	14,551
Weight filled	lbs	16,094
Moment of inertia	lbs-ft²	276.26
Direction of rotation (from flywheel view)		left
Flywheel connection		SAE 18"
Radio interference level to VDE 0875		N
Starter motor output	kW	13
Starter motor voltage	V	24

Thermal energy balance

Energy input	MBTU/hr	12,072
Intercooler	MBTU/hr	976
Lube oil	MBTU/hr	563
Jacket water	MBTU/hr	1,365
Exhaust gas total	MBTU/hr	3,787
Exhaust gas cooled to 356 °F	MBTU/hr	2,515
Exhaust gas cooled to 212 °F	MBTU/hr	3,177
Surface heat	MBTU/hr	242
Balance heat	MBTU/hr	119

Exhaust gas data

Exhaust gas temperature at full load	°F [8]	878
Exhaust gas mass flow rate, wet	lbs/hr	17,853
Exhaust gas mass flow rate, dry	lbs/hr	16,592
Exhaust gas volume, wet	scfhr	234,966
Exhaust gas volume, dry	scfhr	209,360
Max.admissible exhaust back pressure after engine	psi	0.870

Combustion air data

Combustion air mass flow rate	lbs/hr	16,460
Combustion air volume	SCFM	3,593
Max. admissible pressure drop in front of intake-air filter	psi	0.145

base for exhaust gas data: natural gas: 100% CH_4; biogas 65% CH_4, 35% CO_2

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Sound pressure level

Aggregate b)		dB(A) re 20µPa	97
31,5	Hz	dB	79
63	Hz	dB	87
125	Hz	dB	98
250	Hz	dB	95
500	Hz	dB	91
1000	Hz	dB	86
2000	Hz	dB	88
4000	Hz	dB	92
8000	Hz	dB	89
Exhaust gas a)		dB(A) re 20µPa	115
31,5	Hz	dB	95
63	Hz	dB	117
125	Hz	dB	115
250	Hz	dB	113
500	Hz	dB	108
1000	Hz	dB	105
2000	Hz	dB	108
4000	Hz	dB	109
8000	Hz	dB	107

Sound power level

Aggregate	dB(A) re 1pW	117
Measurement surface	ft²	1,152
Exhaust gas	dB(A) re 1pW	123
Measurement surface	ft²	67.60

a) average sound pressure level on measurement surface in a distance of 3.28ft according to DIN 45635, precision class 2.
b) average sound pressure level on measurement surface in a distance of 3.28ft (converted to free field) according to DIN 45635, precision class 3.
Operation with 1200 rpm see upper values, operation with 1800 rpm add 3 dB to upper values.
Engine tolerance ± 3 dB

0.03 Technical data of generator

Manufacturer		STAMFORD e)
Type		PE 734 E2 e)
Type rating	kVA	2,300
Driving power	bhp	1,966
Ratings at p.f.= 1.0	kW	1,426
Ratings at p.f. = 0.8	kW	1,415
Rated output at p.f. = 0.8	kVA	1,768
Rated current at p.f. = 0.8	A	1,702
Frequency	Hz	60
Voltage	V	600
Speed	rpm	1,800
Permissible overspeed	rpm	2,160
Power factor lagging		0,8 - 1,0
Efficiency at p.f.= 1.0	%	97.3%
Efficiency at p.f. = 0.8	%	96.5%
Moment of inertia	lbs-ft²	1055.93
Mass	lbs	7,729
Radio interference level to VDE 0875		N
Construction		B3/B14
Protection Class		IP 23
Insulation class		H
Temperature rise (at driving power)		F
Maximum ambient temperature	°F	104
Total harmonic distortion	%	1.5

Reactance and time constants

xd direct axis synchronous reactance	p.u.	2.47
xd' direct axis transient reactance	p.u.	0.09
xd" direct axis sub transient reactance	p.u.	0.07
Td" sub transient reactance time constant	ms	20
Ta Time constant direct-current	ms	20
Tdo' open circuit field time constant	s	2.46

e) GE Jenbacher reserves the right to change the generator supplier and the generator type. The contractual data of the generator may thereby change slightly. The contractual produced electrical power will not change.

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0.04 Technical data of heat recovery

General data - Hot water circuit external

Total recoverable thermal output	MBTU/hr	5,192
Return temperature	°F	149.0
Forward temperature	°F	185.0
Hot water flow rate	GPM	287.8
Design pressure of hot water	psi	145
Pressure drop hot water circuit	psi	5.8
Maximum Variation in return temperature	°F	+0/-36
Max. rate of return temperature fluctuation	°F/min	18

Mixture Intercooler (1st stage)

Type		gilled pipes
Design pressure of hot water	psi	145
Pressure drop hot water circuit	psi	4.35
Hot water connection	in/lbs	4"/145

Mixture Intercooler (2nd stage) (Intercooler separate)

Type		gilled pipes
Design pressure of hot water	psi	145
Pressure drop hot water circuit	psi	10.15
Hot water connection	in/lbs	2½"/145

Heat exchanger lube oil

Type		plate heat exchanger
Design pressure of hot water	psi	145
Pressure drop hot water circuit	psi	2.90
Hot water connection	in/lbs	4"/145

Decoupling Heat exchanger

Type		plate heat exchanger
Design pressure of hot water	psi	145
Pressure drop hot water circuit	psi	2.90
Hot water connection	in/lbs	4"/145

Exhaust gas heat exchanger (OPTION)

Type		shell-and-tube
PRIMARY:		
Exhaust gas pressure drop approx	psi	0.22
Exhaust gas connection	in/lbs	12"/145
SECONDARY:		
Design pressure of hot water	psi	87
Pressure drop hot water circuit	psi	2.90
Hot water connection	in/lbs	4"/145

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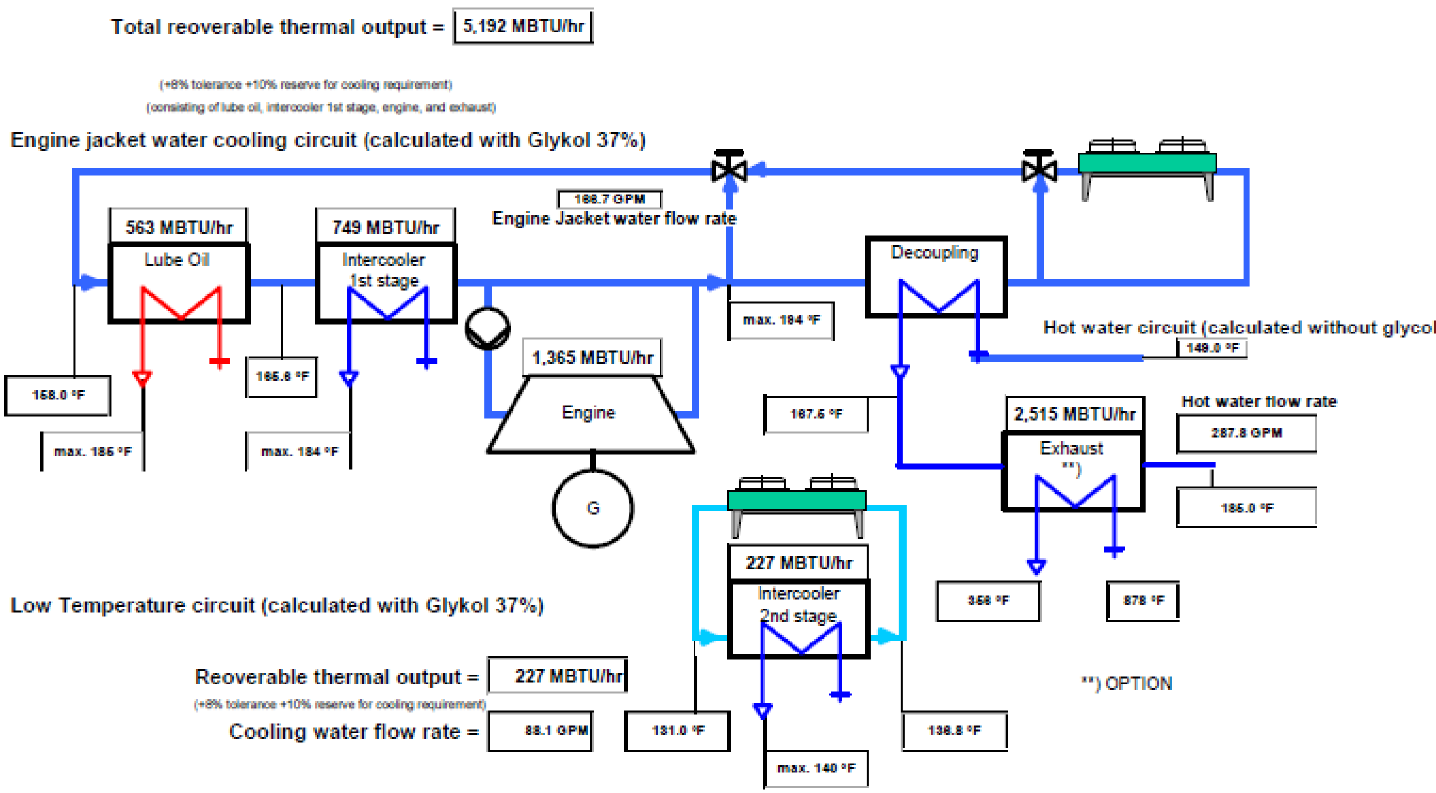
Total reoverable thermal output =
5,192 MBTU/hr
(+8% tolerance +10% reserve for cooling requirement)
(consisting of lube oil, intercooler 1st stage, engine, and exhaust)
Engine jacket water cooling circuit (calculated with Glykol 37%)
168.7 GPM
Engine Jacket water flow rate
563 MBTU/hr
Lube Oil
749 MBTU/hr
Intercooler
1st stage
1,365 MBTU/hr
Engine
G
158.0 °F
max. 185 °F
165.8 °F
max. 184 °F
max. 184 °F
Decoupling
Hot water circuit (calculated without glycol)
149.0 °F
187.6 °F
2,515 MBTU/hr
Exhaust
**)
Hot water flow rate
287.8 GPM
185.0 °F
358 °F
878 °F
Low Temperature circuit (calculated with Glykol 37%)
227 MBTU/hr
Intercooler
2nd stage
Reoverable thermal output =
227 MBTU/hr
(+8% tolerance +10% reserve for cooling requirement)
Cooling water flow rate =
88.1 GPM
131.0 °F
138.8 °F
max. 140 °F
**) OPTION

ATTACHMENT C

Organic Feedstock for
Lethbridge Biogas Cogeneration Plant

Feedstock	Description	Sources
A. LIVESTOCK MANURES[1]		
Dairy Manure	Manure (raw and/or separated) from dairy operations	Intensive Livestock Operations (ILO)
Hog Manure	Manure (raw and/or separated) from hog operations	
Poultry Manure	Manure from poultry operations	
Beef Manure[2]	Manure from feedlot operations	
B. ORGANIC FOOD RESSOURCES[3]		
B.1 Fats, Oils and Greases (FOG)		
Dissolved Air Flotation Slurry (DAF)/ Centrifuged Dissolved Air Flotation Slurry (CDAF)	Fats & proteins skimmed from wash water	Slaughterhouses, meat packing operations
Grease Trap Fat & Food Interceptor Solids	Fats, oils & greases captured in grease traps & food interceptors	Restaurants, food processors, cafeterias, grocery stores
Used Vegetable Oil	Vegetable oil used for deep frying	
Mixed Processed Meat & Fish Wastes	Cooked & uncooked meat & fish residues	Food processors, meat packers, canneries
B.2 Food Processing Residues		
Oils Seed Processing Residues	Residues from extraction oils from seed incl. canola cake canola oil, bleaching clay	Oil seed processors
Feed Mill Residues	Dust & wet grain residues	Feed mills, farm operations

[1] Estimated to be >50% of annual feedstock quantity processed (by weight)
[2] Only suitable if without any mechanical contamination
[3] Estimated to be 20-30% of annual feedstock quantity processed (by weight)

Cereal, Grain & Spice Processing Residues	Grain dust, husks, hulls, billies	Grain processors, elevators, flour mills, cereal processors
Fruit & Vegetable Residues	Pomace, peelings, rinds, juices	Vegetable processors, juice processors, canneries, wineries
Corn Processing Residues	Effluent from corn wet milling, stillage, distillers grain, silage, squeeze	Distillers, breweries, ethanol plants, food processors, starch producers
Beet Processing Residues	Beets, beet tops, trash, tailings, molasses	Sugar production
Potato Processing Residues	Potato sludge, peelings, chips	Potato plants
Dairy Processing Residues	Whey, milk, ice cream, proteins, wash water & other residues	Cheese factories, dairy processors
Aerobic Sludge	Aerobic sludge from non-municipal wastewater treatment	Food processors
Pet Food Residues	Pet food	Pet food processors
Process Water	Liquid residues, wash water	Food processors
B.3 Kitchen & Market Residues		
Bakery & Bread Residues	Dough, flour, yeast & crumbs	Bakeries, pizza parlours, restaurants, cafeterias
Confectionary Residues	Candies & cookies	Food processors
Mixed Food/Kitchen Residues	Cooked & treated vegetables, fruits & grains, frozen food	Food processors, restaurants, grocery stores, cafeterias, hospitals, universities
C. ANIMAL BY-PRODUCTS[4]		
Animal Carcasses & Animal Parts	Deadstock (cattle, hog, poultry, horse, bison), roadkill (deer, elk, moose)	Intensive livestock operations, slaughterhouses, packing plants

[4] Estimated to be 10-20% of annual feedstock quantity processed (by weight). Animal by-products that are legally classified as Specified Risk Material (SRM) will be pre-treated with thermal hydrolysis at 180 degree C, 12 bar for 40 minutes as required by the Canadian Food Inspection Agency (CFIA).

Animal Entrails	Stomach & intestines from slaughtered animals	Slaughterhouses, packing plants
Animal Blood	Blood drained & collected from slaughtered animals	
Paunch Manure	Manure removed from stomachs of slaughtered animals	
D. OTHER		
Glycerin/Glycerol	Alcohol by-product	Industrial biodiesel production
Horticultural Residues	Residues from plants & flowers	Greenhouses, garden centers, flower shops
Green (Garden) Residues	Grass	Municipalities, households
Energy Crops	Silage (corn, grain, grass)	Farm operations
Pulp & Paper Residues	Sludge	Paper mills

Disclaimer:

Feedstock list is preliminary at this time and shows all feedstock currently considered that the plant will be technically capable of processing. Not all feedstock might be relevant for the Lethbridge area and only feedstock will be used that is suitable for the sensitive biological diet at the time a feedstock becomes potentially available. Biological suitability will be determined by Lethbridge Biogas through feedstock samples and microbiological analysis. Sampling and testing of digested sludge will follow the requirements as outlined in Section 4.4.12 of approval #224576-00-00 and its amendments.

ATTACHMENT D

Alberta Environment and Sustainable Resource Development

Policy Division
Air and Climate Change
Policy Branch
12th Floor, 10025 106 Street
Edmonton, Alberta T5J 1G4
Canada
Telephone: 780-427-5200
www.alberta.ca

September 30, 2013

Graham Harris
VP, Technical Services
Blue Source Canada
Suite 700, 717-7th Avenue S.W.
Calgary, Alberta, T2P 0Z3

Dear Mr. Harris:

Subject: **Request for Approval and Deviation from Alberta Environment and Sustainable Resource Development's Flagged Quantification Protocol for the Anaerobic Decomposition of Agricultural Materials**

Thank you for your letter dated August 29, 2013 requesting approval to use, and deviation from the Quantification Protocol for the Anaerobic Decomposition of Agricultural Materials.

Alberta Environment and Sustainable Resource Development has determined that the project (Lethbridge Biogas) may use the flagged protocol in its current state for the crediting of biogas energy production and use providing it can be accurately separated from the natural gas component. As you know, the landfill gas diversion model is currently being revised to address identified risks and is unable to be used until revised. Once the landfill gas diversion methodology is revised this project will be able to use it on a go forward basis. This project will not be able to generate credit under this protocol from the natural gas cogeneration. This is a new activity that will likely require a new protocol and must complete all the required stages of protocol development within Alberta's offset system.

In addition, Alberta Environment and Sustainable Resource Development will be reviewing its cogeneration policy with the renewal of the *Specified Gas Emitters Regulation*.

Please direct any questions you may have to AENV.GHG@gov.ab.ca.

Sincerely,

N. Walia

Neenu Walia
Section Head, Climate Change Regulatory and Mitigation Policy