GUNSTER
FLORIDA'S LAW FIRM FOR BUSINESS

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November 25, 2020

E-PORTAL

Mr. Adam Teitzman, Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 20200216-GU - Request for approval of tariff modifications to accommodate receipt and transportation of renewable natural gas from customers, by Florida City Gas.

Dear Mr. Teitzman:

Attached for electronic filing, please find Florida City Gas's Responses to Staff's Second Set of Data Requests.

Thank you for your assistance in connection with this filing. If you have any questions whatsoever, please do not hesitate to let me know.

Sincerely,

s/Beth Keating
Beth Keating
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(850) 521-1706

Cc:// J.R. Kelly, Stephanie Morse (Office of Public Counsel)

QUESTION:
Please describe the process FCG would take if an RNG customer produces more gas than it consumes.

RESPONSE:
The proposed new Rate Schedule RNGS, if approved, will allow FCG to contract with customers that produce waste biogas and install conditioning equipment to clean and upgrade the biogas to renewable natural gas so that it may be used onsite by the customer and/or injected into FCG's system for delivery to another location. The new Rate Schedule RNGS will require that all renewable natural gas be cleaned and conditioned such that the RNG can be utilized onsite by the producing customer and/or be delivered into the Company's distribution system for transportation and delivery, and that all renewable natural gas that is delivered into FCG's system meets applicable gas quality and heat standards.

In the event that the RNG customer produces more renewable natural gas than it consumes onsite, the RNG customer will have several options available. First, the RNG customer can make arrangements with FCG to inject the excess renewable natural gas into FCG's system for delivery to the producing customer at another location on FCG's system or to a third party purchasing customer on FCG's system. Second, the RNG customer can make arrangements with FCG to inject the excess renewable natural gas into FCG's system for delivery to the interstate pipeline for sale in the interstate market, including for sale to other utilities, gas suppliers, and brokers. Under both scenarios, the RNG customer would contract directly with the purchasing entity for the sale of the RNG gas. Third, the RNG customer could store the excess renewable natural gas if such facilities were installed or available to the RNG customer. Fourth, the RNG customer could temporarily discontinue production of renewable natural gas until needed for consumption. Finally, depending on the price, location, and market conditions, the gas could potentially be purchased by FCG as part of its system supply, thereby displacing a portion of the traditional natural gas supply included in the Company's portfolio with a renewable source, as well as effectively increasing system capacity for new customer growth.

With the exception of the last option, it is the RNG customer's decision what to do with any excess renewable natural gas produced. In the event that the RNG customer seeks to make arrangements with FCG to inject the excess renewable natural gas into FCG's system for delivery, FCG would only accept the gas for delivery if it meets applicable gas quality and heat standards, and FCG's system can safely accommodate the additional volumes of gas. If so, the RNG customer would be required to pay the applicable distribution rate under FCG's tariff for delivery of the excess renewable natural gas from the RNG producer to the delivery point.

QUESTION:
FCG states in response to staff's first data request, question 3, that it "has been in contact with or has been contacted by a number of municipalities or private business that intend to produce or use RNG." How many entities have contacted FCG about taking service under this tariff? Please describe the status of these discussions.

RESPONSE:
FCG has been in contact with five entities who are evaluating the production of RNG from landfill gas and or waste treatment facilities.

The discussions with the five entities have varied based on their individual business objectives; however, the most common request is for FCG to potentially transport pipeline quality RNG on their behalf and deliver it to other purchasing customers. Most conversations include questions as to what the anticipated costs to transport certain volumes of RNG will be and what specifications FCG may have for meeting pipeline quality standards.

In all cases, FCG has advised these entities that its proposed RNG tariff is currently pending before the Commission, and that FCG may not provide the proposed RNG service absent Commission approval.

QUESTION:
In its response to staff's first data request, question five, the utility states "The biogas conditioning equipment could be located on Company-owned property if there isn't room on the customer's property or if there is an advantage to FCG and the customer to locate the biogas conditioning and associated equipment on Company property." (a) Please explain the transportation process of the biogas to the RNG facility, if a customer elected to have the equipment built on FCG property. (b) ease explain how FCG would ensure safe transportation of the unconditioned biogas to a conditioning facility, if the facility was built on FCG property

RESPONSE:

a. Transportation of the biogas from the source to the conditioning equipment will be accomplished through a natural gas rated compressor, gathering lines, and related ancillary equipment. The biogas producer will own and operate these facilities and will be solely responsible for the safe delivery of the biogas to the conditioning equipment. This process for transporting the biogas to the conditioning equipment is the same regardless of whether the conditioning equipment is located on the RNG customer's property or FCG's property. In the event that the biogas delivery facilities and/or conditioning equipment need to be located on FCG's property due to constraints on area that is available, the RNG customer would be required to obtain appropriate easements, access, and/or consents necessary to locate, construct, and operate the biogas delivery facilities and conditioning equipment located on FCG's property.

b. The process for safe transportation of the biogas to the conditioning equipment is the same regardless of whether the conditioning equipment is located on the RNG customer's property or FCG's property. As explained above, regardless of where the conditioning equipment is located, the biogas producer will own and operate these facilities and will be solely responsible for the safe delivery of the biogas to the conditioning equipment. As part of the RNG contract negotiated with the RNG producer, FCG will require that the landfill operator and/or biogas owner operate their systems in compliance with all federal, state, and local statutes, regulations, rules, and codes applicable to that type of business activity, and obtain all necessary permits, licenses, certificates, approvals, and authorizations. FCG will also review the biogas owner's safety practices and procedures and ensure that these procedures adhere to the safe handling and transportation of biogas to the point of conditioning. Finally, in the event that the RNG customer seeks to have the conditioned RNG injected into FCG's system for transportation and delivery, the proposed new Rate Schedule RNGS tariff requires that renewable gas must meet the applicable gas quality and heat standards. If the conditioning facility is to be built on FCG property, an accessible shut off valve would be required at the point of entry to FCG property as well installation of overpressure protection equipment to safely vent the line transporting biogas. The RNG customer will be required to ensure a retention system is in place to prevent spills or contamination of FCG property and ensure waste products produced are not to be stored on FCG property. The RNG customer will be required to have supervisory control and data acquisition (SCADA) monitoring of their critical facilities and any expense or liability for the operation and or maintenance of the RNG customer's facilities incurred are their responsibility.

QUESTION:
The company states in its response to staff's first data request, question 7, that "the costs could vary across a broad range, but based on publically available information and case studies, it is anticipated that the costs for biogas conditioning equipment and associated equipment could generally be in the range of $5MM to $25MM dollars." Please provide all sources and case studies referred to in this statement.

RESPONSE:
Attached are the following responsive documents:

- Attachment No. 1 – H2A Biomethane
- Attachment No. 2 – From Biogas to RNG
- Attachment No. 3 – Biogas in the United States
- Attachment No. 4 – Renewable Natural Gas Toolkit
- Attachment No. 5 – Natural Gas Utility Business Model
- Attachment No. 6 – UM 2030
- Attachment No. 7 – Renewable Sources of Natural Gas
- Attachment No. 8 – Draft Comparative Assessment of Technology Options for Biogas Clean-up.

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H2A Biomethane Model Documentation and a Case Study for Biogas From Dairy Farms

Genevieve Saur and Ali Jalalzadeh-Azar

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

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Prepared under Task No. H2782330

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Introduction

The new H2A Biomethane model was developed to estimate the levelized cost of biomethane by using the framework of the vetted original H2A models for hydrogen production and delivery. For biomethane production, biogas from sources such as dairy farms and landfills is upgraded by a cleanup process. The model also estimates the cost to compress and transport the product gas via the pipeline to export it to the natural gas grid or any other potential end-use site. Inputs include feed biogas composition and cost, required biomethane quality, cleanup equipment capital and operations and maintenance (O&M) costs, process electricity usage and costs, and pipeline delivery specifications. (All costs are presented in 2005 dollars unless otherwise noted.)

The original H2A model capabilities can be found in the user guides [1, 2]. These should be used with this document for a complete description of the current model.

New Model Features

New Worksheet – Biogas Upgrade

A new worksheet, ‘Biogas Upgrade’, was developed to help users provide the required inputs for characterizing the upgrade process with respect to biomethane yield, energy consumptions, emissions, and costs. This can be used to upgrade biogas from any source (e.g., dairy farms or landfills) to natural gas pipeline quality. Figure 1 to Figure 3 show the required inputs in orange. These input data are also required for other calculations.

Potential projects will vary with respect to the input biogas and the required output biomethane quality. For instance, pipeline quality natural gas varies slightly from one state to another and from one utility to another. This model can capture some basic elements, but does not design a cleanup and purification system, which are highly dependent on feedstock composition, quality, and variation. This model calculates the volume and energy content of the input biogas and output biomethane based on the methane (CH_4), carbon dioxide (CO_2), and nitrogen (N_2) contents in an average annual flow. This approximation does not account for seasonal or other variations. Additionally, delivery components of the model may be sized for peak flow or an annual average, depending on the level of detail desired. This model provides a broad techno-economic analysis to help users identify worthwhile projects for more in-depth consideration.

The CH_4, CO_2, and N_2 components of the biogas and biomethane are used to calculate energy contents of the input and output streams and the energy usage, (see Figure 2). Other impurities are listed for completeness and to provide space for an extended analysis. The energy content values are used in several places to determine energy usage values and resulting emissions. Cells in green are for informational purposes. Further units and constant conversion information are in the ‘Constants and Conversions’ tab. All calculations can be seen by clicking in blue cells.

The values for electricity and biogas usage reflected in this worksheet (cells 'Biogas Upgrade'!B24 and 'Biogas Upgrade'!B25, respectively) should then be added as utility and feedstock, respectively in the ‘Input_Sheet_Template’ Variable Operating Costs: Energy Feedstocks, Utilities, and Byproducts section. This is done in the same way as in the standard H2A Production model [1].

Figure 3 shows the capital costs section in the ‘Biogas Upgrade’ tab. The total installed costs here are used in the levelized cost of biomethane as seen in cell ‘Input_Sheet_Template’!C53. The user can either enumerate costs here or unlink to this worksheet and specify the costs in cell C53 of the ‘Input_Sheet_Template’ tab.

Input Biogas Composition		Notes	Output Biomethane Requirement			Notes
Rate (Nm3/h)	2000	Enter in 'Input_Sheet_Template'	Rate (Nm3/hr)	1225	905 kg/hr	
Methane (CH4) (%)	60%	by volume	CH4 Recovery Factor	99%		How much CH4 recovery from input to output? (1-loss)
CO2 (%)	38%	by volume	Methane (CH4) (%)	97%	851 kg/hr	
Nitrogen (%)	2%	by volume	CO2 (%)	1%	24 kg/hr	
			Nitrogen (%)	2%	31 kg/hr	
H2S (ppm)	600-800		H2S (ppm)	<4		
Siloxane (mg/m3)	60-80		Siloxane (ppb)	<30		
Biogas Density	1.201 kg/Nm3		Biomethane Density	0.739 kg/Nm3		

Figure 1. Gas composition inputs in 'Biogas Upgrade'

Energy Content				Biogas Cleanup Plant Utility Usage		
Methane (CH4) LHV	0.052	GJ/kg methane		Electricity Consumption	0.230	kWh/nm3 biogas
LHV Biogas	0.0223	GJ/Nm3 biogas				
LHV Biomethane	0.0361	GJ/Nm3 biomethane				

Energy Usage		Units	Notes
Total Electricity Usage	**0.610**	kWh/kg biomethane	
Compression	0.102	kWh/kg biomethane	For information only, change values on 'Biomethane Compressor' sheet.
Process	0.508	kWh/kg biomethane	IMPORTANT: IF Process Electricity Usage values change, the Utility in Variable Operating Costs must be deleted/re-added on Input_Template_Sheet
Biogas Usage	**2.209**	Nm3 biogas/kg biomethane	IMPORTANT: IF Biogas Usage values change, the Feedstock in Variable Operating Costs must be deleted/re-added on 'Input_Template_Sheet'

Figure 2. Energy content and usage in 'Biogas Upgrade'

The following can be used for calculating costs to be put in 'Capital Costs' tab

Use Default Scaling	yes								
List of equipment required for biogas conditioning	Reference Unit Size (nm3/hr)	Scaling Factor	Reference Unit Uninstalled Costs ($(2005))	Size Required (nm3/hr)	Baseline Uninstalled Costs ($(2005))	Installation Factor	Baseline Installed Costs ($(2005))	Comments	Data Source
Purification/upgrading system (Default Scaling)	5000	0.65	4,656,101	2000	2,566,619	1.29	3,310,939	Recommended default scaling	
User Defined 1				2000	0	1.29	0		
User Defined 2				2000	0	1.10	0		
User Defined 3				2000	0	1.10	0		
User Defined 4				2000	0	1.10	0		
User Defined 5				2000	0	1.10	0		
User Defined 6				2000	0	1.10	0		
User Defined 7				2000	0	1.10	0		
User Defined 8				2000	0	1.10	0		
User Defined 9				2000	0	1.10	0		
Total Cost					**$2,566,619**		**$3,310,939**		

Figure 3. Biogas capital costs in 'Biogas Upgrade'

The biogas capital costs section in 'Biogas Upgrade' can be used in one of two ways:

- Select "yes" next to "Use Default Scaling" (cell B28).
- Select "no" next to "Use Default Scaling" (cell B28) (include uninstalled costs and an installation cost factor in the designated space).

Default values are included in the first line of the cost table (Figure 3) to indicate appropriate uninstalled costs. The default scaling is based on vendor quotes for cleanup of biogas from dairy farms. The capital costs of a biogas cleanup plant depend on the composition and impurity level of feed biogas and the required quality of the output gas; therefore, these values are not applicable for all cases.

Scaling uses the standard equation, $C = C_{ref}\left({}^{q}/_{q_{ref}}\right)^{SF}$ for the capital costs. From vendor data two capacity ranges are modeled for representative biogas from a single or group of dairy farms. The variable definitions and the reference values are shown in Table 1.

Table 1. Default Scaling Ranges for Uninstalled Costs

Biogas Flow Rate Range (Nm^3/h)	Reference Rate (q_{ref})	Reference Cost (C_{ref})	Scaling Factor (SF)
$150 \leq q < 700$	400	$1.16 M	0.250
$700 \leq q \leq 10{,}000$	5,000	$4.66 M	0.65

New Worksheet – Biomethane Pipeline

The biomethane pipeline cost is adapted from the H2A Delivery Components model [3]. Three types of pipelines can be modeled:

- A high-pressure transmission line
- Medium-pressure trunk lines
- Low-pressure distribution lines.

Cost results for the trunk and distribution lines are combined; transmission line costs are shown separately on the 'Biomethane Pipeline' tab (see Figure 4). Figure 5 provides the results in a $/mi metric The 'Results' tab shows the total cost breakdown for the pipeline system.

For most case studies involving biomethane, a new transmission line will probably be unnecessary because the system will use natural gas transmission lines. In general the expansion of the natural gas pipeline network to accommodate new biomethane sources might only include a distribution or trunk line from the biogas conditioning plant to the network. However, a feature of the 'Biomethane Pipeline' worksheet is to model the costs and dimensions of more complex systems if required.

Calculation Outputs (Be sure ALL data is entered before checking)			
	Pipeline Type		
Result	**Transmission**	**Trunk / Distribution**	**Total**
Pipeline Portion of Real Levelized Delivered Biomethane Cost ($(2005)/kg)	$0.00	$0.11	$0.11
Capital Cost Contribution to the Pipeline Share of Real Levelized Delivered Biomethane Cost ($(2005)/kg)	$0.00	$0.07	$0.07
Energy/Fuel Cost Contribution to the Pipeline Share of Real Levelized Delivered Biomethane Cost ($(2005)/kg)	$0.00	$0.00	$0.00
Other Cost Contribution to the Pipeline Share of Real Levelized Delivered Biomethane Cost ($(2005)/kg)	$0.00	$0.04	$0.04

Figure 4. 'Biomethane Pipeline' summary of cost results layout

Calculation Outputs per Mile (For information use only)			
	Pipeline Type		
Result	**Transmission**	**Trunk**	**Distribution**
Total Length of Pipelines (mi)	0	0	10
Total Pipeline Real Cost ($/mi-yr)	$0.00	$0.00	$86,304.82
Est. Total Pipeline Cost ($/mi)	$0.00	$0.00	$416,633.65
Pipeline Capital ($/mi)	$0.00	$0.00	$347,087.60
Pipeline Land RoW ($/mi)	$0.00	$0.00	$41,390.58
Pipeline Labor Costs ($/mi)	$0.00	$0.00	$8,548.86
Pipeline Fixed O&M ($/mi)	$0.00	$0.00	$19,606.61

Figure 5. 'Biomethane Pipeline' excerpt of results in $/mi metric

The spreadsheet inputs can be categorized as design inputs, scenario inputs, economic assumptions, capital investment, and O&M costs. The main difference between the current module and the H2A Delivery Components model is that revised values are used for compressibility factor (Z), density conversions, and costs for biomethane delivery rather than hydrogen. The compressibility factor (Z) is used to determine pipeline diameter by Equations (1) and (2) [2]. Calculating the pipeline diameter is necessary for economic evaluation of the delivery pipeline [2]. In formulating the compressibility factor (Z), the critical temperature and pressure obtained from the NIST Web book on CH_4, the main component in biomethane, are used where T_c equals 190.6 K and P_c equals 46.1 bar [2, 4]. The density of biomethane was used in several conversion equations in place of hydrogen. Finally, the costs were adjusted to remove a 10% surcharge on hydrogen pipelines over natural gas pipelines, which is consistent with the original source material [2, 5]. Further details can be found in the H2A Delivery Components Model version 1.1 Users Guide for the H2 Pipeline [2].

$$q_{sc} = 737\left(\frac{T_{sc}}{P_{sc}}\right)^{1.02}\left(\frac{(P_1^2 - P_2^2)d^{4.961}}{\gamma^{0.961}LT_mZ_m}\right)^{0.51}E \qquad \textbf{Equation 1}$$

$$\boldsymbol{d = e^{0.2016\left(\frac{\ln(q_{sc})}{0.51}+ln\left(\frac{LT_m Z_m \gamma^{0.961}}{P_1^2-P_2^2}\right)-19.916\right)}} \qquad \textbf{Equation 2}$$

where

q_{sc}	=	gas flow rate at standard conditions (scf/day)
T_{sc}	=	temperature at standard conditions (°R) (= 530°R in Equation 2)
P_{sc}	=	pressure at standard conditions (psia) (= 14.7 psia in Equation 2)
P_1	=	inlet pressure (psia)
P_2	=	outlet pressure (psia)
d	=	inside pipeline diameter (in)
γ	=	mean gas relative density (air = 1)
L	=	pipeline length (mi)
T_m	=	mean temperature of pipeline (°R)
Z_m	=	mean compressibility factor
E	=	pipeline efficiency (= 0.92 in Equation 2)

New Worksheet – Biomethane Compressor

The biomethane compressor model is adopted from the H2A Delivery Components model [3]. It can be used for further external compression of biomethane to a pipeline or other end-use pressure. Multiple reciprocal compressors can be installed in parallel to handle large throughput (see Figure 6), including the use of spare compressors. Each compressor can consist of up to three compression stages.

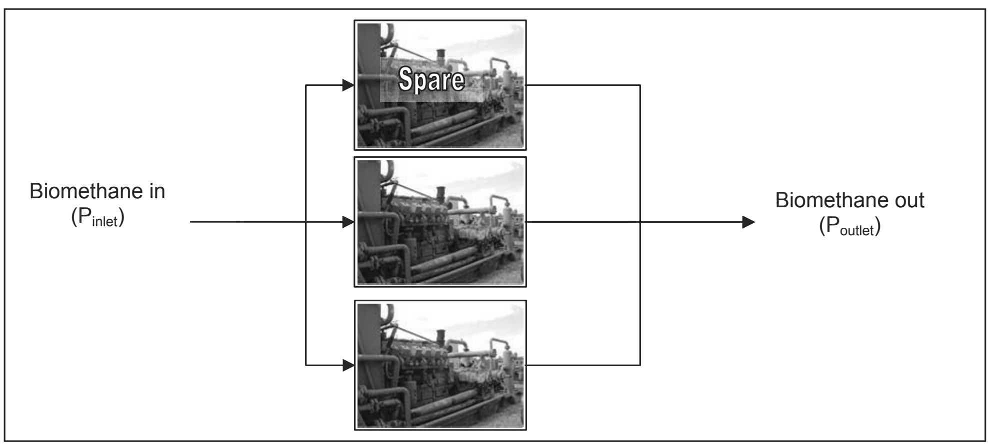


Figure 6. Compressor layout for external compression
(from DOE, *H2A Delivery Components Model Version 1.1: Users Guide*, April 7, 2006)

The spreadsheet inputs (‘Biomethane Compressor’ tab) can be categorized as design inputs, economic assumptions, capital investments, and O&M costs. Input cells are colored in orange, an H2A model standard, down column B in the ‘Biomethane Compressor’ tab.

The main changes made to the tab from the H2A Components Delivery model are the compressibility (Z) factor, specific heat ratio (c_p/c_v), and default costs. The compressibility factor Z is used in the theoretical power and electricity usage calculations (see H2A Components Delivery Model 1.1 User Guide for a detailed explanation) [2]. The formulation of the compressibility factor (Z) is based on the approach used for pipelines. The specific heat ratio was changed to 1.32 because the working fluid was changed from hydrogen to natural gas or CH_4. The default costs for a biomethane compressor were adjusted for natural gas compressors, which put the total costs in line with the original cost report [6]. Furthermore, in several conversion calculations, biomethane density was substituted for hydrogen density. Further details can be found in the H2A Components Delivery Model 1.1 User Guide in the H2 Compressor section [2].

The 'Biomethane Compressor' tab models a single pressure differential. If multiple compression stations are required, the results from several input scenarios need to be combined. For instance, a three-stage external compression station can compress biomethane from 90 psia (distribution pipeline) to 600 psia (trunk pipeline). If a second station is required for 600 psia (trunk pipeline) to 1000 psia (transmission line), the input scenario would need to be run separately and manually combined with previous results.

Worksheet Modification – 'Results'

The 'Results' tab includes three sections: Costs, Energy, and Emissions. The latter two provide the results for the cleanup process modeled and the upstream processes.

The *Costs Results* table is shown in Figure 7 and includes cost results in $/kg and $/GJ. Conversion to MMBtu is also possible, but not implemented in the current version. The conversion between GJ and MMBtu is 1.055 GJ/MMBtu, based on the lower heating value (LHV) of both. The cost breakdown is separated by production process (biogas cleanup plant), pipeline costs, and external compressor costs.

Specific Item Cost Calculation		***Total Cost of Delivered Biomethane***	**$0.64/kg**	**$13.11/GJ**		
Cost Component	**Biomethane Production Cost Contribution ($/kg)**	**Pipeline Costs ($/kg)**	**Compressor Costs ($/kg)**	**Biomethane Production Cost Contribution ($/GJ)**	**Pipeline Costs ($/GJ)**	**Compressor Costs ($/GJ)**
Capital Costs	$0.08	$0.07	$0.03	$1.63	$1.50	$0.63
Decommissioning Costs	$0.00			$0.02		
Fixed O&M	$0.03	$0.04	$0.01	$0.67	$0.73	$0.29
Feedstock Costs	$0.34	$0.00	$0.01	$6.95	$0.00	$0.10
Other Raw Material Costs	$0.00			$0.00		
Byproduct Credits	$0.00			$0.00		
Other Variable Costs (including utilities)	$0.03			$0.58		
Sub Total	**$0.48**	**$0.11**	**$0.05**	**$9.86**	**$2.23**	**$1.02**

Figure 7. Example of cost results excerpted from 'Results' tab

The Energy section includes the *Energy Data* table (Figure 8), which summarizes energy inputs for feedstocks and utilities for the production process and external compression. It also summarizes the energy outputs or other by-products that were included. The biogas feedstock energy usage is based on the energy content and quantity of biogas input versus biomethane output. The *Upstream Energy Usage* table (Figure 9) calculates total, fossil fuel, and petroleum energy consumed by the energy inputs shown in the *Energy Data* table (Figure 8) in accordance with the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model [7].

Energy Data						
Feedstock	**Energy Input (GJ/kg biomethane)**	**Energy Input (kWh/kg biomethane)**	**LHV (GJ or mmBtu/usage unit)**	**Usage (/kg biomethane)**	**Unit**	**Unit System Conversion Factor**
Biogas_metric	0.049	13.708	0.022	2.209	Nm3 @ 0°C	1
Utility						
Industrial Electricity_metric	0.002	0.508	0.004	0.508	kWh	1
External Compression						
Industrial Electricity_metric	0.000	0.102	0.004	0.102	kWh	1
	Energy Output (GJ/kg biomethane)	**Energy Output (kWh/kg biomethane)**	**LHV (GJ or mmBtu/usage unit)**	**Production (/kg biomethane)**	**Unit**	**Unit System Conversion Factor**
Biomethane (1 kg)	0.049	13.572	0.049	1.000	kg	1
Byproducts						

Figure 8. Example Energy Data table excerpted from 'Results' tab

Upstream Energy Usage (GJ/kg Biomethane)			
Feedstock	**Total Energy**	**Fossil Fuels**	**Petroleum**
Biogas_metric	-4.08E-02	-3.53E-02	-1.93E-03
Utility			
Industrial Electricity_metric	2.97E-03	2.57E-03	1.41E-04
External Compression			
Industrial Electricity_metric	5.99E-04	5.18E-04	2.83E-05

Figure 9. Example Upstream Energy Usage table excerpted from 'Results' tab

The Emissions section calculates the greenhouse gas (GHG) emissions based on direct energy inputs to the production process and the upstream energy use. There are summary and detail tables for both *Production Process GHG Emissions* and *Upstream GHG Emissions* (see Figure 10 and Figure 11). By default, in the production process calculation, all emissions are counted as CO_2. Emissions are calculated in accordance with the GREET model [7].

Production process emissions from the biogas feedstock are included in Table A, 'HyARC Physical Property' tab. This includes CO_2 and CH_4 that are lost or vented during the biogas cleanup process. The process emissions are calculated from the specified biogas cleanup process in the 'Biogas Upgrade.'

Production Process GHG Emissions (/kg biomethane)				
Feedstock	**CO2**	**CH4**	**N2O**	**Total GHG (CO2 eq)**
Biogas_metric	1.622	9.49E-03	0.00E+00	1.840
Utility				
Industrial Electricity_metric	0.000	0.00E+00	0.00E+00	0.000
External Compression				
Industrial Electricity_metric	0.000	0.00E+00	0.00E+00	0.000

Figure 10. Example of detailed Production Process GHG Emissions excerpted from 'Results'

Upstream GHG Emissions (kg/kg biomethane)				
Feedstock	**CO2**	**CH4**	**N2O**	**Total GHG (CO2 eq)**
Biogas_metric	-2.271	1.86E-03	2.04E-05	-2.222
Utility				
Industrial Electricity_metric	0.382	5.01E-04	5.22E-06	0.395
External Compression				
Industrial Electricity_metric	0.077	1.01E-04	1.05E-06	0.080
TOTAL	-1.812	2.46E-03	2.67E-05	-1.748

Figure 11. Example of detailed Upstream GHG Emissions excerpted from 'Results'

Case Study – Biomethane From Dairy Waste

The revised model was used to perform the following hypothetical case study for production of biomethane from stranded biogas in a dairy farm. The average annual rate of biogas was 2000 Nm^3/h. The case study system was designed based on this flow rate to show basic design functionality with an implicit assumption that peak hourly flow rate could be controlled to not exceed the annual average for sizing of system components. After purification and cleanup, the biomethane product is transported by a pipeline for further compression and injection into the natural gas pipeline. The case study models a breakdown in costs and associated emissions for three distinct subsystems: (1) biogas purification/cleanup; (2) low-pressure pipeline transport; and (3) additional compression for injection into a natural gas trunk line.

Description and Process Flow

Figure 12 describes the purpose and process flow of the system being modeled, illustrating the 'Process Flow' tab of the model.

Biogas Feedstock – Cost

A biogas feedstock was added to the AEO 2005 High A case prices, 'Energy Feed & Utility Prices' tab, as a user-defined feedstock. A constant cost of $7.6/GJ in 2010$ [8] was used for the lifetime of the plant and converted to 2005 dollars by using the GDP Implicit Deflator Price Index, Table 9A, in the Short Term Energy Outlook September 2009 [9]. The actual cost used is based on the energy content as calculated in the 'Biogas Upgrade.' In the case study, the energy content of the feed biogas was 0.0223 GJ/Nm^3 based on the CH_4 content and total biogas volume.

Biogas Feedstock – Upstream Energy Use and Emissions

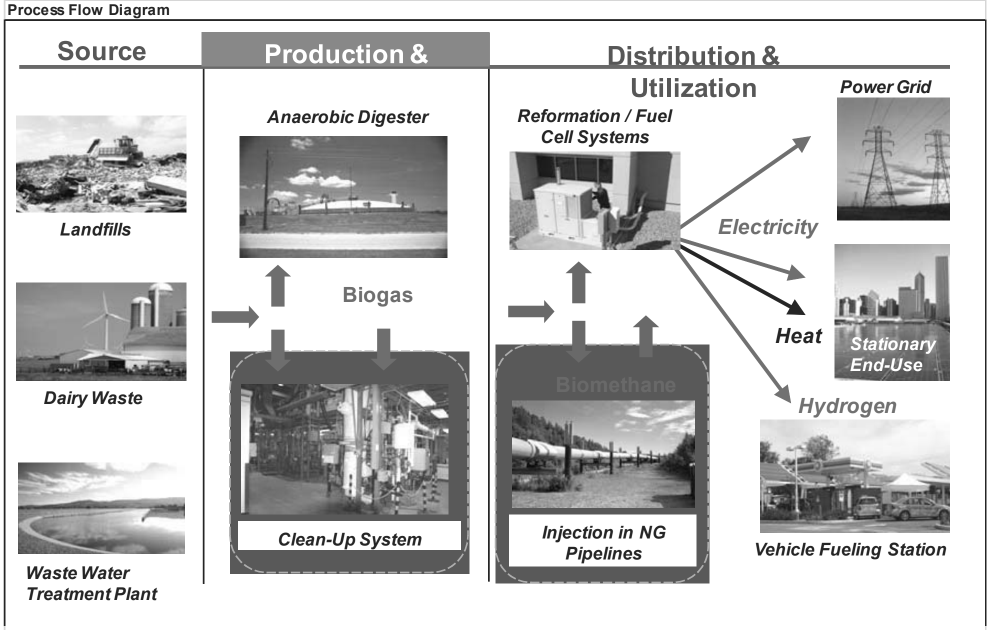
Upstream energy and emissions data for the biogas feedstock are calculated using a newly released report by the California Air Resources Board (CARB) [10]. This can be seen in Figure 13, an excerpt of Table C1 in the 'HyARC Physical Property Data' tab. The CARB report is based on a modified version of the GREET model [7, 11] to calculate the associated energy and emissions for upgrading biogas from dairy farms to natural gas quality. A breakdown of numbers matching those from the CARB report can be seen in the associated cells.

Total Energy Usage

Total Energy for biogas (Figure 13) was determined from the CARB report [10]. This includes the total energy for biogas recovery, biogas processing to natural gas quality, and transport by pipeline to a compressed natural gas (CNG) fueling station or other end-use application. The length of the pipeline is adjusted relative to the 50 miles assumed in the CARB report. Fossil fuels and petroleum usage portions of the "Total Energy" circled in red (Figure 13) were calculated using the same respective ratios for industrial electricity (circled in green in Figure 13 because the main energy input for upgrading the biogas will be electricity, so that is the main source of upstream emissions. The fossils fuel and petroleum energy usage is related to the electricity usage for the biogas recovery, processing, and transportation. All calculations can be accessed within individual cells for details. More details are available in the CARB report.

If additional compression is used in the model (cell 'Biogas Upgrade'!B23 is not zero), the total energy is calculated from energy usage values in the 'Biomethane Compressor' tab using GREET values for U.S. average mix industrial electricity.

Process Flow Diagram



Shaded areas represent the boundaries of this model.

Stream Summaries

Upgrading biogas for biomethane involves the following key processes:

1. Compression of feed gas to about 100 psig (6.8 bar)
2. Hydrogen sulfide removal
3. Siloxane and VOC removal
4. Carbon dioxide removal
5. Compression of biomethane to high pressure (e.g. pipeline pressure), if required.
6. Thermal oxidizer / flaring of purge (tail) gas, if included in the analysis

The product gas upstream of the compression process is about 90 psig (6.2 bar). The methane content of the purge (tail) gas can be modulated to faciliate flaring/oxidizing.

PSA technology is used for the removal of impurities (H_2S, CO_2, etc.). In addition to the PSA units, the system consists of gas analyzer, flowmeters, cooling devices, and controls. Note that other technologies such as chemical absorption and cryogenic separation can be used instead of PSA if desired.

The product gas has the natural gas pipeline quality:
CH_4: 96% - 98% by volume
CO_2: Less than 2%
H_2S: Less than 4 ppm
Siloxane: Less than 30 ppb.

The inlet biogas quality (chemical composition) varies depending on the source of biogas--landfills, dairy farms, waste water treatment plant, etc.
(The inlet gas composition is recorded at the "Biogas Upgrade" tab)

Figure 12. Excerpt from 'Process Flow' tab
(from NREL/PO-560-46899)

Table C1 2005 Upstream Energy and Emissions for H2 Feedstocks: for each MJ (LHV, or as noted) of feedstock available at H2 production site. Source: GREET 1.8b, 09/5/2008 for year 2005 technologies

		Energy: J/MJ			Greenhouse Gas Emissions: grams/MJ			Total Greenhouse Gas Emissions: grams/MJ
Feedstock/Fuel	Description	Total Energy	Fossil Fuels	Petroleum	CO2	CH4	N2O	GHGs
Commercial Natural Gas_metric	North American sources -- at plan	65,830	65,387	4,195	4.759	0.130	0.000	7.772
Industrial Natural Gas_metric	North American sources -- at plan	65,830	65,387	4,195	4.759	0.130	0.000	7.772
Electric Utility Natural Gas_metric	North American sources -- at plan	65,830	65,387	4,195	4.759	0.130	0.000	7.772
Commercial Electricity_metric	U.S. Average - at Wall Outlet	1,626,707	1,407,727	77,032	208.947	0.274	0.003	216.091
Industrial Electricity_metric	U.S. Average - at Wall Outlet	1,626,707	1,407,727	77,032	208.947	0.274	0.003	216.091
Electric Utility Steam Coal_metric	at Plant Gate	19,878	19,241	13,877	1.548	0.113	0.000	4.154
Retail Diesel_metric	at Forecourt	149,143	146,120	65,864	11.466	0.095	0.000	13.708
E85 Ethanol_metric	74 wt% ethanol from corn and 26	1,254,723	608,478	91,705	-8.078	0.105	0.031	3.554
Retail Gasoline_metric	at Forecourt	206,668	202,867	94,357	15.515	0.099	0.000	17.878
Woody Biomass_metric	Poplar at Plant Gate	30,911	30,497	24,723	-101.108	0.003	0.001	-100.771
Steam_metric	Assume steam generation from na	76,814	76,297	4,895	5.553	0.152	0.000	9.069
Commercial Natural Gas	North American sources -- at plan	65,830	65,387	4,195	4.759	0.130	0.000	7.772
Industrial Natural Gas	North American sources -- at plan	65,830	65,387	4,195	4.759	0.130	0.000	7.772
Electric Utility Natural Gas	North American sources -- at plan	65,830	65,387	4,195	4.759	0.130	0.000	7.772
Electric Utility Steam Coal	at Plant Gate	19,878	19,241	13,877	1.548	0.113	0.000	4.154
Retail Diesel	at Forecourt	149,143	146,120	65,864	11.466	0.095	0.000	13.708
E85 Ethanol	74 wt% ethanol from corn and 26	1,254,723	608,478	91,705	-8.078	0.105	0.031	3.554
Retail Gasoline	at Forecourt	206,668	202,867	94,357	15.515	0.099	0.000	17.878
Woody Biomass	Poplar at Plant Gate	30,911	30,497	24,723	-101.108	0.003	0.001	-100.771
Steam	Assume steam generation from na	76,814	76,297	4,895	5.553	0.152	0.000	9.069
User Defined Feed 1								0.000
User Defined Feed 2								0.000
User Defined Feed 3								0.000
User Defined Feed 4								0.000
Biogas_metric	Detailed California-Modified GREE	-826,347	-715,108	-39,131	-46.02524238	0.037722536	0.000413837	-45.035
Landfill Gas_metric	Detailed California-Modified GREE	-839,556	-726,539	-39,757	-46.58590588	0.053465664	-0.000793746	-45.591
Electricity - NGCC - at Wall Outlet	NGCC - at Wall Outlet	1,326,688	1,326,077	5,246	133.381	0.370	0.003	143.602

Figure 13. Table C1 in 'HyARC Physical Property Data' tab

Greenhouse Gas Emissions

Greenhouse gas emissions include CO_2 (including volatile organic compounds and carbon monoxide), CH_4, and nitrous oxide (N_2O) in grams/MJ, and total GHGs in CO_2eq. These values were determined using calculations from the CARB report on biogas [10]. This includes the direct and upstream GHGs for biogas recovery, biogas processing to natural gas quality, and transport by pipeline to a CNG fueling station or other end-use application. It includes an adjustment for the specified length of pipeline modeled relative to the 50 miles assumed in the CARB report. Full details can be found in the CARB report and by clicking in individual cells of this model (Figure 13).

If additional compression is used in the model ('Biogas Upgrade'!B23 is not zero), the greenhouse gases (GHGs) are calculated from emissions values in the 'Biomethane Compressor' tab using GREET values for U.S. average mix industrial electricity.

Biogas Feedstock – Production Process Emissions

The production process GHG emissions are based on the purification and losses associated with processing the biogas to biomethane quality. In the upgrading process, the losses include a trace of CH_4 (as reflected in the CH_4 recovery factor in the 'Biogas Upgrade') and the separated CO_2. In the current version, both gases are assumed to be vented or lost to the atmosphere during the purification process. Figure 14 shows an excerpt of Table A in the 'HyARC Physical Property Data' tab where the boxes outlined in red are the emissions related to the production process. (Figure 14 has been split for readability. The blue arrows show the divided ends.) These are calculated based on the composition of the input and output feed stream in the 'Biogas Upgrade.'

TABLE A - Energy Feedstock and Utility Properties Table			Done			
Feedstock Type	Source	Source Year (for original price data)	H2a Reference Year	Units for Feedstock Price Table	HHV/LHV Source	HHV/LHV
Biogas_metric				$(2005)/GJ LHV	GJ biogas/Nm3 biogas	

H2A Usage Input Unit/ kg H2	H2A LHV (GJ or mmBtu/ H2A usage input unit)	List	CO2 Emissions Factor (kg CO2 produced/GJ or mmBtu feed)	Unit System	CH4 Emissions Factor (kg CH4 produced/GJ or mmBtu feed)	N2O Emissions Factor (kg N2O produced/GJ or mmBtu feed)
Nm3 @ 0°C	0.0223	Feed Utility	32.87	Metric	0.19	

Figure 14. Excerpt Table A in the 'HyARC Physical Property Data' tab

Biomethane Pipeline System

For this case study a single distribution line of 10 miles was modeled. Using the maximum design feed biogas capacity, a pipeline diameter of 5 in. was determined by the delivery component of the model. The outlet pressure of the biogas conditioning plant is assumed to be around 100 psia, which becomes the inlet pressure to the pipeline. The pressure at the outlet of the connecting pipeline is assumed to be 90 psia.

The total capital investment was $3,884,782 and total O&M was $281,555/yr. This investment worked out to be approximately $0.11/kg ($2.23/GJ) biomethane.

External Compression Plant

By default, the 'Biomethane Compressor' tab models three parallel compressors with up to three stages per compressor. Two are used in normal operation; the third is a backup unit for contingency. The biomethane is compressed from the output pressure of a low-pressure pipeline (e.g., 90 psia), which connects the biogas cleanup plant to the external compression plant, to the pressure of natural gas transmission/distribution line (e.g., 600 psia) at the point of injection.

For the default input data, the total capital investment of the compressor was $1,631,963 and the total O&M was $151,336/yr, resulting in an investment of $0.05/kg ($1.02/GJ) biomethane.

Case Study Parameters for Biogas Upgrading Process

Cost data from vendors were collected to determine the cost of biomethane from biogas. The costs are commensurate with the upgrading process and are converted to the base currency of the model using the EIA GDP Implicit Deflator Price Index [9].

The biogas composition is assumed to be 60% CH_4, 38% CO_2, 2% N_2, hydrogen sulfide (H_2S) of 600–800 ppm, and siloxane of 60–80 mg/m^3. The volume and energy content of the biogas are based on the CH_4, CO_2, and N_2 content; the other impurities are noted for detail of pipeline quality requirements. The other values have little effect on energy or volume; however, siloxane, H_2S, and other impurities are important for the biogas cleanup design in a real system. In line with the quality of pipeline natural gas, the product-gas composition is 96%–98% CH_4 (97% used), < 1% CO_2 (1% used), < 4 ppm H_2S, < 30 ppb siloxane. All percentages are by volume. The expected average flow was 2000 Nm^3/h (~875 scfm) assuming that peak flow could be moderated to not exceed that average. The system has an annual operating capacity factor of 90%, resulting in an annual operation of 7,884 h.

The variable operating costs consist of utility electricity and biogas feedstock. The electricity usage for the upgrading process was determined to be 0.23 kWh/Nm^3 of feed gas based on the vendors' data. A constant cost of 0.055/kWh for industrial rate electricity was used so sensitivities could be run on the price of electricity. Estimated dairy biogas feedstock costs ranged from 2.9/GJ (2010 dollars) for a covered-lagoon digester to 7.6/GJ (2010 dollars) for a plug-flow digester and to 11/GJ (2010 dollars) for a well-mixed anaerobic digester system [8]. A baseline cost of 7.6/GJ (2010 dollars) was assumed as the default value in this case study. The biogas usage was calculated to be 2.209 Nm^3/kg biomethane using an energy content of 0.0223 GJ/Nm^3 as calculated in the 'Biogas Upgrade' from the biogas composition.

The uninstalled capital cost is estimated to be $2.57 M with an installation factor of 1.29. This multiplier was estimated based on vendor input and covers the full installation costs; therefore, no additional costs are included in the indirect depreciable capital costs section of the 'Input_Sheet_Template'. The annual O&M cost is determined to be 6% of the uninstalled capital cost. The system life is 20 years with a salvage value of 10% at end of life. An H2A standard 10% internal rate of return is used.

Table 2 shows the summary of parameters used for the case study.

Table 2. Baseline Parameters for Upgrading Biogas From Dairy Farms

Parameter	Baseline Value
Feedstock biogas composition	60% CH_4, 38% CO_2, 2% N_2, H_2S in 600–800 ppm, siloxane 60–80 mg/m^3
Product biomethane composition	97% CH_4, 1% CO_2, < 4 ppm H_2S, < 30 ppb siloxane
Feed biogas flow rate	2,000 Nm^3/h
Capacity factor	90% (7,884 h/yr)
Electricity usage	0.23 kWh/Nm^3 biogas
Biogas price	$(2010) 7.6/GJ
Uninstalled capital cost	$(2005) 2.57 M
Installation factor	1.29
Annual O&M	6% uninstalled capital cost
System life	20 years
Salvage value	10%
IRR	10%

Case Study – Results

The format of the results can be seen in the following figures, which are in line with the current H2A presentation. The breakdown of costs can be seen in Figure 15, excerpted from the 'Results' tab in the spreadsheet model.

The emissions summary can be seen in Figure 16. Production of the biogas results in a net reduction of CO_2, but the purification results in some loss of that initial benefit. CO_2 cleaned from the biogas is assumed to be vented to the atmosphere as well as a small loss of CH_4 during the cleanup process. Overall there is a net reduction in total CO_2 from well to end-use application, but the total GHG is a net increase because some CH_4 and N_2O are lost.

Case Study – Sensitivity

A sensitivity analysis was run on several key parameters/variables (see Table 3). Their respective low and high limits were used to determine the range of effects their variations might have on biomethane cost.

Table 3. Sensitivity Parameters With Percent Change From Baseline in Parenthesis

Parameter	Baseline Value	Low Value	High Value
Biogas price	6.8 ($(2005)/GJ)	2.6	9.85
Total direct capital cost	$(2005)3,310,939	$2,979,845 (–10%)	$3,642,033 (+10%)
Biogas usage	2.209 (nm^3/kg biomethane)	2.099 (–5%)	2.319 (+5%)
Operating factor	90%	95%	85%
Electricity price	0.055 ($/kWh)	0.050 (–10%)	0.061 (+10%)
Electricity usage	0.508 (kWh/kg biomethane)	0.483 (–5%)	0.533 (+5%)
Pipeline length	10 (mi)	8 (–20%)	12 (+20%)
External compression outlet pressure	600 (psia)	540 (–10%)	660 (+10%)

Specific Item Cost Calculation		*Total Cost of Delivered Biomethane*	$0.64/kg	$13.11/GJ		
Cost Component	**Biomethane Production Cost Contribution ($/kg)**	**Pipeline Costs ($/kg)**	**Compressor Costs ($/kg)**	**Biomethane Production Cost Contribution ($/GJ)**	**Pipeline Costs ($/GJ)**	**Compressor Costs ($/GJ)**
Capital Costs	$0.08	$0.07	$0.03	$1.63	$1.50	$0.63
Decommissioning Costs	$0.00			$0.02		
Fixed O&M	$0.03	$0.04	$0.01	$0.67	$0.73	$0.29
Feedstock Costs	$0.34	$0.00	$0.01	$6.95	$0.00	$0.10
Other Raw Material Costs	$0.00			$0.00		
Byproduct Credits	$0.00			$0.00		
Other Variable Costs (including utilities)	$0.03			$0.58		
Sub Total	**$0.48**	**$0.11**	**$0.05**	**$9.86**	**$2.23**	**$1.02**

Figure 15. Breakdown baseline scenario cost for biomethane from dairy biogas

Emissions Summary	CO2	CH4	N2O	Total GHG (CO2 eq)
Total upstream emissions (kg/kg biomethane)	-1.81	2.46E-03	2.67E-05	-1.748
Total process emissions (kg/kg biomethane)	1.62	0.01	0.00	1.84
Total well to pump emissions (kg/kg biomethane)	-0.19	1.20E-02	2.67E-05	0.093

Figure 16. Emissions Summary from 'Results' tab of baseline scenario for biomethane from dairy biogas

The tornado chart in Figure 17 and Table 4 show the results. Biogas price has the largest effect by far with a low biogas price producing biomethane at \$9.01/GJ and at a high price \$17.50/GJ. All other variables had a net effect of only ± \$0.36/GJ. The electricity and biogas usage varied by ± 5% of their baseline value, because efficiency was expected to vary in a smaller range, whereas capital cost and electricity price varied ± 10%. The outlet pressure of the compression plant varied by ± 10% and the distribution pipeline length by ± 20%. The pipeline length had a significant effect, even within a few miles. Biogas price was given a high and low value based on the USDA paper [8].

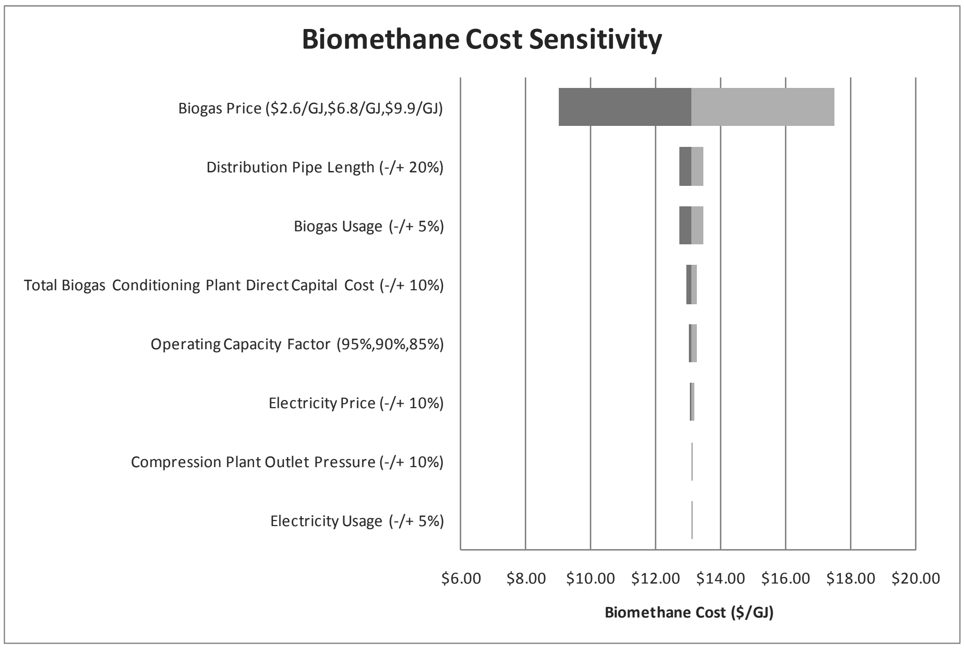


Figure 17. Sensitivity of several parameters on the cost of biomethane

Table 4. Sensitivity Results for High and Low Biomethane Cost

Parameter	Low Cost (\$/GJ Biomethane)	High Cost (\$/GJ Biomethane)
Electricity usage (± 5%)	\$13.08	\$13.14
Compression plant outlet pressure (± 10%)	\$13.07	\$13.14
Electricity price (± 10%)	\$13.04	\$13.18
Operating capacity factor (95%, 90%, 85%)	\$12.99	\$13.23
Total biogas conditioning plant direct capital cost (± 10%)	\$12.94	\$13.27
Biogas usage (± 5%)	\$12.75	\$13.46
Distribution pipe length (± 20%)	\$12.75	\$13.47
Biogas price (\$2.6/GJ,\$6.8/gj,\$9.9/GJ)	\$9.01	\$17.50

Summary

A biomethane cost-analysis model based on the H2A Production and H2A Delivery Components models was developed to calculate the costs associated with biogas purification, transport, and compression. Biogas resource potential is geographically widespread and might easily be integrated into natural gas networks [11]. Biomethane production and use offer environmental benefits and can help meet the requirements of the evolving renewable portfolio standards. The original H2A models were used with necessary modifications to determine the levelized cost of biomethane at the production plant and point of delivery to the natural gas grid or any other end-use site. The H2A Biomethane model includes additional worksheet tabs.

A new worksheet, 'Biogas Upgrade,' was designed to help users characterize the biogas cleanup plant by providing data such as the chemical compositions of the biogas and biomethane streams, biogas feed flow rate, and process energy usage. As an option, the worksheet also allows the users to input itemized capital costs and implement a scaling factor. These data help determine the properties of the inlet and outlet streams and project the total costs, energy consumption, and emissions. Another new worksheet, 'Biomethane Pipeline,' analyzes a network of pipelines that might be used for either collection of biogas from several sources to a central purification plant or export of biomethane to the natural gas grid or to other application sites. A 'Biomethane Compressor' worksheet was also added to account for the costs of any pressure-boosting compressors that may be required depending on the end-use application (e.g., injection into the natural gas pipeline).

A case study was developed for a hypothetical scenario where biomethane is produced from biogas and is exported to the natural gas grid. In this scenario, biogas is purchased from a dairy farm at a cost of \$6.80/GJ. The assumptions for the cost analysis include: 10% rate of return, 20-year life time, and 1.9% inflation rate. The biogas upgrading plant processes 2000 Nm^3 biogas/h for an approximate output of 9.6 M Nm^3/yr (360 M scf/yr; 7.1 M kg/yr) of pipeline quality biomethane recognizing that some volume is lost in the cleanup process, which removes CO_2, N_2, and other impurities. The projected levelized cost of biomethane delivered to the natural gas pipeline is about \$13.11/GJ LHV, which includes the costs of purification, pipeline transport, and compression.

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14. ABSTRACT *(Maximum 200 Words)*
The new H2A Biomethane model was developed to estimate the levelized cost of biomethane by using the framework of the vetted original H2A models for hydrogen production and delivery. For biomethane production, biogas from sources such as dairy farms and landfills is upgraded by a cleanup process. The model also estimates the cost to compress and transport the product gas via the pipeline to export it to the natural gas grid or any other potential end-use site. Inputs include feed biogas composition and cost, required biomethane quality, cleanup equipment capital and operations and maintenance costs, process electricity usage and costs, and pipeline delivery specifications.

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h2a, biomethane, hydrogen, dairy farm, landfill

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27 October 2016

FROM BIOGAS TO RNG: OVERVIEW OF BIOGAS UPGRADING TECHNOLOGIES & UTILITY INTERCONNECTION

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RENEWABLES AND ENERGY EFFICIENCY

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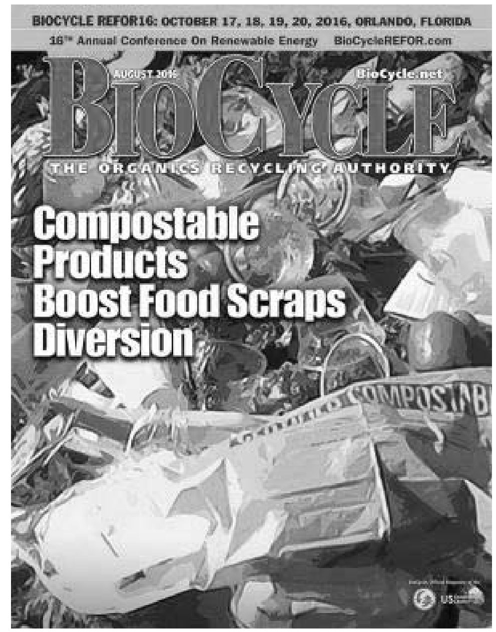
RECENT B&V WORK FOR SCG

- **Economic evaluations of biogas conditioning and upgrading technologies**

- **Key questions to address:**
  - Which technologies are best suited to upgrade biogas at scale?
  - At a conceptual level, how would these projects be designed?



Interested in more?

- **Biocycle Magazine, August 2016**
- **Public Document from SCG**

TECHNOLOGY SUPPLIERS REVIEWED

CO_2 Separation – PSA Carbotech Guild/Molecular Gate Xebec	**CO_2 Separation – Membrane** Air Liquide (MEDAL) Air Products (PRISM) Generon IGS MTR	**CO_2 Separation – Amine/Water** Purac Puregas (Amine) Greenlane Biogas (Water Wash)
Siloxane Removal Clean Methane Systems ESC Energy Systems Unison Solutions Venture Engineering Pioneer Air Systems	**H_2S Removal** Clean Methane Systems Unison Solutions Paques (THIOPAQ) Biorem Technologies	**N_2/O_2 Removal** Guild/Molecular Gate Newpoint Gas (X-O2) Sep-Pro Systems

- Not an exhaustive list
- Several OEMs offer "full solution"

ECONOMIC CONCLUSIONS – BASE CASES

CASE	BIOGAS	FLOW RATE (SCFM)	CAPITAL COST ($000)	OPERATING COST ($000/YR)	LEVELIZED $/MMBTU
A	Landfill Gas	3,000	20,000 to 25,000	1,000 to 1,500	7 to 9
B	Digester Gas	1,050	7,000 to 10,000	400 to 700	8 to 10
C	Digester Gas	400	5,000 to 8,000	300 to 500	14 to 15

- Gas cleaning ONLY. Does not include costs for AD or other equipment.
- All-in costs, including owner's cost allocation, interconnection incentives, and California specific labor factors

DESIGN AND ECONOMIC CONCLUSIONS

- **Consensus of biogas upgrading suppliers: commercial systems are technologically capable of meeting requirements of SCG Rule 30 and AB 1900**
- **Economies of scale hamper smaller scale projects**
  - Cost curve inflection at ~1 MMSCFD
- **Incentives of $3/MMBtu to $5/MMBtu are needed to reduce the cost of biomethane to a value similar to natural gas prices**
  - Transportation fuel incentives are currently the most lucrative (California LCFS and EPA RINs)

POTENTIAL BARRIERS TO DEVELOPMENT

- Gas Monitoring Practices
- Interconnection Costs
- Unfavorable Economies of Scale
- Lack of Biogas-Specific R&D Drivers

THANK YOU!

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NICHOLAS INSTITUTE REPORT

Biogas in the United States

An Assessment of Market Potential in a Carbon-Constrained Future

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Nicholas Institute for Environmental Policy Solutions, Duke University

February 2014

Duke
NICHOLAS INSTITUTE
FOR ENVIRONMENTAL POLICY SOLUTIONS

NI R 14-02

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EXECUTIVE SUMMARY

The substitution of biogas, an energy source derived from biological feedstock, for fossil natural gas can mitigate the build-up of greenhouse gases in the atmosphere. This makes biogas an attractive renewable energy source in a carbon-constrained future. It can be produced through anaerobic digestion of organic feedstock such as manure or wastewater sludge, through thermal gasification of residual or dedicated lignocellulosic biomass feedstock, or by trapping of landfill gas. Although upgraded, pipeline-quality biogas can augment the natural gas market supply, researchers and energy industry experts have little studied its long-term potential. This report aims to answer the question of whether, and under what conditions, a substantial decentralized domestic biogas market could develop in the United States by 2040.

The report examines biogas supply potential for the United States by developing supply functions using detailed cost, feedstock, and technology data. It uses feedstock availability studies, technical literature on the configuration, cost, and efficiency of different conversion technologies, and restrictions on the production of pipeline-quality biogas to calculate levelized costs of energy for biogas production facilities operating with landfill waste, animal manure, wastewater sludge, and biomass residue feedstocks. It then estimates the aggregate national biogas supply potential assuming that various sources of biogas enter the market at their corresponding breakeven price. Cost estimates include gas collection or production (through anaerobic digestion or gasification), clean up, compression, and piping. Combined, these data yield feedstock and technology pathway-specific supply functions, which are also aggregated to produce a single national biogas supply function.

Under a range of specified assumptions, generation of biogas could be expanded to perhaps 3–5% of the total natural gas market at projected prices of $5–6/MMBtu. The largest potential biogas source appears to be thermal gasification of agriculture and forest residues and biomass, and the smallest, wastewater treatment plants. Biogas could be used on-site to generate electricity or to produce pipeline biogas; typically, the latter option has a lower cost. However, when projected electricity and natural gas prices and the value of offsetting energy purchases are factored in, it appears that using biogas for electricity generation may be more profitable than supplying it to the pipeline in many cases.

The report concludes with an analysis of enabling factors and barriers to market development, and assesses the likelihood of diffusion over the next few decades. It finds that because market signals have not spurred widespread adoption of biogas, policy incentives are necessary to increase its use. In particular, trade-offs between pipeline biogas supply and onsite electricity generation are important to consider. Because the latter may be more profitable in many circumstances, the true rate and extent of biogas market diffusion will depend on how electric power and gas markets evolve and on the specific design and implementation of future policy initiatives used to favor one product over the other. Successes and failures of other countries' policy incentives for biogas expansion should be considered.

INTRODUCTION

Although the U.S. Congress decided to forgo comprehensive climate change legislation in recent sessions, greenhouse gas (GHG) emissions control efforts are still very much a reality. Under the auspices of the Clean Air Act, the U.S. Environmental Protection Agency (USEPA) has begun the process of regulating greenhouse gases from large stationary sources such as power plants—a process that could in principle expand to GHG sources in other sectors. California's statewide multi-sector cap-and-trade program got under way in 2013. Power plants in the northeastern United States have had emissions capped for several years now under the Regional Greenhouse Gas Initiative (RGGI). GHG emissions intensities are already part of qualifying criteria for transportation policies such as the national Renewable Fuels Standard (RFS2) and the California low-carbon fuel standard (LCFS). Whether or not a future Congress passes a carbon tax, a nationwide cap-and-trade program, or some other comprehensive climate policy, businesses need to plan for and manage a carbon-constrained operating environment.

In such an environment, renewable, low-GHG fuels will have certain advantages over their higher-GHG fossil counterparts. Biogas—methane (CH_4) derived from biological feedstocks such as waste in wastewater treatment plants (WWTPs) or landfills, animal waste, wood chips and agricultural residues—is one potential renewable fuel with multiple potential uses. For example, biogas could be captured and used where it is produced to generate distributed electricity, or it could be refined and transported through pipelines to centralized electricity generation facilities, centralized chemical refineries (e.g., gas-to-liquids or GTL plants), or elsewhere for other energy uses. By having lower net GHG-emitting biogas as an available fuel component, companies that extract, process, or use natural gas and other fossil fuels may be able to better manage their future carbon liabilities.

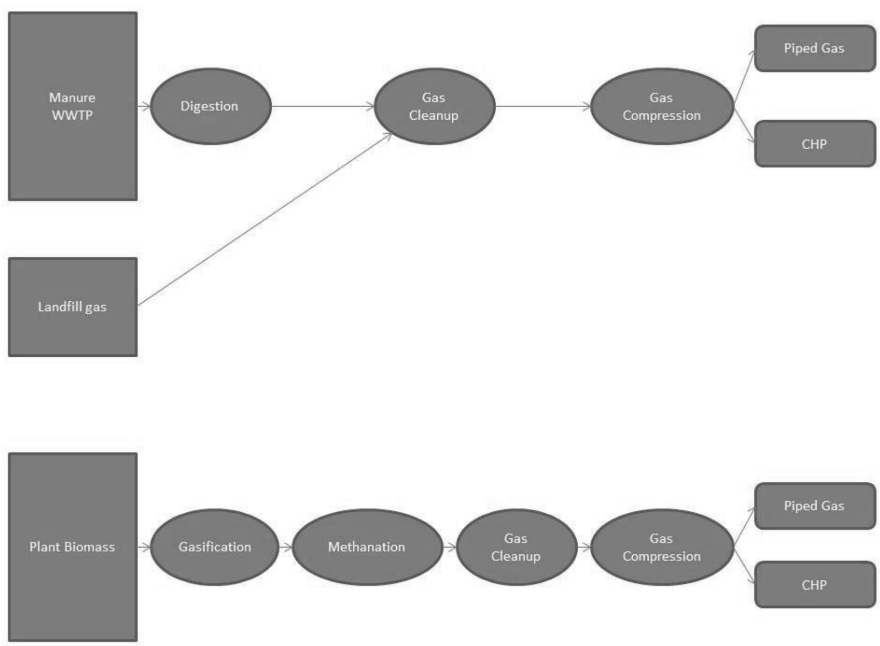
A key question, however, is whether a deep and decentralized market could develop for biogas, thereby allowing that energy source to become a viable substitute for fossil natural gas, and under what conditions? This study explores this question from a supply-and-demand perspective. Because infrastructure and markets take time to develop, the time horizon for assessment is 2040.

The analysis begins by describing the biogas production process, product attributes, substitutability with fossil gas, and underlying features of demand. A critical determinant of the economic feasibility of biogas is the availability of low-cost and dependable feedstock sources on the supply side. Evaluation of feedstock cost and availability therefore play a central role in this analysis. In reviewing potential biogas users and uses in a carbon-constrained economy, the analysis considers the size of potential biogas supply relative to potential future demand for all natural gas and the corresponding specific demand for biogas as a low-carbon substitute. It concludes with an assessment of factors enabling biogas market development and options for addressing barriers to market development. Finally, it draws lessons from emerging biogas markets in other regions of the world to provide insights into the prospects for development of a biogas market in the United States.

BIOGAS ATTRIBUTES AND PRODUCTION PROCESSES

Biomethane, commonly called biogas, is methane-rich gas generated during the breakdown of organic material in anaerobic conditions (Weiland 2010). Methane, a major component of purified biogas and natural gas, is generated through natural processes, but the controlled environment of anaerobic digesters (ADs) and gasifiers increases the percentage of gas produced and captured. Biogas can be produced through biological or thermochemical pathways; the end-products of the two conversion processes are the same (Figure 1). The *biological pathway* refers to the use of anaerobic digesters to provide suitable conditions for bacteria to break down organic material having low lignocellulosic content. Lignin and cellulose make up a large percentage of plant biomass but are difficult for bacteria to break down. Typically, organic material such as landfill waste, animal manure, or wastewater can be processed through the biological pathway.

Figure 1. Biogas production through anaerobic digestion of manure and WWTP, and thermal gasification of plant biomass.



Note: Anaerobic digestion is suitable for biogas production from organic material with low lignocellulosic content, whereas gasification is typically used for biogas production from biomass with low moisture and high lignocellulosic content (e.g., forest residues). *Gas cleanup* refers to upgrading biogas to pipeline quality.

The *thermochemical pathway* refers to the thermal gasification of high-lignocellulosic biomass into syngas, which is mainly composed of carbon monoxide (CO), and hydrogen (H_2). (Tijmensen et al. 2002; Gassner and Marechal 2009; Sims et al. 2010; Kirkels and Verbong 2011). Typically, agricultural and forest residues, other wood residues, and dedicated biofuel crops such as switchgrass can be broken down through this pathway. The syngas produced in gasifiers is then treated in a methanation reactor to increase its methane content, yielding substitute or synthetic natural gas (SNG). Regardless of pathway, the end product is referred to as *biogas.*

Biogas can subsequently be purified, and upgraded in terms of percent of methane content (approaching 100%); the resulting gas becomes a substitute for fossil natural gas (Ryckebosch et al. 2011). The biogas then can be conditioned, compressed, and piped; flared; or used on-site for electricity generation. This report focuses on the supply of pipeline biogas but also evaluates on-site electricity generation as an alternative use that could compete with pipeline injection.

Following a literature review of potential biogas feedstocks and substrates (Symons and Buswell 1933; Chynoweth et al. 1993; Chynoweth 1996; Gunaseelan 1997; Chynoweth et al. 2001; Milbrandt 2005; Labatut et al. 2011), this report considers (1) trapping existing waste resources processed in anaerobic digesters and (2) feeding collected biomass into gasifiers. Existing waste sources include landfill gas (LFG); swine, beef, and dairy operations; and wastewater treatment plants (WWTPs). Collected biomass includes residues left over from forest and agricultural operations, municipal organic waste, and dedicated feedstock, which includes materials specifically grown for biogas production, such as perennial grasses, woody crops, or algae.

ESTIMATING THE MARKET POTENTIAL FOR BIOGAS

This analysis of biogas market potential assesses both potential demand and supply in the coming decades. In several distinct but interrelated stages, it (1) assesses potential demand for the use of biogas as an energy source, (2) estimates the cost and availability of biogas in a hypothetical future market, (3) compares the estimated supply potential to the scale of demand potential to assess how significant a role biogas could play under different conditions, and (4) examines potential hurdles for and enablers of biogas market growth through 2040.

Source and Scale of Potential Demand

Overall demand for natural gas (including biogas) as an energy source and demand for biogas as a low-carbon substitute for fossil gas are described below.

Overall Demand for Natural Gas

Natural gas (NG) is a methane-rich fuel used for heating of residential and industrial structures; for production of electricity with generators, turbines, and reciprocal engines; and in combined heat and power (CHP) applications wherein both the chemical and thermal energy in natural gas is harnessed to generate electricity and productive heat. In addition, natural gas is used as a transportation fuel if it is compressed (CNG) or liquefied (LNG) for ease of transport and reduction of volume. Thus, the energy and transportation sectors are the two key sources of demand for natural gas.

Table 1 lists U.S. natural gas consumption by end use in 2012. Nearly 36% is used for electric power; industrial use accounts for 28%, as does the sum of residential and commercial use.

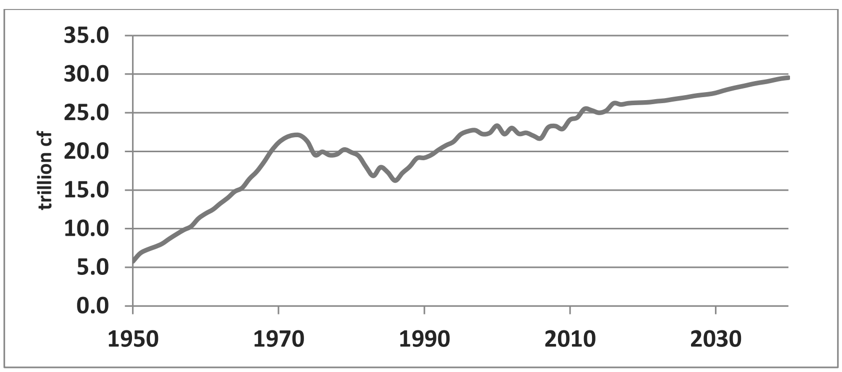
Table 1. U.S. natural gas consumption by end use in 2012.

Uses	MMcf	Percent of total
Total consumption	25,502,251	100.0%
Lease and plant fuel consumption	1,393,190	5.5%
Pipeline and distribution use	715,054	2.8%
Delivered to U.S. consumers	23,394,007	91.7%
Residential	4,179,740	16.4%
Commercial	2,906,884	11.4%
Industrial	7,137,697	28.0%
Vehicle fuel	32,940	0.1%
Electric power	9,136,746	35.8%

Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use (http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm).

Natural gas consumption rose five-fold between 1950 and 2012 (Figure 2), with an initial surge in demand between 1950 and 1970 as the economy and natural gas discoveries grew in the post-war era. This growth was followed by a decrease between 1970 and 1990 as new gas discoveries declined, prices rose, and substitution occurred. Natural gas use resurged after 1990, particularly in the latter part of the last decade as new extraction technologies such as hydraulic fracturing made abundant resources of shale gas economically accessible. U.S. natural gas consumption is projected to increase by 0.7% per year between 2011 and 2040 under baseline projections in the U.S. Energy Information Administration's *Annual Energy Outlook 2013 with Projections to 2040* (USEIA 2013).

Figure 2. U.S. total natural gas consumption: 1950–2012, with projections to 2040.



Sources: Historic data—U.S. Energy Information Administration, Natural Gas Consumption by End Use http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm). Projections—EIA Annual Energy Outlook, 2013 (http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=0-AEO2013&table=13-AEO2013&region=0-0&cases=ref2013-d102312a).

Demand for Biogas as a Low-Carbon Substitute

Once impurities such as siloxanes and hydrogen sulfide (H_2S) are removed from biogas, the fuel is essentially identical to fossil natural gas in terms of chemical composition and heat content. As long as biogas can be processed to the characteristics of fossil natural gas, the two fuels are perfect (physical) substitutes, and sources of demand may be the same for both. The key differentiators between the fuels at that point would be relative costs, carbon footprint, and attributes such as net reduction in non-GHG pollutants (e.g., air particulates, odor, and nutrient discharges to water bodies) generated by biogas capture.

The focus here is the market-level demand for biogas as a fossil gas substitute. Incentives created by renewable energy and GHG mitigation policies deserve particular attention. These incentives may differentiate biogas from fossil gas in the marketplace by inducing demand for the former's low-carbon attributes.

Renewable Energy Policy

Because it comes from biological feedstocks, biogas is considered a renewable energy source. Multiple states offer incentives for the production of biogas, combustion of biogas, or both. For example, landfill gas is an eligible fuel source under at least one tier of compliance for 30 of 31 renewables portfolio standard (RPS) programs according to the Database of State Incentives for Renewables and Efficiency (DSIRE).[1] At the federal level, biogas may qualify as an advanced biofuel under the RFS2. Under the RFS2 and RPS programs, the production of biogas generally creates a secondary, tradable commodity (renewable identification numbers, or RINs in the case of the RFS2; renewable energy credits, or RECs in the case of RPS programs). Other incentives or regulations promoting the use of biogas include production tax credits, low-interest financing, direct grants, and special depreciation and cost recovery provisions. The ultimate effect of these policies is to either increase the value or lower the cost of biogas relative to a fossil fuel alternative. The expected influence of renewable energy policy on biogas demand is discussed below.

GHG Mitigation Policy

Policies seeking to reduce GHG emissions may directly or indirectly provide an incentive for biogas consumption. Eligibility of biogas to contribute to a low-carbon fuel standard (LCFS) creates a direct production incentive, because the fuel can help entities meet compliance obligations. Establishment of a carbon price, through a carbon tax or a cap-and-trade program, would lower the cost of using biogas relative to higher-carbon fossil alternatives. In doing so, a carbon price would also create an incentive for biogas production, because the resulting gas could be sold to the market at a price equal to the prevailing price of natural gas plus the carbon price associated with its consumption.

Take, for instance, a situation in which carbon dioxide (CO_2) emissions from fossil gas use are priced through an emissions trading system (as in California and Europe) or a carbon tax (as in British Columbia and Australia until recently). Table 2 translates a range of policy-relevant CO_2 prices into their fossil gas \$/MMBtu equivalent. This table indicates the potential price difference that could emerge if CO_2 emissions content were priced for fossil natural gas, but not for biogas. For example, parties facing a \$15/t CO_2e price for CO_2 emissions from fossil gas use may be willing to pay a price premium up to \$0.80/MMBtu for biogas if biogas is deemed to be emissions-free.

Emissions allowances have been trading in the range of \$10–16 in California since inception of the state's emissions trading system in 2013; recent prices have settled toward the lower end of that range

[1] Available at http://www.dsireusa.org/ (last accessed August 12, 2013).

(Thompson Reuters Point Carbon 2013a). Allowances in the EU Emissions Trading System traded as high as \$40/tCO_2e in 2008 but plummeted after the global financial crisis caused a sag in emissions and therefore allowances demand. Future CO_2 price projections are highly uncertain due to economic and policy factors, but the California system does have a price floor of \$10/tCO_2e, rising by inflation and a real escalation factor over time, and an allowance price reserve that serves to rein in high prices should demand pressures surge. Thompson Reuters Point Carbon (2013b) has projected that prices in California will trade close to the price floor for the foreseeable future, but previous behavior of emissions markets suggests that conditions and price trends can change rather quickly. Given this inherent volatility and uncertainty, a more in-depth discussion of the expected influence of GHG mitigation policy on biogas demand is provided below.

Table 2. CO_2 price impact in terms of \$/MMBtu of gas.

CO_2 price \$/tCO_2e	\$/MMBtu [a]
\$5	\$0.27
\$10	\$0.53
\$15	\$0.80
\$20	\$1.06
\$25	\$1.33
\$30	\$1.59
\$35	\$1.86
\$40	\$2.12
\$45	\$2.39
\$50	\$2.65

Source: USEPA Cleaner Energy: Calculations and References (http://www.epa.gov/cleanenergy/energy-resources/refs.html; last accessed October 7, 2013).
[a] tCO2e per MMBtu = 0.05306.
Note: This price is assigned for the CO_2 emissions from natural gas combustion, not for direct emissions of natural gas methane (CH4), which would be 21–25 times more potent from the perspective of global warming potential.

Other Demand Drivers

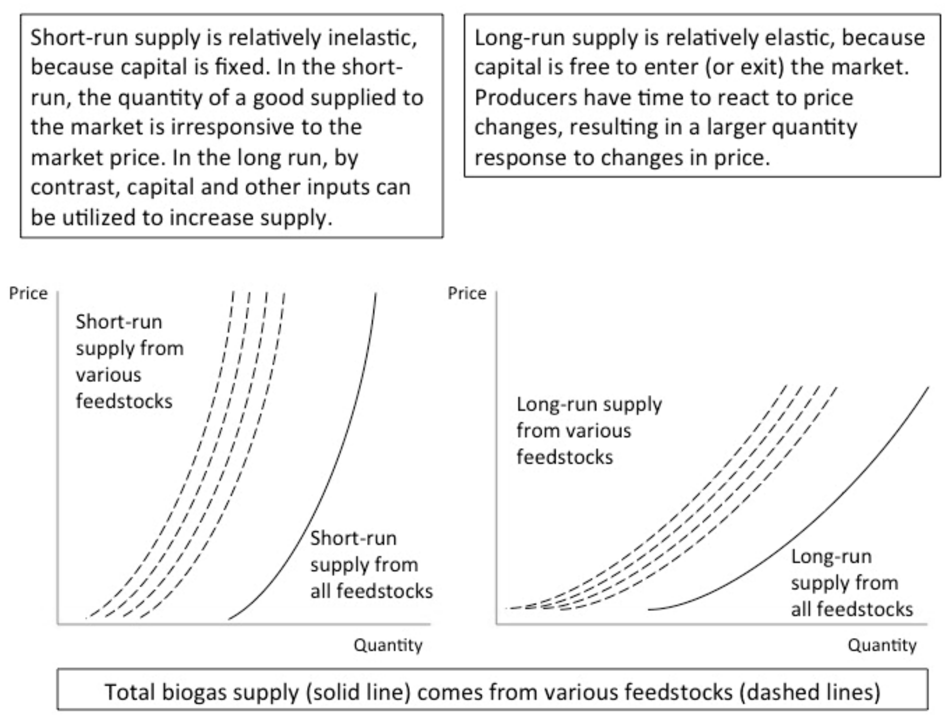
Demand for biogas may also be created by individual facility or corporate objectives. For example, an increasing emphasis on corporate social responsibility (CSR) may create a preference for low-carbon, renewable energy sources such as biogas. Biogas can also play a role in diversifying energy generation portfolios, though its capacity to hedge against large swings in the fossil fuel market depends on achieving significantly greater market penetration.

Estimation of Supply Potential

Biogas supply potential is presented in the form of a supply function, which quantifies how much biogas can be supplied to the market annually at different expected prices or costs. In general, some level of production can be supplied at relatively low costs, but increasing the production level typically incurs higher marginal costs, requiring higher prices to induce willing supply. Two perspectives can be taken when a supply function is constructed (Figure 3). The first is a short-run perspective, whereby the potential supply of a commodity is largely determined by a fixed capital stock in place at the time of estimation. The function shows the price/quantity relationship of additional units of supply being brought into the market by increasing output from existing or easily convertible production units. For the purposes of this analysis, a short-run supply function is largely irrelevant, because little biogas capital is in place and the market to supply is small.

The second approach is to take a long-run perspective, which is the focus of this analysis. A long-run supply function allows new capital to freely enter or exit the market. In contrast to a short-run supply function, each point in a long-run supply function represents a unique allocation of capital; the number, type, and size of facilities for one quantity/price point may be completely different than those for another. For instance, a long-run function may represent that, with adequate time for capital entry and at a certain price per unit of output, biogas production is economically feasible from, say, x percent of all landfills, x percent of all animal manure management operations, and x percent of all wastewater treatment plants and could support x agriculture and forest residue biogas-processing facilities, collectively producing x million cubic feet per year. In Figure 3, the long-run function is "flatter" than the short-run function, reflecting that, in the short run, capacity is largely fixed and supply response to price is limited. Price response is stronger in the long run, when the supply side of the market has more time to react to price signals. If prices rise—and appear to stay high—new entrants will set up production. If prices fall in a sustained way, marginal producers will leave, and supply will decline with it. This study estimated potential supply in the 2040 time period, and thus assumes that there is sufficient time for a market to develop and for capital to form in pursuit of it.

Figure 3. Short-run and long-run supply functions.



Note: Supply functions are different, because capital is free to enter and produce over the long run.

In the initial estimation of long-run biogas supply functions, no particular attention is paid to how the technology may diffuse or how identified barriers may be overcome. The analysis assumes only that biogas will be supplied if it is economical to do so. But as discussed in more detail below, GHG and renewable energy policy are expected to play a significant role in biogas market expansion. Owing to the unique attributes of biogas, over-the-counter (OTC) transactions are also likely to play a key role in growing the market before the emergence of a robust spot market with numerous sellers and buyers.

Supply Estimation

The analysis begins by grouping feedstocks into two main categories of biogas supply on the basis of conversion technology, anaerobic digestion, and thermal gasification (Figure 1). Within each category, a subset of sources or feedstocks is selected for detailed analysis on the basis of availability, energy yield, processing cost, physical characteristics, and price paid (if any) for the feedstock. The analysis makes use of (1) existing studies of feedstock availability; (2) technical literature on the configuration, cost, and efficiency of different conversion technologies; and (3) identified restrictions on the production of pipeline-quality biogas (i.e., certain applications deemed technically difficult or cost-prohibitive to generate commodity grade biogas).

Methodology and Assumptions

To estimate the supply function, total cost of biogas production was converted into a levelized cost per unit energy (LCOE) generated over the life of the project using the following equation:

$$\boldsymbol{LCOE} = \frac{\sum_{t=1}^{20} \frac{\textit{Capital cost}_t + \textit{Operations and maintenance cost}_t}{(1+r)^t}}{\sum_{t=1}^{20} \frac{\textit{Electricity generation}_t}{(1+r)^t}} \qquad \textbf{(1)}$$

According to equation (1), the discounted stream of annual costs for each source of biogas (LFG, manure, WWTP, and biomass gasification) over the 20-year assumed life of the installed capital was divided by the discounted stream of biogas produced over the same period. The analysis assumes a real (inflation-adjusted) discount rate of 5% (r=0.05) for both.

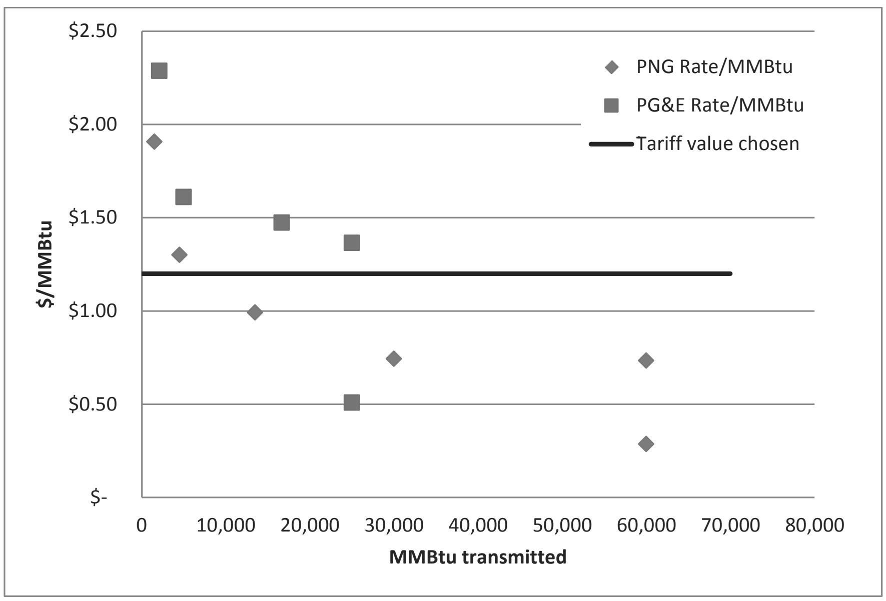
To calculate annual costs, data on the upfront (capital) cost and the annual (operating and maintenance) cost for the 20-year equipment life were gathered. These cost estimates for wastewater treatment plants and landfill gas were based on Prasodjo et al. (2013) and Cooley et al. (2013). Costs specific to livestock operations and biomass gasification are presented below. Costs were converted to real terms (the same dollar years) using the producer price index (PPI) for building-related engineering projects in the engineering services industry, in which the annual cost increase averaged 2.7% for the past 10 years.

Costs to transport biogas from the source to the end user were estimated using a per-unit transmission tariff of $1.20/MMBtu. This tariff was calculated as the average posted rate across the range of amount of gas transmitted—an average based on published transmission tariffs by PG&E and PNG[2] (Figure 4). In doing so, the analysis assumes that a third party finances the construction and operation of distribution lines and that subsequent facilities simply pay a fee to access this network.

[2] PG&E transmission tariff data are available at http://www.pge.com/tariffs/GRF.SHTML#GNT (last accessed September 29, 2013). PNG transmission tariff data are available at http://www.piedmontng.com/files/pdfs/rates/nc_rates_2013-08.pdf (last accessed September 29, 2013).

By using this tariff number, the analysis effectively averages transmission costs across a range of transmission distances. An alternative approach would be to estimate the approximate distance of each generating facility from the pipeline network, to calculate the total costs of running a distribution line between that facility and existing transmission lines, and to attribute that amount to the facility's upfront capital costs. This approach becomes problematic when constructing a long-run supply function comprised of new entrants, because assumptions of pipeline distance begin to hold an outsized influence on biogas costs. To assess the effect of these transportation assumptions on estimated potential, two sensitivity analyses were performed—one to pipeline cost assumptions under the $1.20 tariff assumption and one under the assumption of the annual cost per gas-producing facility of maintaining 1- or 15-mile (based on Cooley et al. 2012) gas transmission lines at $180,000 per mile (based on Prasodjo et al. 2013) that feed into the NG pipeline system. These sensitivity analyses are presented after the main results below.

Figure 4. Natural gas transmission tariffs.



Note: Tariffs for different amounts of gas transmitted by PNG and PG&E. Quantity transmitted reflects the amount of gas transmitted on a per-transaction basis.

To estimate the amount of biogas generated for all sources, the analyses use conversion factors from the literature and account for changes in yield between the year data were collected and the year that a biogas market could develop. Specifically, gas yield from landfill waste was adjusted for long-term yield using average annual waste in place. Manure from animal operations for biogas production was adjusted according to recent and projected trends regarding the number and size of operations. Effluent to wastewater treatment plants was adjusted using a population growth factor. After facilities were arranged in an ascending order on the basis of estimated biogas yield in 2040, they were grouped into tiers on the basis of size categories and calculated total biogas yield for each tier. As an example, the size categories for landfills are shown in Table 3. The analyses then ordered each capacity tier by the LCOE (lowest to highest) and plotted the results against the cumulative amount of biogas available at that price to construct a supply function. The key assumption when constructing supply functions this way is that all tiers would enter the market at their corresponding breakeven price. This procedure was repeated for each source of biogas.

Table 3. Conditioning, compression, and collection equipment and O&M costs.

	Conditioning unit cost		Compressor unit cost		Collection equipment cost		
Size category feed flow (scfh)	Unit cost	O&M cost	Unit cost	O&M cost	Unit cost	O&M cost	Electricity
6,000	$845,000	$36,535	$132,500	$9,465	$165,180	$375	$7,416
21,000	$2,270,000	$86,600	$200,000	$16,400	$578,130	$1,313	$25,956
42,000	$3,000,000	$132,000	$225,000	$45,500	$1,156,260	$2,625	$51,912
72,000	$3,800,000	$315,100	$325,000	$119,900	$1,982,160	$4,500	$88,992
120,000	$5,200,000	$526,200	$450,000	$193,800	$3,303,600	$7,500	$148,320
300,000	$8,600,000	$1,276,000	$600,000	$474,000	$8,259,000	$18,750	$370,800

Sources: Conditioning and compression costs are based on Prasodjo et al. (2013) and Cooley et al. (2013); collection cost is based on the EPA-LMOP Project Development Handbook (http://www.epa.gov/lmop/documents/pdfs/pdh_chapter3.pdf; last accessed June 18, 2013).
Note: Costs used for biogas supply calculations were taken from landfills (collection, conditioning, compression), animal operations (conditioning and compression), wastewater treatment plants (conditioning and compression), and biomass gasification (compression). Feed flow, in units of standard cubic feet per hour, was used to create size categories or bins into which all landfills were grouped. Those landfills with feed flows larger than 300,000 scfh were equipped with the most cost-effective combination of units.

Supply Potential by Feedstock

As described above, biogas is already being produced as a byproduct of normal operations at some facilities. Production for use involves capturing, conditioning, and compressing the biogas. For a range of economic and policy reasons, this production already occurs at some landfills, wastewater treatment plants, and agricultural (swine, beef, and dairy) operations. These three supply sources are likely to be the first to come online in a biogas market. By contrast, biomass gasification using forest and agricultural residues is rare and remains in pre-commercial stages of market development.

This study reviewed research on the technical and economic potential of landfill, wastewater treatment plant, and agricultural biogas supply sources. Although several state-level assessments of biological feedstock availability exist (Milbrandt 2005; Walsh et al. 1999), these studies are dated and are generally of limited use to the current exercise. Accordingly, this study developed estimates of potential supply. Described below are the methodology and the rationale for any key assumptions. Initial estimates for each of the three existing biogas supply sources are presented, along with an estimate of total biogas market potential that results from combining these estimates with estimates of biomass gasification. Key uncertainties and data needs are discussed.

Biogas from Landfill Waste

Landfill gas (LFG) is produced when the organic portion of landfilled material decomposes in the absence of oxygen, typically away from the surface, where pressure is higher due to larger volume, and temperature fluctuations are smaller. To access landfill gas, a collection system composed of pipes and blowers is typically installed. As of mid-2013, 564 of 2,434 (23%) landfills in the United States were collecting gas for electricity generation or direct use, and more than 1,700 additional landfills (70%) could potentially collect gas. This study evaluated the technical potential of both groups.

At least two studies have looked at national-level LFG potential but without estimating the cost of supplying the gas (Milbrandt 2005; USEPA 2005). EPA projections suggest baseline LFG emissions from municipal solid waste in the United States will be 124.1 $MtCO_2e$ in 2015 and decrease to 123.5 $MtCO_2e$ by 2020 (USEPA 2005). To calculate the technical potential of biogas supply from landfill gas in the United States, this study used the Environmental Protection Agency's Landfill Methane Outreach Program (EPA-LMOP) database, which contains data on landfill location, size, and operating status and on LFG end uses.[3] Themelis and Ulloa (2007) and Cooley et al. (2013) provided a starting point for development of a methodology to estimate the technical biogas potential from landfills. The EPA-LMOP was the source of data for waste in place (WIP) in metric tons at various landfills, both operational and with LFG generation potential, in the United States. The WIP data from EPA-LMOP was projected to 2040 for those landfills that had both opening and closure years given in the dataset. Specifically, annual average WIP (between opening and 2012) was added to these landfills until 2040. WIP for landfills with incomplete data were not adjusted. Year 2040 landfill waste in place was then converted to methane using conversion factors based on Milbrandt (2005). This study provided different generation rates based on landfill size and on whether the landfill is located in an arid region. The resulting methane generation potential broken down by landfill size categories is shown below (Table 4).

Table 4. Landfills in the EPA-LMOP database.

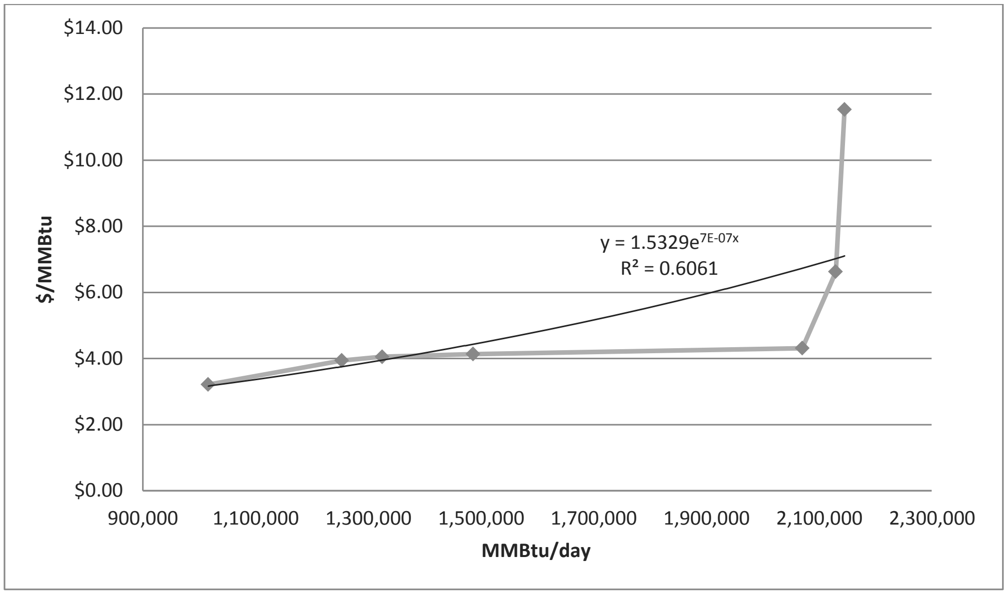
LF category	Size category: landfill output (scfh)	Generation unit used	Number of landfills	Total methane generation in LF category (scfh)	Total methane generation in LF category (MMBtu/day)
1	<6000	Recipr. engine	417	655,148	15,724
2	6,000–21,000	Steam turbine	320	2,471,423	59,314
3	21,000–42,000	Steam turbine	130	2,990,366	71,769
4	42,000–72,000	Steam turbine	171	6,711,396	161,074
5	72,000–12,0000	Steam turbine	150	9,885,534	237,253
6	12,0000–30,0000	Steam turbine	188	24,353,853	584,492
7	>300,000	Steam turbine	98	42,337,937	1,016,110

Note: Landfills were grouped into seven size categories on the basis of output in standard cubic feet per hour (scfh). Total methane generation for each category is expressed in terms of scfh and million British thermal units (MMBtu) per day, and the former was converted to the latter using the conversion factor 1 scft = 1,000 MMBtu.

For each size category, the LCOE was calculated using the method described above. LFG collection costs were calculated on the basis of the EPA-LMOP Project Development Handbook, and all other costs, shown in Table 3, were as described above.[4] On the basis of these costs, the study estimated the base case LFG biogas supply function shown in Figure 5.

[3] National and state lists of landfills and energy projects are available at http://www.epa.gov/lmop/projects-candidates/index.html (last accessed September 19, 2013).
[4] Available at http://www.epa.gov/lmop/documents/pdfs/pdh_chapter3.pdf (last accessed June 18, 2013).

Figure 5. Biogas supply potential from landfills in the United States.



This analysis of LFG potential has several caveats. First, the supply function reflects a high degree of averaging across units in the same category. Each of the seven landfill categories is represented by a single point (price-quantity combination). There is likely to be heterogeneity of cost and yield conditions within each category that is not reflected here due to data limitations. In addition, because LFG generation declines over time for a given amount of waste, various sizes (and thus costs) of conditioning and compression units might be optimal at different times throughout the analysis timeframe. Also, piping cost is a major component of total cost of biogas production, but, as discussed above, this cost is accounted for as a fixed per-unit transmission charge regardless of landfill location and methane generation rate. Although both assumptions have the potential to change the quantity of available biogas and the price at which it is delivered, LFG generation could not be modeled for each individual landfill. Instead, sensitivity analyses of pipeline costs and choice of energy production application (e.g., pipeline gas versus electricity generation) are presented below.

Biogas from Swine, Beef, and Dairy Operations

Livestock operations produce manure in large volumes with varying moisture content. Methane is produced naturally in manure storage lagoons, but an anaerobic digester can be used to control temperature, improve mixing of the feedstock for higher yields, and capture the gas. The biogas coming out of the digester is typically 65% methane and 35% CO_2. Various types of digesters have been developed to handle different types of manure. Fixed-film digesters that can handle the higher moisture content of swine manure can also digest wastewater at treatment plants (see below), whereas covered-lagoon, complete-mix, and plug-flow digesters are commonly used to digest manure.

Biogas generated from livestock systems is an existing and continually produced feedstock for biogas. But no study appears to have examined total technical livestock biogas potential in the United States and the cost of realizing that potential. Therefore, this study constructed a supply function for biogas from livestock manure using the methodology described above.

To calculate biogas potential from livestock operations, this study collected data on (1) number of livestock and livestock operations in the United States, (2) annual manure output per head of livestock, (3) manure-to-biogas conversion factors for various types of anaerobic digesters, and (4) digestion and gas-processing cost data specific to manure. Main sources of data specific to this part of the analysis included ICF International (2013) for digester capital and O&M costs, gas cleanup costs, and post-digestion solids separation costs; the USDA-NASS database for livestock numbers; and the EPA-AgSTAR database for data on currently operating digesters.[3] The study assumed a reduction in the number of small animal operations by 2040, consistent with trends observed in NASS data (NASS 2013). It excluded small animal operations (cattle < 500 animals; swine < 2,000 animals) from the biogas supply on the basis of the observation that biogas production in animal operations below the sizes above are generally not profitable (USEPA 2011a).

The number of swine and dairy operations by size and head (cattle, beef, dairy, and swine) from the 2012 USDA-NASS database were combined with USDA-NASS 2013 spring inventory data to calculate the number of livestock in livestock operations of various sizes (Table 5).[4] Next, the study considered the different types of digesters that might be used and the best allocation of those technologies across livestock operations. This allocation was based on two factors: (1) a review of the suitability of each type of digester to handle manure generated from a given type of livestock and (2) an analysis of the AgSTAR database, specifically, a calculation of the prevalence of digester types used for different livestock systems with operational anaerobic digesters. Most livestock operations do not operate an anaerobic digester. For the small subset of operations that do, AgSTAR data shows that covered-lagoon digesters are used at 10% of dairy and 60% of swine operations; complete-mix digesters are used at 40% of dairy and 30% of swine operations; and plug-flow digesters are used at all beef, 50% of dairy, and 10% of swine operations. On the basis of ICF International (2013), the study calculated annual methane capture (assumed to be 85% of generation) from manure per head of livestock for each type of digester.

[3] AgSTAR data are available at http://www.epa.gov/agstar/projects/index.html#database (last accessed September 29, 2013); USDA-NASS data are available at http://www.nass.usda.gov/ (last accessed June 18, 2013).
[4] Available at http://www.nass.usda.gov/Statistics_by_Subject/index.php?sector=ANIMALS & PRODUCTS (last accessed September 29, 2013).

Table 5. Number of livestock operations, number of livestock, and total and average number of livestock by operation size.

Number of operations				
Operation size	**Cattle**	**Beef**	**Dairy**	**Swine**
Less than 100 head	749,000	660,000	43,000	48,700
100–499 head	137,000	63,400	11,700	5,000
500–999 head	18,400	4,230	1,570	2,300
1,000–1,999 head	6,440	1,050	950	3,300
2,000–4,999 head	3,000	270	780	5,700
5,000–9,999 head	700	50		3,300
10,000–19,000 head	260			
20,000+ head	200			
Total	915,000	729,000	58,000	68,300
Total number of animals by operation size				
Operation size	**Cattle**	**Beef**	**Dairy**	**Swine**
Less than 100 head	18,753,000	13,155,700	1,582,400	527,200
100–499 head	26,968,600	11,251,200	2,235,600	1,252,100
500–999 head	12,144,800	2,637,000	1,094,800	1,713,400
1,000–1,999 head	8,037,000	1,289,200	1,288,000	4,810,700
2,000–4,999 head	8,037,000	615,300	2,999,200	16,804,500
5,000-9,999 head	4,465,000	351,600		40,792,100
10,000–19,000 head	3,304,100			
20,000+ head	7,590,500			
Total	89,300,000	29,300,000	9,200,000	65,900,000
Average number of animals by operation size				
Operation size	**Cattle**	**Beef**	**Dairy**	**Swine**
Less than 100 head	25	20	37	11
100–499 head	197	177	191	250
500–999 head	660	623	697	745
1,000–1,999 head	1,248	1,228	1,356	1,458
2,000–4,999 head	2,679	2,279	3,845	2,948
5,000–9,999 head	6,379	7,032		12,361
10,000–19,000 head	12,708			
20,000+ head	37,953			

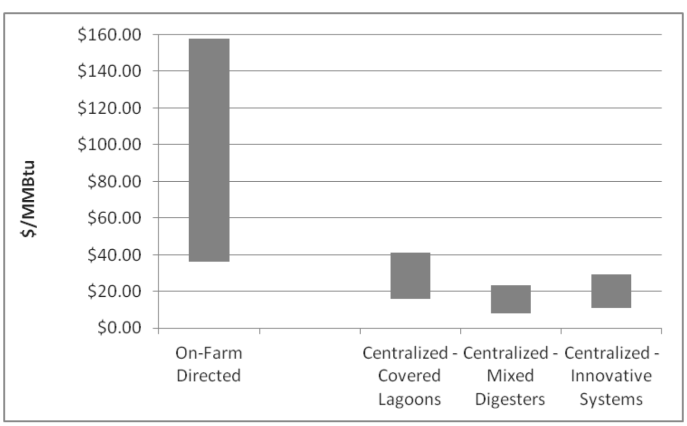
Next, the capital costs of the anaerobic digester and generator for each operation size were calculated on the basis of the following regression equations relating livestock operation size and capital cost (ICF 2013):

> Covered lagoon capital cost = $599,566 + $400/cow (last term scaled by 0.31 for swine and beef)
>
> Complete mix capital cost = $320,864 + $563/cow (last term scaled by 0.31 for swine and beef)
>
> Plug flow capital cost = $566,006 + 617/cow (last term scaled by 0.31 for swine and beef)

The calculation included annual O&M costs for the digester – 4% of capital costs, annual post-digestion solid separation costs (for dairy and beef only) – 6.4% of capital costs, annual H_2S treatment costs – 3.1% of capital costs, annual electricity charges to run the operation – 5.3% of capital costs. Capital and O&M costs for the appropriate compression units were calculated for each digester size and type (Table 6). Pipeline gas transmission tariffs were also included, as described above.

After performing this analysis assuming that all participating animal operations are equipped with their own anaerobic digester and other processing equipment, the study grouped facilities to estimate the cost savings associated with centralized biogas processing. Prasodjo et al. (2013) find significant cost advantages in centralized versus individual conditioning and compression for swine farms in North Carolina (Figure 6). On the basis of the differences in mean costs from Prasodjo et al. (2013), the study calculated a conditioning and compression cost reduction of 74% for covered-lagoon and plug-flow digesters and 85% for complete-mix digesters. Facilities distribution also factors into estimates of total pipeline cost. Rather than come up with estimates of the costs of the pipeline needed to connect each facility to the pipeline network, the study operates on the assumption of a flat per-unit transmission fee—an assumption for which it performs a sensitivity analysis. After discounting both the methane generation stream and annual costs, the study arrived at the supply function shown below (Figure 7).

Figure 6. Range of costs for individual/on-farm versus centralized/group biogas conditioning and compression.



Source: Derived from Prasodjo et al. (2013).
Note: Cost ranges are shown for several digester types in centralized collection configurations.

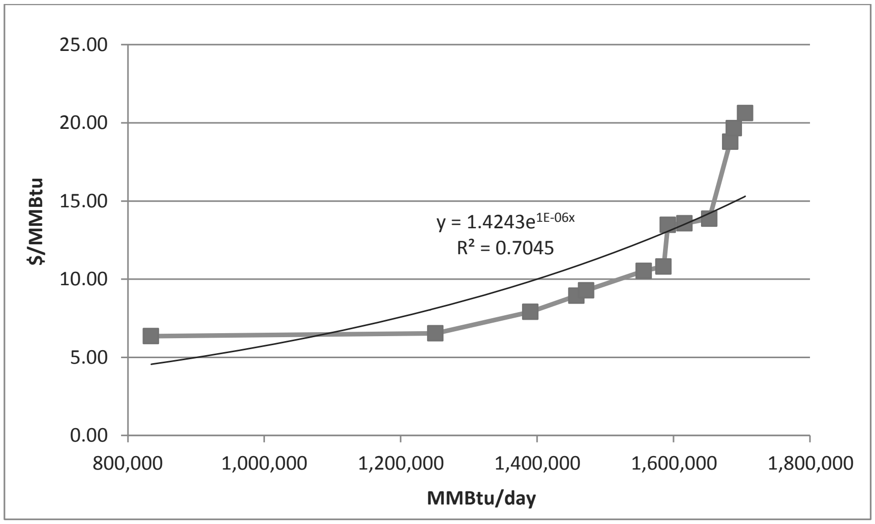
Table 6. Costs associated with biogas production from anaerobic digestion of dairy, swine, and beef manure.

Farm type	Operation size	Digester type	Methane production (m3/yr/op)	Methane production (scfh)	Digester capital cost	Compressor unit capital cost	Digester operating cost per year	Compressor unit operating cost per year	Gas treatment per year	Post-digestion solids-separation system cost per year	Utility charges per year
Dairy	500–999	Covered lagoon	405,529	1,622	902,082	132,500	36,083	9,465	27,965	57,733	47,810
	1,000–1,999		788,948	3,156	1,172,799	132,500	46,912	9,465	36,357	75,059	62,158
	2,000–4,999		2,237,098	8,948	2,195,280	200,000	87,811	16,400	68,054	140,498	116,350
	5,000–9,999										
	10,000–19,000										
	20,000+										
	500–999	Complete mix	481,104	1,924	732,533	132,500	29,301	9,465	22,709	46,882	38,824
	1,000–1,999		935,979	3,744	1,113,568	132,500	44,543	9,465	34,521	71,268	59,019
	2,000–4,999		2,654,011	10,616	2,552,710	200,000	102,108	16,400	79,134	163,373	135,294
	5,000–9,999										
	10,000–19,000										
	20,000+										
	500–999	Plug flow	481,104	1,924	1,022,948	132,500	40,918	9,465	31,711	65,469	54,216
	1,000–1,999		935,979	3,744	1,440,530	132,500	57,621	9,465	44,656	92,194	76,348
	2,000–4,999		2,654,011	10,616	3,017,707	200,000	120,708	16,400	93,549	193,133	159,938
	5,000–9,999										
	10000–19,000										
	20,000+										
Swine	500–999	Covered lagoon	186,457	746	711,775	132,500	28,471	9,465	22,065	-	37,724
	1,000–1,999		360,549	1,442	801,428	132,500	32,057	9,465	24,844	-	42,476
	2,000–4,999		1,893,005	7,572	1,590,603	200,000	63,624	16,400	49,309	-	84,302

	5,000–9,999										
	10,000–19,000										
	20000+										
	500–999	Complete mix	186,457	746	464,676	132,500	18,587	9,465	14,405	-	24,628
	1,000–1,999		360,549	1,442	590,863	132,500	23,635	9,465	18,317	-	31,316
	2,000–4,999		1,893,005	7,572	1,701,627	200,000	68,065	16,400	52,750	-	90,186
	5,000–9,999										
	10,000-19,000										
	20,000+										
	500–999	Plug flow	186,457	746	729,400	132,500	29,176	9,465	22,611	-	38,658
	1,000–1,999		360,549	1,442	867,689	132,500	34,708	9,465	26,898	-	45,988
	2,000–4,999		1,893,005	7,572	2,084,993	200,000	83,400	16,400	64,635	-	110,505
	5,000–9,999										
	10,000–19,000										
	20,000+										
Beef	500–999	Plug flow	84,728	339	703,667	132,500	28,147	9,465	21,814	45,035	37,294
	1,000–1,999		167,008	668	822,509	132,500	32,900	9,465	25,498	52,641	43,593
	2,000–4,999		633,080	2,532	1,495,690	132,500	59,828	9,465	46,366	95,724	79,272
	5,000–9,999										
	10,000–19,000										
	20,000+										

Note: Costs are based on ICF International (2013).

Figure 7. Maximum economic supply potential for biogas generated from livestock operations.



Note: Assuming centralized biogas conditioning and compression.

Biogas from Wastewater Treatment Plants

Biogas production can occur in both wastewater and sludge portions of WWTP effluent streams should anaerobic conditions develop either intentionally or incidentally.[5] When installed in WWTP facilities, anaerobic digesters can help to reduce the volume of residual organic solids. Liquids produced from the sludge digestion process can be recycled through the plant for additional treatment, while the resulting methane can be captured and reused for pipeline or on-site electricity generation applications.

Large amounts of biogas are naturally produced as a byproduct of the wastewater treatment process. Nationally, biogas emissions from domestic wastewater treatment plants accounted for roughly 0.1% of total U.S. GHG emissions in 2011, or approximately 7.6 Tg CO_2e (USEPA 2013).[6] The 2011 WWTP total includes both centralized (~2.5 Tg CO_2e) and diffuse septic systems (~5.0 Tg CO_2e). These numbers largely exclude wastewater processed in aerobic facilities, which are assumed to be well-managed and to generate little or no biogas during the treatment process. USEPA (2013) also assumes that methane generated in anaerobic digesters is destroyed with 99% efficiency. Therefore, within the WWTP sector, biogas generation as reported by USEPA (2013) is likely significantly less than pipeline biogas potential.

[5] Most of the data used in this portion of the analysis is derived from a recent study by the U.S. EPA Combined Heat and Power Partnership (USEPA 2011). Fuel and electricity pricing data were derived from EIA AEO projections (EIA 2013). Compression, conditioning, and pipeline costs were derived from recent Duke University studies on biogas potential from swine operations (Prasodjo et al. 2013) and landfill gas (Cooley et al. 2013).

[6] Although the source publications are unclear, this study assumes that municipal wastewater treatment plants described by USEPA (2011c) include those same facilities labeled *domestic* wastewater treatment plants by USEPA (2013). USEPA (2013) discusses a second plant category—*industrial*—that is pertinent to specific industrial operations (e.g., pulp and paper production; ethanol production; meat, poultry, fruit, and vegetable processing) and that apparently falls outside the municipal category.

Approximately 60% of flow associated with municipal wastewater treatment plants is already associated with anaerobic digestion (USEPA 2011b), implying that a sizable and ready-made source of biogas is available.

This study estimated the potential supplied by (1) existing municipal wastewater treatment plants with anaerobic digesters but without combined heat and power and (2) new plants brought online to accommodate an expanding population.[7] Analysis is limited to this subset of facilities, because they are likely to face the lowest direct costs to supply biogas to the market. They need only install the infrastructure to transport the gas already being produced to a larger distribution network. Furthermore, facilities without digesters are unlikely to install them for the express purpose of biogas generation (USEPA 2011b).[8] Although these facilities could decide to install digesters and biogas pipeline infrastructure, they are likely to be among the highest-cost producers and are less likely to be economical under foreseeable circumstances. Facilities without digesters also represent a minority of the total and are skewed toward smaller capacities. For these reasons, this study does not consider the retrofit of existing facilities. It does, however, assume that new facilities entering service are equipped with anaerobic digesters.

To estimate biogas potential from wastewater treatment plants, data from USEPA (2011b) are used to identify the aggregate wastewater flow associated with facilities of different capacities and to calculate an approximate flow-to-digester gas conversion rate, which is then multiplied by a population growth constant and an assumed digester gas methane content, and finally converted to Btu (Eq. 2).[9] This equation yields the data used in this study's WWTP biogas supply estimates and all of the ensuing analysis (Table 7).

$$\boldsymbol{Total\ Flow\ (MGD) \times 1.18 \times \frac{10{,}000\ ft^3\ digester\ gas}{MGD} \times 65\%\ CH_4 by\ volume \times \frac{1000\ Btu}{1 ft^3 CH_4}} \qquad \mathbf{(2)}$$

[7] The implicit assumption here is that facilities already using combined heat and power are unlikely to dismantle existing infrastructure and install new infrastructure for the express purpose of generating pipeline biogas.
[8] For example, use of anaerobic digesters for biosolids management can reduce the volume of waste that must otherwise be disposed off-site.
[9] The study assumes that the present distribution of WWTP sizes remains constant over time but that the total number of facilities expands to accommodate population growth. U.S. projected population in year 2040 is approximately 1.18 times today's population. Population projections are derived from 2012 National Population Projections Summary Tables, Middle Series, at http://www.census.gov/population/projections/data/national/2012/summarytables.html (last accessed September 20, 2013).

Table 7. Year 2040 biogas potential from wastewater treatment plants.

WWTP facility size (MGD)	Total cumulative flow (MGD)	Cumulative 2040 flow with anaerobic digestion (MGD)	MMBtu/day @ 65% CH_4 content	MMBtu/year @ 65% CH_4 content
>200	4,682	3,742	24,323	8,877,895
100–200	3,206	2,577	16,753	6,114,845
75–100	2,575	1,872	12,165	4,440,225
50–75	1,744	1,351	8,779	3,204,335
20–50	4,899	3,257	21,170	7,727,050
10–20	4,038	2,590	16,838	6,145,870
5–10	3,779	2,221	14,435	5,268,775
1–5	6,074	3,032	19,706	7,192,690
Total	**30,996**	**20,641**	**134,170**	**48,972,050**

Note: Wastewater treatment plants (WWTP) are already outfitted with anaerobic digesters. Flow rates and cumulative flows are derived from USEPA (2011b) and are adjusted to account for population growth. Facilities are sorted by flow rate, expressed in units of millions of gallons per day (MGD).

Next, the study estimated the cost of providing biogas to a national market. First, it assessed the costs associated with installation of conditioning, compression, and pipeline infrastructure for each WWTP size category indicated in Table 7. Because conditioning and compression equipment is often sized in units of standard cubic feet per hour (scfh), the study estimated an average flow per facility. It then estimated the size and number of conditioning units necessary to process that amount of digester gas, choosing the sizing configuration that minimizes the cost of equipment purchase, operation, and maintenance. Using conditioning-unit-specific loss rates, it next estimated the amount of gas that is available for compression, again sizing compression equipment to minimize the cost of equipment purchase, operation, and maintenance. Table 8 shows the results of this exercise for each facility size grouping.

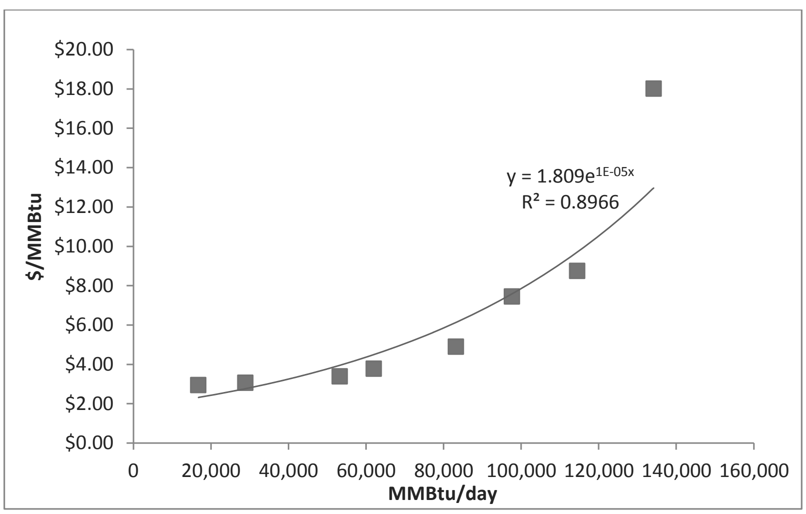
Table 8. Installation and O&M costs associated with biogas conditioning and compression.

WWTP facility size (MGD)	# of WWTPs	Gas per facility (SCFH)	Conditioning installation	Conditioning O&M	Post-condition compression load	Compression installation	Compression O&M
>200	9	173,244	$8,600,000	$1,276,000	97,813	$450,000	$193,800
100–200	16	67,118	$3,800,000	$315,100	37,922	$225,000	$45,500
75–100	21	37,134	$3,000,000	$132,000	20,954	$200,000	$16,400
50–75	21	26,798	$3,000,000	$132,000	15,122	$200,000	$16,400
20–50	98	13,848	$2,270,000	$86,600	7,834	$200,000	$16,400
10–20	166	6,502	$2,270,000	$86,600	3,678	$132,500	$9,465
5–10	273	3,390	$845,000	$36,535	1,830	$132,500	$9,465
1–5	1002	1,261	$845,000	$36,535	681	$132,500	$9,465

Note: WWTP size and number of facilities with anaerobic digesters are derived from USEPA (2011b) and are adjusted to account for population growth. Costs and loss rates are sourced from Prasodjo et al. (2013). Installation costs are incurred in the first year of operation; O&M costs are incurred annually for the life of the equipment, assumed here to be 20 years. Pipeline costs are annual and assume a rounded average across all pipe sizes and cost ranges, which is added to the average of interconnection fees and right-of-way (ROW) maintenance costs for a one-mile section of pipeline.

Supply functions are estimated using the methodology outlined above—that is, plotting WWTP biogas LCOE against produced quantity (Figure 8). According to these calculations, approximately 83,000 MMBtu/day (30.4 million MMBtu/year) of biogas would be available at a cost comparable to the costs of delivered industrial natural gas as projected over the next few decades by the Energy Information Administration's Annual Energy Outlook. This biogas availability equals about 0.1 percent of the current annual consumption level of natural gas in the United States (see Table 1).

Figure 8. Supply curve for biogas produced from wastewater treatment plants.



Forest and Agricultural Residues and Energy Crops

Organic material left over from forest or agricultural harvest operations can be utilized in biogas production. This production requires installation of a gasifier to generate synthesis gas (or syngas), which is later upgraded to commercially useable synthetic natural gas (SNG). (Again, for the purposes of this report, the term *biogas* is used to denote SNG from gasification as well as gas from the AD processes discussed above). If prices for biomass increase, some production of forest and agricultural energy crops might be dedicated to provision of biogas feedstock for gasification. Both scenarios represent a departure from the models above, in which the biogas feedstock is collected as part of some other business activity (e.g., waste management or livestock production) and therefore is essentially free. However, using residues and energy crops introduces the prospect of payment for the feedstock to cover growing, harvesting, and transport costs.[10] These feedstock cost factors were incorporated into the present analysis.[11]

The quantity of biomass produced, collected, and loaded on to transport vehicles at $20, $30, $40, and $50 per dry ton (adjusted to dollar years used in other sections of this report) was derived from Walsh (2008). Biomass in this dataset includes urban wastes, mill wastes, forest residues, agricultural residues, switchgrass, and short rotation woody crops (SRWCs). For this analysis, the selected heat contents of these feedstocks were 16 MJ/kg for forest residue; 18 MJ/kg for agricultural residue; 19 MJ/kg for urban residue, switchgrass, and short rotation woody crops; and 20 MJ/kg for wood residue (Appendix A reviews natural gas supply projections from the U.S. Energy Information Administration).[12] Once these values were converted to MMBtu/dry ton (dt) biomass, biogas yield per dry ton of biomass was calculated as 68% of MMBtu/dt of biomass after the biomass-to-biogas production efficiency of direct gasification presented in Zwart et al. (2006). This approach allowed biogas yield per state as well as the national cumulative total to be calculated at all price levels between $50 and $20 per dry ton biomass.

The cost of each gasifier was calculated as follows. First, the capacity needed to handle a given tonnage of biomass was calculated as 28 dry tons of biomass per MW capacity (Bain et al. 2003; Table 4.3). Beginning with capital and O&M costs from Bain et al. (2003) for 75 and 150MW direct gasification facilities, costs for 125MW and 150 MW facilities were interpolated. These four facility sizes—75MW, 100MW, 125 MW, and 150 MW—correspond to 2,100, 2,800, 3,500, and 4,200 dry-tons-per-day facilities, respectively. The cost of a methanation reactor, used in synthesizing methane from syngas, was calculated as 22.9% of the cost of the gasifier, according to Gray et al. (2007); the costs of gas compression and gas piping were calculated as described above.

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[10] For dedicated energy crops, presumably all costs from field to biogas processing facility would need to be covered. For residues, growing and harvesting costs may be covered by prices paid for primary products (e.g., food and timber), but any additional gathering and transporting costs must be covered.

[11] This class of biogas feedstock faces additional barriers that could inhibit realization of its technical potential. These barriers could include the availability of infrastructure to support feedstock production, processing, and distribution.

[12] Heat Content Ranges for Various Biomass Fuels (dry weight basis) with English and Metric Units, http://www1.eere.energy.gov/biomass/feedstock_databases.html (last accessed September 7, 2013).

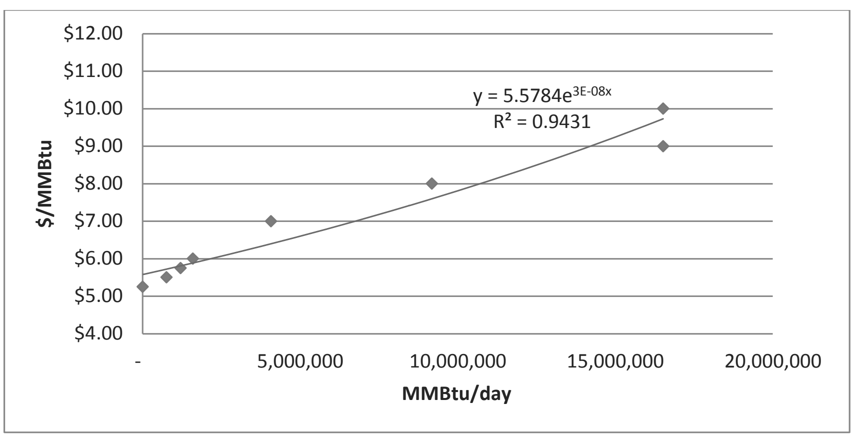
Table 9: Gas yield, capital, and O&M costs for biomass gasification facilities.

Size		Gas Yield	Costs ($)			
MW	Dt/Day	MMBtu biogas/Day	Capital cost for CHP	Capital cost for pipeline biogas	Annual O&M cost for CHP or biogas (without biogas compression)	Annual O&M cost for compression
75	2,100	22,260	119,385,375	125,033,844	8,603,415	1,422,000
100	2,800	29,680	148,934,000	156,046,456	10,879,920	1,896,000
125	3,500	37,100	173,359,375	181,726,399	12,860,775	2,370,000
150	4,200	44,520	192,661,500	202,073,675	14,545,980	2,844,000

Sources: Costs based on Bain et al. (2003) and Gray et al. (2007); MW to dt/day equivalency was calculated on the basis of Bain et al. (2003); gas yield was calculated on the basis of biomass heat content data published by USDOE-EERE (http://www1.eere.energy.gov/biomass/feedstock_databases.html; last accessed September 28, 2013).

Estimation of potential biogas supply from residues and energy crops is complicated by the need to link biogas markets with forest and agricultural feedstock markets. Calculation of LCOE for all four gasification facility sizes was performed on an MMBtu gas basis by first dividing the total cost by total biogas production and adding a $1.20/MMBtu gas transportation tariff. To estimate the amount of feedstock material available at different biogas prices, this combined processing cost was subtracted from a range of biogas prices that encompass expected NG prices in the coming decades ($4–12/MMBtu). This calculation yielded a residual payment ($) that could be spent (i.e., willingness to pay) to purchase biomass feedstock at each gasification facility size. For each residual price that the processing facility is willing to pay for biomass input, the analysis estimated the potential feedstock supply. This quantity of feedstock was then converted to quantity of biogas, and the supply curve was plotted as other biogas sources were plotted (Figure 9).

Figure 9: Pipeline biogas supply from biomass gasification.



Other Feedstock Options

The literature review of biomass feedstock options identified other potential biomass feedstocks not analyzed herein because they are not widely researched, are ambiguous in terms of overall quantity and cost, and are likely to be the highest-cost options. Technologies and processes could emerge that make these feedstocks feasible, but no foundation is available for quantitatively including them in this report. Instead of estimating their supply functions, this study reviewed their potential qualitatively.

Regarding algae, a report by Chynoweth (2002) concludes that the greatest uncertainties are related to the technical and economic feasibility of large-scale growth of macroalgae in the open ocean, especially concerning provision of nutrients. Both the AD and gasification conversion pathways could be considered for this feedstock. The anaerobic conversion process for algae is developed and is not likely to be significantly different than that for similar feedstocks. However, biogas cost estimates for marine biomass systems are estimated to be three to six times those for fossil NG fuel gas.

Several other potential biogas feedstocks exist, but annual yields per unit area, and biogas generation costs from these sources have not been widely studied. For example, the methane yields of corn, sweet sorghum, and miscanthus species have been reported in the literature (Klimiuk et al. 2010) but have not been considered for large-scale biogas production. Smyth et al. (2010) performed a detailed analysis of biogas potential from forage grasses in Ireland and concluded that (1) given then-limited government support (i.e., subsidies), the only financially viable option for these grasses was use in an on-site CHP plant and (2) pipeline injection was not competitive with natural gas use in terms of price. Domestically, large areas in the central and western United States may provide feedstock for grass-based biogas.

Labatut et al. (2011) and Gunaseelan (1997) provide methane yields of various other potential biogas feedstocks, including vegetables, vegetable oil, and fats, oils, and greases (FOGs). Some of these feedstocks have high potential methane yields as compared to those of manure and switchgrass, but their use for large-scale biogas production has not been widely studied. However, there is evidence in the literature that co-digestion of these feedstocks with more traditional feedstocks, such as manure, can increase methane yields due to improved carbon-to-nitrogen ratio.[13] Even less studied is co-digestion of wastewater and FOGs (Zhu et al. 2011), algal sludge and paper waste (Yen and Brune 2007), cattle slurry and fruit and vegetable waste (Callaghan et al. 2002), and sisal pulp and fish waste (Mshandete et al. 2004). Thus, feedstocks other than the ones quantitatively analyzed in this report could increase total biogas potential in the United States. Because the availability and biogas production cost implications of these feedstocks are largely unknown, their impact on the long-term biogas supply potential remains unknown.

Aggregate National Supply Potential

To plot an aggregate national biogas supply function, biogas produced through anaerobic digestion and biomass gasification are horizontally summed (Figure 10). That is, after biogas supply functions for landfill gas, animal operations, wastewater treatment plants, and biomass gasification were estimated, the quantities of biogas available from each source were summed at each price level (Figure 11; Table 10). Only the marginal cost of producing biogas for pipeline use at different levels by the collective sources is shown; the cost of alternative uses of the biogas (e.g., on-site power) and the net benefits of installing one type of energy generation technology versus another are not shown.

[13] Available at http://www.epa.gov/agstar/documents/codigestion.pdf (last accessed September 29, 2013).

Figure 10: Schematic of combined national biogas supply calculation.

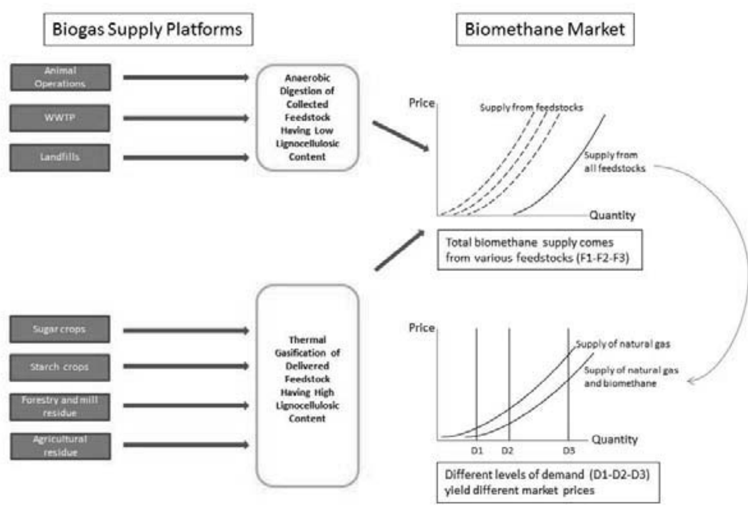
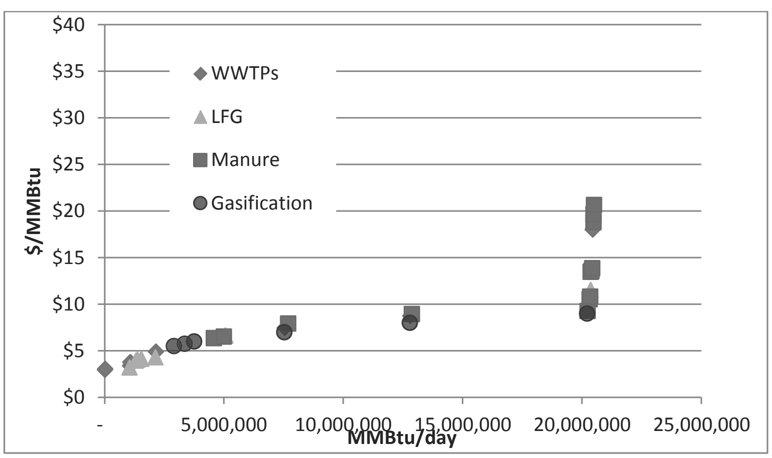


Figure 11. Combined supply function for four biogas sources.



Note: WWTPs = wastewater treatment plants; LFG = landfill gas; manure = livestock operations; gasification = forest and agricultural biomass gasification.

Table 10. Aggregate biogas supply at various price points.

Biogas price	Aggregate quantity supplied (MMBtu/day)	Quantity as % of 2011 natural gas supply
$3.00	0	0.0%
$4.00	1,315,383	1.9%
$5.00	2,153,889	3.1%
$6.00	3,751,664	5.5%
$7.00	7,537,251	11.0%
$8.00	12,799,033	18.7%
$9.00	20,225,965	29.5%
$10.00	20,240,204	29.5%
$15.00	20,436,460	29.8%
$20.00	20,492,178	29.9%
$25.00	20,508,709	29.9%

Note: Aggregate supply as a percentage of the year 2011 average daily natural gas supply (68.5 billion cubic feet (bcf)/day) is also indicated.

Role of Substitutes for Pipeline-Directed Biogas

The analysis above provides cost estimates to generate and deliver biogas to the pipeline under the implicit assumption that the gas would be supplied to the market if it can be sold at a given price. Other uses of biogas could, in principle, compete with pipeline delivery, however. Therefore, any analysis of biogas market potential would be incomplete without an evaluation of the economics of these alternative uses.

This study evaluated the potential for electricity generation at landfills, animal operations, wastewater treatment plants, and biomass gasifiers. Costs and electricity production potential were estimated using performance and cost data for CHP systems, a mature technology that can achieve higher system efficiencies than stand-alone electricity generators. For example, Willis et al. (2012) report that approximately 8% of WWTP facilities with anaerobic digesters already operate CHP systems using biogas produced on-site. The bulk of this exercise is devoted to an evaluation of the electricity production component of installed CHP systems. The capture and utilization of waste heat is what yields such high system CHP efficiencies, but analysis of the benefits of the heat component of CHP requires multiple assumptions about facility process energy needs and operating environment (e.g., hot or cold climate). Therefore, unless otherwise noted, all estimates below consider only on-site biogas electricity generation potential.

The approach to estimation of WWTP electricity supply potential was similar to that for WWTP biogas bound for the pipeline.[14] First, the lowest-cost generation technology option provided by USEPA (2013) at each capacity level was selected as the configuration to represent that particular tier (Table 11). Next, the LCOE for each was calculated from the installation and maintenance costs outlined in USEPA (2011b), but here the discounted stream of equipment costs for a 1kW unit was divided by the discounted

[14] USEPA (2011c) reports CHP supply potential from existing WWTP anaerobic digesters, but this study could not replicate its numbers exactly using its input data and assumptions. Although this study's results were similar to the USEPA's, it opted for consistency of approach, instead using the raw data on installation, operation, and maintenance costs provided by USEPA (2011c) to calculate LCOE using the method outlined above.

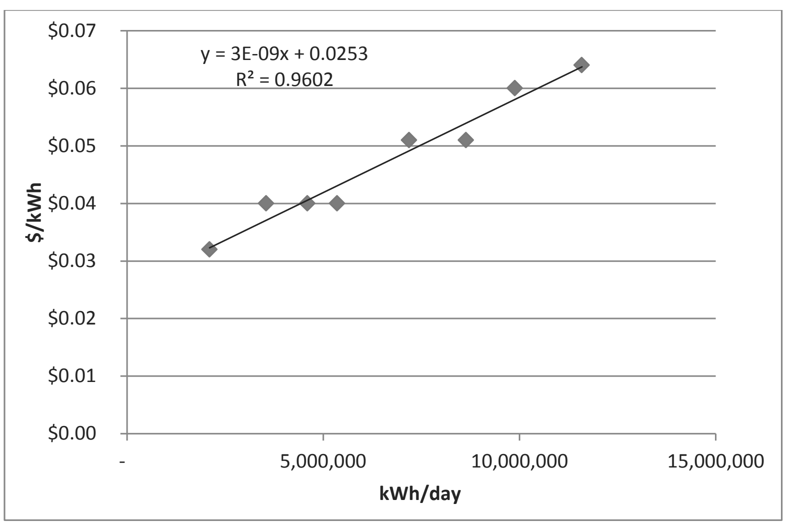
stream of electricity generation from that unit.[15] The electricity supply function across all potential units is shown in Figure 14. This process of matching biogas generation in cubic foot per hour with the needed electricity generator units was repeated for LFG and animal operations. Installation and maintenance costs of reciprocating engines and turbines from USEPA (2008) were used for landfills and animal operations. Cost data and electricity generation efficiency of turbines from Bain et al. (2003) were used in the calculation of electricity generation from biomass gasification. Electricity generation efficiencies were assumed to be 0.26–0.35 for the units used at landfills, animal operations, and wastewater treatment plants (USEPA 2008, 2011) and 0.36 for turbines used at biomass gasification facilities (Bain et al. 2003).

Table 11. Estimated generation cost by WWTP capacity tier.

		Estimated generation cost ($/kWh)				
WWTP capacity (MGD)	Corresponding system size (kW)	Microturbine	RichBurn engine	Fuel cell	LeanBurn engine	Turbine
1–5	30–130	0.064	0.073			
5–10	130–260	0.064	0.060	0.083		
10–20	260–520	0.064	0.060	0.083	0.051	
20–40	520–1,040			0.083	0.051	
40–150	1,040–3,900			0.083	0.040	
>150	>3,900				0.040	0.032

Note: Lowest-cost configurations at each tier are highlighted in red.

Figure 12. Supply curve for electricity produced from WWTP facilities already possessing anaerobic digesters.

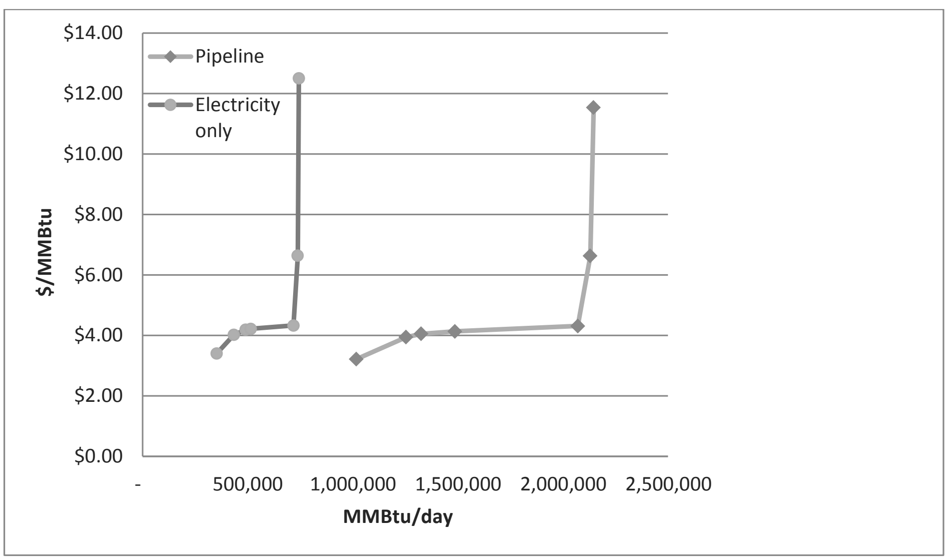


[15] Here, installation and maintenance costs include conditioning of digester gas; these costs are not added separately as they are in the WWTP pipeline biogas example above.

Comparing the costs of pipeline biogas and electricity generation requires transforming units onto a common axis. Because kilowatt hours are a function of biogas supply, electricity prices can be reduced to units of MMBtu/day by adjusting for system efficiency and then by converting kWh to Btu at a rate of 3,412 kwh/btu.[16] The resulting conversion is shown for each of the biogas sources in Figure 13, Figure 14, Figure 15, and Figure 16, respectively. Compared with pipeline gas, electricity and heat plus electricity are, notably, available in lesser quantities owing to their lower conversion efficiency. Figure 15 includes both electricity-only and full CHP system energy production potential in wastewater treatment plants. The primary difference is the efficiency of the system; combined heat and power yields relatively more usable energy output per unit biogas input.

At the lower-quantity ends of the supply functions, pipeline biogas is generally the lower-cost option, though the cost-supply relationship does vary somewhat between feedstock source and pathway. Where supply function curves do not cross, interpretation of the curves is simple. If cost is the only basis for comparison, the lower curve always represents the preferred lower-cost application. Where the curves cross, greater care must be given to interpretation, because different efficiencies of use for the same underlying supply of biogas are being assessed. Generally, however, one technology would be the preferred choice up until the point at which the curves cross and another technology becomes available for a lower cost.

Figure 13: Comparison of pipeline biogas and electricity supply functions for landfills.



[16] These are assumed to be 26-38% for electricity only and 55%-76% for both heat and electricity, depending on configuration (USEPA 2011b).

Figure 14: Comparison of pipeline biogas and electricity supply functions for animal operations.

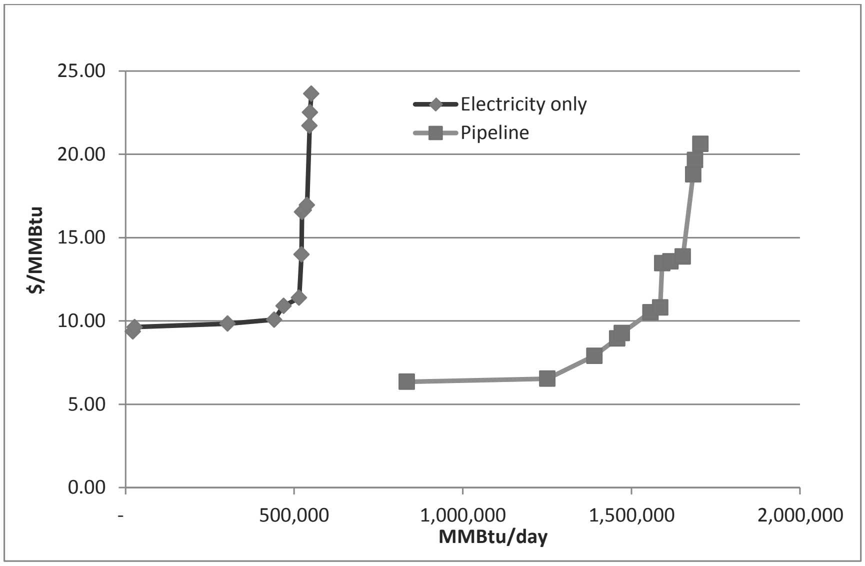


Figure 15. Comparison of pipeline biogas, electricity, and CHP supply functions for WWTP facilities already possessing anaerobic digesters.

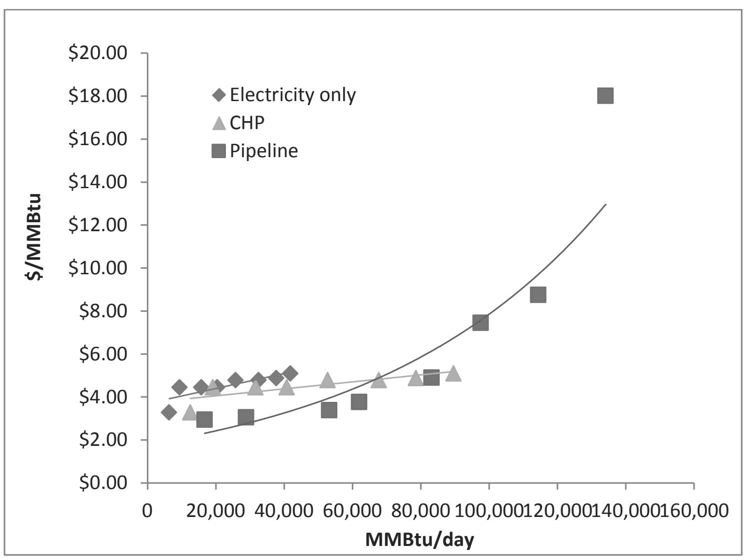
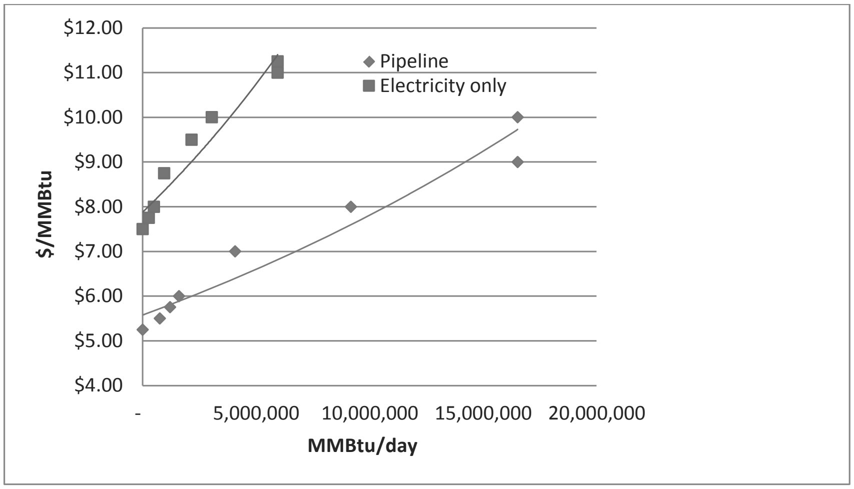


Figure 16: Comparison of pipeline biogas and electricity supply functions for biomass gasification.

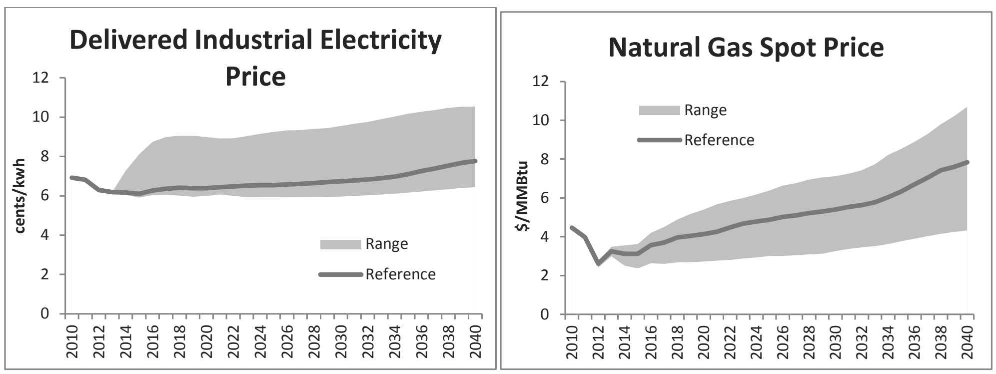


The figures above show that electricity generation is typically more expensive on a per MMBtu basis than pipeline biogas. Therefore, pipeline biogas might be expected to outcompete direct power production in most cases. However, the costs represented in the functions are unlikely to be the only basis for comparison, because both pipeline biogas and electricity production have different potentials to generate revenue and offset internal operating costs. In the case of pipeline biogas, a wastewater treatment plant might sell the biogas to the market at the spot price or at some other price negotiated as part of a long-term contract with a buyer. In the case of electricity production, electricity generated by a unit might be used to reduce electricity demand or might even be sold back to the grid. Biogas produced on-site can also be used in full CHP applications to satisfy internal heating requirements, implying that any increase or reduction in internal biogas use could also affect the amount of natural gas that is purchased from the market. The decision of whether to install pipeline biogas or electricity/CHP infrastructure is therefore a complicated one involving a combination of cost reduction and revenue factors that will vary across units due to market, legal, and institutional factors.

Factoring in Prices Received for Sale of Natural Gas and Electricity

The foregoing analysis focused on cost differences between producing pipeline biogas and producing power on-site using the same biogas. Because the net financial benefit of producing biogas for either pipeline or electricity applications depends on the price of natural gas and electricity, investment decisions will reflect the future prices of each as well as the costs. As seen in Figure 19, however, prices for both are projected to vary over time and across scenarios. To capture this range, this analysis assessed the net benefit of both pipeline biogas and electricity across a variety of prices: the U.S. Energy Information Administration's *Annual Energy Outlook, 2013* (USEIA 2013) reference price, the scenario with the highest price in 2040, and the scenario with the lowest price in 2040. The analysis assumes that all electricity generated would otherwise have been purchased from the grid and so provides a credit in each year using the delivered electricity price for that year but ignoring any price premium paid for "green electricity."[17] The analysis further assumes that all pipeline biogas is sold at the natural gas spot price for that year but ignores any price premium that may be paid for its low carbon attributes, and so credits the proceeds from biogas sale in each year.[18] This process was repeated for calculation of LCOE, but this time it included both costs and revenues for either displaced electricity costs or biogas sale. Electricity units were again converted to MMBtu to allow for both series to be displayed in the same figure.

Figure 17. Range of delivered industrial electricity prices and natural gas spot prices as reported by AEO (2013).



Note: The reference case value is shown for both prices. Low values for each represent the "high resource" scenario, which assumes high rates of recovery of existing shale, tight energy resources, and increased discovery of new resources. High values represent the "GHG $25" case, in which a $25 per metric ton carbon price is applied economy wide in 2013, rising by 5% per year through 2040.

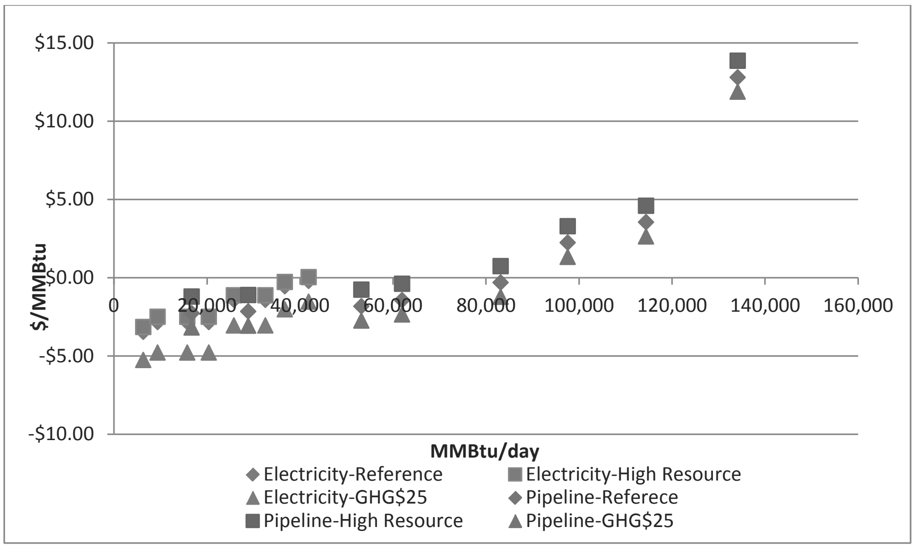
Figure 18 shows the net costs of WWTP electricity and pipeline biogas, respectively. Negative costs indicate a net benefit to that particular use relative to a "do nothing" scenario, wherein no biogas is captured and produced for use or sale. Figure 18 shows that, once electricity credits and biogas revenue are factored in, electricity is a more favorable investment than pipeline biogas at all levels of supply and across all pricing scenarios. Although not included in Figure 18, CHP heat energy is largely immaterial at lower levels of supply, because increasing the efficiency of energy production would only lower its relative cost further and extend the supply of energy further along the x-axis. Similar net cost comparisons for landfills and animal operations also show that electricity generation is typically the preferential option because of lower net costs (higher net benefits) as compared to pipeline biogas (Figure 19 and Figure 20). The methodology used to calculate LCOE for biomass gasification assumed linked

[17] The assumption is that all electricity produced is consumed on site. If the facility were to become a net producer of electricity, it would no longer displace internal electricity consumption at the delivered industrial rate but could have the potential to sell electricity to the grid at the wholesale rate. This assumption is consistent with other recent work on the subject (e.g., USEPA 2011c).

[18] Heating is more complicated. USEPA (2011c) shows that displacing natural gas used in WWTP space heating does not dramatically affect the economics of CHP installation. Displacing natural gas used for digester heating does have a dramatic effect on the economics of combined heat and power, however. For the purposes of this analysis, the role of heating in either pipeline biogas or combined heat and power was ignored. To include it here would require an analysis of heating demand across WWTP facilities. Furthermore, adding in additional credits would only increase the favorability of combined heat and power relative to pipeline biogas (Figure 18).

markets for biogas and biomass feedstock. These markets are assumed to be in equilibrium, meaning that a change in any revenue stream would result in a new market equilibrium and a different quantity of supplied biogas. However, the trend should be similar to that for the other evaluated sources: increasingly negative net costs for electricity generation as compared to pipeline gas.

Figure 18. Comparison of net costs of electricity and pipeline biogas for wastewater treatment plants.



Note: Negative net cost represents positive net benefits for the producer. The reference case value is shown for both. The “high resource” case reflects low price values for both gas and power, which assumes high rates of recovery of existing shale, tight energy resources, and increased discovery of new resources. The “GHG $25” case represents high price values, as it reflects a $25 per metric ton CO_2 price applied economy wide in 2013, rising by 5% per year through 2040, which drives up the cost of both gas and power across the economy.

Figure 19. Comparison of net costs of electricity and pipeline biogas for landfills.

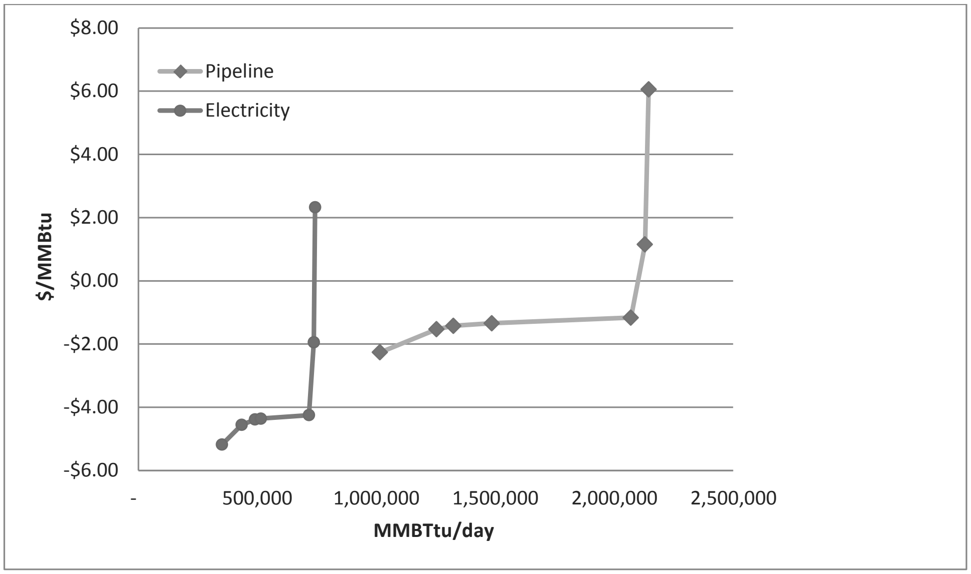
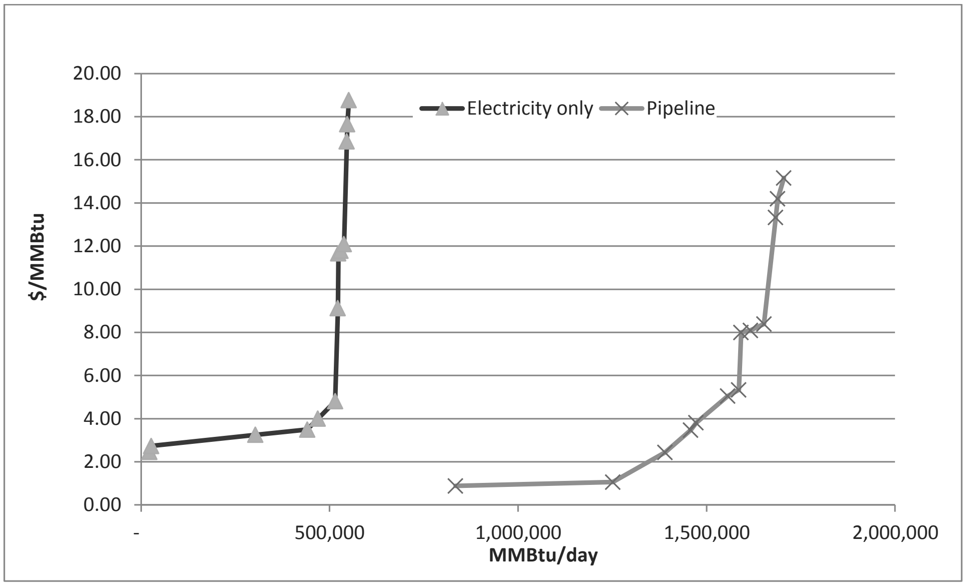


Figure 20. Comparison of net costs of electricity and pipeline biogas for animal operations.



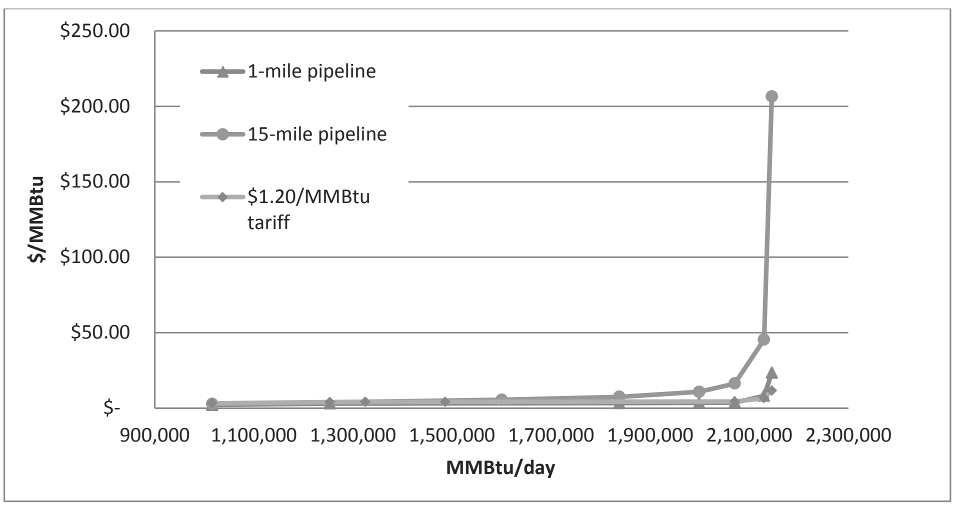
The Role of Facility Configuration and Transmission Financing

Many factors other than those estimated above could lead to different conclusions at individual facilities. This study assessed one such factor: the sensitivity of LCOE to different assumptions about pipeline costs

(Figures 21–24). These costs refer to the costs of injecting natural-gas-quality biogas into the NG pipeline system. Piping costs were a significant percentage of total costs of production, yet were difficult to assume for a wide range of biogas facilities of various sizes. Most operating biogas facilities do not inject gas into the NG pipeline system, thus determining typical ownership and cost structures of pipelines for this purpose was not possible.

This study considered both a per MMBtu gas transmission fee of $1.20 as well as the annual cost per gas-producing facility of maintaining 1- or 15-mile (based on Cooley et al. 2012) gas transmission lines at $180,000 per mile (based on Prasodjo et al. 2013). The transmission fee was calculated as the mean of published gas transmission fees by two companies, one operating on the East Coast (PNG) and the other on the West Coast (PG&E).[19] For landfills and wastewater treatment plants, the resulting sensitivity analyses show that the different piping-cost assumptions affect only LCOE near the high end of the calculated range. Specifically, although the results under the $1.20 tariff and the 1-mile pipeline cost assumptions were similar, high-end LCOE increased under the 15-mile pipeline cost assumption. LCOE figures for animal operations were similar under the tariff and 1-mile pipeline cost assumptions, but the 15-mile pipeline cost assumption led to substantially higher LCOE for the entire range of biogas production, making it a comparatively uneconomic supply source at these pipeline distances. LCOE for biomass gasification facilities did not appear to be affected by the pipeline cost assumption.

Figure 21. Comparison of LCOE under two biogas piping-cost assumptions for landfills.



[19] As above, the gas transmission fees posted by PNG and PG&E depend on the amount of gas transmitted in one transaction.

Figure 22. Comparison of LCOE under two piping-cost assumptions for animal operations.

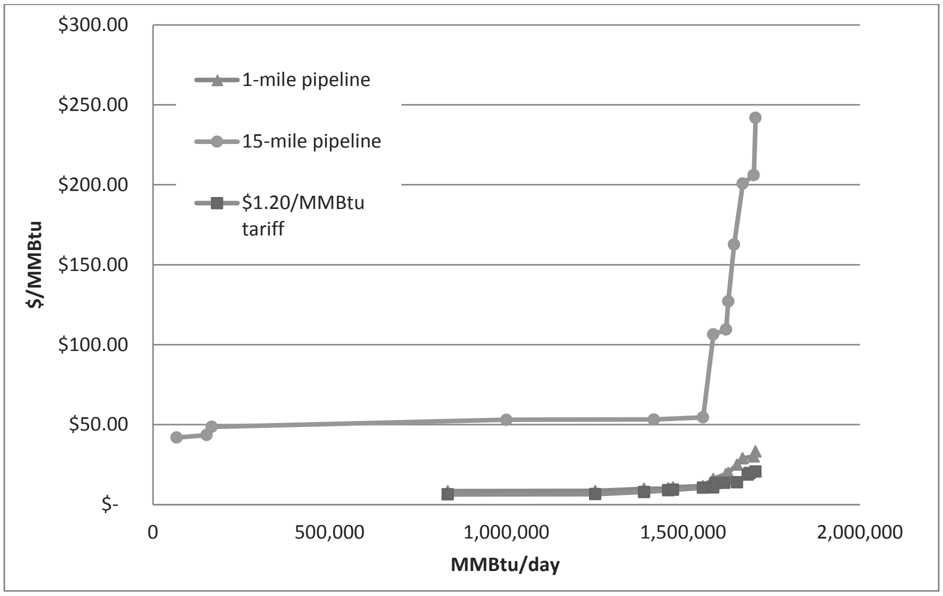


Figure 23. Comparison of LCOE under three piping-cost assumptions for wastewater treatment plants.

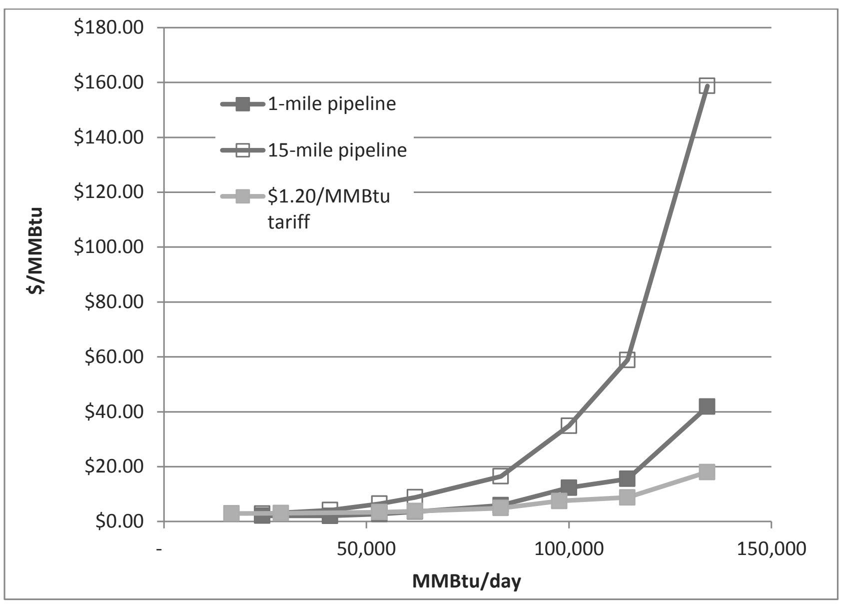
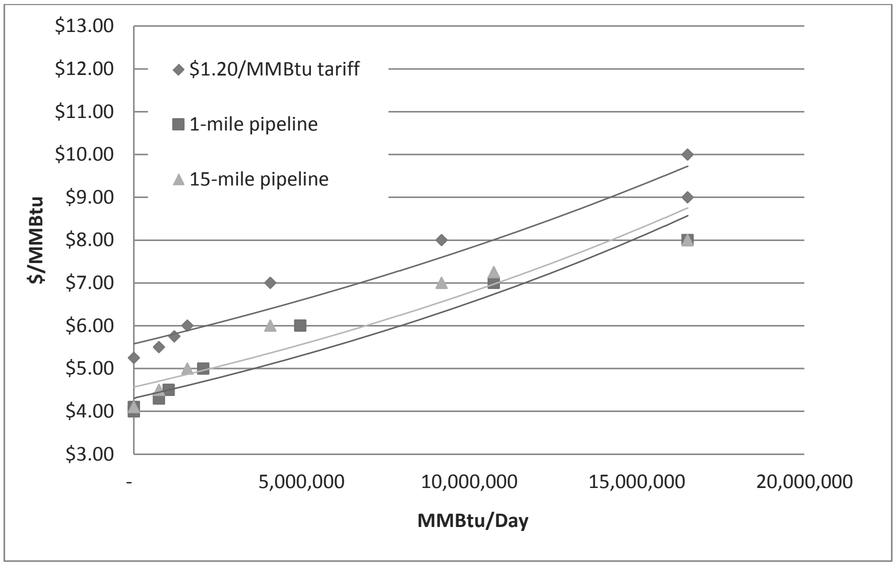


Figure 24. Comparison of LCOE under two piping-cost assumptions for biomass gasification



Biogas Market Dynamics, Barriers, and Opportunities

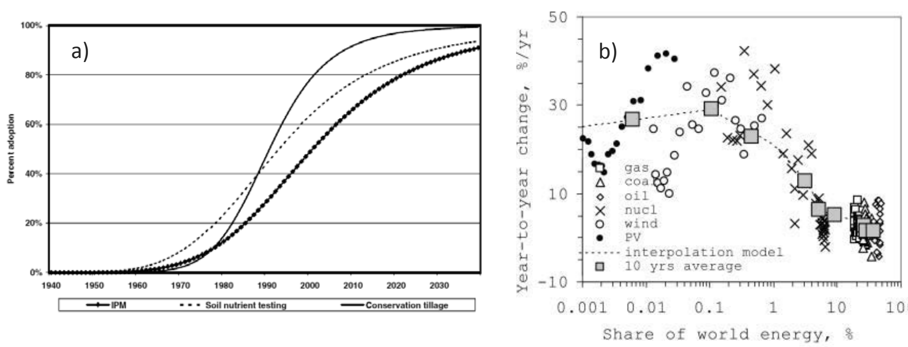
The supply analyses above implicitly assume the emergence of factors that enable or impede long-run growth in the market. Having examined the long-run economic potential of biogas at different prices, the study turned to the question of how that potential can be realized. It identified key barriers to market development and assessed the feasibility of overcoming them (Appendix B describes how the European Union has overcome some of these barriers). It also assessed factors that could facilitate emergence of a biogas market. Finally, it assessed that market in light of each of the reviewed elements.

Technology Development, Adoption, and Diffusion

The supply analysis identifies conditions under which biogas production for pipeline distribution has market potential. The rate at which a new technology enters a market depends on the attributes of both the new technology and the technology it is replacing or supplementing. Some technologies gain market share simply because they are technologically superior in meeting market needs (e.g., digital cameras versus film cameras). Other paths of diffusion, including those for some biofuels, are strongly influenced by policy intervention, entrenched interests, and other external drivers. Although the former situation may be fitting for early energy technologies (e.g., coal replacing wood as a major fuel source), the latter is perhaps more fitting for more recent changes in energy portfolio mix (e.g., renewable power sources such as wind and solar supplanting nonrenewable fossil fuels). These new technologies, like biogas, do not necessarily outcompete traditional fossil sources on cost and energy content basis. Instead, their low-carbon nature makes them distinct and potentially alters their adoption value relative to fossil fuels.

Traditionally, new entrants diffuse along an "s-shaped" curve, which is characterized by slow initial growth in technology adoption, periods of rapid growth later on, followed by slowing growth as market saturation is reached (Figure 25A). Rate of adoption is largely driven by the net benefit differential between new and existing technologies, itself a function of production experience/declining costs and increased market maturity. Alternatively, renewable energy technology growth can be characterized by the relationship between growth rate and market share (Figure 25b). In this approach, historical diffusion in one renewable sector is used to project rates of change, which are generally expressed as a function of changes in volume and market share (see, e.g., Lund 2010a; Lund 2010b).

Figure 15. Models of technology diffusion.



Note: (a) Predicted path of agricultural conservation technology diffusion (from Fuglie and Kascak 2001). (b) Observed relative volume changes of global energy sources by market share during growth and saturation phases (from Lund 2010a).

The renewable energy technology literature is replete with studies categorizing barriers to diffusion and their respective solutions. Tsoutsos and Stamboulis (2005) cite eight categories of barriers that could impede the diffusion of renewable energy technologies: technological, regulatory, cultural, demand, production, infrastructure, socio-environmental, and economic. Street and Miles (1996) cite three general categories: policy, technical, and non-technical. Jacobsson and Johnson (2000) likewise cite three, but label them actors and markets, networks, and institutions. For the purposes of this review, the framework discussed by Jacobsson and Johnson (2000) is most relevant and useful.

Actors and Markets

Jacobsson and Johnson (2000) associate barriers (or as they refer to them, "failures") with poorly articulated demand, increasing returns of established technology, local search processes, and incumbent market control. These barriers collectively imply that nascent biogas markets will have difficulty expanding due to mismatches between biogas suppliers and users, information shortages, and reduced opportunities for direct competition with natural gas and other conventional fuels. Many of these, and in particular the first—mismatches between biogas suppliers and users—could be addressed in the near term through so-called over-the-counter (OTC) or "brokered" transactions. Prior to the establishment of a robust spot market for biogas, individual buyers and sellers could transact for negotiated quantities of biogas at negotiated prices. This strategy increases search costs until a central spot market or exchange develops.

Regardless of the contracting model, biogas must ultimately compete on the basis of both price and performance for a market to be to established (Jacobsson and Johnson 2000). This market, in turn, depends on opportunities for technological advancement and both the opportunities and limitations created by inherent geographic and feedstock characteristics. Technology advancement has the potential to increase performance (e.g., efficiency) and reduce cost, potentially facilitating biogas diffusion. This potential is particularly important for the gasification portion of this study's estimated supply curve, given that large-scale commercial application of the technology remains in its infancy. Regardless of the technology—digestion or gasification—technological advancement is likely to simultaneously facilitate the use of both electricity/combined heat and power and pipeline biogas. This phenomenon implies that technological improvements may not necessarily translate into increased amounts of pipeline biogas.

As discussed further below, expansion of exploration for natural gas may also lower the costs of pipeline access by increasing the reach of the existing network. If it does not occur evenly, this expansion may favor some regions more than others. The existing pipeline network also tends to favor some feedstocks more than others. For example, biogas facilities using feedstock predominantly found in rural areas (e.g., manure, residues, energy crops) may be less likely to be near existing lines and thus may face higher piping costs. The opposite may be true for wastewater treatment plants, and, to some extent, landfill gas (Cooley et al. 2013). Regardless of network configuration, facility location can also influence the cost-effectiveness of anaerobic digester operation; digesters in cold climates require greater energy to heat than those in warmer climes (USEPA 2011).

Networks

Network barriers or failures refer to the personal associations between biogas producers and users. They may include poor connectivity and insufficient guidance on the condition of future markets. In the case of biogas, these factors can reduce capacity to share information, to establish standardized approaches for operation, and to establish expectations about technology innovation and market opportunities. In established networks, inertia or lock-in may inhibit technological change. Biogas diffusion will therefore require an expansion of personal networks to include a broader suite of users and producers. Early experience in the OTC market could help to facilitate growth of these networks, as could case studies, pilot projects, professional conferences, and trade associations. Scale and time will support the development of networks as well. If the market grows, it will provide the critical mass and time for networks to operate efficiently.

Institutions

Institutional factors affecting adoption include legislation, education, skewed capital markets, and underdeveloped political power. The first includes laws and incentive programs that promote biogas or its competitors. Policy played a strong role in the differential diffusion of renewable energy technologies such as wind (Street and Miles 1996) and is expected to be instrumental in the future diffusion of biogas. A further review of potential policy drivers is provided below. The second factor, education, is potentially less of an issue in existing technologies such as digesters, but may be more important an issue in the case of newer technologies like gasification. Working knowledge and hands-on experience will likely only increase with widening application of the technology. The third factor, capital access, is likely to present a problem as biogas technology scales up, particularly with less-tested applications like gasification raising investment risks. Resolution of the first three factors is influenced by the fourth factor, political power, which is inherently linked to the above categories of networks and actors and markets.

The interconnectedness of the above-noted factors implies that time, experience, and exposure to biogas technology and opportunities will be necessary for biogas diffusion. Given the availability of an established, low-cost alternative in the form of fossil natural gas, markets for biogas are unlikely to spontaneously expand in the near term absent policy and other interventions.

Pipeline Infrastructure Development

Once produced, biogas must be transported to end users, requiring expansion of the existing natural gas pipeline network to include the biogas generation sources discussed above. The rate and manner in which this expansion occurs could greatly influence this study's estimates of the long-run biogas supply available to the market.

Pipelines may be built or existing lines may be upgraded or expanded to accommodate new sources of natural gas and to deliver natural gas to new or widening markets. In recent years, for example, the pipeline network experienced growth in the area of shale gas extraction (GAO 2012). A similar expansion could accompany the deployment of biogas generation facilities if warranted by scale and economic attractiveness.

These considerations raise the question of the cost of pipeline expansion, which is directly related to configuration—the size of the pipeline and the distance it must be run. Previous analyses of optimal configuration in response to new supply sources (Cooley et al. 2013; Prasodjo et al. 2013) indicate that the existing configuration and the manner in which new biogas sources are connected strongly influence the estimated cost of expansion within a single state (North Carolina). The nation-wide and long-run nature of this biogas assessment does not allow for a similar analysis to be conducted here. Leveraging existing public data to inform the rate and manner of pipeline expansion in response to new source development (e.g., hydraulic fracturing) is also difficult.[20]

A second question is the manner in which the pipeline is financed. When demand has been sufficient, new or expanded pipelines have traditionally been funded by third parties that then charge a per-unit-transported use or connection fee to recoup the cost of initial investment. It is also possible that an entity would choose to self-finance or contract for the construction of its own dedicated pipeline network. In either situation, the amount of biogas (due to some combination of facility size or concentration) must be large enough to justify investment.

Infrastructure development, therefore, has the potential to influence long-run biogas supply, although estimating the magnitude of its effect is difficult. Many of the biogas sources discussed in this report, and especially those on the margin of economic feasibility, are alone unlikely—due to their limited size and diffuse nature—substantial enough to induce infrastructure development.

Energy Markets

The future market for pipeline biogas, a perfect substitute for fossil methane, is closely tied to broader energy market trends, especially those in the natural gas market. If new exploration continues to reveal large reserves and fossil fuels are not subject to additional GHG controls, natural gas will remain relatively low cost and will continue to place downward pressure on the demand for biogas. If demand for

[20] The true extent of the natural gas pipeline network is difficult to ascertain due to security concerns and gaps in oversight and data collection. The gaps are particularly pronounced in the case of the small "gathering" lines that link diffuse sources to larger collection and compression facilities (see, e.g., GAO 2012).

natural gas grows more than supply (e.g., for transportation fuels or for export markets), then upward pressure on all gas sources, including biogas, would be expected. To proxy for these dynamics, this study examined EIA projections of total gas use to 2040 and explored the effects of the EIA's gas and electricity price assumptions. Although informative, the EIA's projections provide only a rough indication of the range of future gas and electricity market conditions. Global energy markets are volatile, and multiple factors can shift supply, demand, and prices. Even so, estimated costs of biogas are comparable to or slightly higher than projected spot prices for natural gas under multiple policy scenarios (Figure 17). This finding suggests that natural gas prices, even in the presence of GHG restrictions, are unlikely in and of themselves to drive biogas market development.

Policy Incentives

This study's analysis of biogas market opportunities and barriers included a review of policies and other market interventions that can either increase the potential supply of biogas or increase the demand for it as a substitute fuel. The review focused on the role that a carbon price (again, from either a cap-and-trade policy or a carbon tax) or state/federal renewable energy mandates will have on the market for biogas. It put particular emphasis on the incremental pricing benefit associated with biogas use over natural gas use.[21]

Renewable Energy Mandates

Biogas is considered a renewable energy resource. As discussed above, several state-level renewable portfolio standards (RPS) instruments already promote the use of landfill and other sources of biogas for the purposes of power generation. As the sensitivity analysis of electricity production versus pipeline biogas showed (Figure 18), electricity production can compete favorably across a variety of electricity and natural gas pricing scenarios. The added incentive created by a renewable energy mandate may further increase the advantage held by electricity production/combined heat and power, making pipelining of biogas even more unlikely. At the same time, RPS support for biogas can encourage technological improvements by spurring investment and deployment of digesters, gasifiers, and conditioning equipment, helping to lower costs for all biogas producers, regardless of end use. In this respect, renewable energy policy may act as a "pull" on pipeline biogas market development.

Renewable fuel standards (e.g., RFS2) can more directly facilitate development of the pipeline biogas market by creating an incentive for the production of an end use product sourced from biogas. It is possible to refine biogas into a liquid transportation fuel at or near the source, but pipeline transportation of biogas to a centralized refinery is likely necessary to produce fuel at a larger scale. The RFS2 classifies biogas-sourced transportation fuel as an advanced biofuel,[22] meaning that biogas faces competition with other fuel types (biomass-based diesel, cellulosic ethanol, and so on) to meet the category's 21 billion gallon production target and with corn-based ethanol to meet the programmatic target of 36 billion

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[21] Production incentives and other interventions (e.g., grants, loan guarantees, accelerated depreciation) can be instrumental in promoting early diffusion of new technologies but are not considered here at length. Market transformation at the scale considered here is likely achieved only through economy-wide policies like carbon constraints or renewable energy mandates.

[22] Such a fuel is derived from landfill gas, manure digesters, and wastewater treatment plants. Propane derived from the conversion of organic matter is also eligible to contribute to the advanced biofuels production target (75 ***Fed. Reg.*** 14864; March 26, 2010).

gallons.[23] Renewable fuel mandates can therefore act as a direct "push" for pipeline biogas market development, but the size of the targets implies that the absolute effect of existing policy is likely to be small in the foreseeable future.

GHG Restrictions, Pricing, and Standards

As discussed above, GHG policy—in the form of emissions limits, emissions pricing (through emissions trading or a carbon tax), or minimum performance standards (a low carbon fuel standard or LCFS)—can provide direct and indirect incentives to use biogas. The particulars of GHG policy—design, timing, scale, and scope—will ultimately determine the extent to which it actually facilitates a robust biogas market.

Another consideration is the likelihood that a GHG policy will be established in the lifespan of this analysis. Internationally, deliberations to reduce greenhouse gases continue through the UN Framework Conference on Climate Change (UNFCCC). However, a binding global treaty to place quantitative limits on greenhouse gases appears less likely now than it did prior to the Copenhagen Climate Change Conference in 2009. Near-term efforts focus largely on measurement, monitoring, and verification of emissions; on technology transfer and deployment; on revision, expansion, and implementation of forest and land use change programs; and on financing development of adaptation plans for future climate change.

In the United States, the prospect of comprehensive GHG policy is uncertain. Attempts at national comprehensive climate legislation failed late last decade, and Congress appears unlikely to revisit it in the immediate future. However, the Obama administration is meeting its obligation to control greenhouse gases, as required by the Supreme Court decision in *Massachusetts v EPA* (549 U.S. 497 (2007)), by using the powers of the Clean Air Act to regulate these gases as a pollutant. The act is being used to establish GHG emissions standards for the electric power sector; the presumption is that these standards will expand to other sectors. More broadly, the Obama administration announced a climate change action plan in June 2013 that included a number of policy objectives achievable through administrative action. Though several of these broad objectives have the potential to promote biogas production and use (e.g., power plant emissions limits; renewable energy deployment; RFS implementation, and next-generation-fuel support), questions about the design and implementation of related policies remain.

Other tangible examples of GHG policy implementation can be found at the state level. California is undertaking a variety of policy initiatives to reduce GHG emissions. Front and center is implementation of AB 32, which requires GHG emissions to be reduced to 1990 levels by 2020. The presence of GHG restrictions in any particular sector provides the incentive for use of biogas in all applications, including electricity, fuel, and combined heat and power. Relative incentives for each application would depend on the net cost differential between natural gas and biogas, a function of the cost of generating biogas, the GHG content of the biogas, the GHG content of the replaced fuel, and the explicit or implicit price of CO_2 emissions.

Although a CO_2 price may change the terms of trade between the use of fossil gas and the use of biogas, it may not change the terms of trade between sending biogas to the pipeline network and using it on-site to

[23] Of the 21 billion gallons of advanced biofuels that must be produced, 16 billion gallons must be cellulosic and 1 billion must be biomass–based diesel, minimizing the size of the carve-out for which biogas is eligible.

generate power. The sensitivity analysis above (Figure 18) includes estimates of natural gas and electricity prices in the presence of a GHG price. The failure of GHG pricing to change the ordering of electricity and biogas curves, in this study's rough approximation, suggests that the presence of a carbon price may be insufficient to encourage the use of pipeline biogas over electricity production or combined heat and power.

California is also home to a low-carbon fuel standard, which requires a 10% reduction in the carbon intensity of the state's transportation fuels by 2020. Fuels achieving reductions in carbon intensity relative to a fossil baseline (e.g., gasoline or diesel) are eligible for credits against a declining baseline. Credits are determined by the difference in carbon intensity between the low-carbon fuel and the fossil alternative and the amount of fossil alternative that is displaced. Biogas-sourced fuels (landfill and dairy digester-generated compressed natural gas from landfill or dairy digester gas, fuels generated from anaerobic digestion of food waste, and so on) possess some of the lowest carbon intensities of identified fuel pathways.[24] Although data to paint a long-term trend are lacking, LCFS credit prices are increasing; recent analyses report early spring 2013 prices at \$35 per tCO_2e, up from \$12.50 per tCO_2e just a few months before (Yeh et al. 2013). If this trend continues, LCFS implementation could help to drive early deployment of biogas resources, at least on a localized basis (e.g., fleet vehicle powering at point of generation).

Other Potential Policy Drivers

A variety of other policy drivers could influence biogas market development. CAA boiler standards (e.g., maximum achievable control technology or MACT standards) and regulations on new and existing sources of GHG pollution (e.g., 111(d) rules, NSR regulations, and PSD regulations) could hasten a conversion to natural gas-fired boilers and power plants. These policy drivers could lead to an increase in the price of natural gas by creating a greater demand for its use. In the immediate future, this price increase could allow biogas to better compete on the natural gas spot market on the basis of price alone and perhaps create a price premium for biogas if its use is further credited with reducing GHG emissions intensity. In the mid- to long-run, a natural gas price increase could also help to lower the costs of biogas pipeline delivery by facilitating greater natural gas exploration and associated expansion of the pipeline network.

Regulatory barriers exist also. Adding an anaerobic digester could trigger a permitting process or other regulatory oversight, especially if the resulting gas is flared or combusted for electricity generation. In those situations, operations could be required to meet ambient air quality standards, to install appropriate emissions control technology (e.g., best available control technology), or both. Even once biogas or biogas-fed electricity is produced, interconnection limitations or requirements may inhibit their transmission to the larger distribution network.[25]

Due to the indirect and varied mechanisms by which these policies can affect the biogas market, it is impossible to accurately predict their collective effect on the long-run supply of biogas. In general,

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[24] http://www.arb.ca.gov/fuels/lcfs/121409lcfs_lutables.pdf (last accessed September 19, 2013).
[25] Multiple examples exist. A net metering program for biogas digesters in California is limited on the basis of facility operation date and cumulative generation total; (http://www.pge.com/mybusiness/customerservice/nonpgeutility/generateownpower/netenergymetering/biogasnem/ (last accessed September 19, 2013). Krom (2011) discusses a variety of issues associated with biogas pipeline interconnection, including gas quality, volume restrictions, liability, and line extensions and upgrades.

policies that tend to promote the use of natural gas over other fossil fuels will tend to encourage biogas market development, as will policies that credit biogas for its lower carbon intensity relative to fossil gas. Policies that discourage the retrofits necessary for existing structures to create, capture, or distribute biogas will tend discourage market development.

CONCLUSIONS

The purpose of this paper is to assess the long-term potential for the development of a biogas market in the United States—a market in which a ready supply of biogas can help meet the future demand for low-carbon fuel sources. This emerging demand may expand as new policies place carbon constraints on fuel use. Therefore, the following findings should be of interest to companies that plan to operate in a carbon-constrained future and policy makers who may set the terms under which they operate:

- **Biogas use for energy is now fairly limited**. Much of the current biogas energy activity is in facilities that generate or treat waste as part of their normal business (landfills, wastewater treatment plants, and animal manure handling). Some of these facilities view the conversion of this waste to biogas—for example, through anaerobic digestion—as a viable alternative to meet core waste management needs (e.g., increasing waste-stream efficiency, reducing runoff, controlling odor) and, sometimes, energy demands. However, because biogas is typically more expensive to produce than alternative energy forms, energy market signals alone have not been sufficient to spur its widespread adoption.
- **In the long run, biogas could make up a larger share of the market.** Through generation from existing technologies and technologically feasible options such as thermal gasification of agriculture and forest biomass, biogas could be expanded to perhaps 3–5% of the total U.S. natural gas market at projected prices of $5–6/MMBtu. Its market share could rise considerably higher, perhaps up to 30%, but only under a very high price mark-up relative to expected gas price levels (well above $7/MMBtu). The largest physical potential in these price ranges appear to come from thermal gasification of agriculture and forest residues and biomass; the smallest, from wastewater treatment plants.
- **Policy incentives appear necessary to spur growth in the biogas market.** Given the economics just described, the energy market alone seems unlikely to induce a shift to biogas under current expectations of natural gas prices. Use of renewable fuels mandates or subsidies, low-carbon incentives (such as a CO_2 price), and other incentives specifically targeted at biogas appears necessary to create a robust market for biogas. Carbon dioxide prices in the range of recent history could produce a price premium for biogas that makes it substantially more economic.
- **Parties that want to tap a biogas market for low-carbon fuel sourcing need to recognize that they will likely face many sources of competition**. Although some biogas feedstock is provided essentially for free (waste streams that must be managed), others must be bid away from other uses such as agriculture and forest products. Bidding feedstocks away from competing uses into biogas production raises the cost of procurement. Likewise, competing on-site uses of biogas at the point of generation, such as electric power can limit the amount supplied to pipelines for use offsite. Under some conditions and given certain prices in the natural gas market, generating and transporting biogas from facilities to the pipeline might appear profitable, but keeping the gas on-site and using it for power generation might be even more profitable. Thus, biogas may hit the

market through its use in electricity production rather than through transmission in pipeline form. Regardless, more low-carbon energy on the market means more opportunity to lower compliance costs in a carbon-constrained world—that is, fewer allowances might be needed, or more offset credits might be available if biogas penetrates the energy market at scale. But if biogas is used to create electricity on-site, it will be less available to parties primarily interested in having access to biogas through the larger natural gas distribution system. Once biogas makes it into this system, these buyers will face competition from yet other buyers seeking biogas for its unique environmental qualities.

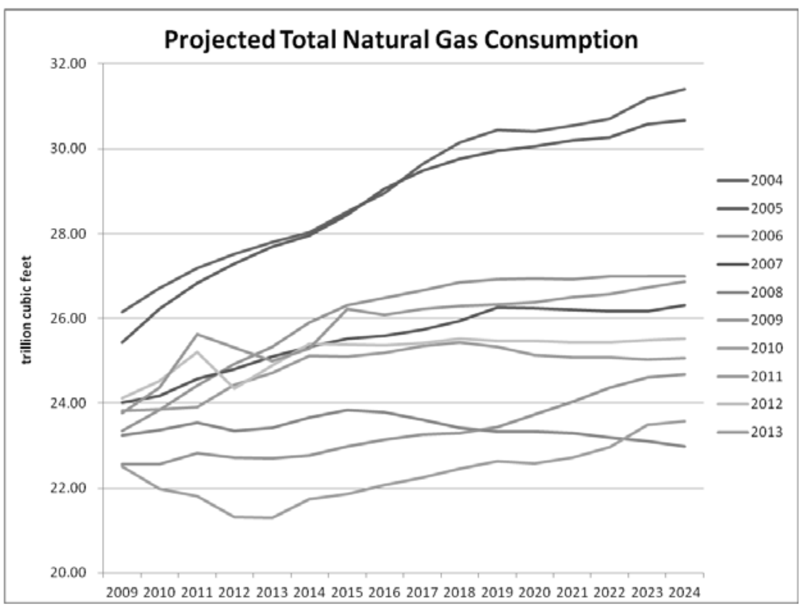
- **In addition to economic hurdles, full-scale appreciation of biogas potential faces technological, market, and institutional hurdles**. Technology diffusion is an open-ended process subject to many institutional factors that are hard to predict. Accordingly, this analysis cannot definitively speak to the size or presence of a robust biogas market in the coming decades. It can, however, offer insight into the advantages and disadvantages of biogas as a hedge in a carbon-constrained future. The barriers identified in this study can presumably be overcome if biogas provides an adequate financial return to warrant the necessary investments in technology, networks, and infrastructure.
- **Many biogas market hurdles have been overcome in the European Union, where 2% of gas consumption comes from biogas.** Whether EU approaches to biogas market hurdles could be taken in the United States remains to be seen. Recent efforts to increase renewable energy use in the United States have met with mixed response at the federal and state level.

APPENDIX A. REVIEW OF NATURAL GAS SUPPLY PROJECTIONS

The Energy Information Administration (EIA) projects natural gas consumption and price estimates in its annual energy outlook (AEO). What is clear from these projections is that natural gas markets are subject to great uncertainty. As seen below, past projections of total consumption (Figure A1) and price (Figure A2) vary widely. In recent years, this variation has largely been a function of changes in technology and economic activity, which in turn have a direct influence on the recoverable supply of and the expected demand for natural gas.

Within the last decade, technological advancement allowing for increased recovery of so-called unconventional resources such as shale gas has markedly changed perspectives on future natural gas market conditions. The 2003 AEO reflected uncertainty about whether domestic supplies would be available to meet projected demands.[26] Hydraulic fracturing was first mentioned in the 2004 AEO.[27] But it was not mentioned again until the 2010 AEO.[28] The 2007 AEO predicted that new coal-fired generation would displace natural gas in the electric power sector between 2020 and 2030.[29] The 2013 AEO expected natural gas exports to exceed imports by 2020.[30]

Figure A1. Reference-case-projected total natural gas consumption as reported in the United States.



Note: The colored lines indicate the AEO edition in which the projection was made.

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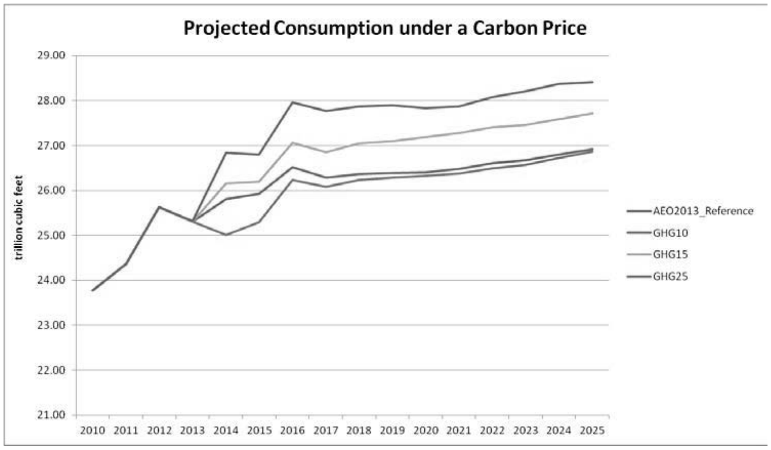
26 http://www.eia.gov/forecasts/archive/aeo03/ (last accessed May 3, 2013).
27 http://www.eia.gov/forecasts/archive/aeo04/issues_2.html (last accessed May 3, 2013).
28 http://www.eia.gov/forecasts/archive/aeo10/gas.html (last accessed May 3, 2013).
29 http://www.eia.gov/forecasts/archive/aeo07/gas.html (last accessed May 3, 2013).
30 http://www.eia.gov/forecasts/aeo/MT_naturalgas.cfm#natgas_consump (last accessed May 8, 2013).

Figure A2. Reference-case-projected natural gas price (2011 dollars) as reported in the United States.

Note: The colored lines indicate the AEO edition in which the projection was made.

How imposition of a carbon price could affect consumption of natural gas is uncertain. So, too, are the likelihood and eventual magnitude of a carbon price. Shown below are total U.S. natural gas consumption (Figure A3) and the price of delivered natural gas to industrial users (Figure A4) under several carbon price scenarios. Although little changes from a reference scenario at low carbon prices, higher prices ($15, $25) result in significant shifts in both price and consumption in the later years of each projection.

Figure A3. Variation of total U.S. natural gas consumption under a reference scenario and three carbon prices: \$10, \$15, and \$25 tCO_2e^{-1}.



Note: Magnitude of carbon price is indicated for each scenario.

Figure A4. Variation of delivered industrial price under a reference scenario and three carbon prices: \$10, \$15, and \$25 tCO_2e^{-1}.

Note: The magnitude of carbon price is indicated for each scenario.

APPENDIX B. CASE STUDY: BIOGAS MARKET DEVELOPMENT IN THE EUROPEAN UNION

In contrast to the United States, the European Union has a larger but not yet fully developed biogas market. EU biogas production was 10.9 Mtoe in 2010 (approximately 432,213,435 MMBtu/year or 1,184,146 MMBtu/day), an increase of more than 30% from 2009 levels (van Foreest 2012).[31] Within the European Union, Germany is the leader in terms of total production with 61% of the total and more than 7,000 biogas plants mostly run on manure, only 82 (1.2%) of which inject upgraded biogas into the gas pipeline system. Other countries of significant biogas output, mostly from landfills, include the United Kingdom, France, the Netherlands, Italy, and Sweden. The EU's total biogas potential has been estimated as high as 16 million MMBtu/day (Thran et al. 2007), enough to meet 33% of the total EU gas demand.

Technology

Most of the biogas production the European Union uses anaerobic digesters (van Foreest 2012) at landfills, for which many of the technological and adoption barriers have been addressed. Barriers to further biogas production exist primarily in the context of biomass gasification and methanation processes, which have high upfront capital costs. Gasification is in the R&D phase and is expected to be economically viable before 2030; four gasification demonstration plants in the 1–200MW range are operating in Europe. Also hindering biogas production are costly and time-consuming administrative and approval procedures (van Foreest 2012). Finally, expansion of biogas production is dependent on subsidies to attract investors.

The economics of biogas production are closely linked to the price of natural gas and the price of CO_2 (which the European Emissions Trading System establishes) as well as to the size and feedstock mix of the biogas facility (van Foreest 2012).As in the United States, biogas production costs in the European Union tend to be considerably higher than the market price of natural gas (Balussou et al. 2012). To overcome this economic barrier, subsidies make up a large percentage of the revenue for producers. Subsidies may consist of energy crop bonuses, technology bonuses, feed-in tariffs, and avoided network fees.

Biogas market development is greater in the European Union than in the United States for several other reasons. European countries view bioenergy production in general, and biogas production in particular, as playing an important role in maintaining rural economies. Some of the most developed of EU countries (e.g. Germany, Sweden, the United Kingdom) have sought to create biogas-related jobs (AEBIOM 2009). Recent natural gas crises due to conflicts between Russia and Ukraine have also raised energy security concerns in the European Union. A net oil and natural gas importer, the European Union considers bio-based fuels one way to reduce dependence on energy exports and to decrease the fluctuation of transportation fuel prices.

Policy

The European Union has set renewable energy targets as part of its commitment to a low-carbon economy. Although the European Union has no overarching policy for biogas, several EU directives have addressed biogas (van Foreest 2012). Specifically, biogas is included in the Renewable Energy Directive (2009/28/EC), the Directive on Waste Recycling and Recovery (2008/98/EC), and the Directive on Landfills (1999/31/EC). The result of these directives is an EU-wide goal of producing 20% of energy

[31] In this section we mostly summarize the report by van Foreest (2012) on biogas market development in the European Union (EU) but also draw on additional reports from Europe.

consumption from renewable sources by 2020 (European Commission 2012). To meet this goal, individual EU member countries have also taken on national renewable energy targets of 10–49% of total generation within the framework of the National Renewable Action Plan.

EU member states have implemented their own certification systems, feed-in tariffs, market and flexibility premium programs, tax benefits, and investment support to overcome barriers to biogas market development. For example, the EU leader in total biogas production, Germany, implemented subsidies specifically for biogas production with its Renewable Energy Source Act (BMU 2012). Although support programs have been effective in Germany, Sweden, and the United Kingdom, they still carry a certain amount of risk due to potential modifications.

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The Nicholas Institute for Environmental Policy Solutions

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RENEWABLE NATURAL GAS (RNG)

TOOL KIT

SoCalGas A Sempra Energy utility®

Last updated February 2020

FOREWORD

SoCalGas® believes that renewable gas will play a fundamental role in California's clean energy future, alongside wind and solar. Developing renewable gas resources from our state's abundant organic waste streams provides an exciting solution to California's ambitious climate change goals, while also creating additional renewable fuel and jobs for our communities, and potentially billions of dollars in economic benefits.

SoCalGas has more than a decade of experience fostering the growth of renewable gas. Our culture is deeply rooted in customer service and we are committed to finding innovative solutions to meet customers' needs. To date, several projects have demonstrated that biogas can be successfully cleaned to meet pipeline quality specifications.

- In February 2019, Calgren Dairy Fuels, working with SoCalGas, began injecting RNG sourced from cow manure from dairy clusters in Pixley, California.
- At a wastewater treatment plant in Point Loma, California, SoCalGas collaborated with its sister company, San Diego Gas & Electric Company (SDG&E®), to install a renewable gas pipeline interconnection facility to deliver renewable gas into the SDG&E pipeline network.
- In July 2018, CR&R, a waste and recycling management company, began injecting renewable natural gas sourced from landfill-diverted food and green waste into SoCalGas's pipeline to fuel CR&R's waste hauling trucks.

California has a challenging path ahead. Meeting the state's climate goals will require a fundamental shift in the way we power our homes and businesses, transport goods, and manage the lifecycle of our food and waste. By developing renewable gas in California, we can help to meet our climate goals sooner, while diversifying our carbon-free energy sources and improving energy resilience and reliability. SoCalGas stands ready to support biogas producers and to pursue renewable gas projects with pipeline injection. We created this tool kit to assist producers with information and technical guidance to support the interconnection process.

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RENEWABLE NATURAL GAS

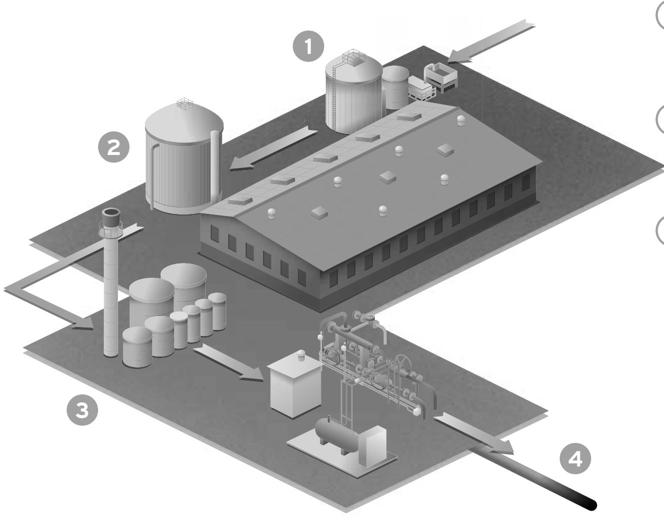
PART OF CALIFORNIA'S RENEWABLE ENERGY FUTURE

WHAT IS RENEWABLE NATURAL GAS?

Traditionally, pipeline natural gas comes from deep underground wells and is often associated with petroleum production. On the other hand, renewable natural gas (RNG) is natural gas derived from organic waste material found on the surface of the earth. In California, and throughout the United States, there are a variety of sources of this organic waste, which we see in daily life. These include food waste, garden and lawn clippings, animal and plant-based material as well as degradable carbon sources such as paper, cardboard and wood. The abundance of this material can allow for production of biogas in significant quantities.

The most common source of biogas is the naturally occurring biological breakdown of organic waste at facilities such as wastewater treatment plants and landfills. Biogas typically consists of methane and carbon dioxide, with traces of other elements. Biogas is cleaned and conditioned to remove or reduce non-methane elements in order to produce RNG. The converted RNG is then put into the utility pipeline as a replacement for traditional natural gas. This process helps promote the safe and reliable operation of the natural gas pipeline distribution network as well as the natural gas equipment and appliances used by customers.

HOW ORGANIC WASTE IS CONVERTED INTO RNG



1. Waste products, such as sludge, food waste or manure are processed in a biodigester.
2. The biodigester breaks down the organic material to create biogas — a mixture of methane and other elements.
3. The biogas can then be processed and conditioned leaving behind RNG, which can be used interchangeably with traditional natural gas.
4. This RNG can be used where it is produced for things like generating electricity or fueling vehicles, or it can be injected into a utility pipeline for transportation to other customers.

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GREENHOUSE GAS REDUCTIONS

RNG comes from organic sources that originally removed carbon dioxide from the atmosphere during photosynthesis, so it is considered a carbon-neutral fuel. Often, RNG can be produced from organic waste that would otherwise decay and create methane emissions. Capturing these methane emissions can actually make RNG a carbon-*negative* fuel by removing emissions from the atmosphere. Reducing carbon dioxide and other greenhouse gas levels is important to help reduce global warming.

GREEN ENERGY AROUND THE CLOCK HELPS CALIFORNIA'S ECONOMY

Unlike certain other sources of renewable energy, such as solar and wind technologies, RNG is available 24 hours per day, seven days a week. It can be deployed when and where it is needed through the existing pipeline network. Converting waste products into RNG could help California meet its energy needs with local resources. Investing in RNG production in California could help create jobs in all regions of the state while improving air quality by better managing our waste streams.

UP TO 400 PERCENT CARBON DIOXIDE REDUCTIONS FOR TRANSPORTATION

Studies conducted by the University of California at Davis have estimated that more than 20 percent of California's current residential natural gas use can be provided by RNG derived from our state's existing organic waste alone[1]. This can help reduce the need for other fossil-based fuels, and increase our supplies with a local renewable fuel. According to the California Air Resources Board[2], RNG sourced from landfill diverted food and green waste can provide a 125 percent carbon dioxide reduction, and RNG from dairy manure can result in a 400 percent carbon dioxide reduction when replacing traditional vehicle fuels.

More than half of all natural gas dispensed in California for transportation is RNG, powering buses, refuse trucks and heavy-duty trucks.

SOCALGAS® IS A SUPPORTER OF RNG

As part of our commitment to help the environment and support California in meeting its greenhouse gas reduction goals, SoCalGas® offers expertise and assistance to customers and project developers who want to convert organic waste material into biogas or RNG. Through our network of natural gas pipelines, SoCalGas offers the opportunity for RNG to be accepted into our transmission and distribution system and delivered to our customers.

FIND OUT MORE

For more information visit:

socalgas.com/rng

Or contact our Market Development Team at:
MarketDevelopment@socalgas.com

1. "The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute", Prepared for the California Air Resources Board and the California Environmental Protection Agency by Amy Jaffe, Principal Investigator. STEPS Program, Institute of Transportation Studies, UC Davis: https://ww3.arb.ca.gov/research/apr/past/13-307.pdf
2. "Low Carbon Fuel Standard Pathway Certified Carbon Intensities": https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm

RENEWABLE NATURAL GAS (RNG)

INTERCONNECTION PROCESS

OVERVIEW

Renewable Natural Gas (RNG), also known as biomethane, is biogas that has been processed and upgraded to be interchangeable with traditional natural gas. RNG that meets the standards adopted pursuant to California Health and Safety Code Section 25421 can be injected into the existing utility natural gas pipelines. SoCalGas' Tariff Rule No. 30, "Transportation of Customer-owned Gas," describes the specifications, terms and conditions adopted that must be met in order for SoCalGas® to accept RNG into its pipeline network.

The process begins with biogas, which is produced by the anaerobic decomposition of organic material, which occurs naturally. This process happens at facilities such as landfills, landfill diversion facilities, dairies and wastewater treatment plants. This raw biogas is made up of mainly methane and carbon dioxide, with traces of other elements such as water, hydrogen sulfide, siloxanes, nitrogen, and oxygen. Prior to injection into the pipeline, biogas must be conditioned and upgraded to remove or reduce non-methane elements to promote the safe and reliable operation of the pipeline network and end-use natural gas equipment.

BIOGAS PROCESSING TECHNOLOGIES

There are several methods and technologies available to condition biogas. Technology selection can be based on many criteria, including biogas and product gas makeup and site and operating conditions. Some examples of technologies used in biogas conditioning:

- High-selectivity membranes
- Pressure swing adsorption systems
- Water scrubbing systems
- Solid scavenging media
- Regenerative or non-regenerative adsorbent media
- Catalytic O_2 removal

It is common to find a combination of these technologies working in conjunction to meet a set of specifications.

BIOMETHANE INJECTION PROCESS

SoCalGas' Tariff Rule No. 39, "Access to the SoCalGas Pipeline System," provides detailed information on the requirements to interconnect and inject natural gas into utility pipelines. The section below describes the three basic steps of the interconnection process.

STEP 1

INTERCONNECTION CAPACITY STUDY

The process starts with an Interconnection Capacity Study, which determines the utility's downstream capacity to take the renewable natural gas away from the interconnection point and the associated utility facility enhancement cost. The Capacity Study step also provides interconnectors with the option to request a deviation from the gas quality specifications defined in SoCalGas' Tariff Rule 30, Paragraph I.3.[1] Interconnectors are responsible for the actual costs needed to perform the Interconnection Capacity Study. These costs typically range from $2,000 to $5,000 and require 45 calendar days to complete.[2]

STEP 2

PRELIMINARY ENGINEERING STUDY

The Preliminary Engineering Study develops the preliminary cost estimates for land acquisition, site development, right-of-way, metering, renewable natural gas quality, permitting, regulatory, environmental, unusual construction, operating and maintenance costs. Interconnectors are responsible for the actual costs needed to perform the Preliminary Engineering Study. These costs typically range from $65,000 to $75,000 and require 80 calendar days to complete.[2]

STEP 3

DETAILED ENGINEERING STUDY

There are three elements in the Detailed Engineering Study, including:

1. Description of all costs of construction
2. Development of complete engineering construction drawings
3. Preparation of all construction and environmental permit applications and right-of-way acquisition requirements

Interconnectors are responsible for the actual costs needed to perform the Detailed Engineering Study. These costs typically range from $325,000 to $600,000 and require 150 calendar days to complete.[2]

Interconnectors may have the option to request and fund the Preliminary and Detailed Engineering Studies (Steps 2 and 3) concurrently.

BIOMETHANE INTERCONNECTION INCENTIVE PROGRAM

In 2015, the California Public Utilities Commission established the Biomethane Interconnector Monetary Incentive Program.[3] This program can provide an incentive that can contribute up to 50 percent of interconnection costs, with a cap of $3 million per project. The cap is $5 million for dairy cluster projects, defined as three or more dairies in close proximity. The program is described in detail in SoCalGas' Tariff Rule 39 Section A.3.a. Your SoCalGas account executive can help to navigate the qualification and application process for this incentive. The program has a statewide funding cap of $40 million and is available until December 31, 2026, or until the program has exhausted its $40 million funding.

FIND OUT MORE

For more information, please visit:

socalgas.com/rng

or contact us at:

GasStudyRequests@socalgas.com

1. socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf

2. The provided estimated costs are based on historical projects and can vary based on site-specific conditions. The estimated costs and timeline do not include requests involving a deviation from the gas quality specifications.

3. D.15-06-02: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K572/152572023.PDF

The Biomethane Interconnection Incentive Program is funded by California utility customers and administered by Southern California Gas Company (SoCalGas®) under the auspices of the California Public Utilities Commission. Program funds, including any funds utilized for rebates or incentives, will be allocated on a first-come, first-served basis until such funds are no longer available. This program may be modified or terminated without prior notice.

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TOOLS AND TIPS

FOR RENEWABLE NATURAL GAS (RNG) PROJECTS CONNECTING TO THE SOCALGAS® PIPELINE

INTRODUCTION

Renewable natural gas (RNG) is a carbon-neutral gaseous fuel that replaces traditional natural gas. RNG can play an important role in reducing the impact of greenhouse gas (GHG) emissions from the natural gas system. RNG typically comes from biogas sources such as landfills, wastewater treatment facilities, manure, and food and green waste. This raw biogas contains byproducts or compounds that need to be removed so they won't negatively impact end-use equipment or the environment. Removing these compounds, also called conditioning and/or upgrading, ensures the RNG can meet pipeline standards, as defined in SoCalGas' Tariff Rule No. 30.[1] Conditioning and upgrading biogas to meet pipeline standards typically includes removal of water, carbon dioxide (CO_2), hydrogen sulfide (H_2S) and other elements. Numerous commercially-available conditioning and upgrading systems are already in use here in the United States and in Europe.

Once RNG is conditioned and upgraded, it can be injected into SoCalGas® pipelines. The location of the interconnection is critical. A nearby pipeline must have the capacity to accept the volume of RNG produced. Customer demand fluctuates daily and seasonally, and natural gas pipelines typically flow in one direction — from higher pressure feeder systems to lower pressure distribution systems. For this reason, SoCalGas must conduct an engineering analysis to find a feasible location.

WHAT FACTORS DETERMINE THE VIABILITY OF PRODUCING PIPELINE RNG?

The necessary components and related costs to condition and upgrade raw biogas and inject it into the pipeline can vary, depending on the source and quality of the raw biogas as well as the project location. Below a certain quality level and scale, it may not be economical to produce RNG without incentives. Typically, the larger the project and the cleaner the raw biogas, the more economically feasible that project will be. Project scale isn't the only design factor that may impact project economics. Some other major components that can play a significant, but often manageable, role in project costs are:

- Equipment to remove nitrogen and oxygen (capital and operating cost driver)
- Compression for processing and pipeline injection (capital and operating cost driver)
- Long-distance high pressure pipeline extension (capital cost driver)

1. **REMOVING NITROGEN AND/OR OXYGEN**
Often landfills and other biogas sources have air infiltration, meaning that nitrogen and oxygen can be inadvertently mixed with raw biogas. Both nitrogen and oxygen removal can increase capital and operating costs while reducing methane recovery efficacy. A recent Black & Veatch study estimated that eliminating the need to remove nitrogen during biogas processing can result in up to 20 to 25 percent cost reduction.[2] Because of this, it is often more cost-effective to reduce air infiltration upstream of the conditioning system by improving system integrity and adjusting landfill gas collection systems, or by implementing measures that limit or avoid introduction of air in anaerobic digesters.

2. **COMPRESSION FOR PROCESSING AND PIPELINE INJECTION**
Several biogas processing technologies require gas compression, and depending on the utility pipeline network pressure, final injection of RNG may require higher levels of compression (400 PSIG and greater). Conversely, lower pressure utility pipeline networks may be closer, but they typically have less connected demand available to accept RNG deliveries. Compression energy and maintenance costs can account for one-half to two-thirds of total operating costs, depending on final delivery pressure required. Siting projects to access lower pressure pipelines for injection can result in up to 5 to 15 percent savings in total operating costs.[3]

3. **DISTANCE TO NEAREST VIABLE INJECTION LOCATION**
The length of the pipeline extension necessary to interconnect with the utility system is also a critical cost driver. Finding routes for pipelines that require minimal traffic control and re-paving during installation can significantly reduce costs. For example, a 1,000-foot pipeline could equate to around one percent of estimated project lifecycle costs for a typical economically sized upgrade and injection project but can grow up to 20 percent of project lifecycle costs when a two-mile pipeline is required.[3]

HOW CAN I FIND OUT MORE ABOUT SITING A PROJECT NEAR AN EXISTING PIPELINE?

To get a general idea about project siting, review the SoCalGas pipeline maps online at: **socalgas.com/rng**

Keep in mind that the existence of a pipeline on this map is not a guarantee it will have the capacity necessary to support renewable natural gas injection. These maps also don't include many lower-pressure pipelines which could provide injection access. Learn more about the interconnection process at: **socalgas.com/rng**

The SoCalGas low-carbon fuels Market Development Team can also provide you with more information about renewable natural gas project development. You can email the team at: **MarketDevelopment@socalgas.com**

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1. socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf
2. "Biogas Conditioning and Upgrading Technologies, Technical Characterization and Economic Evaluation" Black & Veatch, Commissioned by SoCalGas, 2015.
3. The provided estimates are based on internal evaluation and assessment work and can vary based on site-specific conditions.

RENEWABLE NATURAL GAS (RNG)

GAS QUALITY STANDARDS

THE SOCALGAS® GAS QUALITY STANDARDS

SoCalGas® Rule 30 describes the requirements for natural gas to be injected into the utility pipeline. These requirements reflect the first and foremost priority of SoCalGas to protect its customers, employees, contractors and pipeline system, as well as the public. The standards described in Rule 30 cover two major aspects: gas constituent limits (composition-based specifications) and gas interchangeability specifications (performance-based quality specifications). Gas constituent limits restrict the concentration of gas impurities to protect pipeline integrity and ensure safe and proper combustion in end-user equipment.
The interchangeability specifications address end-user combustion performance, ensuring safe and proper combustion for customers.

SoCalGas Rule 30, Section I.5. provides interconnectors with the option to request specific deviations from meeting the defined gas quality specifications in Section I.3. If SoCalGas determines such gas will not negatively impact system operations, SoCalGas is then required to file an Advice Letter for California Public Utilities Commission (CPUC) approval before the gas is permitted to flow into the utility pipeline system.

The table below shows some gas quality standards from across the United States[1]. These requirements are specific to each pipeline network.

Pipeline Company	Heating Value (Btu/scf)		Water Content	Various Inerts			Hydrogen Sulfide (H_2S)
	Min	Max	(Lbs/ MMscf)	CO_2	O_2	Total Inerts	(Grain/100scf)
SoCalGas	970	1150	7	3%	0.20%	4%	0.25
Dominion Transmission	967	1100	7	3%	0.20%	5%	0.25
Equitrans LP	970	–	7	3%	0.20%	4%	0.3
Florida Gas Transmission Co.	1000	1110	7	1%	0.25%	3%	0.25
Colorado Intrastate Gas Co.	968	1235	7	3%	0.001%	–	0.25
Questar Pipeline Co.	950	1150	5	2%	0.10%	3%	0.25
Gas Transmission Northwest Co.	995	–	4	2%	0.40%	–	0.25

TYPICAL GAS CONSTITUENTS FOUND IN BIOGAS

In 2012, the CPUC issued a decision in the Biomethane Phase I Order Instituting Rulemaking (OIR)[2] in response to California Assembly Bill 1900 (AB 1900) (Gatto, 2012). In this OIR the CPUC, in collaboration with other state agencies, adopted 17 constituents of concern that can potentially be found in biogas. The CPUC established reasonably acceptable levels of these constituents to protect human health and system integrity, and ordered them to be included in SoCalGas Rule 30 (See Section J.5). As directed by AB 1900, the protection levels for each constituent along with the monitoring, testing, reporting and recordkeeping requirements are reviewed and updated every five years, or sooner, if new information becomes available. Siloxanes, one of the constituents of concern, can be found in a variety of consumer products. Siloxanes are typically present in biogas created at landfills and wastewater treatment plants, and can sometimes be found in diverted food and green

1. Source: American Gas Association, Report #4A Natural Gas Contract Measurement and Quality Clauses (2009). Some standards have been updated based on publicly available information

2. R.13-02-008

waste biogas. Siloxanes can create problems in end-user equipment because during combustion, they can coat equipment with a fine layer of silica and silocates. This is especially problematic for sensitive end-user equipment found in Southern California. For example, siloxanes can cause expensive catalysts to fail. These catalysts perform an important service reducing emissions to keep our air clean, and are found in all fuel cells, natural gas vehicles, and the majority of electric power generators. The local aerospace industry and other manufacturers have also expressed concerns with siloxanes potentially entering their sensitive facilities through the fuel supply.

CLEANING BIOGAS TO PIPELINE QUALITY STANDARDS

Several methods and technologies are available to condition and upgrade biogas into renewable natural gas (RNG) and remove constituents of concern. Technology selection can be based on many criteria, including the makeup of the biogas as well as site and operating conditions. Some examples of technologies used in biogas conditioning and upgrading are:

- High-selectivity membranes
- Pressure swing adsorption systems
- Water scrubbing systems
- Solid scavenging media
- Regenerative or non-regenerative adsorbent media
- Catalytic O_2 removal

It is common to find a combination of these technologies working together to meet a set of specifications.

GAS CONSTITUENT MONITORING AND MEASUREMENT

Gas quality is maintained by two different types of monitoring, based on the Biomethane OIR requirements. Some attributes such as carbon dioxide, total inerts, and heating value are continuously monitored at the point of utility interconnection. Other constituents, such as siloxanes, are monitored by taking quarterly or annual samples of the gas and testing it in a laboratory.

SoCalGas Rule 30 requires gas quality testing on biomethane constituents of concern be done by independent certified third-party laboratories[3]. The NELAC Institute (TNI) maintains a list of laboratories (http://lams.nelac-institute.org/search) which are able to test for constituents of concern, including the measurement of siloxanes below the defined trigger level.

FIND OUT MORE

For more information, please visit:

socalgas.com/rng

Or contact our Low Carbon Fuels Market Development Team at:
MarketDevelopment@socalgas.com

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[3] SoCalGas utilizes an independent third party laboratory and may include a performance sample when measuring siloxane levels.

BIOGAS CONDITIONING/UPGRADING SERVICES TARIFF

The Biogas Conditioning/Upgrading Services Tariff is a fully elective, optional, nondiscriminatory tariff service for customers that allows SoCalGas® to plan, design, procure, construct, own, operate, and maintain biogas conditioning and upgrading equipment on customer premises. The biogas will be conditioned/upgraded to the gas quality specifications as requested by the customer and agreed to by SoCalGas.

KEY ELEMENTS

- The Biogas Conditioning/Upgrading Services Tariff is a service fully paid for by participating customers. Monthly tariff services pricing will vary based on the size, scope and location of each project.
- The Biogas Conditioning/Upgrading Services Tariff will be provided through a long-term Service Agreement, typically 10-15 years. At the end of the contract term, customer may request to extend the term of the agreement or ask SoCalGas to remove the equipment.
- The tariff service is neither tied to any other tariff or non-tariff services the customer may receive from SoCalGas nor will it change the manner in which these services are delivered.
- Non-utility service providers may offer services that are the same or similar to the Biogas Conditioning/Upgrading Services Tariff and customers are encouraged to explore these service options.
- To assist customers in understanding all of their service options, SoCalGas maintains and provides customers with a list of non-utility service providers at **socalgas.com/rng**

FREQUENTLY ASKED QUESTIONS

WHAT ARE SOME EXAMPLES OF END-USE APPLICATIONS THAT WOULD USE THIS TARIFF?

Examples of customer end-use applications that can be served by the Biogas Conditioning/Upgrading Services Tariff include but are not limited to: renewable natural gas for pipeline injection, compressed natural gas for vehicle refueling stations, and conditioned/upgraded biogas for combined heat and power (CHP) facilities.

IS THE BIOGAS CONDITIONING/UPGRADING SERVICES TARIFF MANDATORY IF CUSTOMERS WANT TO PUT RENEWABLE NATURAL GAS (BIOMETHANE) INTO THE PIPELINE?

No. Customers may elect to install and maintain their own biogas conditioning and upgrading equipment or engage a third party to install and maintain their biogas conditioning and upgrading equipment rather than take the Biogas Conditioning/Upgrading Services Tariff from SoCalGas.

DOES ENROLLMENT IN THIS TARIFF RESULT IN ANY PREFERENTIAL TREATMENT WHEN IT COMES TO GETTING GAS SERVICE?

No. The Biogas Conditioning/Upgrading Services Tariff is a fully elective, optional, non-discriminatory tariff service that is neither tied to any other tariff or non-tariff services the customer may receive from SoCalGas nor will it change the manner in which these services are delivered. As an example, requests for an interconnection capacity study are processed on a "first come, first served" basis for all customers, including customers that elect to take the Biogas Conditioning/Upgrading Services Tariff and customers that do not.

WHO CAN RECEIVE SERVICE UNDER THE BIOGAS CONDITIONING/UPGRADING SERVICES TARIFF?

The Biogas Conditioning/Upgrading Services Tariff is generally applicable to producers of biogas. Any agreement to provide service under the Biogas Conditioning/Upgrading Services Tariff is at the discretion of SoCalGas and will depend on non-discriminatory factors such as safety, SoCalGas resource availability, technical feasibility, and acceptability of commercial terms.

UNDER THIS SERVICE, WILL SOCALGAS BE RESPONSIBLE FOR ALL EQUIPMENT CONNECTED TO THE BIOGAS CONDITIONING AND UPGRADING FACILITIES?

No. This service does not cover any activities either upstream from the receipt point of untreated biogas or downstream from the point of service delivery for conditioned/upgraded biogas.

WHO OWNS BIOGAS TREATED UNDER THE BIOGAS CONDITIONING/UPGRADING SERVICES TARIFF?

Any gas processed under the Biogas Conditioning/Upgrading Services Tariff is solely owned by the customer before, during, and after processing. It is solely the customer's responsibility to ensure that treated biomethane intended for pipeline injection meets Rule 30 standards for pipeline injection of customer-owned gas. The customer is solely responsible for any damage to pipeline integrity or human health which results from improperly treated gas entering SoCalGas' natural gas pipeline system.

FIND OUT MORE

For more information, please visit:

socalgas.com/rng

Or contact our Low Carbon Fuels Market Development Team at:
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BIOGAS INDUSTRY LIST

Last updated February 2020

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Provided for information purposes only. There are numerous qualified non-utility providers of products and services needed for construction and operation of biogas conditioning and upgrading facilities, but SoCalGas does not recommend or endorse the products or services of any particular party listed herein, or represent that the particular products or services are fit for any particular purpose or use. By publishing this list, SoCalGas is not acting in an advisory capacity, and does not assume any responsibility for use of the list by customers. Although commercially reasonable efforts are used in posting this list, no representation is made that it is complete or free from error. Related information is posted at socalgas.com. To be added to the list, please send an e-mail to MarketDevelopment@socalgas.com. Vendors are listed alphabetically and the order of listing implies no preference.

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Rule No. 30 Sheet 1

TRANSPORTATION OF CUSTOMER-OWNED GAS

The general terms and conditions applicable whenever the Utility System Operator transports customer-owned gas, including wholesale customers, the Utility Gas Procurement Department, other end-use customers, aggregators, marketers and storage customers (referred to herein as “customers") over its system are described herein.

A. General

1. Subject to the terms, limitations and conditions of this rule and any applicable CPUC authorized tariff schedule, directive, or rule, the customer will deliver or cause to be delivered to the Utility and accept on redelivery quantities of gas which shall not exceed the Utility's capability to receive or redeliver such quantities. The Utility will accept such quantities of gas from the customer or its designee and redeliver to the customer on a reasonably concurrent basis an equivalent quantity, on a therm basis, to the quantity accepted.

2. The customer warrants to the Utility that the customer has the right to deliver the gas provided for in the customer's applicable service agreement or contract (hereinafter "service agreement") and that the gas is free from all liens and adverse claims of every kind. The customer will indemnify, defend and hold the Utility harmless against any costs and expenses on account of royalties, payments or other charges applicable before or upon delivery to the Utility of the gas under such service agreement.

3. The point(s) where the Utility will receive the gas into its intrastate system (point(s) of receipt, as defined in Rule No. 1) and the point(s) where the Utility will deliver the gas from its intrastate system to the customer (point(s) of delivery, as defined in Rule No. 1) will be set forth in the customer's applicable service agreement. Other points of receipt and delivery may be added by written amendment thereof by mutual agreement. The appropriate delivery pressure at the point(s) of T
delivery to the customer shall be that existing at such point(s) within the Utility's system or as T
specified in the service agreement.

B. Quantities

1. The Utility shall as nearly as practicable each day redeliver to customer and customer shall accept, a like quantity of gas as is delivered by the customer to the Utility on such day. It is the intention of both the Utility and the customer that the daily deliveries of gas by the customer for transportation hereunder shall approximately equal the quantity of gas which the customer shall receive at the point(s) of delivery. However, it is recognized that due to operating conditions either (1) in the fields T
of production, (2) in the delivery facilities of third parties, or (3) in the Utility's system, deliveries into and redeliveries from the Utility's system may not balance on a day-to-day basis. The Utility and the customer will use all due diligence to assure proper load balancing in a timely manner.

(Continued)

Rule No. 30 Sheet 2

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

B. Quantities (Continued)

2. The gas to be transported hereunder shall be delivered and redelivered as nearly as practicable at uniform hourly and daily rates of flow. The Utility may refuse to accept fluctuations in excess of ten percent (10%) of the previous day's deliveries, from day to day, if in the Utility's opinion receipt of such gas would jeopardize other operations. Customers may make arrangements acceptable to the Utility to waive this requirement.

3. The Utility does not undertake to redeliver to the customer any of the identical gas accepted by the Utility for transportation, and all redelivery of gas to the customer will be accomplished by substitution on a therm-for-therm basis.

4. Transportation customers, including the Utility Gas Procurement Department, wholesale customers, contracted marketers, and Core Transport Agents (CTAs) will be provided monthly balancing services in accordance with the provisions of Schedule No. G-IMB. T

C. Electronic Bulletin Board

1. The Utility prefers and encourages customers, including the Utility Gas Procurement Department, to use Electronic Bulletin Board (EBB) as defined in Rule No. 1 to submit their transportation nominations to the Utility. Imbalance trades are to be submitted through EBB or by means of the Imbalance Trading Agreement Form (Form 6544). Use of EBB is not mandatory for transportation only customers.

2. Transportation nominations may be submitted manually or through EBB. D

D. Operational Requirements

1. Customer Representation

   The customer must provide to the Utility the name(s) of any agents ("Agent") used by the customer for delivery of gas to the Utility for transportation service hereunder and their authority to represent customer.

   A customer may choose only one of the following gas supply arrangements: 1) one Contracted Marketer, 2) one or multiple Agents (in addition to a Contracted Marketer if desired), or 3) itself for purposes of nominating to its end-use account (OCC). T T

(Continued)

Rule No. 30 Sheet 3

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

2. Receipt Points

Utility accepts nominations from transportation customers or their representatives at the following Receipt Points into the SoCalGas system, as referenced in Schedule No. G-BTS*:

- El Paso Pipeline at Blythe (Southern Transmission Zone)
- North Baja Pipeline at Blythe (Southern Transmission Zone)
- Transportadora de Gas Natural de Baja California at Otay Mesa (Southern Transmission Zone)
- Kern River Pipeline and Mojave Pipeline (Wheeler Transmission Zone)
- PG&E at Kern River Station (Wheeler Transmission Zone)
- Occidental of Elk Hills at Gosford (Wheeler Transmission Zone)
- Transwestern Pipeline at North Needles (Northern Transmission Zone)
- Transwestern Pipeline at Topock (Northern Transmission Zone)
- El Paso Pipeline at Topock (Northern Transmission Zone)
- Kern River Pipeline and Mojave Pipeline at Kramer Junction (Northern Transmission Zone) D
- Line 85 (California Supply)
- North Coastal (California Supply)
- Other (California Supply)
- Storage

* Additional Receipt Points will be added as they are established in the future.

3. Backbone Transmission Capacity

Each day, Receipt Point and Backbone Transmission Zone capacities will be set at their physical operating maximums under the operating conditions for that day. The Utility will schedule nominations for each Receipt Point and Backbone Transmission Zone to the maximum operating capacity of that individual Receipt Point or Backbone Transmission Zone. The maximum operating capacity is defined as the facility design or contractual limitation to deliver gas into the Utility's system adjusted for operational constraints (i.e. maintenance, localized restrictions, and upstream delivery pressures) as determined each day.

The NAESB elapsed pro rata rules require that the portion of the scheduled quantity that would have theoretically flowed up to the effective time of the intraday nomination be confirmed, based upon a cumulative uniform hourly quantity for each nomination period affected. As such, the scheduled quantities for each shipper are subject to change in the Intraday 1 Cycle, the Intraday 2 Cycle, and the Intraday Cycle 3. However, each shipper's resulting scheduled quantity for the Gas Day will be no less than the elapsed prorated scheduled quantity for that shipper.

(Continued)

Rule No. 30 Sheet 4
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

3. Backbone Transmission Capacity (Continued)

Each day, the Utility will use the following rules to confirm nominations to the Receipt Point and Backbone Transmission Zone maximum operating capacities. The Utility will also use the following rules to confirm nominations to the system capacity limitation as defined in Section F for OFO events during the Intraday 1 and Intraday 2 cycles; and during the Intraday 2 cycle when an OFO event is not called and nominations exceed system capacity.

Confirmation Order:

- Nominations using Firm Primary backbone transportation rights will be first; pro-rated if over-nominated*.
- Nominations using Firm Alternate backbone transportation rights within the associated transmission zone will be second ("Firm Alternate Within-the-Zone"); pro-rated if over-nominated.
- Nominations using Firm Alternate backbone transportation rights outside the associated transmission zone will be third ("Firm Alternate Outside-the-Zone"); pro-rated if over-nominated.
- Nominations using Interruptible backbone transportation rights will be fourth, pro-rated if over-nominated.
- Southern Transmission Receipt Points will not be reduced in any cycle below 110% of the Southern System minimum flowing supply requirement established by the Gas Control Department.

Bumping Rules:

- Firm Primary rights can "bump" any Firm Alternate scheduled quantities through the Evening Cycle.
- Firm Alternate Within-the-Zone rights can "bump" Firm Alternate Outside-the-Zone scheduled quantities through the Evening Cycle.
- Firm Primary and any Firm Alternate can "bump" interruptible scheduled quantities through the Intraday 2 Cycle subject to the NAESB elapsed pro-rata rules. T
- Bumping will not be allowed in the Intraday 3 Cycle. T

* If the available firm capacity at a particular receipt point or within a particular transmission zone is less than the firm capacity figures stated in Schedule No. G-BTS, scheduling of firm backbone transportation capacity nominations will be pro rata within each scheduling cycle. Any nominations of firm backbone transportation rights acquired through the addition of Displacement Backbone Transmission Capacity facilities will be reduced pro rata to zero at the applicable receipt point or within the applicable transmission zone prior to other firm backbone transportation rights nominations being reduced.

(Continued)

Rule No. 30 Sheet 5

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

3. Backbone Transmission Capacity (Continued)

Priority Rules:

a. Firm primary scheduled quantities in the Evening Cycle will have priority over a new firm primary nomination made in the Intraday 1 Cycle.
b. Firm Alternate Inside-the-Zone scheduled quantities in the Evening Cycle will have priority over a new Firm Alternate Inside-the-Zone nomination made in the Intraday 1 Cycle.
c. Firm Alternate Outside-the-Zone scheduled quantities in the Evening Cycle will have priority over a new Firm Alternate Outside-the-Zone nomination made in the Intraday 1 Cycle.
d. Interruptible scheduled quantities in the Evening Cycle will have priority over a new Interruptible nomination made in the Intraday 1 Cycle.
e. This same structure will be applied in going from Intraday 1 Cycle (Cycle 3) to Intraday 2 Cycle (Cycle 4) to Intraday 3 Cycle (Cycle 5). However, this hierarchy will not affect Intraday 4 Cycle (Cycle 6) nominations or the elapsed pro-rata rule.

4. Storage Service Capacity

Each day, storage injection and withdrawal capacities will be set at their physical operating maximums under the operating conditions for that day and posted on the Utility's EBB. These capacities will take into account offsetting injection or withdrawal activity that effectively increase withdrawal or injection capacities. *Injection nominations will be held to the injection capacity specified in the Operational Flow Order (OFO) calculation on the EBB in every flowing cycle regardless of OFO status.** The Utility will use the following rules to limit the nominations to the storage maximums. N | N

As necessary, withdrawal or injection allocated to the daily balancing function will be set aside and given first priority every day. N N

- Nominations using Firm storage rights will have the next priority, pro-rated, if necessary to the available storage capacity. N,D
- All other nominations using Interruptible storage rights will have the lowest priority, pro-rated if over-nominated based on the daily volumetric price paid. N,D
- On low OFO days the volume of interruptible withdrawal will be cut in half relative to the calculation on a non-OFO day. If interruptible nominations immediately prior to the low OFO were above this level, then they will be held constant through the low OFO. N | N
- Firm storage rights can "bump" interruptible scheduled storage quantities through the Intraday 3 cycle.

Notice to bumped parties will be provided via the Transactions module in EBB. Bumping is subject to the NAESB elapsed prorata rules.

(Continued)

Rule No. 30 Sheet 6
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

5. Off-System Delivery (OSD) Service

For each flow date, the Utility will determine the quantity of capacity available for off-system deliveries. The quantity will include that available via physical redelivery from the Utility system along with displacement of forward haul flowing supplies. For each nomination cycle, the Utility customers who have contracted with the Utility for off-system delivery service may submit a nomination for such service pursuant to Schedule No. G-OSD and Section D.6. “Nominations” below, for deliveries to the PG&E system and to the Utility Transmission system’s interconnection points with all interstate and international pipelines, but excluding California-produced gas supply lines.

The following rules will be used in scheduling of Off-System Delivery Services:

- Nominations using Firm OSD rights will have first priority; pro-rated if over-nominated.
- Nominations using Interruptible OSD rights will have second priority; pro-rated if over-nominated.
- Firm OSD rights can “bump” Interruptible OSD scheduled quantities through the Intraday 2 Cycle, subject to the NAESB elapsed pro-rata rules.
- Bumping of Interruptible OSD rights by Firm OSD rights will not be allowed in the Intraday 3 Cycle.
- Both Firm and Interruptible OSD rights, at any Delivery Point, can be reduced in any cycle, including during curtailment events, (subject to the NAESB elapsed pro rata rules) if, in the sole judgment of the Utility, the discontinuation or reduction of OSD service at that Delivery Point would diminish the need for the Utility to bring additional gas into the Utility’s system at an additional cost or reduce the level of curtailment to any Utility customer. D N D,N D,N N N
- Reduction of Interruptible OSD nominations at any Delivery Point will be prorated at that particular Delivery Point. D
- Reduction of Firm OSD nominations at any Delivery Point will be prorated at that particular Delivery Point. D

(Continued)

Rule No. 30 Sheet 7
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

6. Nominations

The customer shall be responsible for submitting gas service nominations to the Utility no later than the deadlines specified below.

Each nomination shall include all information required by the Utility's nomination procedures. Nominations received by the Utility will be subject to the conditions specified in the service agreements with the Utility. The Utility may reject any nomination not conforming to the requirements in these rules or in applicable service agreements. The customer shall be responsible for making all corresponding upstream nomination/confirmation arrangements with the interconnecting pipeline(s) and/or operator(s).

Evening and Intraday nominations may be used to request an increase or decrease to scheduled volumes or a change to receipt or delivery points.

Intraday nominations do not roll from day to day.

Nominations submitted in any cycle will automatically roll to subsequent cycles for the specified flow date and from day-to-day through the end date or until the end date is modified by the nominating entity.

Nominations may be made in the following manner:

FROM	TO	
Pipeline/CA Producer	Backbone Transportation Service Contract	
Backbone Transportation Service Contract	End User, Contracted Marketer, CTA	
Backbone Transportation Service Contract	Citygate Pool Account	
Backbone Transportation Service Contract	Storage Account	
Citygate Pool Account	End User, Contracted Marketer, CTA	
Citygate Pool Account	Citygate Pool Account	
Storage Account	End User, Contracted Marketer, CTA	
Citygate Pool Account	Storage Account	L
Storage Account	Citygate Pool Account	|
Storage Account	Storage Account	|
Storage Account	Off-System Delivery Contract	|
Citygate Pool Account	Off-System Delivery Contract	|
End User, Contracted Marketer, CTA	Storage Account	L

(Continued)

Rule No. 30 Sheet 8
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

6. Nominations (Continued)

FROM	TO (Continued)	
Off-System Delivery Contract	PG&E Pipeline (at Kern River Station)	
Off-System Delivery Contract	Mojave Pipeline (at Wheeler Ridge)	
Off-System Delivery Contract	Mojave Pipeline (at Kramer Junction)	
Off-System Delivery Contract	Kern River Pipeline (at Wheeler Ridge)	
Off-System Delivery Contract	Kern River Pipeline (at Kramer Junction)	D
Off-System Delivery Contract	Transwestern Pipeline (at North Needles)	
Off-System Delivery Contract	Transwestern Pipeline (at Topock)	
Off-System Delivery Contract	El Paso Pipeline (at Topock)	
Off-System Delivery Contract	El Paso Pipeline (at Blythe)	
Off-System Delivery Contract	North Baja Pipeline (at Blythe)	
Off-System Delivery Contract	Transportadora de Gas Natural de Baja California (at Otay Mesa)	
Receipt Point Pool Account	Receipt Point Pool Account	
Receipt Point Pool Account	Backbone Transportation Contract	

7. Timing

All times referred to below are in Pacific Clock Time. Requests for deadline extensions may be granted for 15 minutes only if request is made prior to the deadlines shown below.

Timely Cycle

Transportation nominations submitted via EBB for the Timely Nomination cycle must be received by the Utility by 11:00 a.m. one day prior to the flow date. Nominations submitted via fax must be received by the Utility by 10:00 a.m. one day prior to the flow date. Timely nominations will be effective at 7:00 a.m. on the flow date.

Evening Cycle

Nominations submitted via EBB for the Evening Nomination cycle must be received by the Utility by 4:00 p.m. one day prior to the flow date. Nominations submitted via fax must be received by the Utility by 3:00 p.m. one day prior to the flow date. Evening nominations will be effective at 7:00 a.m. on the flow date.

(Continued)

Rule No. 30 Sheet 9
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

7. Timing (Continued)

Intraday 1 Cycle

Nominations submitted via EBB for the Intraday 1 Nomination cycle must be received by the Utility by 8:00 a.m. on the flow date. Nominations submitted via fax must be received by the Utility by 7:00 a.m. on the flow date. Intraday 1 nominations will be effective at 12:00 p.m. the same day.

Intraday 2 Cycle

Nominations submitted via EBB for the Intraday 2 Nomination cycle must be received by the Utility by 12:30 p.m. on the flow date. Nominations submitted via fax must be received by the Utility by 11:30 a.m. on the flow date. Intraday 2 nominations will be effective at 4:00 p.m. the same day.

Intraday 3 Cycle

Nominations submitted via EBB for Intraday 3 Nomination cycle must be received by the Utility by 5:00 p.m. on the flow date. Nominations submitted via fax must be received by the Utility by 4:00 p.m. on the flow date. Intraday 3 nominations will be effective at 8:00 p.m. the same day.

Intraday 4 Cycle

Nominations submitted via EBB for the Intraday 4 Nomination cycle must be received by the Utility by 9:00 p.m. Pacific Clock Time on the flow date. Nominations submitted via fax must be received by the Utility by 8:00 p.m. Pacific Clock Time on the flow date.

Temporary provisions regarding the trading of scheduled quantities and daily imbalances are N
*provided in Section N.** N

Intraday 4 nominations are available only for firm nominations relating to the injection of existing flowing supplies into a storage account or for firm nominations relating to the withdrawal of gas in storage to meet an identified customer's usage. A customer may make Intraday 4 nominations from a third-party storage provider that is directly connected to the Utility's system or from the Utility's storage, subject to the storage provider or the Utility being able to deliver or accept the daily quantity nominated for Intraday 4 within the remaining hours of the flow day and the Utility's having the ability to deliver or accept the required hourly equivalent flow rate during the remaining hours of the flow day. Third-party storage providers will be treated on a comparable basis with the Utility's storage facilities to the extent that it can provide the equivalent service and operations.

(Continued)

Rule No. 30 Sheet 10 T

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

8. Confirmation and Ranking Process L

A ranking must be received by the Utility at the time the nomination or the confirmation is submitted. The nominating party will rank its supplies and the confirming party will rank its markets. The Utility will then balance the pipeline system using the "lesser of" rule and the rankings submitted.

The ranking will automatically roll from cycle-to-cycle and day-to-day until the nomination end date, unless modified by the nominating entity.

If no ranking is submitted at the time the nomination is submitted, the Utility will assign the lowest ranking to the nomination.

The Utility will compare the nominations received for each transaction and the corresponding confirmation. If the two quantities do not agree, the "lesser of" the two quantities will be the quantity scheduled by the Utility. Subject to the Utility receiving notification of confirmed transportation from the applicable upstream pipeline(s) and/or operator(s), the Utility will provide scheduled quantities on EBB.

9. As between the customer and the Utility, the customer shall be deemed to be in control and possession of the gas to be delivered hereunder and responsible for any damage or injury caused thereby until the gas has been delivered at the point(s) of receipt. The Utility shall thereafter be deemed to be in control and possession of the gas after delivery to the Utility at the point(s) of receipt and shall be responsible for any damage or injury caused thereby until the same shall have been redelivered at the point(s) of delivery, unless the damage or injury has been caused by the quality of gas originally delivered to the Utility, for which the customer shall remain responsible. L

10. Any penalties or charges incurred by the Utility under an interstate or intrastate supplier contract as a result of accommodating transportation service shall be paid by the responsible customer.

11. Customers receiving service from the Utility for the transportation of customer-owned gas shall pay any costs incurred by the Utility because of any failure by third parties to perform their obligations related to providing such service.

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(Continued)

Rule No. 30 Sheet 11
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

E. Interruption of Service

1. The customer's transportation service priority shall be established in accordance with the definitions of Core and Noncore service, as set forth in Rule No. 1, and the provisions of Rule No. 23, Continuity of Service and Interruption of Delivery. If the customer's gas use is classified in more than one service priority, it is the customer's responsibility to inform the Utility of such priorities applicable to the customer's service. Once established, such priorities cannot be changed during a curtailment period.

2. The Utility shall have the right, without liability, to interrupt the acceptance or redelivery of gas whenever it becomes necessary to test, alter, modify, enlarge or repair any facility or property comprising the Utility's system or otherwise related to its operation. When doing so, the Utility will try to cause a minimum of inconvenience to the customer. Except in cases of unforeseen emergency, the Utility shall give a minimum of ten (10) days advance written notice of such activity.

F. Nominations in Excess of System Capacity D
D

1. In the event customers fail to adequately reduce their transportation nominations, the Utility shall reduce the confirmed receipt point access nominations as defined in Section D. T

D

(Continued)

Rule No. 30 Sheet 12
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

G. Operational Flow Orders and Emergency Flow Orders

1. Operational Flow Order (OFO)

a. The Utility System Operator's protocol for declaring an Operational Flow Order (OFO) is described in Rule No. 41. All OFO declarations will be identified by stage that will specify a Daily Imbalance Tolerance and Noncompliance Charge per the table below. The daily balancing standby rate is not applicable to High OFOs. Pursuant to D.19-05-030, this OFO Noncompliance Charge structure shall remain in effect until October 31, 2021, unless modified by a subsequent Commission decision.

Effective June 1 – September 30

Stage	Daily Imbalance Tolerance[1]	Noncompliance Charge ($/therm)
1	Up to +/-25%	0.025
2	Up to +/-20%	0.10
3	Up to +/-15%	0.50
4	Up to +/-5%	0.50
5	Up to +/-5%	0.50 plus Rate Schedule G-IMB daily balancing standby rate
EFO	Zero	5.00 plus Rate Schedule G-IMB daily balancing standby rate

D

(Continued)

Rule No. 30 Sheet 13

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

G. Operational Flow Orders and Emergency Flow Orders (Continued)

1. Operational Flow Order (OFO) (Continued)

a. (Continued)

Effective October 1 – May 31 N

Stage	Daily Imbalance Tolerance[1]	Noncompliance Charge ($/therm)
1	Up to +/-25%	0.025
2	Up to +/-20%	0.10
3	Up to +/-15%	0.50
3.1	Up to +/-15%	1.00
3.2	Up to +/-15%	1.50
3.3	Up to +/-15%	2.00
4	Up to +/-10%	2.50
5	Up to +/-5%	2.50 plus Rate Schedule G-IMB daily balancing standby rate
EFO	Zero	5.00 plus Rate Schedule G-IMB daily balancing standby rate

[1] Negative daily imbalance tolerances for all stages are capped at up to -5% until Aliso Canyon's withdrawal capacity is available without constraint to the System Operator for load balancing. N

b. The OFO shall apply to all customers financially responsible for managing and clearing transportation imbalances (Balancing Agents), including wholesale customers, Contracted Marketers, core aggregators, California Gas Producers and the Utility Gas Procurement Department. L

c. The OFO period shall begin on the flow date(s) indicated by the Utility Gas Control Department. Generally an initial OFO event will start at Stage 1; however an OFO event may begin at any stage as deemed appropriate by the Utility Gas Control Department with the corresponding noncompliance charge. L

d. An OFO will normally be ordered with at least twelve (12) hours notice prior to the beginning of the gas day, or as necessary as dictated by operating conditions. Charges for the first day of the OFO event will not be imposed if notice is given after *8:00 p.m.** Pacific Time the day prior to the start of the OFO event.

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(Continued)

Rule No. 30 Sheet 14
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

G. Operational Flow Orders and Emergency Flow Orders (Continued)

1. Operational Flow Order (OFO) (Continued)

e. OFO and EFO compliance and charges will be based on the following for determination of daily usage quantities: L

i. For a Noncore End-Use Customer equipped with automated meter reading device (AMR) and SDG&E's Electric & Gas Fuel Procurement Department, compliance during an OFO will be based on actual daily metered usage, and the calculation after the OFO event of any applicable noncompliance charge will be based on actual daily metered usage.

ii. For a Noncore End-Use Customer with non-functioning AMR meters, compliance during an OFO or EFO will be based on the Customer's actual daily metered usage; or the estimated daily usage in accordance with Section C of SoCalGas Rule 14 will be substituted for the actual daily metered usage when actual metered usage is not available.

iii. For a Noncore End-Use Customer without AMR capability compliance during an OFO or EFO will be based on the Customer's MinDQ.

iv. For the Utility Gas Procurement Department, the Daily Forecast Quantity will be used as a proxy for daily usage.

v. For core aggregators, their Daily Contract Quantity will be used as a proxy for daily usage.

vi. For a California Producer with an effective California Producer Operational Balancing Agreement, Form 6452, compliance with an OFO and EFO and calculation of any noncompliance charges will be based on the difference between scheduled receipts and measured receipts for each day of an event. OFO and EFO compliance for a California Producer with an existing non- California Producer Operational Balancing Agreement, Form 6452 access agreement will be treated consistent with the terms of that access agreement. L

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(Continued)

Rule No. 30 Sheet 15

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

G. Operational Flow Orders and Emergency Flow Orders (Continued)

1. Operational Flow Order (OFO) (Continued)

f. If a Balancing Agent's OFO daily gas imbalance exceeds the applicable daily imbalance tolerance by 10,000 therms or less, the OFO, noncompliance charge will be zero. If the daily gas imbalance amount exceeds the daily imbalance tolerance by more than 10,000 therms, the Balancing Agent will be responsible for the full noncompliance charge; i.e. 10,000 therms will not be deducted from the daily gas imbalance that exceeds the daily imbalance tolerance. L

g. The daily measurement quantity used to calculate the Noncompliance Charge for each OFO event will be the daily quantity recorded as of the month-end close of the applicable month.

h. *Low OFO noncompliance charges for the gas flow day will be waived when the confirmation process limiting nominations to system capacity cuts previously scheduled BTS nominations during any of the Intraday 1-3 Cycles.**

i. *SoCalGas will have the discretion to waive OFO noncompliance charges for an electric generation customer who was dispatched after the Intraday 1 (Cycle 3) nomination deadline in response to (1) a SoCalGas System Operator request to an Electric Grid Operator to reallocate dispatched electric generation load to help maintain gas system reliability and integrity, or (2) an Electric Grid Operator request to the SoCalGas System Operator to help maintain electric system reliability and integrity that can be accommodated by the SoCalGas System Operator at its sole discretion. For electric generators served by a contracted marketer, OFO noncompliance charges can be waived under this section only to the extent the contracted marketer nominates their electric generation customer's gas to the electric generation customer's Order Control Code.** L

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(Continued)

Rule No. 30 Sheet 16
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

G. Operational Flow Orders and Emergency Flow Orders (Continued) L

2. Emergency Flow Order (EFO)

a. The Utility System Operator's protocol for declaring an Emergency Flow Order (EFO) is described in Rule No. 41.

b. During an EFO Customer usage must be less than or equal to scheduled supply for a gas day. EFOs will have a zero percent tolerance and a noncompliance charge of $5.00 plus the Schedule G-IMB Daily Balancing Standby Rate for each therm of usage in excess of scheduled supply.

c. The EFO shall apply to all customers financially responsible for managing and clearing transportation imbalances (Balancing Agents), including wholesale customers, Contracted Marketers, core aggregators, California Gas Producers and the Utility Gas Procurement Department.

d. When an EFO is in effect interruptible storage withdrawals are limited to one half of the capacity normally available for interruptible withdrawals. Interruptible storage withdrawal capacity is equal to Withdrawal Capacity minus confirmed firm storage withdrawal nominations minus withdrawal allocated to the balancing function.

e. Daily measurement quantities used to determine EFO compliance and charges are the same as those used to determine OFO compliance and charges.

f. The daily measurement quantity used to calculate the noncompliance charges for each EFO event will be the daily quantity recorded as of the month-end close of the applicable month. L

L

(Continued)

Rule No. 30 Sheet 17
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

G. Operational Flow Orders and Emergency Flow Orders (Continued) L

3. Information regarding the System Sendout, Withdrawal Capacity and Net Withdrawals will be made available to customers on a daily basis via the EBB.

4. If a wholesale customer so requests, the Utility will nominate firm storage withdrawal volumes on behalf of the customer to match 100% of actual usage assuming the customer has sufficient firm storage withdrawal and inventory rights to match the customer's supply and demand.

5. The Utility will accept intra-day nominations to increase deliveries.

6. In all cases, current rules for monthly balancing and monthly imbalance trading continue to apply. Quantities not in compliance with the Daily Imbalance Tolerance that are purchased at the daily balancing standby rate are credited toward the monthly 92% delivery requirements. Daily balancing charges remain independent of monthly balancing charges. Noncore daily balancing and monthly balancing charges go to the Purchased Gas Account (PGA). Net revenues from core daily balancing and monthly balancing charges go to the Noncore Fixed Cost Account (NFCA). Schedule No. G-IMB provides details on monthly and daily balancing charges.

H. Accounting and Billing

1. The customer and the Utility acknowledge that on any operating day during the customer's applicable term of transportation service, the Utility may be redelivering quantities of gas to the customer pursuant to other present or future service arrangements. In such an event, the Utility and customer agree that the total quantities of gas shall be accounted for in accordance with the provisions of Rule No. 23. If there is no conflict with Rule No. 23, the quantities of gas shall be accounted for in the following order:

   a. First, to satisfy any minimum quantities under existing agreements.

   b. Second, after complete satisfaction of (a), then to any supply or exchange service arrangements with the customer.

   c. Third, after the satisfaction of (a) and (b), then to any subsequently executed service agreement. L

L

(Continued)

Rule No. 30 Sheet 18

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

H. Accounting and Billing (Continued) L

2. The customer agrees that it shall accept and the Utility can rely upon, for purposes of accounting and billing, the allocation made by customer's shipper as to the quality and quantity of gas, expressed both in Decatherm and therms, delivered at each point of receipt during the preceding billing period for the customer's account. If the shipper does not make such an allocation, the customer agrees to accept the quality and quantity as determined by the Utility. All quality and measurement calculations are subject to subsequent adjustment as provided in the Utility's tariff schedules or applicable CPUC rules and regulations. Any other billing correction or adjustment made by the customer or third party for any prior period shall be based on the rates or costs in effect when the event occurred and accounted for in the period they are reconciled.

3. The Utility shall render to the customer an invoice for the services hereunder showing the quantities of gas, expressed in therms, delivered to the Utility for the customer's account, at each point of receipt and the quantities of gas, expressed in therms, redelivered by the Utility for the customer's account at each point of delivery during the preceding billing period. The Customer shall pay such amounts due hereunder within nineteen (19) calendar days following the date such bill is mailed.

4. Both the Utility and the customer shall have the right at all reasonable times to examine, at its expense, the books and records of the other to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to service hereunder. The Utility and the customer agree to keep records and books of account in accordance with generally accepted accounting principles and practices in the industry.

I. Gas Delivery Specifications

1. The natural gas stream delivered into the Utility's system shall conform to the gas quality specifications as provided in any applicable agreements and contracts currently in place between the entity delivering such natural gas and the Utility at the time of the delivery. If no such agreement is in place, the natural gas shall conform to the gas specifications as defined below. L

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(Continued)

Rule No. 30 Sheet 19
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

I. Gas Delivery Specifications (Continued)

2. Gas delivered into the Utility's system for the account of a customer for which there is no existing contract between the delivering pipeline and the Utility shall be at a pressure such that the gas can be integrated into the Utility's system at the point(s) of receipt.

3. Gas delivered, except as defined in I.1 above, shall conform to the following quality specifications at the time of delivery:

   a. Heating Value: The minimum heating value is nine hundred and seventy (970) Btu (gross) per standard cubic foot on a dry basis. The maximum heating value is one thousand one hundred fifty (1150) Btu (gross) per standard cubic foot on a dry basis. T,R

   b. Moisture Content or Water Content: For gas delivered at or below a pressure of eight hundred (800) psig, the gas shall have a water content not in excess of seven (7) pounds per million standard cubic feet. For gas delivered at a pressure exceeding of eight hundred (800) psig, the gas shall have a water dew point not exceeding 20 degrees F at delivery pressure.

   c. Hydrogen Sulfide: The gas shall not contain more than twenty-five hundredths (0.25) of one (1) grain of hydrogen sulfide, measured as hydrogen sulfide, per one hundred (100) standard cubic feet (4 ppm). The gas shall not contain any entrained hydrogen sulfide treatment chemical (solvent) or its by-products in the gas stream.

   d. Mercaptan Sulfur: The gas shall not contain more than three tenths (0.3) grains of mercaptan sulfur, measured as sulfur, per hundred standard cubic feet (5 ppm).

   e. Total Sulfur: The gas shall not contain more than seventy-five hundredths (0.75) of a grain of total sulfur compounds, measured as sulfur, per one hundred (100) standard cubic feet (12.6 ppm). This includes COS and CS2, hydrogen sulfide, mercaptans and mono, di and poly sulfides.

   f. Carbon Dioxide: The gas shall not have a total carbon dioxide content in excess of three percent (3%) by volume.

   g. Oxygen: The gas shall not have an oxygen content in excess of two-tenths of one percent (0.2%) by volume, and customer will make every reasonable effort to keep the gas free of oxygen.

   h. Inerts: The gas shall not contain in excess of four percent (4%) total inerts (the total combined carbon dioxide, nitrogen, oxygen and any other inert compound) by volume.

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TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

I. Gas Delivery Specifications (Continued) L

3. (Continued)

i. Hydrocarbons: For gas delivered at a pressure of 800 psig or less, the gas hydrocarbon dew point is not to exceed 45 degrees F at 400 psig or at the delivery pressure if the delivery pressure is below 400 psig. For gas delivered at a pressure higher than 800 psig, the gas hydrocarbon dew point is not to exceed 20 degrees F measured at a pressure of 400 psig.

j. Merchantability: The gas shall not contain dust, sand, dirt, gums, oils and other substances at levels that would be injurious to Utility facilities or that would cause gas to be unmarketable.

k. Hazardous Substances: The gas must not contain hazardous substances (including but not limited to toxic and/or carcinogenic substances and/or reproductive toxins) at concentrations which would prevent or restrict the normal marketing of gas, be injurious to pipeline facilities, or which would present a health and/or safety hazard to Utility employees and/or the general public.

l. Delivery Temperature: The gas delivery temperature is not to be below 50 degrees F or above 105 degrees F.

m. Interchangeability: The gas shall have a minimum Wobbe Number of 1279 and shall not have a maximum Wobbe Number greater than 1385. The gas shall meet American Gas Association's Lifting Index, Flashback Index and Yellow Tip Index interchangeability indices for high methane gas relative to a typical composition of gas in the Utility system serving the area.

Acceptable specification ranges are:

* Lifting Index (IL)
  IL <= 1.06

* Flashback Index (IF)
  IF <= 1.2

* Yellow Tip Index (IY)
  IY >= 0.8

n. Liquids: The gas shall contain no liquids at or immediately downstream of the receipt point. L

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(Continued)

Rule No. 30 Sheet 21 T

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

I. Gas Delivery Specifications (Continued)

4. The Utility, at its option, may refuse to accept any gas tendered for transportation by the customer or on his behalf if such gas does not meet the specifications at the time of delivery as set out in I. 2, I. 3, and J.5, as applicable.

5. The Utility will grant specific deviations to California production from the gas quality specifications defined in Paragraph I.3 above, if such gas will not have a negative impact on system operations. Any such deviation will be required to be filed through Advice Letter for approval prior to gas actually flowing in the Utility system.

6. The Utility will post on its EBB and/or general website information regarding the available real-time Wobbe Number of gas at identified operational locations on its system.

7. Gas monitoring and enforcement hardware and software including, but not limited to, a gas chromatograph and all related equipment, communications facilities and software, identified in Exhibit A to Schedule No. G-CPS, are required, and shall be installed at each interconnection meter site where a California Producer delivers natural gas into the Utility's gas transportation system. The gas chromatograph shall monitor non-hydrogen sulfide constituents in the gas delivered, and deny access to gas that does not comply with the gas specifications set forth in the Gas Delivery Specifications, Section I.1 or I.3 above. Compliance shall be assessed using the 4- to 8-minute monitoring interval adopted in D.07-08-029 and D.10-09-001.

8. The gas chromatograph and all related equipment and software, identified in Exhibit A to Schedule No. G-CPS, shall monitor and enforce the gas quality specifications, using the 4- to 8-minute monitoring interval adopted in D.07-08-029 and D.10-09-001. Access shall be denied by the Utility on a non-latching basis after a second consecutive monitoring interval results in an alarm for gas which exceeds the non-hydrogen sulfide specifications. The gas chromatograph and all related equipment and software shall also enable the Utility to remotely gather and retain gas quality and alarm data. Where additional measures are necessary to promote or enhance safety, SoCalGas may request a deviation from the aforementioned monitoring interval requirements established by the CPUC.

9. For California Producers currently delivering gas into the Utility's transportation system without a gas chromatograph and all related equipment and software in place, as required in Rule No. 39, non-hydrogen sulfide constituents of gas will, on an interim basis, continue to be monitored and access denied under the methods currently in place, until such time as a gas chromatograph and all related equipment and software are installed and operational, subject to Rule No. 39 conditions.

(Continued)

(Continued)

J. Biomethane Delivery Specifications

1. Biogas refers to untreated gas produced through the anaerobic digestion of organic waste material. Biomethane refers to biogas that has been treated to comply with this Rule No. 30.

2. Biomethane delivered, except as defined in Section I.1, must meet the gas quality specifications set out in Section I and the biomethane-specific specifications set out in this Section J. The terms and conditions contained in Section J apply solely to suppliers of biomethane and are incremental to Section I gas quality requirements.

3. Biomethane must not contain constituents at concentrations which would prevent or restrict the normal marketing of biomethane, be at levels that would be injurious to pipeline facilities, or be at levels that would present a health and/or safety hazard to Utility employees and/or the general public.

   a. Health Protective Constituents are constituents that may impact human health and include carcinogenic constituents ("Carcinogenic Constituents") and non-carcinogenic constituents ("Non-Carcinogenic Constituents").

   b. Pipeline Integrity Protective Constituents are constituents that may impact pipeline system integrity.

4. The party interconnected to the Utility pipeline system for purposes of delivering biomethane ("Biomethane Interconnector") shall be responsible for costs associated with periodic biomethane testing requirements contained in this Section J, but shall not be responsible for the Utility's discretionary biomethane testing or monitoring.

5. Biomethane Quality Specifications: Biomethane to be accepted and transported in the Utility pipeline system shall be subject to periodic testing and monitoring based on the biogas source. The Trigger Level is the level where additional periodic testing and analysis of the constituent is required. The Lower Action Level, where applicable, is used to screen biomethane during the initial biomethane quality review and as an ongoing screening level during the periodic testing. The Upper Action Level, where applicable, establishes the point at which the immediate shut-off of the biomethane supply occurs.

(Continued)

Rule No. 30 Sheet 23 T

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

J. Biomethane Delivery Specifications (Continued)

5. Biomethane Quality Specifications: (Continued)

Constituent	Trigger Level mg/m^3 (ppm$_v$)^i	Lower Action Level mg/m^3 (ppm$_v$)	Upper Action Level mg/m^3 (ppm$_v$)
Health Protective Constituent Levels			
	Carcinogenic Constituents		
Arsenic	0.019 (0.006)	0.19 (0.06)	0.48 (0.15)
p-Dichlorobenzenes	5.7 (0.95)	57 (9.5)	140 (24)
Ethylbenzene	26 (6.0)	260 (60)	650 (150)
n-Nitroso-di-n-propylamine	0.033 (0.006)	0.33 (0.06	0.81 (0.15)
Vinyl Chloride	0.84 (0.33)	8.4 (3.3)	21 (8.3)
	Non-Carcinogenic Constituents		
Antimony	0.60 (0.12)	6.0 (1.2)	30 (6.1)
Copper	0.060 (0.02)	0.6 (0.23)	3 (1.2)
Hydrogen Sulfide	30 (22)	300 (216)	1500 (1080)
Lead	0.075 (0.009)	0.75 (0.09)	3.8 (0.44)
Methacrolein	1.1 (0.37)	11 (3.7)	53 (18)
Toluene	904 (240)	9000 (2400)	45000 (12000)
Alkyl Thiols (mercaptans)	(12)	(120)	(610)
Pipeline Integrity Protective Constituent Levels^{ii}			
Siloxanes	0.01 mg Si/m³	0.1 mg Si/m^3	-
Ammonia	0.001vol%	-	-
Hydrogen	0.1vol%	-	-
Mercury	0.08 mg/m³	-	-
Biologicals	4 x 10^4/scf (qPCR per APB, SRB, IOB^{iii} group) and commercially free of bacteria of >0.2 microns	-	-

Notes: i) The first number in this table are in milligrams per cubic meter of air (mg/m^3), while the second number () is in parts per million by volume (ppm$_v$). ii) The Pipeline Integrity Protective Constituent Lower and Upper Action Limits not provided above will be established in the Commission's next AB1900 update proceeding. Until that time, Biomethane supplies that contain Pipeline Integrity Protective Constituents exceeding the Trigger Level, but lacking a Lower or Upper Action Level, will be analyzed and addressed on a case-by-case basis based on the biomethane's potential impact on pipeline system integrity. iii) APB – Acid producing Bacteria; SRB – Sulfate-reducing Bacteria; IOB – Iron-oxidizing Bacteria

(Continued)

Rule No. 30 Sheet 24
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

J. Biomethane Delivery Specifications (Continued)

6. Biomethane Constituent Testing shall be based on the biomethane source:

   a. Biomethane from landfills shall be tested for all Health Protective Constituents and the Pipeline Integrity Protective Constituents.

   b. Biomethane from dairies shall be tested for Ethylbenzene, Hydrogen Sulfide, n-Nitroso-di-n-propylamine, Mercaptans, Toluene, and the Pipeline Integrity Protective Constituents.

   c. Other organic waste sources, including biomethane from publicly owned treatment works (i.e., water treatment and sewage treatment plants) shall be tested for p-Dichlorobenzene, Ethylbenzene, Hydrogen Sulfide, Mercaptans, Toluene, Vinyl Chloride, and the Pipeline Integrity Protective Constituents.

   d. Biomethane Interconnectors that certify that their biogas is sourced only from dairy, animal manure, agricultural waste, forest residues, and/or commercial food processing waste, and that products containing siloxanes are not included in the biogas and not used at their facilities in any way that allows siloxane to enter the biomethane, shall have reduced siloxane testing requirements, as described in Section J.8.e. If the certifications identified above are no longer true, then the Biomethane Interconnector must notify the Utility and the full siloxane testing requirement shall apply. N

7. Collective Health Risk

   a. Group 1 Compounds are Constituents with a concentration below the test detection level or below the Trigger Level.

   b. Group 2 Compounds are Constituents with a concentration at or above the Trigger Level.

   c. For Health Protective Group 2 Compounds, the collective cancer and non-cancer risk from Carcinogenic and Non-carcinogenic Constituents must be calculated by summing the Group 2 Compounds' risk.

      i. Cancer Risk: The potential cancer risk for Group 2 compounds can be estimated by summing the individual potential cancer risk for each carcinogenic constituent of concern. Specifically, the cancer risk can be calculated using the ratio of the concentration of the constituent in the biomethane to the health protective ("trigger") concentration value corresponding to one in a million cancer risk for that specific constituent and then summing the risk for all the Group 2 constituents. (For reference, see CARB/OEHHA Report submitted in R.13-02-008, p. 67.)

(Continued)

Rule No. 30 Sheet 25
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

J. Biomethane Delivery Specifications (Continued)

7. Collective Health Risk (Continued)

c. (Continued)

ii. Non-Cancer Risk: The non-cancer risk can be calculated using the ratio of the concentration of the constituent in biomethane to the health protective concentration value corresponding to a hazard quotient of 0.1 for that specific non-carcinogenic constituent, then multiplying the ratio by 0.1, and then summing the non-cancer chronic risk for these Group 2 Compounds. (For reference, see CARB/OEHHA Report submitted in R.13-02-008 p. 67.)

Collective from Carcinogenic and non-Carcinogenic Constituents			
Risk Management Levels	**Potential Risk from Carcinogenic Constituents (chances in a million)**	**Hazard Index from Non-Carcinogenic Constituents**	**Action**
Trigger Level [11]	≥ 1.0	≥ 0.1	Periodic Testing Required
Lower Action Level [2]	≥ 10.0	≥ 1.0	Supply shut-in after three exceedances in 12-month period in which deliveries occur
Upper Action Level	≥ 25.0	≥ 5.0	Immediate supply shut-in

1. For any Health Protective Constituent.
2. Sum of the Health Protective Constituents exceeding the trigger level.

8. Biomethane Pre-Interconnection Testing: L

a. Prior to the injection of biomethane, the Biomethane Interconnector shall conduct two tests over a two- to four-week period for the constituents identified for that biomethane source (see Section J.6).

b. Pre-interconnection testing will be performed by the Biomethane Interconnector using independent certified third party laboratories (Environmental Laboratory Accreditation Program (ELAP) certified, where applicable). The Utility shall be notified of the biomethane sampling and tests and have the option to observe the samples being taken. Test results will be shared with the Utility within five calendar days of the test results being received by the Biomethane Interconnector. L

(Continued)

Rule No. 30 Sheet 26
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

J. Biomethane Delivery Specifications (Continued)

8. Biomethane Pre-Interconnetion Testing: (Continued)

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c. During pre-injection testing, the Biomethane's collective potential cancer risk and non-cancer risk is calculated by summing the individual risk for each Health Protective Group 2 Compound. If the collective potential cancer risk or non-cancer risk is at or above the Lower Action Level (the cancer risk Lower Action Level is > 10 in a million and the non-cancer risk Lower Action Level is a Hazard Index of >1), the biomethane cannot be accepted or transported by the Utility's pipeline system. The Biomethane Interconnector shall make necessary modifications to lower the collective potential cancer risk or non-cancer risk below the Lower Action Level and restart pre-injection testing. If the Health Protective Constituents are found to be below the Trigger Level or the collective cancer or non-cancer risk from the Health Protective Group 2 Compounds is below the Lower Action Level in both pre-injection tests, then the biomethane may be injected subject to compliance with the periodic testing requirements specified below.

d. If during the pre-injection testing, any Pipeline Integrity Protective Constituents are found to be above the Lower Action Level, if applicable, the biomethane cannot be accepted or transported by the Utility's pipeline system. The Biomethane Interconnector shall make necessary modifications to lower the Pipeline Integrity Protective Constituents below the Lower Action Level and restart pre-injection testing. If the Pipeline Integrity Protective Constituents are found to be below the Trigger Level in both pre-injection tests, then the biomethane may be injected subject to compliance with the periodic testing requirements specified below.

e. Per Section J.6.d, biomethane certified for reduced siloxane testing will be as follows: N

i. If the pre-injection testing siloxane levels are below or at the Trigger Level of 0.01 mg Si/m^3, then no periodic siloxane testing is required under Section J.9.d.

ii. If the pre-injection testing siloxanes level exceed the Trigger Level of 0.01 mg Si/m^3, then quarterly testing is required for one year, and if none of those samples are above the Lower Action Level of 0.1 mg Si/m^3, then no periodic siloxane testing is required under Section J.9.d.

iii. If the siloxanes are above the Lower Action Level of 0.1 mg Si/m^3, then the Section J.6.d biomethane certification for reduced testing is no longer applicable and the Biomethane Interconnector will be required to comply with the periodic testing requirements for siloxane under Section J.9.d. N

(Continued)

Rule No. 30 Sheet 27

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

J. Biomethane Delivery Specifications (Continued)

9. Biomethane Periodic Testing:

a. Group 1 Constituent Testing

i. A Group 1 Compound shall be tested once every 12-month period in which deliveries occur. Thereafter, if the Group 1 Compound is found below the Trigger Level during two consecutive annual periodic tests, the Group 1 Compound may be tested once every two year-period in which deliveries occur.

ii. A Group 1 Compound will become a Group 2 Compound if testing indicates a concentration at or above the Trigger Level.

b. Group 2 Compound Testing

i. A Group 2 Compound shall be tested quarterly (at least once every three- month period in which deliveries occur).

ii. A Group 2 Compound will become a Group 1 Compound if testing indicates a concentration below the Trigger Level during four consecutive tests.

c. Collective Risk from Carcinogenic and Non-carcinogenic Constituents:

i. If four consecutive quarterly tests demonstrate that the Health Protective Group 2 Compound's collective cancer and non-cancer risk is below the Lower Action Level, monitoring can be reduced to once every 12-month period in which deliveries occur.

ii. If annual testing demonstrates that the Health Protective Group 2 Compound's collective cancer or non-cancer risk is at or above the Lower Action Level, then testing will revert to quarterly.

d. Pipeline Integrity Protective Constituents N

i. Constituents shall be tested once every 12-month period in which deliveries occur. Thereafter, constituents found below the Trigger Level during two consecutive annual periodic tests, the constituent may be tested once every two year-period in which deliveries occur.

ii. If the constituent was tested above the Trigger Level, then it will be tested quarterly.

iii. If there are four consecutive quarterly tests below the Lower Action Level, then it will be reduced to once every 12-month period in which deliveries occur. N

(Continued)

Rule No. 30 Sheet 28
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

J. Biomethane Delivery Specifications (Continued) L

10. Biomethane Shut-Off and Restart Procedures: The Biomethane Interconnector may be shut-off when the following occurs:

a. The CPUC determines that a change in the biogas source at the facility or the upgrading equipment will potentially increase the level of any constituent over the previously measured baseline levels.

b. Testing indicates constituents are exceeding allowable concentration levels:

i. The collective cancer or non-cancer risk from Health Protective Group 2 Compounds is found at or above the Lower Action Level three times in a 12-month period in which deliveries occur.

ii. The collective cancer or non-cancer risk from Health Protective Group 2 Compounds is found at or above the Upper Action Level.

iii. If applicable, a Pipeline Integrity Protective Constituent is found at or above the Lower Action Level three times in a 12-month period in which deliveries occur.

iv. The biomethane contains constituents at concentrations which prevent or restrict the normal marketing of biomethane, are at levels that are injurious to pipeline facilities, or are at levels that present a health and/or safety hazard to Utility employees and/or the general public.

c. In order to restart injection after a Biomethane Interconnector has been shut-off, the Biomethane Interconnector shall test the biomethane using independent certified third party laboratories (ELAP certified where applicable). Deliveries can then resume, subject to the periodic testing requirements in Section J.9, if the test indicates: (1) the biomethane complies with the gas quality specifications contained in Section I of this Rule; (2) the collective cancer and non-cancer risk of Health Protective Group 2 Compounds is below the Lower Action Level; and, if applicable, (3) the Pipeline Integrity Protective Constituents are below the Lower Action Level. Thereafter, constituents shall be reevaluated by the Utility for eligibility for less frequent testing. L

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(Continued)

Rule No. 30 Sheet 29
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

J. Biomethane Delivery Specifications (Continued)

11. Testing Procedures: The Utility shall collect samples at the receipt point utility meter. The Biomethane Interconnector shall collect samples upstream of the utility meter. Samples will be analyzed by independent certified third party laboratories (ELAP certified where applicable). Testing for Health Protective Constituents shall be by the methods specified in Table V-4 of CARB/OEHHA Report submitted in R.13-02-008 and adopted in D.14-01-034. Testing for Pipeline Integrity Protective Constituents shall be by the methods approved in D.14-01-034. Retesting shall be allowed to verify and validate the results. The cost of retesting shall be borne by the entity requesting the retest.

12. Continuous Monitoring of Upgrading Process Integrity: Absent an agreement otherwise, the Biomethane Interconnector's compliance with the Utility's continuously monitored Section I gas quality specifications shall be used as an indicator that the upgrading system is effectively conditioning and upgrading the biomethane. If the indicator(s) used to continuously monitor biomethane constituent levels indicates the biomethane has not been sufficiently conditioned and upgraded, the Utility may accelerate the biomethane periodic testing schedule and initiate testing. Accelerated periodic testing shall count toward the recommended periodic testing requirements described in Section J.9.

13. Recordkeeping and Reporting Requirements will be as prescribed in Commission D.14-01-034 and as specified in the CARB/OEHHA Report submitted in R.13-02-008.

14. Prohibition of Biomethane from Hazardous Waste Landfills: Hazardous waste landfills ("Hazardous Waste Landfills") include all contiguous land and structures, and other appurtenances and improvements, on the land used for the treatment, transfer, storage, resource recovery, disposal, or recycling of hazardous waste. The facility may consist of one or more treatment, transfer, storage, resource recovery, disposal, or recycling hazardous waste management units, or combinations of these units. Biomethane from Hazardous Waste Landfills, including landfills permitted by the Department of Toxic Substances Control, will not be purchased, accepted or transported. Before a Biomethane Interconnector can interconnect with the Utility's system, the Biomethane Interconnector must demonstrate and certify to the Utility's satisfaction that the biogas was not collected from a Hazardous Waste Landfill.

15. The biomethane rules in this section are intended to implement D.14-01-034 and D.19-05-018, including rules regarding constituent concentration standards, monitoring and testing requirements, and reporting and recordkeeping requirements. N

(Continued)

Rule No. 30 Sheet 30 N
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

K. Termination or Modification L

1. If the customer breaches any terms and conditions of service of the customer's service agreement or the applicable tariff schedules and does not correct the situation within thirty (30) days of notice, the Utility shall have the right to cease service and immediately terminate the customer's applicable service agreement.

2. If the contract is terminated, either party has the right to collect any quantities of gas or money due them for transportation service provided prior to the termination.

L. Regulatory Requirements

1. Any gas transported by the Utility for the customer which was first transported outside the State of California shall have first been authorized under Federal Energy Regulatory Commission (FERC) regulations, as amended. Both parties recognize that such regulations only apply to pipelines subject to FERC jurisdiction, and do not apply to the Utility. The customer shall not take any action which would subject the Utility to the jurisdiction of the FERC, the Economic Regulatory Administration or any succeeding agency. Any such action shall be cause for immediate termination of the service arrangement between the customer and the Utility.

2. Transportation service shall not begin until both parties have received and accepted any and all regulatory authorizations necessary for such service.

M. Warranty and Indemnification

1. The customer warrants to the Utility that the customer has the right to deliver gas hereunder and that such gas is free from all liens and adverse claims of every kind. Customer will indemnify, defend and save the Utility harmless against all loss, damage, injury, liability and expense of any character where such loss, damage, injury, liability or expense arises directly or indirectly out of any demand, claim, action, cause of action or suit brought by any person, association or entity asserting ownership of or any interest in the gas tendered for transportation hereunder, or on account of royalties, payments or other charges applicable before or upon delivery of gas hereunder.

2. The customer shall indemnify, defend and save harmless the Utility, its officers, agents, and employees from and against any and all loss, costs (including reasonable attorneys' fees), damage, injury, liability, and claims for injury or death of persons (including any employee of the customer or the Utility), or for loss or damage to property (including the property of the customer or the Utility), which occurs or is based upon an act or acts which occur while the gas is deemed to be in the customer's control and possession or which results directly or indirectly from the customer's performance of its obligations arising pursuant to the provisions of its service agreement and the Utility's applicable tariff schedules, or occurs based on the customer-owned gas not meeting the specifications of Sections I or J of this rule. L

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(Continued)

Rule No. 30 Sheet 31 N
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

*N. OFO Trading** L

1. *Trading Scheduled Quantities**

   a. *Customers may arrange to trade scheduled quantities. The trades are to be arranged outside of the EBB and communicated to the Utility via a trade form.*
   b. *Customers may trade scheduled quantities between End Use contracts only by adjusting scheduled quantities after Cycle 6 has been processed.*
   c. *Trades will only be available for OFO days.*
   d. *Trades must be submitted to the Utility's scheduling department via email or fax by 9 PM Pacific Clock Time one business day following the Gas Day for which the OFO was declared.*
   e. *The Utility may file an expedited Tier 2 Advice Letter to suspend this tariff provision if curtailments are more severe or more frequent due to the offering of this service. Protests and responses to any such Advice Letter would be due within 5 business days, and the Utility's reply would be due within 2 business days from the end of the protest period.*

2. *Trading Daily Imbalances**

   a. *California Producer cash-outs on OFO days will be delayed until 9:00 p.m. Pacific Clock Time one business day following the Gas Day pending submittal of the imbalance trade. If the imbalance is not traded, it will be cashed out.*
   b. *California Producers may arrange to trade daily OFO imbalances with other California Producers. The trades are to be arranged outside of the EBB and communicated to the Utility via a trade form after Cycle 6 has been processed.*
   c. *Trades will only be available for OFO days.*
   d. *Trades must be submitted to the Utility's scheduling department via email or fax by 9 PM Pacific Clock Time one business day following the Gas Day for which the OFO was declared.*
   e. *The Utility may file an expedited Tier 2 Advice Letter to suspend this tariff provision if curtailments are more severe or more frequent due to the offering of this service. Protests and responses to any such Advice Letter would be due within 5 business days, and the Utility's reply would be due within 2 business days from the end of the protest period.*

O. Temporary Settlement Term

1. The Sections of this Rule italicized and followed by an asterisk (*) are temporary and will end upon the expiration of the term in the settlement approved by D.16-12-015 and modified by D.18-11-009. Specifically, that settlement term will conclude upon the earlier of: (1) any superseding decision or order by the Commission, (2) return of Aliso Canyon to at least 450 MMcfd of injection capacity and 1,395 MMcfd of withdrawal capacity, or (3) the implementation date of a final decision in A.18-07-024, SoCalGas' 2020 Triennial Cost Allocation Proceeding. L

Rule No. 39 Sheet 1

ACCESS TO THE SOCALGAS PIPELINE SYSTEM

The Utility shall provide nondiscriminatory open access to its system to any party (hereinafter "Interconnector") for the purpose of physically interconnecting with the Utility and effectuating the delivery of natural gas, subject to the terms and conditions set forth in this Rule and the applicable provisions of the Utility's other tariff schedules including, but not limited to, the gas quality requirements set forth in Rule No. 30, Section I. None of the provisions in this Rule shall be interpreted so as to unduly discriminate against or in favor of gas supplies coming from any source.

A. Terms of Access

1. The interconnection and physical flows shall not jeopardize the integrity of, or interfere with, normal operation of the Utility's system and provision of service to its customers.

2. The Interconnector and Utility must execute Form No. 6450, Interconnection Agreement (IA) and Form No. 6435, Operational Balancing Agreement (OBA). If the Interconnector is a California Producer without an effective agreement providing for access to the Utility's system, then that Interconnector and the Utility must execute Form No. 6454, California Producer Interconnection Agreement (CPIA) and Form No. 6452, California Producer Operational Balancing Agreement (CPOBA).

3. The Interconnector shall pay for all equipment necessary to effectuate deliveries at point of interconnection, including, but not limited to, valves, separators, meters, quality measurement, odorant and other equipment necessary to regulate and deliver gas at the interconnection point. The Interconnector shall also pay for computer programming changes to the Utility's Electronic Bulletin Board (EBB) scheduling system, if any, required to add the Interconnector's new interconnection point. The Interconnector and the Utility must execute Form No. 6430, Exhibit D, Interconnect Collectible System Upgrade Agreement or Form 6456, Exhibit C, California Producer Interconnect Collectible System Upgrade Agreement (CPICSUA).

   a. Pursuant to D.15-06-029, as modified by D.16-12-043, the Utility shall provide a monetary N
   incentive to eligible Biomethane Interconnectors built before December 31, 2021. The monetary D,N
   incentive program shall be in effect until the end of December 31, 2021, or until the program has D,N
   exhausted its $40 million funding, including the California Council on Science and Technology N
   study costs. If there are funds remaining at the time of program termination, Biomethane N
   Interconnectors that have started to deliver qualifying biomethane into the Utility's pipeline system as of the termination date of this program are eligible for an incentive payment if they
   otherwise meet the program criteria. The monetary incentive is for up to 50% of the eligible N
   interconnection costs incurred by a Biomethane Interconnector, up to $3 million per |
   interconnection for a non-dairy cluster biomethane project. For a dairy cluster biomethane |
   project, as defined in the Public Utilities Code Section 399.19, the monetary incentive is for up to |
   50% of the eligible interconnection costs and costs incurred for biogas gathering lines. N

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(Continued)

Rule No. 39 Sheet 2

ACCESS TO THE SOCALGAS PIPELINE SYSTEM

(Continued)

A. Terms of Access (Continued)

a. (Continued)

"Biogas gathering lines" means multiple pipelines installed to transport biogas from three or more dairies in close proximity to one another to a centralized gas processing facility for pipeline injection. To be eligible, Biomethane Interconnector deliveries must: (1) comply with Utility Tariff Rule Nos. 30 and 39; and (2) produce biomethane flow for 30 out of 40 days within the minimum and maximum measurement range of the meter. Biomethane Interconnectors must declare in a written notice to the Utility at least two business days in advance, the specific start and end date of this 40 day testing period. The 30 out of 40 day requirement is extended 1 day for each day that the Biomethane Interconnector is unable to produce flow because of an interruption of delivery as set forth in Rule No. 23. Biomethane Interconnectors may elect to restart the 40 day testing period by providing a new written notice declaring the new start and end dates at least two business days in advance of when the new 40 day testing period is to begin. The monetary incentive is limited to eligible interconnection costs, which include Consulting Service Agreement (interconnection capacity study and preliminary and detailed engineering studies) costs, and costs associated with facilities downstream of the Biomethane Interconnectors' processing plants used for delivering biomethane into the Utility's system. For dairy cluster biomethane projects, the costs incurred for biogas gathering lines to help reduce emissions of short-lived climate pollutants pursuant to Section 39730 of the Health and Safety Code shall be considered an eligible cost. Other costs associated with processing and blending facilities upstream of Utility point of receipt interconnection point, including facilities serving natural gas to the Biomethane Interconnector's facilities, are ineligible.

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Within 60 days following successful compliance with the 30 out of 40 day biomethane delivery requirement, the Utility will pay the Biomethane Interconnector in the amount up to 50% of the eligible reconciled and undisputed portions of the interconnection costs, not to exceed $3 million per interconnection for a non-dairy cluster biomethane project, or $5 million per interconnection for a dairy cluster biomethane project. Payment will be provided to the Biomethane Interconnector if all costs have been paid in full; if there are remaining costs it shall be treated as a credit. In the event that all interconnection costs have not been reconciled by the Utility and the Biomethane Interconnector within 60 days following the successful compliance with the 30 out of 40 day biomethane delivery requirement, the Utility shall resume paying the Biomethane Interconnector upon cost reconciliation. If additional eligible cost information becomes available within 12 months following the initial payment, the Utility shall pay to the Biomethane Interconnector up to 50% of the remaining eligible interconnection costs, not to exceed $3 million per interconnection for a non-dairy cluster biomethane project, or $5 million per interconnection for a dairy cluster biomethane project, including all previous payments. The Utility will provide notification to the CPUC Director of the Energy Division and the Biomethane Interconnector of the initial payment as well as any other potentially eligible future payments.

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Rule No. 39 Sheet 3

ACCESS TO THE SOCALGAS PIPELINE SYSTEM

(Continued)

A. Terms of Access (Continued)

4. The point of interconnection shall be established as a transportation scheduling point, pursuant to the provisions of Rule No. 30, if the Interconnector abides by the standards of the North American Energy Standards Board. L | L

5. The maximum physical capacity of the interconnection will be determined by the sizing of the point of receipt, including the metering and odorization capacities, but is not the capacity of the Utility's pipeline system to transport gas away from the interconnection point and is not, nor is it intended to be, any commitment by the Utility of takeaway capacity. The Utility separately provides takeaway services, including the option to expand system capacity to increase takeaway services, through its otherwise applicable tariffs.

6. The available receipt capacity for any particular day may be affected by physical flows from other points of receipt, physical pipeline and storage conditions for that day, and end-use demand on the Utility's system.

7. The Utility will expand specific receipt point capacity and/or takeaway capacity at the request and expense of a supply source, third party storage providers, CPUC-regulated intrastate pipelines, interconnecting interstate pipelines, or other parties. The Interconnector and the Utility must execute a Collectible System Upgrade Agreement (Form 6420) prior to any work being completed.

8. As defined in an IA, the Interconnector shall pay all costs associated with the odorant of the delivered natural gas less the historical costs, on a per unit basis; the Utility has paid for odorant required for existing interstate supplies being delivered as of the date of D.06-09-039. The historical cost is $0.0003 per Dth. As defined in a CPIA (Form 6454), the Interconnector shall pay all costs associated with the odorization of the delivered natural gas.

9. An Interconnector that is a California Producer that currently has, or will be requesting, access to the Utility's transportation system or is presently interconnected to the Utility without a gas chromatograph and all related equipment, communications facilities and software shall fund Utility installation of a gas chromatograph and all related equipment, communications facilities and software for the purpose of gathering data and monitoring and enforcing gas quality, as specified in Rule No. 30. Refusal on the part of a California Producer to accept these conditions will result in the denial of access to the Utility's transportation system.

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Rule No. 39 Sheet 4

ACCESS TO THE SOCALGAS PIPELINE SYSTEM

(Continued)

B. Interconnection Capacity Studies L

1. Any party, including an interconnecting pipeline or a supply source, may request an Interconnection Capacity Study to determine the Utility's downstream capability to take natural gas away from the interconnection point and the associated Utility facility enhancement costs. Upon the request of an entity to establish or increase takeaway capacity from a receipt point, the Utility will make a timely determination of the facilities (and facility modifications) and associated costs that are required to add the requested takeaway capacity on both a Displacement Receipt Point Capacity basis and Expansion Receipt Point Capacity basis. The Utility shall make this determination on a nondiscrimatory and transparent basis, without favoring any region of its territory and without favoring any entity.

2. All analyses shall take into consideration new supplies and facilities that have been or will be installed pursuant to a previously executed Collectible System Upgrade Agreements (CSUA) in effect. Priority for purposes of determining facility costs will be established on the basis of the date a party executes a CSUA. The CSUA shall include the activities from initial study through construction under terms mutually agreeable to the Utility and the party in Appendix "B" to the CSUA. In order to keep its place in the priority established by D.06-12-031 for determining facilities costs, an Appendix "B" must be completed within 90 days of the Commission Resolution approving Advice Letter 3706-A. The Utility shall maintain a queue of executed CSUAs with completed Appendix "B", including project milestones and completion dates. Any CSUA party will be subject to replacement in the queue if any date for performance within its CSUA has expired. The Utility will be provided a 30-day notice of cancellation and allow for a subsequent 60-day period to cure any non-performance. The Utility will file an Advice Letter for Commission approval to re-order the queue due to the non-performance of a CSUA holder.

3. Any party interested in funding an Interconnection Capacity Study must submit a written request for access, which includes where and when the new supply will be delivered to the Utility and the volume required to be received. Within 30 business days, the Utility will provide a written proposal to the party to evaluate the system impact of the new supplies including the estimated time and cost to perform this analysis. For California Producers, the Utility will provide a $\pm$20% cost estimate for the capacity study, but in any event Interconnector is responsible to pay for the entire actual cost of the capacity study.

4. The party and the Utility must execute a Consulting Services Agreement (Form 6440) or Collectible System Upgrade Agreement (Form 6420) and Confidentiality Agreement (Form 6410) prior to any work being completed and provide payment equal to the estimated cost of the Interconnection Capacity Study prior to the Utility proceeding with the Interconnection Capacity Study. The party will be responsible for the actual costs of the analysis; to this end, an invoice or refund will be issued to the supplier at the completion of the analysis for any difference between the actual costs and the estimate. L

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B. Interconnection Capacity Studies (Continued) L

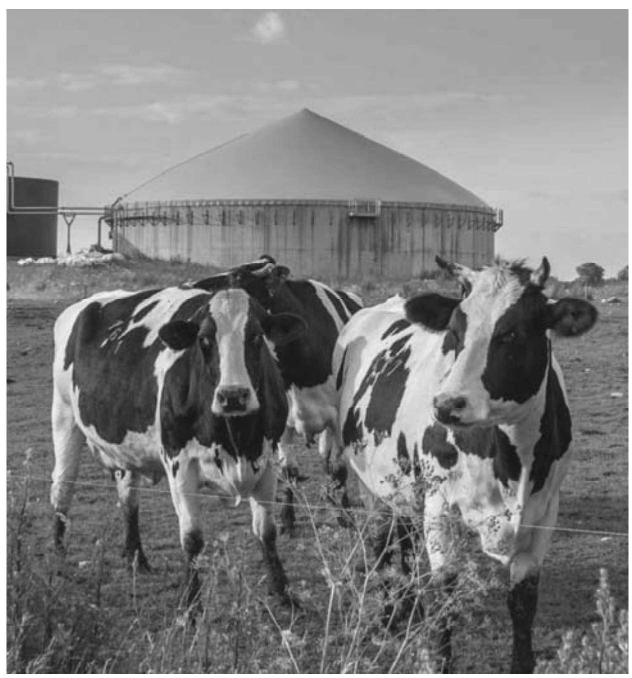
5. The cost estimate provided in the Interconnection Capacity Study will not include cost estimates for land acquisition, site development, right-of-way, metering, gas quality, permitting, regulatory, environmental, unusual construction costs, and operating and maintenance costs. Upon completion of the Interconnection Capacity Study and for an additional charge, the Utility will perform a more detailed Preliminary Engineering Study that will include such cost estimates associated with these elements, if requested by the party in writing. As with the Interconnection Capacity Study, the party will be responsible for the actual costs to perform the Preliminary Engineering Study.

6. In addition, upon formal written request by any party, the Utility will prepare a Detailed Engineering Study, which will: (1) describe all costs of construction, (2) develop complete engineering construction drawings, and (3) prepare all construction and environmental permit applications and right-of-way acquisition requirements. The party shall pay an estimated charge before the Utility will begin the Detailed Engineering Study. As with the Interconnection Capacity Study, the party will be responsible for the actual costs to perform the Detailed Engineering Study.

7. Customers will have three funding options for increasing receipt point capacity. First, a customer may elect to pay 100% of the costs, including applicable CIAC taxes, to the Utility to complete the installation of the necessary facility without any refund of the advanced funds and not be charged an incremental reservation rate on a going forward basis. Second, a customer may elect to pay 100% of the costs to the Utility to complete the installation of the necessary facility, receive a refund of those advanced funds after gas first flows through the receipt point, and be charged an incremental reservation rate on a going forward basis. Third, a customer may elect to install the necessary facility themselves under the direction of the Utility, transfer ownership of the necessary facilities, along with any payment of applicable CIAC taxes, and not be charged incremental reservation rate on a going forward basis. L

Natural Gas Utility Business Models for Facilitating Renewable Natural Gas Development and Use

Renewable Natural Gas Issue Brief ▪ Part II of IV ▪ July 2019



Introduction

This MJB&A Issue Brief is part of a series on renewable natural gas (RNG). This document summarizes natural gas utility business models. Additional issue briefs provide an overview of RNG benefits and supply, policies to support RNG use beyond the transportation and electric sectors, and the economics of RNG projects.

In recent years, an increasing number of states have adopted greenhouse gas (GHG) reduction targets. While strategies to decrease GHG emissions from the electric power and transportation sectors will account for a significant portion of these reductions, emissions from buildings and industry will also need to be addressed to achieve long-term GHG goals. Renewable natural gas (RNG) delivered through existing natural gas infrastructure can provide meaningful and cost-effective GHG reductions in the buildings and industrial sectors and contribute to long-term climate targets.

An important aspect of public utility commission (PUC) oversight is the “least cost” regulatory requirement. This principle requires utilities to demonstrate that their investment and procurement decisions represent the lowest cost options while maintaining certain expectations of risk and reliable service. Simply put, because utility costs are passed down to customers in rates, utility commissions seek to ensure that those costs are minimized. Thus, PUCs would need to review and approve any RNG program that involves higher costs than what would occur without the program. While some utility commissions may have the flexibility to structure a narrowly defined utility pilot program, approval would be subject to state-specific dynamics.

Natural gas utilities can take several actions to support development of RNG production and integration with the gas supply chain. While these steps may require approval from utility regulators, they can be important enablers to RNG projects. Utilities have access to existing distribution infrastructure, have customer bases interested in new, innovative energy sources, and can develop or leverage relationships with RNG suppliers.

Options used by gas utilities to promote RNG use

Gas quality standards and interconnection guidelines;

Gas conditioning and interconnection tariffs;

Voluntary customer programs;

Public-private partnerships; and

Technology pilots and research and development.

Gas Quality Standards and Interconnection Guidelines

Key preliminary steps that LDCs can take to facilitate RNG development include establishing clear gas quality standards, evaluating existing limits on hydrogen concentrations in pipelines, and developing interconnection guidelines for RNG. These policies safeguard system operations, proactively inform project developers of gas quality requirements, and clearly identify interconnection construction, operation, and cost responsibilities.

RNG quality standards provide LDCs and RNG producers with regulatory certainty. Producers receive clear guidance on the specifications their RNG must meet to be accepted by LDCs and pipeline companies. At the same time, LDCs have the assurance that RNG will not harm their infrastructure or customer end-use equipment. Gas quality standards have two primary components: limits on gas constituents and interchangeability requirements. Constituent limits are needed to prevent chemicals present in raw biogas that can harm gas infrastructure and human health from entering the gas supply. Interchangeability specifications address characteristics like heating value and are needed to ensure safe and reliable end-use combustion. Several utilities have developed gas quality standards that specifically address RNG.[1]

In addition to setting gas quality standards, LDCs can also evaluate existing limits on hydrogen concentrations in natural gas pipelines to determine if it is safe to increase injection of renewable hydrogen into utility networks. Adding hydrogen to natural gas can reduce GHG emissions if the hydrogen is produced from low-carbon energy sources. According to the literature, acceptable hydrogen blending ranges fall within 5%-15% hydrogen by volume.[2] Higher permitted hydrogen concentrations could support the development of renewable hydrogen supplies, further reducing the carbon intensity of the fuel that LDCs supply to customers.

In the United Kingdom, projects are underway that test hydrogen concentration limits. British gas distribution utility Northern Gas Networks (NGN) spearheaded two studies in recent years to evaluate conversion from the existing natural gas network to hydrogen served by steam methane reformer hydrogen production facilities with carbon capture and storage.[3] The first, H21 Leeds City Gate project, was launched in 2016 to determine the technical and economic feasibility of converting the existing natural gas network in Leeds, one of the largest cities in the UK, to 100 percent hydrogen. The second, H21 North of England project, expanded on the scope of the Leeds City Gate project to include other major cities in the North.[4] The studies conclude that conversion from natural gas to hydrogen is indeed feasible and cost-effective, and could serve as a critical strategy to achieve climate change targets by decarbonizing the UK economy. The studies equate the conversion from town gas (derived from coal and oil) to natural gas with the transition from natural gas to hydrogen. The North of England conversion would entail a 12.15 gigawatt (GW) natural gas-based hydrogen production facility, 8 terawatt hours (TWh) of hydrogen storage, a 125 GW capacity hydrogen transmission system, and CO_2 transport and storage infrastructure with the capacity to sequester up to 20 million tons of

[1] See PG&E Gas Rule 21, SoCalGas Rule 30, Piedmont Appendix F, and Vermont Gas RNG Quality Assurance Plan available in its RNG Manual.
[2] See "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues", National Renewable Energy Laboratory, March 2013 available at: https://www.nrel.gov/docs/fy13osti/51995.pdf
[3] Information on H21 Leeds City Gate is available at: https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf
[4] See https://www.northerngasnetworks.co.uk/event/h21-launches-national/

CO_2 per year by 2035. The total estimated capital investment necessary is £22,778 million, and operating costs come out to £955 million per year after 2035, once conversion and commissioning are complete.[5]

Interconnection guidelines clarify several important issues: the equipment and steps required to connect RNG projects with LDC pipeline systems, infrastructure ownership, and responsibility for financing and operating interconnection equipment. As with gas quality standards, interconnection guidelines offer certainty for both RNG producers and LDCs. Uniform standards provide important consistency for RNG projects across LDC operations and jurisdictions. In 2019, the Northeast Gas Association is expected to release an RNG Standard Interconnection Guideline that was developed in conjunction with natural gas utilities. While the guidelines focus on New York, they are intended to serve as a framework that can be adopted by other states. In California, LDCs and regulators are currently working on a Joint Utility Biomethane Interconnection Tariff. Like the New York guideline, this document will provide a roadmap for the RNG interconnection process as well as an overview of the current interconnection policies and requirements for California utilities.[6]

[5] Information on H21 North of England is available at: https://northerngasnetworks.co.uk/h21-noe/H21-NoE-23Nov18-v1.0.pdf
[6] A draft of the Joint Utility Interconnection Tariff is available in this document: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M242/K068/242068929.PDF

Biogas Conditioning/Interconnection Tariffs

LDCs can also develop tariffs for biogas conditioning and interconnection services. These tariffs are instrumental to the LDC identifying and promoting RNG opportunities in its service areas. Under these tariffs, LDCs generally build and operate the biogas upgrading and interconnection facilities and can recover capital and operation and maintenance (O&M) costs from the project developer at a set rate (e.g., $/Mcf injected into LDC pipeline). Like interconnection guidelines, these tariffs delineate the obligations and responsibilities of all parties involved. A set tariff charge also reduces financial uncertainty by providing project developers with a clear and consistent price for biogas conditioning and interconnection. As discussed in detail in the *Renewable Natural Gas Project Economics* Issue Brief, RNG project developers are responsible for facility gas and electric operating costs, any required pipeline extensions, and pipeline interconnection. The gas conditioning and upgrading system alone can represent between one quarter to one third of total project cost, and project cost can exceed tens of millions of dollars. Costs of conditioning, upgrading and interconnection demonstrate economies of scale, but the initial investment in this infrastructure is one of the most significant risks for a renewable natural gas project developer. Under the tariff structure, the producer can avoid the significant upfront capital costs that could impede initial project development.

Implementation of biogas conditioning and interconnection service tariffs is highly contingent upon state PUC and regulatory approval, limiting the ease and speed of implementation. However, several of these tariffs have been approved in states like California and Florida, and tariffs could be further expanded if more states directed their PUCs to permit utility investment in this area. SoCalGas has a biogas conditioning/upgrading

tariff that allows the utility to build, own, and operate RNG processing facilities on customer property.[7] TECO Peoples Gas recently made two tariff modifications for its RNG supply area that allow the utility to provide services similar to those of SoCalGas: (1) modifications to current tariffs to accommodate the receipt of RNG from biogas producers and (2) a new rate schedule for Renewable Natural Gas Service (RNGS) for conditioning services.[8] The RNGS rate schedule allows the LDC to build and operate upgrading facilities and interconnection infrastructure. Costs associated with infrastructure upstream of upgrading facilities are not included. Tariff charges cover a percentage of LDC capital investment in upgrading infrastructure, as well as O&M costs.

Southwest Gas Company (SWGC) in Arizona also has a biogas services tariff (Schedule No. G-65, Biogas and Renewable Natural Gas Services).[9] The tariff contains general terms and conditions under which SWGC may enter into a service agreement with a biogas or RNG producer. The tariff includes requirements for access to biogas and RNG producer facilities, interconnection points, and RNG quality testing.

Voluntary Customer Program Offerings

For years, electric utilities have offered voluntary programs that allow customers to opt-in to a renewable electricity supply option. Today, customers are increasingly interested in low-carbon alternatives for their energy needs. This customer base includes both environmentally-conscious homeowners and large multinational companies seeking to achieve corporate climate goals.

LDCs can offer voluntary RNG programs similar to voluntary renewable electricity programs, allowing customers to purchase a certain amount of RNG by paying a premium on their natural gas bill. The cost premium helps LDCs offset higher RNG commodity costs. Therefore, these programs allow customers to purchase a renewable fuel, provide the means for LDCs to integrate RNG into their pipeline systems, and reduce the carbon intensity of their fuel supply in a manner that does not significantly increase costs for all customers. There are several examples of voluntary programs proposed or implemented by LDCs.

In Canada, FortisBC's voluntary program allows customers to pay a premium for RNG.[10] Customers can voluntarily purchase RNG in intervals such that it comprises between five to 100 percent of their gas use at an incremental cost of $7.00 per gigajoule (GJ). This is approximately two times the price of conventional natural gas. The fees do not completely offset the utility's commodity cost – the British Columbia Utilities Commission allows FortisBC to distribute the remaining program costs across non-participating customers. The impact of the proposed rate methodology and cost recovery mechanism on delivery rates for non-participating customers ranged from near zero in 2017 and 2018 to a maximum of $0.0839/GJ in 2021.[11] The Utilities Commission approved Fortis to purchase RNG equivalent to five percent of system throughput, up to an estimated 8.9 million GJ per year. Over the next five years, at least one million GJ per year is projected to be available from existing and planned projects in British Columbia.

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[7] SoCalGas' tariff is available at: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/GO-BCUS.pdf
[8] TECO Peoples Gas' tariff is available at: https://www.peoplesgas.com/files/tariff/tariffsection7.pdf
[9] Southwest Gas' tariff is available at: https://www.swgas.com/1409197529940/G-65-RNG-02262018.pdf
[10] Information of FortisBC's program is available at: https://www.fortisbc.com/naturalgas/renewablenaturalgas/Pages/default.aspx
[11] Decision on FortisBC's Application for Biomethane Energy Recovery Charge Rate Methodology, available at: https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/item/169164/index.do#_Toc458771421

DTE Energy launched a voluntary BioGreenGas program in 2012 and transitioned to a permanent program in 2015. A flat fee of $2.50 per month is added to a customer's bill to support biogas resource development and utilization, and customers can opt out of the program each month. Customer payments are used to recover the cost of the biogas premium. The cost of RNG is not included in a gas cost recovery mechanism; therefore, the program does not affect rates for customers who do not enroll in program.[12]

Vermont Gas (VGS) launched a voluntary RNG program in March 2018.[13] Residential and commercial customers may select a blend consisting of 10, 25, 50 or 100 percent RNG. An RNG "adder" price per hundred cubic feet (Ccf), which reflects the difference in the cost of RNG and conventional natural gas, is included on the customer's bill as a separate charge and updated quarterly. At present, the adder cost is $1.2107 per Ccf for RNG supplied from Canada via pipeline. VGS' customers currently use about 6 Bcf of RNG per year. Given the Canadian Gas Association's estimate that 1,400 Bcf per year of RNG is technically available in North America, there is potential to greatly increase VGS' supply as additional in- and out-of-state RNG resources become available.[14]

In August 2018, CenterPoint Energy proposed a five-year RNG pilot program to allow Minnesota customers to purchase RNG.[15] Voluntary participants would choose to pay a set amount each month to purchase RNG. That amount would purchase as much RNG as possible at the current commodity cost while covering a set program fee. CenterPoint anticipates an RNG cost of $3.50 per therm, which along with administrative costs would result in a total cost of $3.89 per therm for participating customers. The proposal limits costs recovered from general customers to a maximum of $1 million per year, which would increase the average residential customer bill by $0.70 per year.

In February 2019, Southern California Gas Company and San Diego Gas & Electric submitted a proposal to the California Public Utilities Commission to offer a voluntary Renewable Natural Gas Tariff (RNGT) program to their residential, small commercial, and industrial customers that collects program costs through rates charged to program participants. Residential customers would select a pre-defined maximum monthly dollar amount for the purchase of RNG, but small industrial and commercial customers would be given the additional option to purchase RNG as a percentage of their monthly gas bill. The minimum participation commitment would be one year for residential customers and two years for non-residential customers.[16] Shortly following its proposed RNGT, Southern California Gas Company announced a plan to replace 20 percent of its natural gas supply with RNG by 2030. As a first step, the company will pursue regulatory authority to implement an RNG procurement program with a goal of replacing 5 percent of its natural gas supply with RNG by 2022.[17]

In April 2019, National Grid proposed a Green Gas Tariff offering that will enable its Downstate New York customers to voluntarily purchase RNG to meet all or a portion of their energy needs. The offering will

[12] Initial filing for the DTE pilot is available at: https://www.michigan.gov/documents/mpsc/u-17628_4-23-15_569241_7.pdf
[13] Information on VGS' program is available at: https://www.vermontgas.com/renewablenaturalgas/
[14] Information on potential supply is available on slide 8 of: https://www.ccrpcvt.org/wp-content/uploads/2018/05/RNG-CCRPC-April-2018.pdf
[15] An FAQ on CenterPoint's proposed program is available at: https://www.centerpointenergy.com/en-us/inyourcommunity/pages/renewable-gas-faq.aspx
[16] SoCalGas/SDG&E's application for the proposed RNGT is available at: https://www.socalgas.com/regulatory/documents/a-19-02-xxx/Application%20-%20Renewable%20Gas%20(A.19-02-XXX)%20-%20Final.pdf
[17] The SoCalGas March 6, 2019 press release is available at: https://sempra.mediaroom.com/index.php?s=19080&item=137611

include four tiers, allowing customers to select the level of green gas procurement that works for their budget and environmental aspirations. Fees range from $5-$50 per month for residential customers and from $25-$500 per month for non-residential customers.[18]

Public-Private Partnerships

Natural gas utilities can also foster public-private partnerships with local governments to successfully develop RNG projects. Producing RNG at government-owned biogas sources (e.g., wastewater treatment plants and landfills) yields a beneficial use for a resource that can contribute to achieving climate-related goals but might otherwise be wasted. Other benefits to municipal governments from public-private partnerships include outside expertise, transfer of risk to private entities, and alternative project financing. Public-private RNG projects are currently under development in New York City and Portland, Oregon.

The Newtown Creek project is a public-private partnership between National Grid and the New York City Department of Environmental Protection.[19] The Newtown Creek Wastewater Treatment Plant Project, which will be one of the first and largest of its kind in the country, is expected to produce approximately 277,500 dekatherms of RNG per year and reduce CO_2 emissions by approximately 16,000 tons annually (the emissions of about 3,000 automobiles). National Grid is paying for the total project and annual O&M costs through rates. National Grid's agreement with NYC provides for use of the property and methane gas at the wastewater treatment plant at no cost until National Grid's customers have been fully compensated for the project costs through the sale of the project's output. National Grid will seek to monetize the environmental attributes of the RNG produced by the facility and apply those revenues to offset the project's revenue requirement.

NW Natural is working with the City of Portland's Bureau of Environmental Services Columbia Boulevard Wastewater Treatment Plant to capture RNG and inject it into the pipeline for use in the heavy-duty transportation sector.[20] This public-private cooperative effort is expected to cut 21,000 $MTCO_2e$ per year and replace enough diesel to power 154 garbage trucks each year. The project will be the first in Oregon to inject RNG into the natural gas system. NW Natural will pay through rates (minus the environmental attributes) for delivery to customers. The environmental attributes will be separated from the RNG and sold by the city via a third party.

Nevada Senate Bill 154, passed in May 2019, directs the Public Utilities Commission of Nevada to adopt regulations authorizing LDCs in the state to engage in RNG activities. The regulations shall include procedures for utilities to apply to the Commission for approval of a reasonable and prudent RNG activity that will be used and useful and will provide environmental benefits to Nevada; and procedures for utilities to apply to the Commission for the recovery of all reasonable and prudent costs associated with a RNG activity. Furthermore, the bill also requires LDCs to attempt to incorporate RNG into their gas supply portfolios in the following amounts: not less than 1 percent of the total amount of gas sold by public utility to its retail customers by 2025; not less than 2 percent by 2030; and not less than 3 percent by 2035.[21]

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[18] More information on National Grid's Future of Heat Filing is available at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-G-0309&submit=Search
[19] Information on the Newtown Creek project is available at: https://www1.nyc.gov/html/dep/html/press_releases/13-121pr.shtml#.XEIkeVVKjIU
[20] Information on the City of Portland's project is available at: https://www.portlandoregon.gov/bes/77813
[21] See SB 154

Pilot Projects and R&D

Beyond programs to directly incorporate RNG into their pipeline systems, LDCs can advance and support new RNG production technologies through the implementation of pilot projects and through research and development. Natural gas LDCs can invest in gas innovation research and development with a cost recovery mechanism, although this approach typically faces challenges in rate cases. Utilities have a long track record of investment in gas innovation, working to modernize the transmission and distribution networks to improve pipeline safety, reduce methane emissions, improve energy efficiency, and develop more cost-effective pipeline inspection and repair processes. LDC involvement in gas innovation R&D not only supports the development of a potential new RNG supply resource, but also facilitates understanding of how this resource can be integrated into the LDC natural gas supply chain. Given the need to decarbonize the energy system, natural gas LDCs could engage in R&D to improve alternatives to conventional natural gas, including RNG and hydrogen. Research and development efforts could target technical performance, economic cost, and environmental benefits of different technologies and feedstocks depending on service area specifics. By pursuing R&D to support the ability to decarbonize gas supply, natural gas LDCs can contribute to state climate change policy objectives.

Utilities can and do conduct their own research into the current and future potential of RNG, and contract with other organizations to develop reports. For example, a NW Natural-commissioned a study, "Pacific Northwest Pathways to 2050," investigated and demonstrated the role of RNG in long-term decarbonization studies.

A critical area in which pilot projects and research and development are especially relevant is power-to-gas (P2G).[22] P2G is the production of hydrogen or synthetic gas through electrolysis using electricity. The vast majority of hydrogen produced today comes from steam reformation of natural gas for industrial uses. However, hydrogen produced through electrolysis, where the electrolysis process is powered by renewable electricity, holds the promise of integrating and storing intermittent renewable energy while also decarbonizing the gas grid. LDC collaboration on P2G not only supports the development of a potential new RNG supply resource, but also facilitates understanding of how this resource can be integrated into the LDC natural gas supply chain.

SoCalGas is currently supporting two P2G demonstration projects focusing on different components of P2G technology.[23] A project with the National Fuel Cell Research Center at the University of California at Irvine uses solar electricity to generate renewable hydrogen used to fuel the university's power plant. The other project, with National Renewable Energy Laboratory (NREL) in Golden, Colorado, is testing a biomethanation process that uses bacteria to convert hydrogen and CO_2 into methane. National Grid's Future of Heat filing also proposes a P2G demonstration project. Under the proposal, National Grid would assess a project that converts renewable electricity into hydrogen, which in turn is converted into methane in a bioreactor and delivered via the existing natural gas network.

[22] Power-to-gas refers to both hydrogen and methanation of that hydrogen into a renewable gas that can displace fossil natural gas.
[23] Information on SoCalGas' P2G projects is available at: https://www.socalgas.com/smart-energy/renewable-gas/power-to-gas

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About Us

MJB&A provides strategic consulting services to address energy and environmental issues for the private, public, and non-profit sectors. MJB&A creates value and addresses risks with a comprehensive approach to strategy and implementation, ensuring clients have timely access to information and the tools to use it to their advantage. Our approach fuses private sector strategy with public policy in air quality, energy, climate change, environmental markets, energy efficiency, renewable energy, transportation, and advanced technologies. Our international client base includes electric and natural gas utilities, major transportation fleet operators, investors, clean technology firms, environmental groups and government agencies. Our seasoned team brings a multi-sector perspective, informed expertise, and creative solutions to each client, capitalizing on extensive experience in energy markets, environmental policy, law, engineering, economics and business. For more information, we encourage you to visit our website: www.mjbradley.com.

UM 2030: NW Natural's RNG Evaluation Methodology

NW Natural
December 13, 2019

FORWARD LOOKING STATEMENT

This and other presentations made by NW Natural from time to time, may contain forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as “anticipates,” “intends,” “plans,” “seeks,” “believes,” “estimates,” “expects” and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following: including regional third-party projects, storage, pipeline and other infrastructure investments, commodity costs, competitive advantage, customer service, customer and business growth, conversion potential, multifamily development, business risk, efficiency of business operations, regulatory recovery, business development and new business initiatives, environmental remediation recoveries, gas storage markets and business opportunities, gas storage development, costs, timing or returns related thereto, financial positions and performance, economic and housing market trends and performance shareholder return and value, capital expenditures, liquidity, strategic goals, carbon savings, gas reserves and investments and regulatory recoveries related thereto, hedge efficacy, cash flows and adequacy thereof, return on equity, capital structure, return on invested capital, revenues and earnings and timing thereof, margins, operations and maintenance expense, dividends, credit ratings and profile, the regulatory environment, effects of regulatory disallowance, timing or effects of future regulatory proceedings or future regulatory approvals, regulatory prudence reviews, effects of regulatory mechanisms, including, but not limited to, SRRM and the Company’s infrastructure investments, effects of legislation, including but not limited to bonus depreciation and PHMSA regulations, and other statements that are other than statements of historical facts.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements, so we caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed by reference to the factors described in Part I, Item 1A “Risk Factors,” and Part II, Item 7 and Item 7A “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and “Quantitative and Qualitative Disclosure about Market Risk” in the Company’s most recent Annual Report on Form 10-K, and in Part I, Items 2 and 3 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures About Market Risk”, and Part II, Item 1A, “Risk Factors”, in the Company’s quarterly reports filed thereafter.

All forward-looking statements made in this presentation and all subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

Agenda

1) Overview
2) Background
3) Analysis
4) Methodology
5) Questions/Next steps
6) Handouts

NW Natural – 2018 IRP

- NW Natural 2018 IRP filed 8/24/18 – docketed as LC 71
- Requested acknowledgement of Action Plan item 2:

  2) Use the methodology detailed in Appendix H to evaluate renewable natural gas resources against conventional sources based on all-in costs, where all-in costs are defined as:

  *All-in costs = Net Present Value ([cost for delivered gas] + [net GHG emissions intensity*Cost of GHG Emissions Compliance] – [avoided supply capacity costs] – [avoided distribution capacity costs])Renewable Natural Gas*

NW Natural – 2018 IRP (cont)

- As stated in Appendix H:

  Enabled by new information and expertise gained since completing the last IRP, NW Natural evaluated low carbon gas resources in a much more detailed and comprehensive manner in the 2018 IRP. This methodology applies the current least cost and least risk planning standard to RNG resources; it is not meant to expand the scope of integrated resource planning or serve as a policy statement regarding RNG. The methodology and process presented in this appendix is meant to be flexible so that as new policies are enacted they can be incorporated into the analysis.

Staff Recommendation No. 15

Staff’s report presented at the February 26, 2019 Public Meeting, and subsequently adopted by the Commission in Order No. 19-073 contained the following recommendation

(a) As part of an RNG investigation, Staff recommends NWN provide modeling inputs, outputs, and other relevant workpapers to parties in the investigation docket at least 30 days before signing any RNG contract or initiating any RNG project.

(b) Staff recommends acknowledging a revised action item for RNG: "NW Natural will participate in an investigation into the use of the Company's proposed methodology to evaluate renewable natural gas (RNG) cost effectiveness. Until the investigation is complete, NW Natural will procure RNG deemed cost-effective through the methodology in revised Appendix H, up to a 4.5 million therm annual limit on total delivery, for up to ten years (up to 45 million therms in total). The investigation will review the appropriate process for procuring cost-effective RNG resources that do not align with the timeline of acknowledgement in an IRP as well as review the 4.5 million therm annual limit on cost-effective RNG procurement. If NW Natural seeks to procure additional cost-effective RNG before the conclusion of the investigation, it will seek acknowledgment in an IRP update. If the investigation results in the 4.5 million therm annual limit being adjusted or eliminated, or in other changes, the Commission may direct NW Natural to file an update to reflect its findings."

Docket No. UM 2030

- At the 8/27/2019 Public Meeting Staff presented a memo recommending opening of an investigation into:
  - “determining the cost-effectiveness of Renewable Natural Gas (RNG) resources for NW”
- The Commission concurred, opening Docket No. UM 2030
- Today’s workshop will focus on the proposed methodology

Analysis

IRP Guidelines

IRP Guideline 1(a) states:

All resources must be evaluated on a consistent and comparable basis.

All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.

IRP Guideline 8(a) states:

"The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO2 regulatory level to the upper reaches of credible proposals by governing entities."

Renewable Natural Gas vs Conventional Natural Gas

- The first inclination in comparing the cost of RNG with the cost of conventional gas is to compare the commodity cost of the two types of natural gas
- This is not a complete comparison, as both energy *and capacity costs* should be considered
- Comparing the "all-in" cost of different natural gas supply resources is more appropriate
- "All-in" cost represents the total cost to deliver a unit of natural gas to customers (i.e. what customers pay for a unit of gas)
- Comparing the "all-in" cost of different gas resources complies with IRP Guidelines

All-in Cost = Commodity cost of gas + GHG Compliance costs + Supply Infrastructure Costs + Distribution System Capacity Costs

Utility Benefits of RNG

Benefits of RNG	Description
Avoided Commodity & Transport Costs	The marginal costs of daily gas purchases avoided by not having to buy conventional gas and the transportation charges associated with the marginal unit of gas purchased.
Avoided GHG Compliance Costs	The compliance benefit of RNG versus carbon intensity of conventional natural gas.
Avoided Supply Capacity Costs	The avoided supply capacity cost of not needing additional supply capacity in order to meet peak day requirements.
Avoided Distribution System Capacity Costs	The avoided distribution system reinforcement costs by having a supply resource on-system based. This is based on State-wide average.

NW Natural analysis, not for investment purposes.

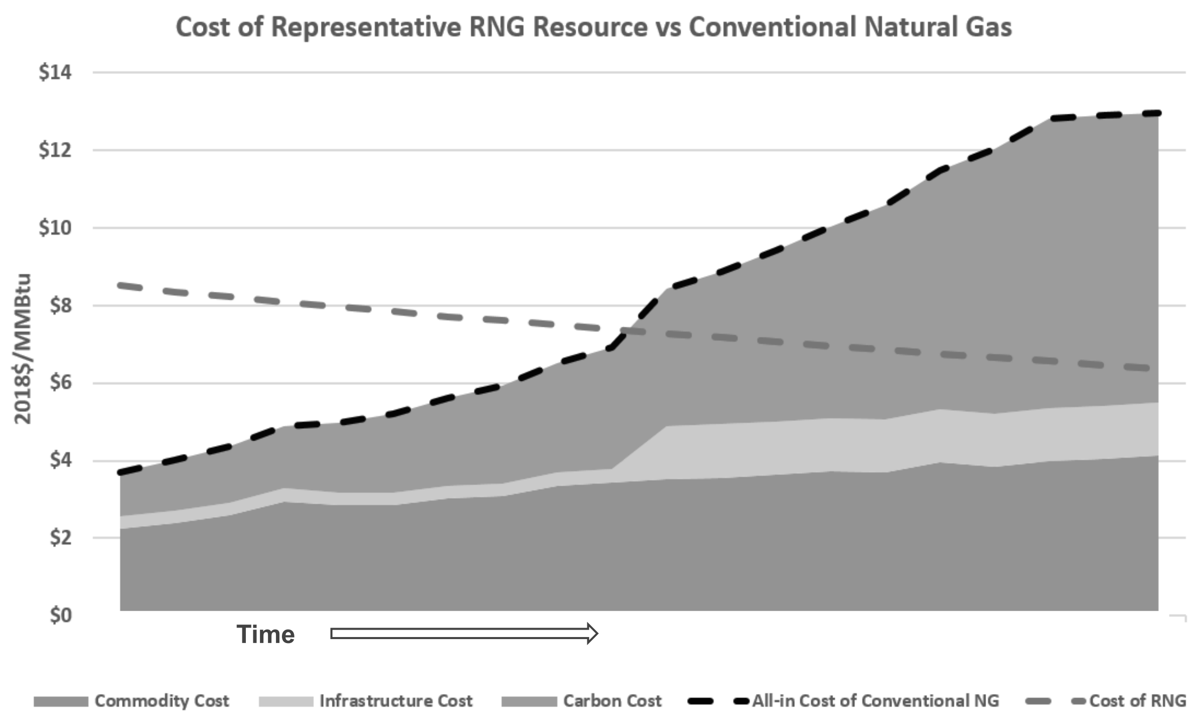
RNG vs Other Energy Resources

	Direct Use Natural Gas		Electricity	
	Conventional	RNG	Natural Gas Generation	Wind and Solar
Renewable		✓		✓
Cost per Btu	$	$$	$	$
Storable- Short Duration	$	$*	$	$$*
Storable- Long Duration	$	$	$	$$$$*
Availability	✓✓✓	✓	✓✓✓	✓✓

*RNG can be stored with existing storage infrastructure, where with wind and solar this infrastructure needs to accompany the development of the resource to be storable

NW Natural analysis, not for investment purposes.

Comparing RNG vs Conventional Gas Costs



NW Natural analysis, not for investment purposes.

Methodology

RNG vs. Conventional Gas

- RNG projects need to be compared to the costs of alternative supplies as directed by the IRP Guidelines.
- Mathematically, the RNG project is a least-cost/least-risk resource to acquire if:

$$\boldsymbol{rPVRR}(\boldsymbol{R}) < \boldsymbol{rPVRR}(\boldsymbol{C})$$

- In this case the all-in, risk-adjusted cost of the RNG project (R) is less than the comparable cost of a portfolio of resources without the RNG project (C)
- The above analysis examines cost and risk, consistent with the IRP mandate to evaluate all options for least-cost/least-risk portfolio to meet customer needs.

Possible Contract Structures

Type of Structure	Ownership of biogas production	Ownership of conditioning and cleanup equipment and/or pipeline interconnection	Cost basis for consideration of cost-effectiveness
1. RNG commodity-only purchase	3rd party	3rd party	Flat $/Dth contract for delivery of gas over a set time period
2. Investment in gas conditioning and/or pipeline interconnection	3rd party	NW Natural	Capital costs of investment in gas cleanup/ interconnection, minus some payment to 3rd party for raw biogas
3. Investment in full RNG project development	NW Natural	NW Natural	Capital costs of gas production and gas cleanup/interconnection
4. Full acquisition of operational RNG project	NW Natural	NW Natural	Asset purchase price, plus any contractual obligations and operating costs

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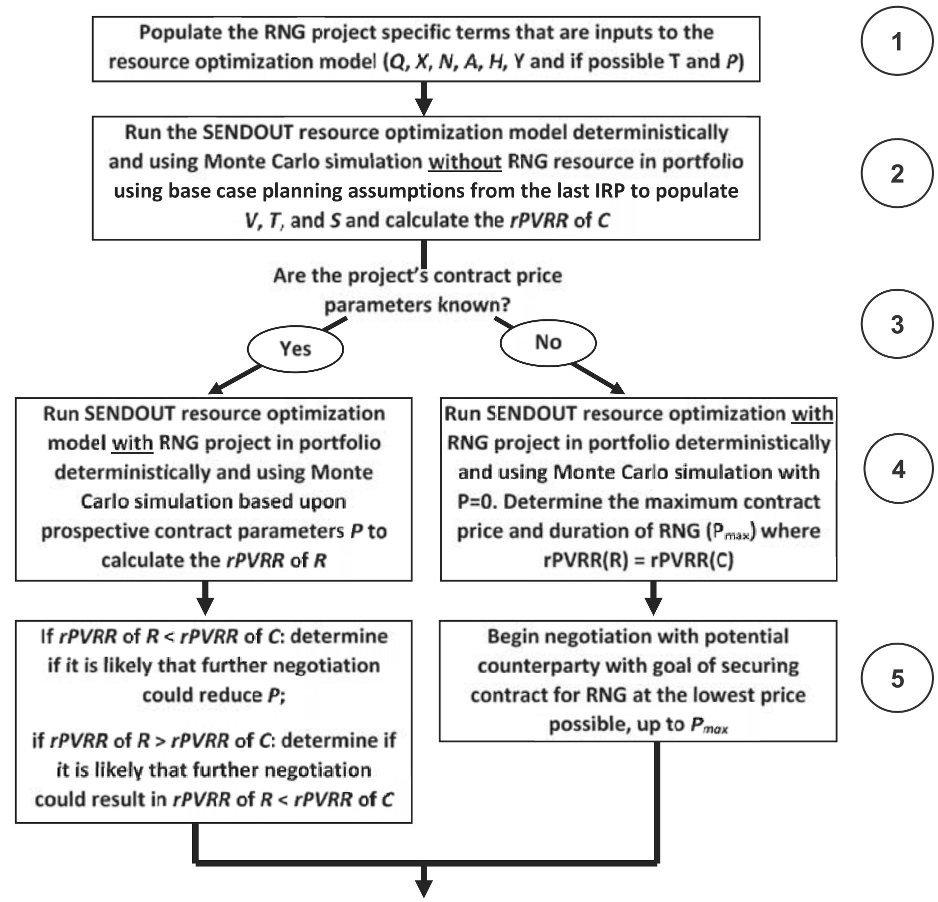
NW Natural RNG Project Evaluation and Procurement Process



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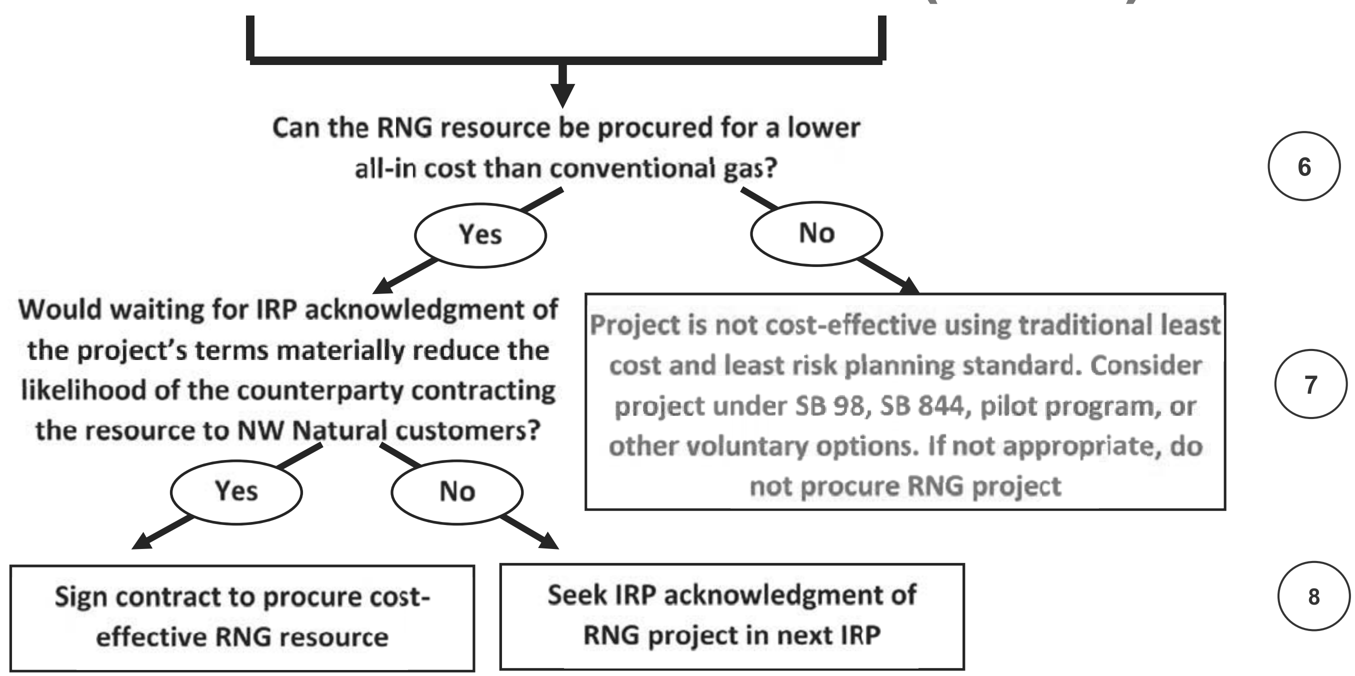
NW Natural RNG Project Evaluation and Procurement Process (cont.)



NW Natural analysis, not for investment purposes.

Cost Calculations

- In general, "all-in costs" of RNG projects calculated with the following equation:

Annual all-in cost of RNG (R) = Cost of methane (M) + Emissions compliance costs (E) – Avoided infrastructure costs (I)

- Calculation will examine the entire lifespan of the project with the simplified equation:

$$R_T = M_T + E_T - I_T$$

Cost

Cost/Benefit

Benefit*

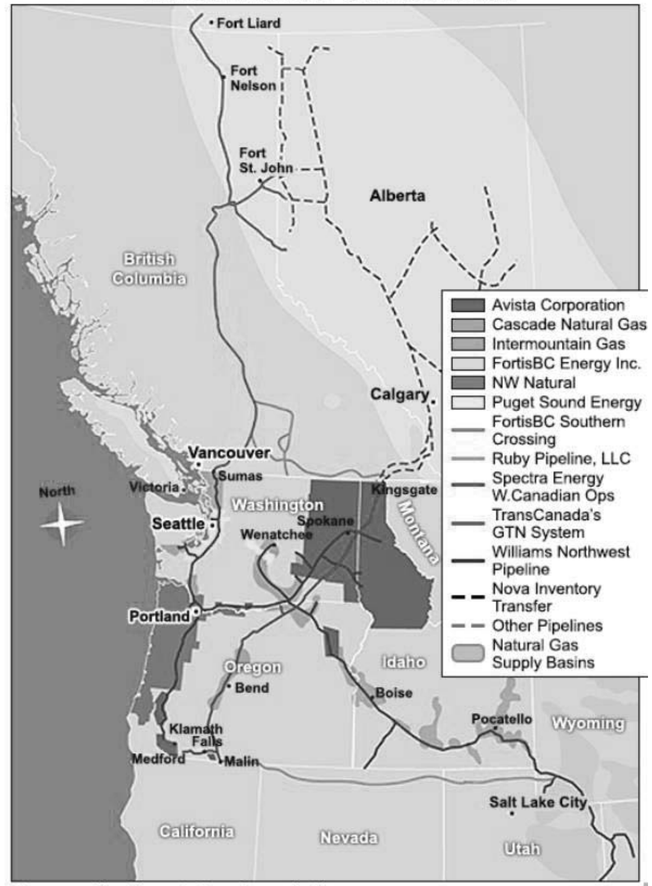
*I_T=0 for Off-system RNG

NW Natural analysis, not for investment purposes.

Avoided Commodity & Transport Cost

- The commodity cost is the cost of the marginal unit of gas purchased
- The transport cost include fuel and variables cost and depends on where the marginal unit was purchased (roughly 1%-3% of the commodity cost)

NWGA Member Service Areas



Source: Northwest Gas Association

NW Natural analysis, not for investment purposes.

Annual Cost Calculations - Components

- Methane cost:

$$M_T = \underbrace{X_T}_{\text{Fixed Costs}} + \sum_{t=1}^{365} \underbrace{[P_{T,t} + Y_{T,t}^{RNG}]}_{\text{Variable Costs}} Q_{T,t}$$

- X_T Annual revenue requirements of capital to access RNG resource ($)
  - Pipeline interconnection costs
  - Conditioning equipment
- $P_{T,t}$ RNG commodity contract price at time t ($/Dth)
- $Y_{T,t}^{RNG}$ RNG variable transport costs at time t ($/Dth)
- $Q_{T,t}$ Quantity received at time t (Dth)

NW Natural analysis, not for investment purposes.

Annual Cost Calculations - Components

- Emissions compliance costs:

$$E_T = \sum_{t=1}^{365} N G_T Q_{T,t}$$

Carbon Intensity
Compliance Cost
Annual Quantity

- N Carbon intensity (CO_2 tons/Dth)
- G_T Carbon price ($/$CO_2$ tons)
- $Q_{T,t}$ Quantity received at time t (Dth)

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Infrastructure Avoided Costs Methodology

Two pieces are needed for the calculation for each Supply Capacity and Distribution Capacity Costs:

1. The incremental cost of serving additional peak load
   - This is the same for all resources
2. The amount of energy that would be saved (e.g. EE) or supplied (e.g. RNG) during a peak
   - This is resource specific

Annual Cost Calculations - Components

- Avoided infrastructure costs:

$$I_T = \underbrace{S_T A_T}_{\text{Avoided Supply Capacity Costs}} + \underbrace{DH_T}_{\text{Avoided Distribution Costs}}$$

- S_T System supply capacity cost to serve one additional dekatherm of peak load based on marginal resource ($/Dth)
- A_T Minimum amount of RNG delivered at time t (Dth)
- D Avoided distribution capacity costs ($/Dth)
- H_T Minimum RNG quantity received at peak hour (Dth)
- Avoided distribution costs apply to on-system resources only

NW Natural analysis, not for investment purposes.

Cost Calculations

- Original equation:

$$R_T = M_T + E_T - I_T$$

- Detailed RNG cost equation is with substitution:

$$R_T = X_T - S_T A_T - DH_T + \sum_{t=1}^{365}\left[P_{T,t} + Y_{T,t}^{RNG} + N^{RNG} G_T\right] Q_{T,t}$$

All-in Costs

- Compared to the conventional supply:

$$C_T = \sum_{t=1}^{365}\left[\underbrace{V_{T,t}}_{\text{Commodity Costs}} + Y_{T,t}^{CONV} + N^{CONV} G_T\right] Q_{T,t}$$

All-in Costs

NW Natural analysis, not for investment purposes.

Cost Calculations – Risk Adjustment

- Adjusting for risk in forecast uncertainty, the all in costs are represented by the following:

$$rPVRR(R)=0.75*deterministic\ PVRR(R)+0.25*95th\ Percentile\ Stochastic\ PVRR(R)$$

$$rPVRR(C)=0.75*deterministic\ PVRR(C)+0.25*95th\ Percentile\ Stochastic\ PVRR(C)$$

- These values are compared to determine if the RNG project is the least cost/least-risk alternative as compared to conventional gas supply

Variable Update Schedule

Input/Assumption/Forecasts	Frequency of Update	Additional Explanation
Resource Under Evaluation	Most Current Estimate	For example, if an RNG project requires any capital costs, the most current estimate of those costs will be run through the cost-of-service model and used for the evaluation.
Gas Prices (Deterministic and Stochastic)	Twice a year	Our third party consultant provides long term gas price forecasts twice each year in August and February.
Peak Day & Annual Load Forecast	Once a year	These forecasts are updated spring/summer to include data from the most recent heating season.
GHG Compliance Cost Expectations (Deterministic and Stochastic)	Once a year	The GHG compliance cost assumptions will be updated each year after the legislation sessions in each state. are updated for each IRP.
Design, Normal, and Stochastic Weather	Each IRP	Resources are planned based on design weather, but are evaluated on cost using normal and stochastic weather.
Supply Resource Costs (Determinisitic and Stochastic)	Each IRP	For the 2018 IRP base case this included the cost of a pipeline uprate, a local pipeline expansion, and representative
Distribution Avoided Costs	Each IRP	NW Natural will calculate and present the avoided distribution avoided costs through the IRP process.

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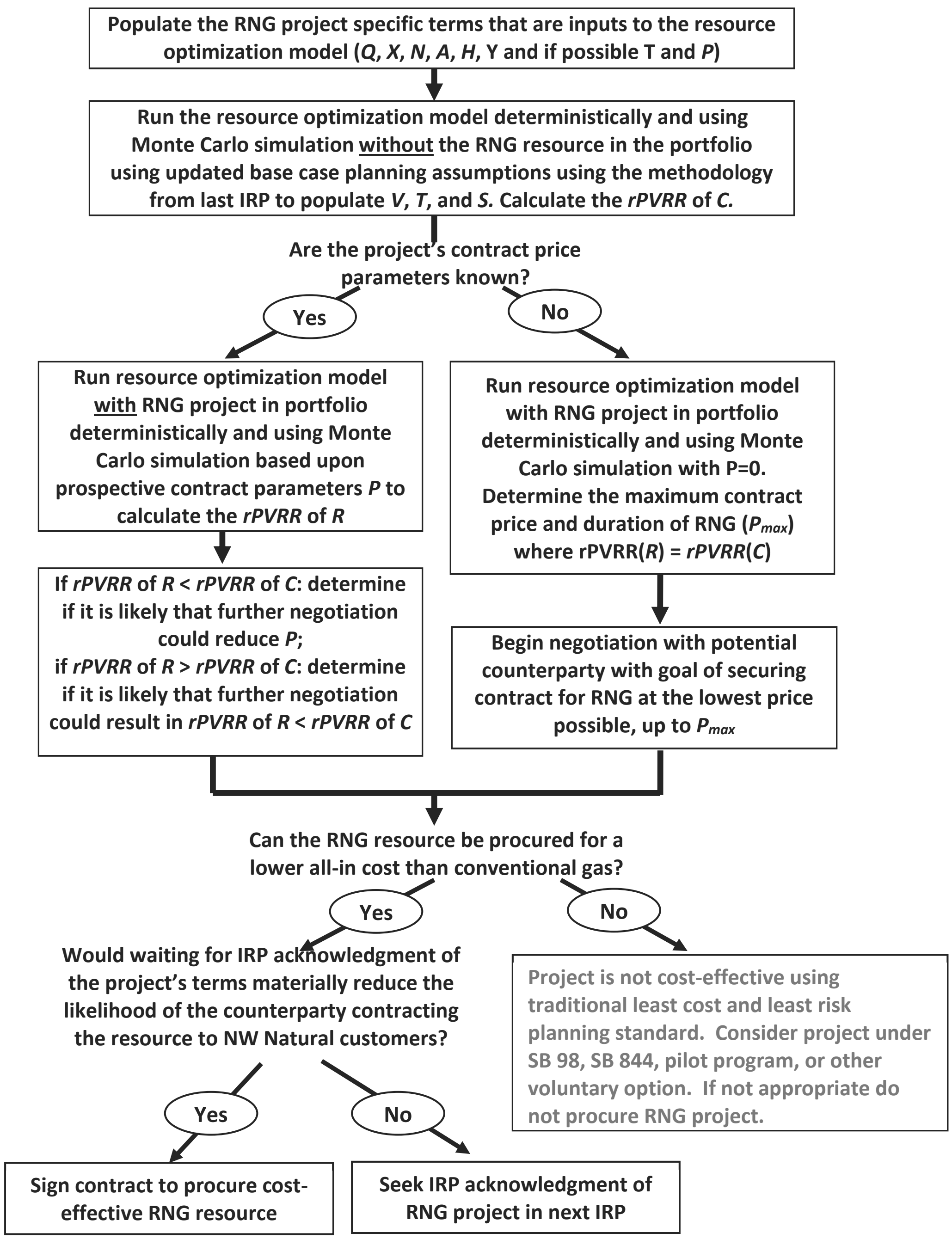
Questions/Next Steps

Handout Material

NW Natural Renewable Natural Gas Project Evaluation and Procurement Process



NW Natural Renewable Natural Gas Project Evaluation Criteria and Calculations

Annual all-in cost of RNG (R) =
Cost of methane (M) + Emissions compliance costs (E) – Avoided infrastructure costs (I)

Or: $R_T = M_T + E_T - I_T$

Where:

$$M_T = X_T + \sum_{t=1}^{365} [P_{T,t} + Y_{T,t}^{RNG}] Q_{T,t}$$

$$E_T = \sum_{t=1}^{365} N^{RNG} G_T Q_{T,t}$$

$$I_T = S_T A_T + DH_T$$

Substituting leaves the annual all-in cost of RNG as:

$$R_T = X_T - S_T A_T - DH_T + \sum_{t=1}^{365} \left[P_{T,t} + Y_{T,t}^{RNG} + N^{RNG} G_T\right] Q_{T,t}$$

Where the annual all-in cost of the conventional natural gas alternative (C) is:

$$C_T = \sum_{t=1}^{365} \left[V_{T,t} + Y_{T,t}^{CONV} + N^{CONV} G_T\right] Q_{T,t}$$

The present value of revenue requirement of all relevant years is used for evaluation where:

$$PVRR(R) = \sum_{T=k}^{T=k+z} \frac{R_T}{[1+d]^T}$$

$$PVRR(C) = \sum_{T=k}^{T=k+z} \frac{C_T}{[1+d]^T}$$

This is risk-adjusted to account for uncertainty in long-term forecasting where:

$$rPVRR(R) = 0.75 * \text{deterministic } PVRR(R) + 0.25 * \text{95th Percentile Stochastic } PVRR(R)$$

$$rPVRR(C) = 0.75 * \text{deterministic } PVRR(C) + 0.25 * \text{95th Percential Stochastic } PVRR(C)$$

The RNG project is a least cost/least risk resource to acquire if:

$$rPVRR(R) \leq rPVRR(C)$$

Table H.1: NW Natural Renewable Natural Gas Project Evaluation Component Descriptions

Term	Units	Description	Source	Project Specific?	Input or Output of Optimization?	Treated as Uncertain?
R	$/Year	Annual all-in cost of prospective renewable natural gas (RNG) project	Output of RNG evaluation process	Yes	Output	Yes
C	$/Year	Annual all-in cost of conventional natural gas alternative	Output of RNG evaluation process	Yes	Output	Yes
M	$/Year	Annual costs of natural gas and the associated facilities and operations to access it	Output of RNG evaluation process	Yes	Output	Yes
E	$/Year	Annual greenhouse gas emissions compliance costs	Output of RNG evaluation process	Yes	Output	Yes
I	$/Year	Annual infrastructure costs avoided with on-system supply	Output of RNG evaluation process	Yes	Output	Yes
Q	Dth	Expected or contracted daily quantity of RNG supplied by project	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
P	$/Dth	Contracted or expected volumetric price of RNG	Project evaluation or RNG supplier counterparty; Max cost-effective price determined in SENDOUT if NWN initiating negotiations	Yes	Input if responding to offer, Output if NWN making offer	If no contractual obligation
T	Year	Year relative to current year, where the current year T = 0, next year T = 1, etc.	Project evaluation or RNG supplier counterparty	Yes	Input if responding to offer, Output if NWN making offer	If no contractual obligation
k	Year	When the RNG purhcase starts in # of years in the future; k = RNG start year - current year	Project evaluation or RNG supplier counterparty	Yes	Input if responding to offer, Output if NWN making offer	If no contractual obligation
z	Years	Duration of RNG purchase in years	Project evaluation or RNG supplier counterparty	Yes	Input if responding to offer, Output if NWN making offer	If no contractual obligation
t	Days	Day number in year ***T*** from 1 to 365	N/A	No	Input	No
V	$/Dth	Price of conventional gas that would be displaced by RNG project	Average price of last ***Q*** quantity of conventional gas dispatched in SENDOUT run without RNG project	Yes	Output	Yes
Y	$/Dth	Variable transport costs to deliver gas to NWN's system	*For off-system RNG* - based upon geographic location of project; *For conventional gas* - determined from last gas dispatched in SENDOUT	Yes	Output	No
X	$/Year	Annual revenue requirement of capital costs to access resource	Engineering project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
N	TonsCO_2e /Dth	Greenhouse gas intensity of natural gas being considered	From actual project certification if available, from California Air & Resources Board by biogas type if no certification has been completed	Yes	Input	No
G	$ /TonCO_2e	Volumetric Greenhouse gas emissions compliance costs/price	Expected greenhouse gas compliance costs from the most recently acknowledged IRP	No	Input	Yes
S	$/Dth	System supply capacity cost to serve one Dth of peak DAY load	Calculated within SENDOUT based upon marginal supply capacity resource that is being deferred using Base Case resource availability from the last IRP	No	Output	Yes
A	Dth	Minimum natural gas supplied on a peak DAY by project	Project evaluation or contractual obligation from RNG supplier counterparty	Yes	Input	If no contractual obligation
D	$/Dth	Distribution system capacity cost to serve one DTH of peak HOUR load	Distribution system cost to serve peak hour load from avoided costs in most recently acknowledged IRP	No	Input	No
H	Dth	Minimum natural gas supplied on a peak HOUR by project	Project evaluation or contractual obligation from RNG supplier counterparty	Yes	Input	If no contractual obligation
d	% rate	Discount Rate	Discount rate from most recently acknowledged IRP	No	Input	No

Table H.2:

NW Natural Renewable Natural Gas Project-Specific Component Definition Fill-In Sheet

Term	#	Question	Project Parameter	
Q: RNG Output	1	How much RNG is the project expected to sell to NW Natural annually?		Dth
	2	Is this volume expected to vary by season, day of the week, or any other factor? If so, provide the expected variation on a separate spreadsheet		
	3	Is there a minimum daily, monthly, or annual quantity included/expected to be included in the prospective contract? If so, what is the minimum daily volume?		Dth per
***T*:** Timing of RNG Purchase	4	Is the duration and timing of the RNG purchase known?		
	5	If Yes, when does the RNG purchase begin?	Date	
	6	If Yes, when does the RNG purchase end?	Date	
	7	If No, when does the RNG purchase begin?	Date	
P: Price of RNG	8	Is the volumetric pricing arrangement for the RNG known?		
	9	If Yes, and it is it a fixed price arrangement, what is the proposed price NW Natural will pay for the RNG? If fixed, but varying through time attach separate spreadsheet and enter average for duration of contract to the right:	$	per Dth
	10	If Yes and it is not a fixed price arrangment, please provide the formula for pricing on a separate spreadsheet and enter average expected price for the duration of the contract to the right:	$	per Dth
***X*:** Required Capital Investment	11	What (if any) is the total annual revenue requirement of any equipment and facilities in which NW Natural needs to invest to access the RNG from the project?	$	per Year
	12	If there is a fixed non-volumetric payment to the RNG supplier as part of the contract, what is the annual payment?	$	per Year
***N*:** GHG Emissions Intensity	13	If the project has already been assessed a greenhouse gas intensity from the EPA or ODEQ, what is the carbon intensity of the RNG?		Metric Tons CO2e/Dth
	14	If the project has not already been assessed a carbon intensity, what is the average GHG intensity for the projects biogas type from the Low Carbon Fuel Standards work done by the California Air & Resources Board		Metric Tons CO2e/Dth
On-System?	15	Will the project inject the RNG onto NW Natural's distribution system?		
	16	Where will NW Natural take custody of the RNG?		
If the answer to *Question 15* is **YES** fill-in **Zero** on *Question 17*				
***Y*:** Variable Transport	17	What are the total variable volumetric transport charges that would be required to bring the off-system RNG to NW Natural's system?	$	per Dth
If the answer to *Question 15* is **NO** fill in **Zero** for the remaining questions				
***A*:** Peak Day Supply	18	What is the mininum daily amount of methane the project would inject into NW Natural during a cold weather event?		Dth per Day
	19	Is this amount a contractual obligation?		
***H*:** Peak Hour Supply	20	What is the minimum amount of methane the project would inject into NW Natural's system during the 7am hour of a cold weather event?		Dth per Hour
	21	Is this amount a contractual obligation		

American Gas FOUNDATION

December 2019

RENEWABLE SOURCES OF NATURAL GAS:

SUPPLY AND EMISSIONS REDUCTION ASSESSMENT

Executive Summary

An American Gas Foundation Study Prepared by:

ICF

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Executive Summary

Renewable natural gas (RNG) is derived from biomass or other renewable resources, and is a pipeline-quality gas that is fully interchangeable with conventional natural gas. The American Gas Association (AGA) uses the following definition for RNG:

> Pipeline compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle carbon dioxide equivalent (CO2-eq) emissions than geological natural gas.

ICF conducted an assessment to outline the potential for RNG to contribute meaningfully and cost-effectively to greenhouse gas (GHG) emission reduction initiatives across the country. The report serves as an update and expansion to a 2011 report published by the American Gas Foundation (AGF) entitled *The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality*. Building upon the previous work, this report is focused on assessing a) the RNG production potential from various feedstocks, b) the corresponding GHG emission reduction potential, and c) the estimated costs of bringing RNG supply on to the system. ICF developed production potential estimates by incorporating a variety of constraints regarding accessibility to feedstocks, the time that it would take to deploy projects over the timeline of the study (out to 2040), the development of technology that would be required to achieve higher levels of RNG production, and consideration of likely project economics—with the assumption that the most economic projects will come online first.

ICF developed low and high resource potential scenarios by considering RNG production from nine (9) feedstocks and three production technologies. The feedstocks include landfill gas, animal manure, water resource recovery facilities (WRRFs), food waste, agricultural residues, forestry and forest product residues, energy crops, the use of renewable electricity, and the non-biogenic fraction of municipal solid waste (MSW).[1] These feedstocks were assumed to be processed using one of three technologies to produce RNG, including anaerobic digesters, thermal gasification systems, and power-to-gas (P2G) in combination with a methanation system. It is important to note that ICF's analysis is not meant to be prescriptive, rather illustrative in terms of how the market for RNG production potential might evolve given our understanding of the feedstocks that can be used and the current state of technology development. Consider for instance that many anaerobic digester projects use a combination of animal manure and agricultural residues as feedstocks—the analysis presented here only considers the anaerobic digestion of animal manure and the thermal gasification of agricultural residues. ICF recognizes that these type of multi-feedstock considerations will continue to exist in the market; however, we needed to make simplifying distinctions for the purposes of the resource assessment.

ICF estimated low and high resource potential scenarios by considering constraints unique to each potential RNG feedstock—these constraints were based on factors such as feedstock accessibility and the economics of RNG production using the feedstock. These constraints were then used to develop low and high utilization assumptions regarding each feedstock. The resource potential reported is also a function of the conversion efficiency of the production technology to which each feedstock is paired. ICF also presents a technical resource potential, which does not consider

[1] ICF notes that the non-biogenic fraction of MSW does not satisfy AGA's definition of RNG; however, this feedstock was included in the analysis. The results associated with RNG potential from this non-biogenic fraction of MSW are called out separately throughout the report for the sake of transparency.

accessibility or economic constraints. The resource assessment was conducted using a combination of national-, state-, and regional-level information regarding the availability of different feedstocks; and the information is presented using the nine (9) U.S. Census Regions.

In the **low resource potential scenario**, ICF estimates that about 1,660 trillion Btu (tBtu) of RNG can be produced annually for pipeline injection by 2040 (see Figure 1 below). That estimate increases to 1,910 tBtu per year when including the potential for the non-biogenic fraction of MSW. In the **high resource potential scenario**, ICF estimates that about 3,780 tBtu of RNG can be produced annually for pipeline injection by 2040 (see Figure 2 below). That estimate increases to 4,510 tBtu per year when including the potential for the non-biogenic fraction of MSW. For the sake of comparison, ICF notes that the 10-year average (2009 to 2018) for residential natural gas consumption nationwide is 4,846 tBtu; this is shown as the black-dotted line in Figure 1 and Figure 2 below. Ultimately, market conditions, technology development, and policy structures will determine the extent to which each of the feedstocks considered can be utilized. For the sake of reference, ICF also reports a technical resource potential scenario of nearly 13,960 tBtu—a production potential intended to reflect the RNG production potential without any technical or economic constraints.

The reported RNG resource potential estimates reported here are 90% and 180% increases from the comparable resource potential scenarios from 2011 AGF Study. These changes are largely attributable to improved access to data regarding potential feedstocks for RNG production and are generally not attributable to more aggressive assumptions regarding feedstock utilization or conversion efficiencies. Furthermore, the analysis presented here includes estimates for RNG production from P2G systems using dedicated renewable electricity. While there are multiple studies regarding P2G technology and its uses, we believe this is the first study to quantify RNG production potential nationwide from P2G.

A diverse array of resources can contribute to RNG production—there is a portfolio of potential feedstocks and technologies that are or will be commercialized in the near-term future that will help realize the potential of the RNG market. Figure 1 and Figure 2 below demonstrate the diversity of RNG resource potential as a GHG emission reduction strategy. On the technology side, most RNG continues to be produced using anaerobic digestion paired with conditioning and upgrading systems. The post-2025 outlook for RNG will increasingly rely on thermal gasification of sustainably harvested biomass, including agricultural residues, forestry and forest product residues, and energy crops. The long-term outlook for RNG growth will depend to some extent on technological advancements in power-to-gas systems.[2]

[2] The RNG potential for P2G/methanation is shown as a pattern fill in Figure 1 and Figure 2 because of the way ICF estimates likely project economics for P2G. In reality, however, the low and high resource potential for P2G using dedicated renewable electricity will be constrained by more factors that could be considered in this report; and it is conceivable that the RNG resource potential from P2G is considerably higher than considered here.

Figure 1. Estimated Annual RNG Production, Low Resource Potential Scenario, tBtu/y

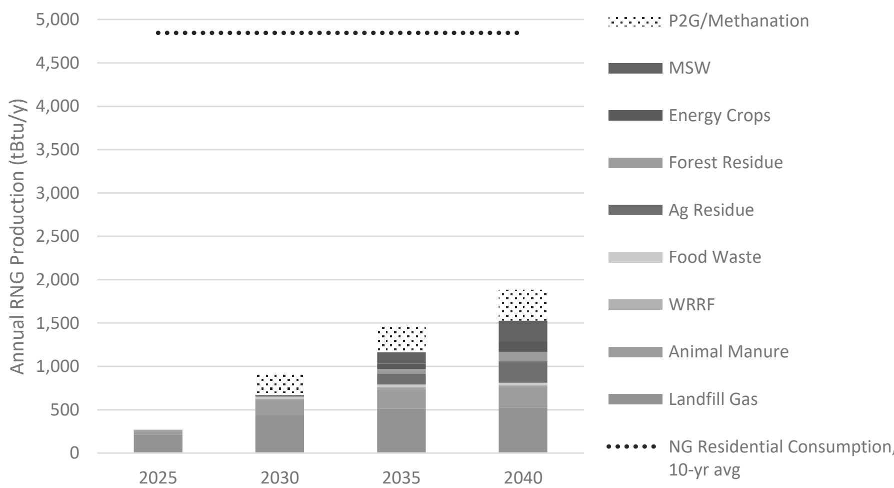
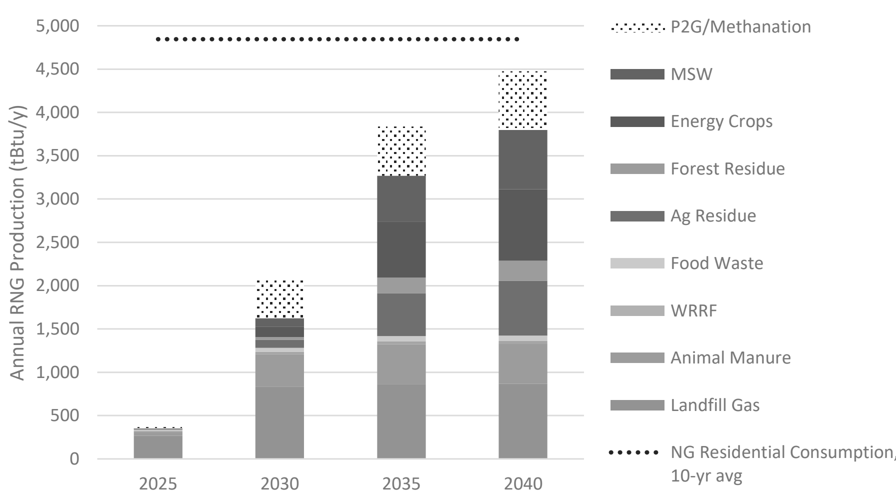


Figure 2. Estimated Annual RNG Production, High Resource Potential Scenario, tBtu/y



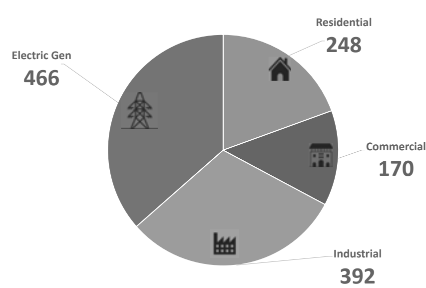
The potential for power-to-gas systems as a contributor to RNG production could be significant. Power-to-gas (P2G) is a form of energy technology that converts electricity to a gaseous fuel. Electricity is used to split water into hydrogen and oxygen, and the hydrogen can be further processed to produce methane when combined with a source of carbon dioxide. If the electricity is sourced from renewable resources, such as wind and solar, then the resulting fuels are carbon neutral. In this study, ICF made the simplifying assumption that all hydrogen produced via P2G would be methanated for pipeline injection. This assumption should not be viewed as a determination of the best use of hydrogen as an energy carrier in the future; rather, it was a simplifying assumption to compare more easily P2G to other potential RNG resources evaluated in this study.

ICF generally finds that the potential for RNG deployment could exceed the estimated high resource potential scenario because we opted to employ moderately conservative assumptions regarding the expected utilization of various feedstocks. These assumptions manifest themselves as constraints on the availability of supply for each feedstock, recognizing there will likely be competition for each feedstock. It is important to note that ICF did not make any assumptions regarding a specific policy or incentive framework that would favor RNG production over some other energy source (e.g., liquid biofuels).

Excluding cost considerations, the deployment of P2G systems for RNG production requires assumptions across a variety of factors, including but not limited to access to renewable electricity, the corresponding capacity factor of the system given the intermittency of renewable electricity generation from some sources (e.g., solar and wind), co-location with (presumably affordable) access to carbon dioxide for methanation, and reasonable proximity to a natural gas pipeline for injection. ICF's analysis did not seek to address all of these project development considerations; rather, we sought to understand the potential for P2G systems assuming access to dedicated renewable electricity production, meaning that these are purpose-built renewable electricity generation systems that are meant to provide dedicated power to P2G systems. ICF did not explicitly consider renewable electricity that could be curtailed from over-supply of renewable electricity as a result of compliance with Renewable Portfolio Standards (RPS). Ultimately, the issue of curtailment is a complicated one, and exploring it in detail was beyond the scope of this analysis. However, ICF's initial assessment indicates that P2G systems running on curtailed renewable electricity will play an important transitional role in helping to deploy the technology and achieve the long-term price reductions that are required to improve the viability of P2G as a cost-effective pathway for RNG production. Despite the importance of curtailed renewable electricity as part of the transition towards more cost-effective P2G systems, ICF's analysis does focus more on the opportunity for, and associated costs of RNG production using P2G systems with dedicated renewable electricity generation. It is important that this assumption by ICF is recognized as a limitation of our analysis, rather than a commentary on how the market will ultimately develop for P2G systems.

ICF estimates that RNG deployment could achieve 101 to 235 million metric tons (MMT) of GHG emission reductions by 2040. The GHG emission reductions were calculated using IPCC guidelines stating that emissions from biogenic fuel sources should not be included when accounting for emissions in combustion. This accounting approach is employed to avoid any upstream "double counting" of emissions that occur in the agricultural or land-use sectors per IPCC guidance. Generally speaking, biogenic carbon in combustion is excluded from carbon accounting methodologies because it is assumed that the carbon sequestered by the biomass during its lifetime offsets emissions that occur during combustion. Figure 3 shows the 10-year average (2009-2018) of carbon dioxide (CO_2) emissions from natural gas consumption across multiple sectors; and most notably that the residential energy

Figure 3. Average Annual CO_2 Emissions (in MMT) from Natural Gas Consumption, 2009-2018



sector on average emitted about 248 MMT of CO_2 emissions nationwide over the 10-years considered.

GHG emission reductions attributable to RNG can be a complicated issue driven by different accounting systems. Although we focus on the GHG emission reductions potential using IPCC guidelines in this report, many stakeholders are likely familiar with the lifecycle accounting approach for GHG emissions that is used by California's Low Carbon Fuel Standard (LCFS) program. In that accounting system, the GHG emissions from production and processing to combustion are accounted for—and fuels like RNG sourced from animal manure generally have a negative emissions factor, which reflects the upstream "crediting" of capturing methane that would have otherwise been vented to the atmosphere. ICF addresses these various accounting systems, and reviews the GHG emission reductions under a lifecycle accounting framework in an appendix.

ICF estimates that the majority of the RNG produced in the high resource potential scenario is available in the range of $7-$20/MMBtu, which results in a cost of GHG emission reductions between $55/ton to $300/ton in 2040. ICF evaluated the potential costs associated with the deployment of each feedstock and technology pairing, and made assumptions about the sizing of systems that would need to be deployed to achieve the RNG production potential outlined in the low and high resource potential scenarios. ICF reports that RNG will be available from various feedstocks in the range of $7/MMBtu to $45/MMBtu. These costs are dependent on a variety of assumptions, including feedstock costs, the revenue that might be generated via byproducts or other avoided costs, and the expected rate of return on capital investments. ICF finds that there is potential for cost reductions as the RNG for pipeline injection market matures, production volumes increase, and the underlying structure of the market evolves.

As noted previously, the opportunity of RNG from P2G systems (and paired with methanation units) warrants further consideration; however, ICF's analysis demonstrates that the combination of production potential and potential cost reductions for P2G systems is promising. With respect to RNG from P2G, the three main drivers for the production costs include: a) the electrolyzer, b) the cost of renewable electricity, and c) the cost of methanation. ICF finds that there is significant cost reduction potential in the P2G market, as the installed capacity (measured in GW, for instance) for electrolyzers increases over the next 10-15 years. ICF assumed that dedicated renewable electricity systems, co-located with P2G systems, could provide electricity at a levelized cost in the range of $10 to $55 per MWh. Lastly, there is significant cost reduction potential for methanation paired with P2G systems.

Public Interest Energy Research (PIER) Program

DRAFT INTERIM PROJECT REPORT

DRAFT Comparative Assessment of Technology Options for Biogas Clean-up

Prepared for: California Energy Commission

Prepared by: California Biomass Collaborative
University of California, Davis

CALIFORNIA BIOMASS COLLABORATIVE

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PREFACE

The California Energy Commission Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

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- Renewable Energy Technologies
- Transportation

Comparative Assessment of Technology Options for Biogas Clean-up is the final report for the Renewable Energy Resource, Technology and Economic Assessments project (contract number 500 – 11 – 020, Task 8) conducted by the University of California, Davis. The information from this project contributes to PIER's Renewable Energy Technologies Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-654-4878.

ABSTRACT

The goal of this report was to summarize the technical limitations, state and county regulations, and investor-owned utility companies' guidelines that shape biogas use for distributed power generation and injection into natural gas pipelines in California. Data and information were collected from a multitude of literature and public sources to compare and assess these various specifications and standards, along with the technologies used to remove contaminants and refine raw biogas required to meet them. Detailed information is provided about all major biogas sources, cleaning and upgrading technologies, and utilization systems. In addition, several example projects from California and other states and countries are discussed for each biogas source. Cost comparisons of individual equipment are also presented, and total project development economics or distributed power generation and pipeline injection are discussed.

Review of current standards and technology specifications demonstrates that California investor-owned utility gas contaminant standards for biomethane pipeline injection are comparable to those found in other states and countries, and that meeting these standards is easily achievable using conventional gas cleaning technologies. In contrast, the higher heating value standards required in California are stricter than those found in other states and countries, and most conventional and emerging gas upgrading technologies may have difficulty in achieving them. Additional discussion and conclusions about biogas cleaning and upgrading, pipeline injection, and distributed power generation, and recommendations to resolve current issues are provided.

Keywords: amine absorption, adsorption, biofiltration, biogas, biomethane, cleaning, composition, conditioning, cryogenic distillation, distributed power generation, fuel cells, gas membrane separation, investor-owned utility, microturbines, pipeline injection, quality, reciprocating engines, regulations, solvent scrubbing, standards, syngas, upgrading, utility companies, water scrubbing

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Executive Summary

This is the report for Task 8 of a larger multi-task project conducted by the California Renewable Energy Collaborative (CREC). This comparative assessment of technology options for biogas clean-up is relevant to the recently enacted statute "Renewable energy resources: biomethane" (Gatto, AB 1900, Chapter 602, Statutes of 2012) which calls for state agencies to compile a list of biogas constituents of concern, develop biomethane standards for pipeline injection, establish monitoring and testing requirements, require investor-owned utilities (IOUs) to comply with standards and requirements and provide access to common carrier pipelines, and require the California Public Utilities Commission (CPUC) to adopt pipeline access rules to ensure nondiscriminatory open access to IOU gas pipeline systems.

The primary goals of this report are to identify the regulatory and technical standards that processed biogas must meet to be accepted into California natural gas pipelines or be converted directly to power using commercially available gas engine generators, gas turbine generators, and fuel cells. This report also assesses the biogas cleaning and upgrading technologies that are commercially available or in development which can be used to meet these standards. Common biogas cleaning processes include adsorption, water scrubbing, biofiltration, and refrigeration. Commercially available biogas upgrading technologies are: pressure swing adsorption (PSA), chemical solvent scrubbing (with alkaline solutions or amines), pressurized water scrubbing, physical solvent scrubbing (with organic glycols), membrane separation, and cryogenic distillation. Several unique variations upon these technologies (e.g., fast-cycle PSA, high-pressure batch-wise and rotary coil water scrubbers, gas-liquid adsorption membranes), as well as several emerging technologies are discussed. The three most commercially applied upgrading technologies—PSA, amine absorption, and pressurized water scrubbing—have comparable levelized costs of energy at high gas throughputs. Overall price differences among theses options will depend mostly upon the specific manufacturer.

In order to address biogas cleaning and upgrading needs, differences in biogas quality and composition from different sources (i.e., landfills, wastewater treatment plants, manure digesters, municipal solid waste digesters, and biomass gasifiers) are first identified. Regulatory and private standards are then outlined. Afterwards, the cleaning and upgrading technologies are outlined. Review of current standards and technology specifications have found that, with the exception of the 12 "constituents of concern", California investor-owned utility gas contaminant standards for biomethane pipeline injection are comparable to those found in other states and countries, and that they are easily achievable using conventional gas cleaning technologies. In contrast, minimum energy content standards are greater than those found in other states and countries, and most conventional and emerging biogas upgrading technologies may have difficulty in achieving them. Biogas cleaning and upgrading costs were also found to be high, sometimes comprising more than half of a project's equipment and capital costs. Interconnection costs were also identified as being comparably high. Consequently, biomethane pipeline injection will likely be economically infeasible for individual dairy farms and other low quantity biogas producers with smaller anaerobic digestion systems.

Based upon the results of this study, recommendations are:

- Reduce the energy content requirement for pipeline biomethane from 990 to 960 – 980 Btu/scf (higher heating value basis);

  It is not clear that 990 Btu/scf biomethane injection is a technical requirement if injection flow is small compared to line capacity at injection point. The main reasons stated by the gas utilities, and accepted by the CPUC, for requiring 990 Btu/scf for biomethane product injection were to ensure both acceptable performance of the gas appliance and energy billing and delivery agreement. Because other states and countries allow lower energy content for biomethane injection, the concerns raised by the California utilities are apparently not encountered elsewhere. Modelling of appropriate injection rates, mixing and effect on delivered gas at point of use should be investigated.

- Collect data on levels (concentrations) of COC in the current California natural gas supply (includes instate and imported sources)

  It appears that the biomethane COCs were selected by comparing limited biogas data against limited natural gas data. While there is a current study to evaluate trace compound and biological components in more detail across a wide range of California biogas sources (e.g., study by Professor Kleeman at UC Davis), a comprehensive understanding of natural gas in California is lacking.

  If the above investigation of COCs in natural gas is not done, then amend the regulation concerning the 12 constituents of concern such that the contaminants are not measured at the point of injection, but rather before biomethane is mixed with natural gas or other higher HHV gases that are assumed to be in compliance with contaminant standards;

- Address costs and provide financial support and incentives for biogas upgrading and pipeline interconnection as well as for small-scale distributed power generation systems

  There are numerous purported societal benefits from utilization of biomass resources for biopower or biomethane (e.g., GHG reductions, nutrient management improvements at dairies, improved surface and ground water, rural jobs and economy, etc.). Investigate means to monetize these benefits (e.g., cap and trade fees for verified GHG reduction by project).

- Develop a streamlined application process with standardized interconnection application forms and agreements to minimize time and manpower spent by all parties.

CHAPTER 1: Introduction

The US is the largest consumer of natural gas, the second largest consumer of electricity, and the second largest emitter of greenhouse gases (GHGs). The largest fraction of GHG emissions derives from fossil fuel combustion, primarily for electricity production and transportation (US EPA 2014d). Because of more recent concerns about global warming and longer-term concerns about unhealthy air quality, the developed nations of the world have been researching new ways to reduce greenhouse gas emissions. Since 2007, U.S. GHG emissions have gradually declined due to efficiency improvements, renewable energy production, the substitution of natural gas for coal as a feedstock for electricity production, improved vehicle efficiency, and reduced vehicle miles traveled. Currently, the U.S. follows China as the second largest producer of renewable electricity, and leads as the largest biofuels producer, (U.S. EIA 2014a and 2014b.

The primary sources of renewable energy are wind, solar, biomass, hydro, and geothermal. Of particular interest in California is biomass-based energy (bioenergy) due to the State's large biomass resource[1] and perceived societal and environmental benefits realized from bioenergy. Bioenergy production involves converting biomass through a biological or thermochemical process to produce heat and power, a combustible gas (e.g., methane or biogas) or liquid fuels (e.g., ethanol, biodiesel). Bioenergy can serve as baseload power or used as energy storage mechanism to offset intermittent power sources.

Biofuel is an overarching label which encompasses many different fuel types and energy applications—Distributed power generation using biogas, natural gas pipeline injection (e.g., biomethane, biohydrogen), and vehicle fuel (e.g., bioethanol, biodiesel, renewable diesel, renewable compressed or liquid natural gas)[2]. With the recent passage of California Assembly Bills 1900 (Gatto) and 2196 (Chesbro) in 2012, biogas and biomethane have begun to receive significant attention. However, in contrast to Europe, biogas utilization is still limited in the United States. As a result, many new rules and regulations are being devised, proposed, and passed by governmental and private entities alike to standardize how this new commodity will be treated. In particular, because biogas contains carbon dioxide and trace amounts of other compounds (some of which may be contaminants), the sensitivity of end-use equipment to these contaminants has focused attention on developing biogas quality standards. This report seeks to address these new standards and directly associated issues to help provide insight for biogas project developers and advise the Commission and other regulatory bodies about the development of future biogas legislation.

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[1] http://biomass.ucdavis.edu/

[2] In-state biofuel production is discussed in: Kaffka et al. 2014. TASK 4_The Integrated Assessment of Biomass Based Fuels and Power in California. CEC contract no 500-11-020.

Report Structure

Chapter 1 provides a brief overview of available biomass resources as well as the biogas and natural gas industry in California, the US, and worldwide.

Chapter 2 outlines the sources from which biogas may be produced, and ends with a listing of the different types and quantities of significant compounds present in biogas, specific to each source.

Chapter 3 reviews different energy-related uses for biogas by describing how they function, their general technical limitations, and changes needed to accommodate biogas use.

In order to apply these biogas utilization technologies, specific technical requirements must be met for proper operation. In addition, many governmental agencies and private entities have provisions that govern how these technologies must be applied through standards that must be met. Chapter 4 presents the technical and regulatory standards that apply to two avenues of biogas utilization: distributed power generation and natural gas pipeline injection. Vehicle fuel applications are mentioned, but are not discussed at length in this report.

To meet the standards discussed in Chapter 4, biogas must be cleaned to remove various contaminants. For certain applications, carbon dioxide may also need to be removed in order to upgrade the biogas to higher methane (and energy) content such that it is close to natural gas quality. Chapter 5 examines the various gas cleaning techniques available for removing primary contaminants and finally compares their attributes and contaminant treatability.

Chapter 6 discusses the most common commercially available biogas upgrading (CO_2-removal) technologies along with several emerging ones, and provides a side-by-side comparison of their technical capacities and efficiencies.

Chapter 7 summarizes the biogas cleaning, upgrading, and utilization technologies reviewed in Chapters 3, 5, and 6 and reviews the associated costs of an integrated biogas system.

Chapter 8 provides conclusions from this study and provides recommendations about technology choices and advantageous regulatory changes related to distributed power generation and pipeline injection.

Biogas Resources, Production, and Utilization

The United States includes an expansive arable land mass with a flourishing agricultural industry, and heavily-populated metropolitan regions, which produce significant quantities of organic residues and wastes. These wastes naturally decompose and under certain anaerobic conditions will release biogas—a gas consisting mainly of methane and carbon dioxide. Methane emissions can be found from landfills, wastewater treatment plants, and farms. Methane is also released into the atmosphere from natural sources including wetlands, bogs, arthropods (especially termites), and ruminant livestock, certain wild animals, geologic sources, etc. Other anthropogenic activities include coal mining and natural gas and petroleum systems.

Data suggest that there have been significant methane capture efforts from landfills and wastewater treatment plants, but also indicate the potential for even more methane recovery. From 1990 to 2012, U.S. methane emissions have dropped from 635.2 $TgCO_2e$ to 567.3 $TgCO_2e$. Following the overall trend, U.S. methane emissions from landfills decreased from 147.8 $TgCO_2e$ to 102.8 $TgCO_2e$. However, U.S. methane emissions from wastewater treatment have remained relatively stable around 13 $TgCO_2e$. Conversely, U.S. methane emissions from manure management increased from 31.5 $TgCO_2e$ to 52.9 $TgCO_2e$ due to the increasing use of liquid systems facilitated by a shift to larger facilities (US EPA 2014d). In fact, the U.S. has the highest methane emissions from manure management of any country—twice as much as second and third place, India and China, respectively. Yet, this only accounts for about 9% of the U.S.'s total methane emissions (US EPA 2014).

California is estimated to have the highest biogas generation potential in the US—around 40% more than the second highest, Texas (NREL 2013) (Figure 1).

Figure 1: Estimated U.S. Methane Generation Potential from Organic Wastes

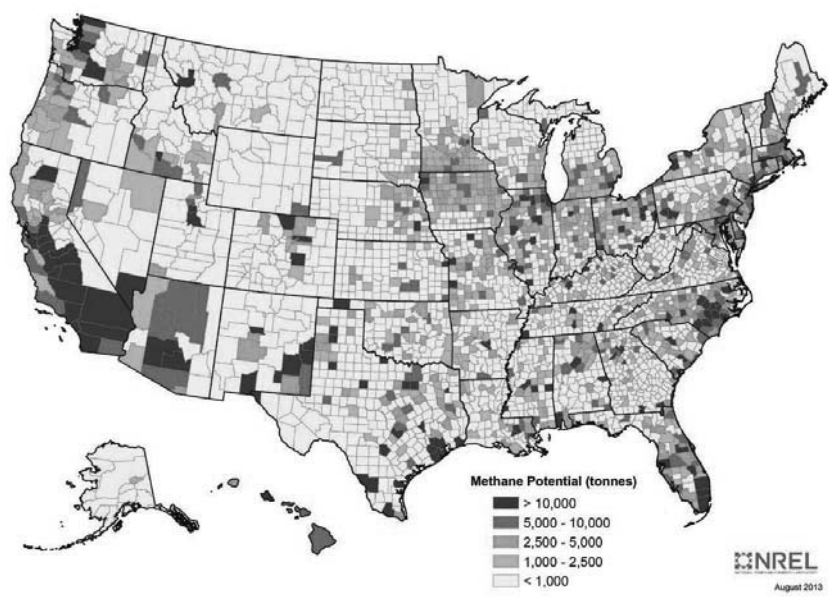


Illustration Credit: NREL (2013)

The technically recoverable amount of California biogas is estimated to be 559MM m^3/year from dairy and poultry manure, 1505MM m^3/year from landfills, 192MM m^3/year from wastewater treatment plants, and 348MM m^3/year from municipal solid waste (Williams et al., 2014). There are 238 wastewater treatment plants (WWTPs) with flows above 1 MGD, 153 of which utilize anaerobic digestion (AD) for to stabilize and reduce solids mass. This represents more than 87% of the total waste water flow in California and 94% of in-state sludge is digested However, only 72% of the 153 facilities use the methane produced (for heating or power). Overall, there is the potential to increase biogas energy production from California's WWTPs by almost 50% (Kester 2014). California biopower facilities and capacity are shown in Table 1.

The majority of biogas captured in the US is disposed of by flaring to safely destroy contaminants or simply burned to produce heat (Lono-Batura, Qi, and Beecher 2012; Morrow Renewables 2014). Biogas that is utilized for power generally goes to electricity production and cogeneration. Though the US is the largest producer of bioenergy, it is evident that there is still a largely disproportionate amount of biogas utilization compared to the amount that is produced (U.S. EIA 2014a and 2014b; . As a comparison, the U.S. has about 2,000 biogas facilities while Europe has over 10,000, with nearly 8000 in Germany alone (USDA, US EPA, and US DOE 2014).

Table 1: California biopower facilities and capacity (Nov. 2013)

Biomass Source	Facilities	Net Electricity (MW)
Solid Fuel (Woody & Ag)	27	574.6
Solid Fuel (MSW)	3	63
LFG Projects	79	371.3
WWTP Facilities	56	87.8
Farm AD	11	3.8
Food Processing/Urban AD	2	0.7
Totals	178	1101

Source: California Biomass Collaborative facilities database (2013)

The California Renewable Portfolio Standard (RPS) eligibility for biogas delivered by pipeline was suspended on March 28, 2012 due to lack of confidence in biomethane delivery reporting methods. The concerns were addressed by AB 2196 (Chesbro) and SB 1122 (Rubio)—both enacted on September 7, 2012. AB 2196 (Chesbro) allowed electrical generating facilities using landfill or digester gas to qualify for RPS and set limitations on the ability of out-of-state biomethane for RPS. On April 30, 2013, the new RPS eligibility requirements for biomethane were implemented in the Seventh Edition of the Renewables Portfolio Standard Eligibility Guidebook. SB 1122 (Rubio) directs the investor owned electrical corporations to procure at least l 250 MW of new biopower capacity (maximum 3 MW per project) through eligible bioenergy feed-in tariff power purchase agreements. The 250 MW was allocated among the following categories: 1) 110 MW: Biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion; 2) 90 MW: Dairy and other agricultural bioenergy; and 3) 50 MW: Bioenergy using byproducts of sustainable forest management.

As the US biogas industry continues to mature, other avenues of biogas utilization are beginning to open, including the injection of biogas into natural gas pipelines. Doing so will diversify the energy supply and may foster in-state production of biogas and biomethane. As shown in Figure 2, only 9.4% – 14.8% of natural gas used in California comes from in-state sources (California Energy Commission 2011). Utility companies deliver about 80% of natural gas consumed in California while the rest is delivered directly by the Kern River Gas Transmission Company and other California gas producers.

Figure 2: California Daily Natural Gas Consumption by Source

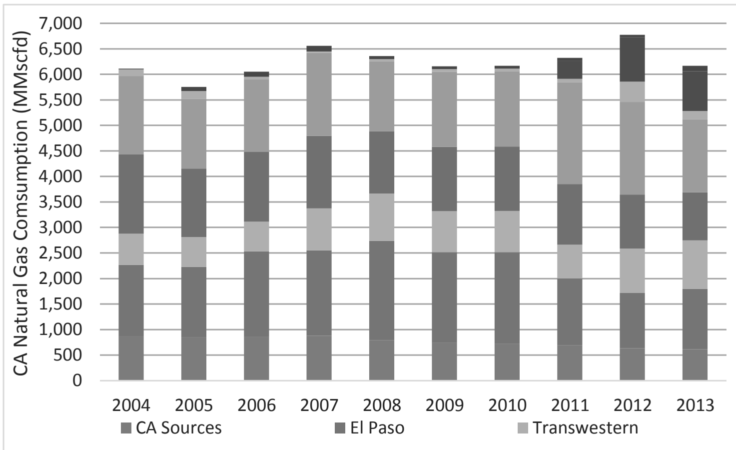
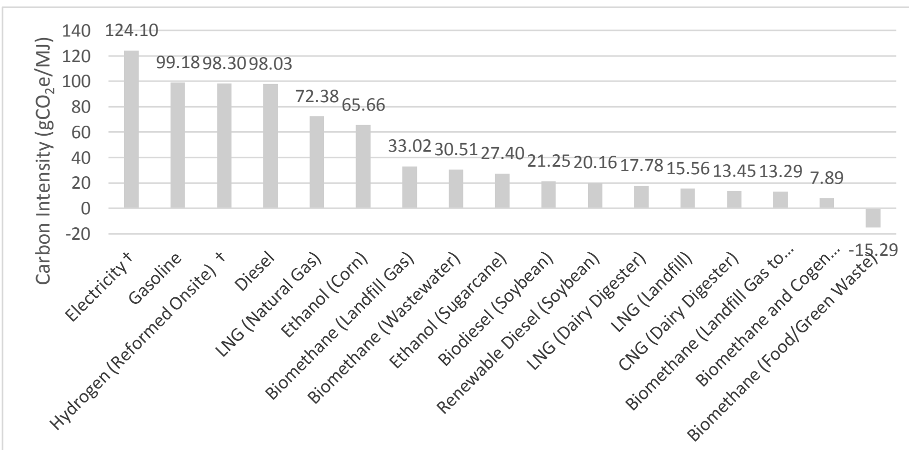


Chart Credit: Author; Data Credit: Southern California Gas Company et al. (2009); Southern California Gas Company et al. (2014)

Biogas pipeline injection is an attractive alternative to distributed power generation for biogas producers in nonattainment air districts, where restrictive air quality standards limit small-scale onsite burning and utilization of biogas. It also provides the potential for all of the biogas to be utilized, and converted at higher efficiency if used for power generation, compared to use if smaller, less efficient distributed facilities. However, high capital investment cost constrain pipeline injection to large-scale projects that can afford them, such as landfills and large capacity digesters near existing pipelines. Pipeline injection of biogas also requires removing contaminants (cleaning), upgrading to biomethane (remove carbon dioxide to achieve pipeline standards. As of 2012, Germany and Sweden, followed by Switzerland and the Netherlands, lead the way in implementing biogas cleaning and upgrading technologies. As of 2010, Germany the leading producer of biomethane, generated from energy crops, manure and MSW residues, with the gas being injected into the natural gas distribution system (Canadian Gas Association 2012). Germany alone had 83 biogas upgrading plants by the end of 2011 out of 200 in Europe (The Biogas Handbook: Science, Production and Applications). Sweden implemented the use of biogas in 2002 with upgrading of biogas to biomethane for natural gas grid injection, primarily for vehicle fuel use. By 2008, biomethane was being used to operate 130,000 vehicles (Canadian Gas Association 2012).

Overall, biogas utilization can assist in the development of sustainable waste management practices and reduce greenhouse gas emissions by avoiding uncontrolled natural release of methane through decomposition and by displacing fossil carbon-intense fuels. One way to indicate net process (or energy pathway) greenhouse gas emissions is by calculating its carbon intensity (CI with units of grams of carbon dioxide emission equivalents per unit of energy). The California Air Resources Board (ARB) has developed CIs for a number of transportation fuel pathways based upon Argonne National Laboratory's GREET model for use in the California Low Carbon Fuel Standard (LCFS). Biofuels from residue materials produced and used in-state have the lowest carbon intensities compared to most other gas and liquid fuel systems (Figure 33). For example, the proposed pathway for biomethane produced from high-solids anaerobic digestion of food and green waste has a carbon intensity of -15.29 g CO_2e/MJ, while biomethane produced from anaerobic digestion of wastewater sludge at low/medium and medium/large wastewater treatment plants have proposed carbon intensities of 30.51 and 7.89 g CO_2e/MJ, respectively (California Air Resources Board 2014b; California Air Resources Board 2014c).

Figure 3: ARB Pathways and Fuel Carbon Intensities



† Values will be significantly lower if generated using renewables (e.g., 33% renewable onsite hydrogen has a carbon intensity of 76.10 CO_2e/MJ)

Note: The carbon intensity values listed above are subject to change in February 2015 when the ARB is expected to readopt the LCFS and transition from using the CA-GREET 1.8b model to the CA-GREET 2.0 model to determine new values for all past and future pathways, until a time in which the model is updated again.

Chart Credit: Author; Data Credit: California Air Resources Board (2014b); California Air Resources Board (2012)

CHAPTER 2:
Biogas Quality and Composition

Biogas is a product of anaerobic (biological) decomposition (it occurs naturally in wetlands, rice fields, and landfills, in ruminant livestock, or in engineered anaerobic digestion systems). It is composed primarily of methane and carbon dioxide, with minor amounts of trace contaminants, e.g., hydrogen sulfide, ammonia, siloxanes, volatile organic carbons, and halogenated compounds. Because raw biogas is created in a moist or water-based medium, it is usually saturated with water vapor. Nitrogen and oxygen may also be present depending upon how well the anaerobic digestion process is sealed from the atmosphere. Biomass derived methane can also be synthetically created using thermochemical processes, i.e., gasification.

Anaerobic Digestion Process

Anaerobic digestion is the biological process by which communities of microorganisms consisting of bacteria and archaea metabolically break down complex organic molecules in the absence of oxygen to produce biogas—. The metabolic process of anaerobic digestion can be viewed as four consecutive steps: hydrolysis, acidogenesis, acetogenesis, and methanogenesis (

Figure 4). In hydrolysis, large organic particulates and macromolecules are broken apart into soluble macromolecular compounds. Acidogenesis then breaks the soluble organics down further into volatile fatty acids (VFAs), i.e., butyric acid, propionic acid, and acetic acid. Through acetogenesis, all of the VFAs are converted into acetic acid and other single-carbon compounds. Finally, by methanogenesis, aceticlastic methanogens convert acetic acid into methane and carbon dioxide while other methanogens convert hydrogen gas and carbon dioxide into methane.

Figure 4: Anaerobic Digestion Pathways

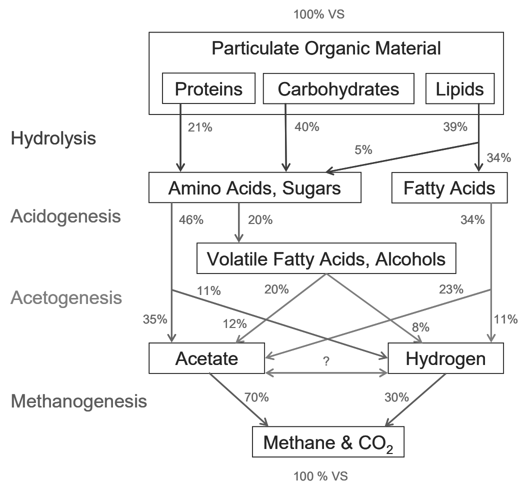
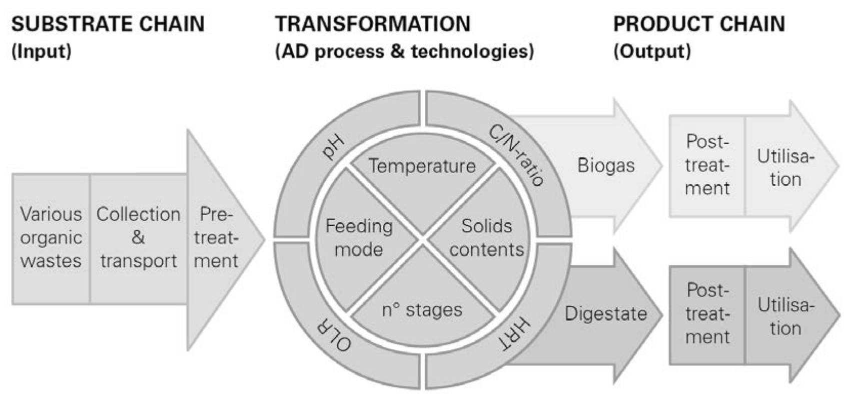


Illustration Credit: Adapted from Gujer and Zehnder (1983)

Trace amounts of hydrogen sulfide, ammonia, siloxane, non-methane volatile organic carbons, and halocarbons are also typically generated by other species of microbes present in the complex community. The concentrations and production rates of these compounds, as well as of methane and carbon dioxide, will vary depending upon the source/feedstock material, process design, and environmental factors (Figure 5). The following sections summarize typical quality and composition of biogas from landfills, wastewater treatment plants, agricultural waste and manure digesters, and municipal solid waste digesters.

Figure 5: Anaerobic Digestion Process Chain



HRT: Hydraulic Retention Time, OLR: Organic Loading Rate

Illustration Credit: Vögeli et al. (2014)

Thermal Gasification

Renewable methane, or renewable synthetic natural gas (RSNG), can be created via thermal gasification with follow-on gas cleaning and processing. Thermal gasification is the process whereby solid or liquid carbonaceous matter is converted into fuel gases and other by-products. The fuel gases can be used directly for energy production (heat and/or power), or, with sufficient gas cleaning and processing, can be used to produce chemicals such as methanol and liquid and gaseous vehicle fuels. Common feedstocks for gasification include coal and woody biomass. The raw product gas is called producer gas and consists of carbon monoxide, hydrogen, carbon dioxide, methane and light hydrocarbons, water vapor, tar, particulate matter, trace compounds, and, depending on the gasifier design, up to 50% nitrogen and small amounts of oxygen. Synthesis gas (or syngas) is made from cleaning and processing the producer gas. Syngas nominally consists of carbon monoxide and hydrogen. Some definitions of syngas allow for methane, and other hydrocarbons, carbon dioxide and nitrogen in addition to the carbon monoxide and hydrogen. The relative concentration of each gas depends upon the composition of the material feedstock used and process operating conditions, e.g., temperature, pressure, autothermal or allothermal gasifier, steam, air, or oxygen fed, etc.

Methane can be produced from syngas by reacting carbon monoxide and carbon dioxide with hydrogen gas using a metal catalyst, such as nickel and ruthenium. The metal catalysts and reaction conditions induce methanation, Sabatier, and water-gas shift reactions which contribute to the formation of methane from syngas (Table 2). Methanation catalysts strongly bond with sulfur, thereby deactivating and poisoning the catalyst. Thus, sulfur compounds should be removed from the syngas prior to methanation. Fortunately, sulfur concentrations in syngas are minimal compared to those found in biogas. Nevertheless, the catalysts require eventual replacement. With proper gas pretreatment, Ni/Al_2O_3 catalysts used for industrial methanation have a lifetime of 5 – 10 years while conventional tubular nickel steam reforming catalysts have a typical lifetime of 3 – 5 years (Hagen 2006; Wagner, Osborne, and Wagner 2003).

Table 2: Methane from Syngas Reactions

Methanation	$CO + 3H_2 \rightarrow CH_4 + H_2O$
Water-gas shift	$CO + H_2O \rightarrow CO_2 + H_2$
Sabatier reaction	$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$

An emerging thermal process is hydrothermal catalytic gasification (HCG). HCG is a thermochemical process by which organic matter reacts with a catalyst (e.g., methanation catalysts, alkaline hydroxides) under moderate temperature and high pressure (typically 300 – 450 °C and 1246 psi). High pressures keep water and most other liquids in the liquid phase, thereby saving energy that would have been expended on evaporation making it more feasible to thermally process high moisture feedstocks. The product gas consists primarily of methane, hydrogen, and carbon dioxide. Without an HCG catalyst, the process would be pressurized pyrolysis producing a bio-oil—an aqueous mixture resembling crude oil (Yu 2012). HCG processes can achieve high gasification efficiencies greater than 90% at relatively low reaction times—within minutes to hours—using assorted biomass feedstocks, including lignocellulosic materials (Azadi et al. 2012; Elliott 2008). However, research is still being conducted to develop HCG catalysts and catalyst mixtures with longer lifetimes and greater resistance to fouling and poisons to make the process cost-effective.

Biogas Sources

The four largest potential waste-derived biogas sources (excluding thermal conversion methods) for which gas collection systems can be feasibly implemented are landfills, wastewater, animal manure, and organic municipal solid waste. As shown in Figure 6, landfills are California's current greatest potential biogas resource.

Figure 6: California Biogas Production Potential by Source

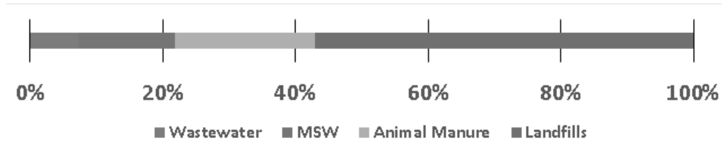


Chart Credit: California Biomass Collaborative

The following subsections outline the method, nature, and status of gas production from these five bio-derived fuel gas sources, as well as summarize the gas quality expected from each.

Landfills

More than 1.2 billion tons of solid waste have been amassed in California's 370 landfills, with approximately 30 million tons added each year (California Air Resources Board 2013). Landfilled municipal solid waste becomes buried beneath layers of soil and fresh waste while aerobic microorganisms quickly consume oxygen trapped in the lower layers, creating an anaerobic environment that allows for the organic fraction to decompose and be converted into biogas. Material can continue to produce gas for more than 50 years after being placed into the landfill. Generally, landfills must put systems in place to recover and then dispose of landfill gas (LFG)to minimize emission of methane and odorous gas, however there is still significant fugitive emission of—approximately 6.72 MMT CO_2e in 2010 (California Air Resources Board 2013). The most prevalent emissions control technology is flaring. Landfill gas is also collected to avoid incidents that can occur from the accidental formation of explosive gas mixtures, since methane is explosive at a 5 – 15% concentration in air. However, gas collection may not be practical for all landfill systems. In general, biogas collection is only practical for landfills larger than 35 acres, at least 35 ft deep, and with more than 1 million tons of waste (Agency for Toxic Substances and Disease Registry 2014).

Compared to the other biogas sources, landfills have the largest biogas production potential and existing generating capacity, benefit from existing waste collection and disposal infrastructure, and are therefore easier to feasibly implement. Existing systems that flare their gas would already have the collection systems in place and commonly only require the addition of gas cleaning and/or upgrading and utilization equipment. However, landfill gas systems are also less well-sealed from the atmosphere, leading to lower raw gas quality and higher concentrations of O_2 and N_2 which are difficult to remove. This may limit gas utilization options at certain landfills or simply increase the cost of gas upgrading.

As of January 6, 2014, the US has 636 landfill gas energy projects and the potential for 450 more. In California alone, there are 79 landfill energy projects—more than twice of any other State—with the potential to feasibly add another 32. (US EPA 2014a, California Biomass Collaborative).

Wastewater Treatment Plants

Of the more than 16,000 WWTPs in the US, roughly 1,200 – 1,500 use anaerobic digestion, and about 860 beneficially use the produced biogas (Sinicropi 2012). In addition to number of currently existing WWTP digesters that can add biogas utilization systems, there is the potential for 4,000 more WWTPs to implement anaerobic digestion technology (Traylen 2014). In California, there are approximately 140 WWTPs that utilize anaerobic digesters and 56 that generate electricity (US EPA 2013, California Biomass Collaborative). For a typical WWTP that processes 100 gallons/day/person, about 1 cf/day/person of biogas is produced. When used for CHP, this comes out to roughly 100 kW electricity per 4.5 MGD processed (Eastern Research Group, Inc. and Resource Dynamics Corporation 2011).

Although anaerobic digestion at waste water treatment facilities is far from widespread, it has become an accepted option for wastewater treatment operations seeking to reduce the amount of solid waste (sludge) produced in the treatment process. This works by pumping settled solids from the primary and secondary clarifiers into an anaerobic digester to convert a fraction of the organic solids into gas. Anaerobic digestion provides some energy savings by reducing the load on biological aerobic organics destruction and can potentially turn wastewater treatment plants (WWTPs) into net energy producers (McCarty, Bae, and Kim 2011). Anaerobic digestion has also been shown to aid in disinfection, especially under thermophillic conditions, removing pathogenic bacteria by up to 99% (Smith et al. 2005). There are several engineering consulting firms that support the design and development of anaerobic digesters for wastewater treatment plants in California (e.g., Kennedy/Jenks Consultants, West Yost Associates).

Agricultural Waste and Manure Digesters

For the agricultural industry, anaerobic digestion represents a potential alternative waste disposal option. Dairy manure solids reductions of 29 – 62% within the digester tank and 52 – 76% for the entire processing system are common. Meanwhile, fugitive methane emissions from manure can be reduced by 60 – 70% (Summers 2013). Nitrogen compounds are also converted into ammonia, and effluents can be used as a liquid fertilizer.

Digesters can be designed as standard complete-mix tanks, plug-flow basins, or covered lagoons. The different designs will affect the hydraulic retention time, digestion efficiency, cost, and physical footprint of the system. Design selection is typically based upon limiting factors such as available land area and total volume requirements, but can sometimes depend on preferences and judgments of project developers.

Although farm-based digesters have been encouraged in Europe, they are still relatively rare in the US. In the US, there are around 8,200 dairy and swine operations that can support biogas recovery systems, but only 239 farms actually have anaerobic digesters (US EPA 2011; US EPA 2014a). This is due to economics (i.e., higher energy prices in Europe) and stricter US regulations that limit digester implementation. California has approximately 11 operational manure digester projects and 10 that had been shut down, primarily due to economic reasons (California Biomass Collaborative).

Figure 7: Complete-Mix Tank (Top Left), Plug Flow (Top Right), and Complete-Mix Lagoon (Bottom) Anaerobic Digesters

Photo Credit: US EPA (2014d)

Municipal Solid Waste Digesters

In 2012, 65.3% of the municipal solid waste (MSW) generated in the United States comprised of readily digestible organic materials—44.6% after recycling and composting (US EPA 2014c). California's landfill disposal stream consists of 59%- 64.% biomass derived material, dominated by paper & cardboard and food waste—17.3% and 15.5%, respectively (Figure 88) (Cascadia Consulting Group 2009). Municipal solid waste digesters operate similarly to agricultural waste and manure digesters, and may even be combined with them. MSW digesters may be more prone to performance variations and upsets than other systems due to constant, large, unpredictable changes in the incoming waste stream (especially with mixed post-consumer food wastes). There are many operating AD systems in Europe utilizing MSW or source-separated MSW components. Total installed capacity is more than 6 million tons per year (De Baere & McDonald, 2012). There are approximately twelve systems operating in California (Franco, 2014).

Figure 8: California's Overall Landfill Waste Stream, 2008

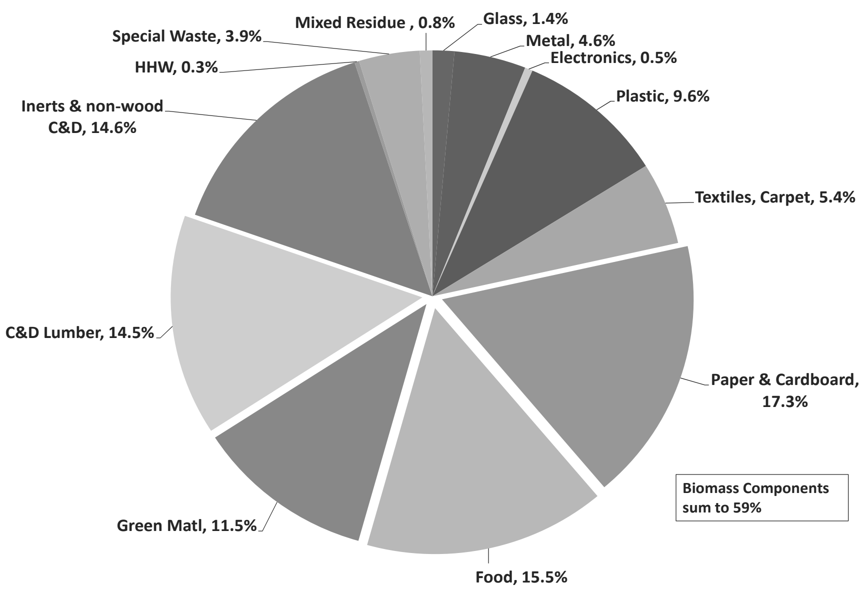
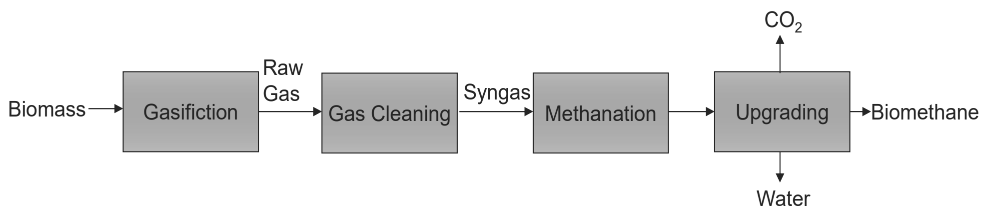


Chart Credit: Cascadia Consulting Group (2009)

Biomethane via Thermal Conversion Pathways (Gasification)

Biomethane can also be produced via thermal gasification with appropriate raw gas cleaning and reforming to a synthesis gas followed by methanation and upgrading to biomethane (Figure 9). Methane synthesized via this thermal gasification / methanation route is sometimes called synthetic natural gas (SNG) and renewable SNG (RSNG) if derived from biomass. Overall efficiency for RSNG would be ~ 65% for commercial scale facilities (Aranda et al., 2014; Kopyscinski et al., 2010; Mensinger et al. 2011). Overall thermal efficiency of biomass to RSNG to electricity would be ~30-33% if burned in a combined cycle natural gas power plant (assumes 50% efficient combined cycle power plant).

Figure 9. RSNG Schematic



Gasification also allows for effective utilization of woody and herbaceous biomass, feedstocks with fairly low methane potential through biological decomposition. Woody and herbaceous biomass have high contents of lignin and hemicellulose, which are extremely difficult for anaerobic digestion microbes to decompose. A majority of lignin and some hemicellulose material is usually left undigested by digester systems.

Biomass-Derived Gas Quality by Source

In addition to methane, biogas can contain these other compounds:

- Carbon dioxide: CO_2 constitutes the largest gaseous byproduct of anaerobic digestion. Any carbon dioxide present will decrease the biogas's energy content.
- Sulfur Compounds: Sulfur is present in all biological materials, especially those containing high protein concentrations. Small sulfur compounds (e.g., H_2S, mercaptans, COS, dimethyl sulfide) are produced by the biological degradation of these materials. Sulfur compounds are odorous and can be detrimental in many ways. Hydrogen sulfide in particular is highly toxic and poses health risks. Hydrogen sulfide in the presence of moisture can be corrosive, and when combusted, hydrogen sulfide is converted to sulfuric acid. Sulfur also poisons many of the metal catalysts that used for a number of different purposes (e.g., fuel cell electrodes, methane reforming).
- Moisture: Biogas will almost always be saturated with water vapor. Water vapor not only lowers the gas's energy content, but any hydrogen sulfide or carbon dioxide present will partially dissolve into the condensed water and form corrosive acids.
- Silicon compounds: Siloxanes, used in many industrial processes and consumer products ranging from tubing and paints to fabric softeners and toiletries, are present in nearly all biogases. When combusted, siloxanes are converted to microcrystalline silicon dioxide (SiO_2), also known as silica, with physical and chemical properties similar to glass. SiO_2 will deposit onto equipment, damaging boilers, engines, heat exchangers, and catalytic exhaust gas treatment systems, as well as fouling surfaces (e.g., sensors, catalysts) and plugging pipes.
- Nitrogen: Nitrogen will be present from any air introduced into the system. Nitrogen will dilute the gas, lowering its energy content.
- Oxygen: Oxygen will also be introduced with any air. Oxygen promotes microbial growth and can create an explosion hazard at certain CH_4-to-O_2 ratios (Figure 10).

Figure 10: Methane Flammability Chart

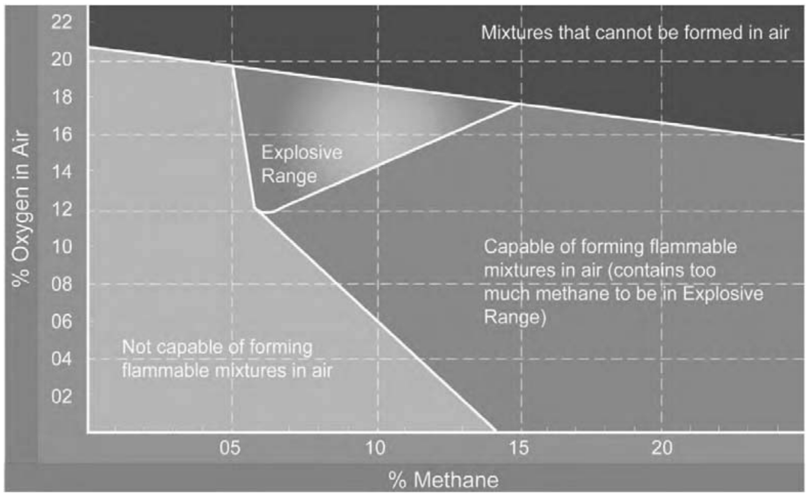


Chart Credit: Environment Canada (2011)

- Volatile organic compounds: VOCs include such compounds as aromatics, oxygenates, alkanes, and halocarbons. In addition to being air pollutants in and of themselves, VOCs can form highly toxic compounds when combusted. VOCs also include non-methane hydrocarbons, which can add to the overall gas's higher heating value.
- Halogen compounds: (e.g., halocarbons) can be found in biogas from the volatilization of compounds in plastics, foams, solvents, and refrigerants. Halogens form corrosive gases when they are run through combustion or reforming processes.
- Particulate Matter: Biogas can contain dust from gas collection systems or oil particles from compressors. Inorganic particulates will abrasively erode equipment and plug/damage the pores of membranes and adsorbents. Fibrous fragments can plug certain points in the gas collection system.

Due to the biological nature of anaerobic digestion, different microbial communities will respond differently to the same feedstocks, and vice versa. Furthermore, differences in feedstock material, microbial communities, reactor conditions (e.g., temperature, pH), and operating parameters (e.g., hydraulic retention time) will produce minor variations in gas quality and composition. However, biogas composition is mostly dependent upon its source. Table 3 shows the properties and ranges of assorted gases that are found in the four major biogas sources (referenced to earlier in this Chapter).

Dr. Michael Kleeman at UC Davis is Principal Investigator of project investigating biogas composition by source. The project is funded by the California Energy Commission and the Air Resources Board.

Table 3: Composition of Biomass-Derived Gas from Different Sources

Compound	Landfill	Wastewater Treatment Plants	Agricultural Digester	MSW Digester
Energy Content (Btu/scf, HHV)	208 – 644	550 – 650	550 – 646	550 – 650
Temperature (°C)	10 – 30	30 – 40	40 – 60	N.D.
Methane	20 – 70%	55 – 77%	30 – 75%	50 – 60%
Carbon Dioxide	15 – 60%	19 – 45%	15 – 50%	34 – 38%
Hydrogen Sulfide	0 – 20,000 ppm	1 – 8,000 ppm	10 – 15,800 ppm	70 – 650 ppm
Total Sulfur	0 – 200 mg/m³	N.D.	N.D.	N.D.
Nitrogen	0 – 50%	< 8.1%	0 – 5%	0 – 5%
Oxygen	0 – 10%	0 – 2.1%	0 – 1%	0 – 1%
Hydrogen	0 – 5%	0%	0%	
Ammonia	0 – 1%	0 – 7 ppm	0 – 150 ppm	
Carbon Monoxide	0 – 3%	0 – 0.01%	N.D.	N.D.
Non-methane Hydrocarbons	0.01 – 0.25%	N.D.	N.D.	N.D.
Aromatics	30 – 1,900 mg/m³	N.D.	N.D.	0 – 200 mg/m³
Halogenated Compounds	0.3 – 2,900 mg/m³	0 – 2 mg/m³	0 – 0.01 mg/m³	100 – 800 mg/m³
Total Chlorine	0 – 800 mg/m³	N.D.	0 – 100 mg/m³	N.D.
Total Fluorine	0 – 800 mg/m³	N.D.	0 – 100 mg/m³	N.D.
Siloxanes	0 – 50 mg/m³	0 – 400 mg/m³	0 – 0.2 mg/m³	N.D.
Moisture	1 – 10%	N.D.	N.D.	5 – 6%
Methyl Mercaptan	0 – 3.91 ppm	N.D.	N.D.	N.D.
Dichlorobenzene	0 – 5.48 ppm	N.D.	N.D.	N.D.
Ethylbenzene	0.576 – 40.2 ppm	< 1 ppm	< 0.34 ppm	N.D.
Vinyl Chloride	0.006 – 15.6 ppm	N.D.	N.D.	N.D.
Copper	< 30 μg/m³	< 30 μg/m³	< 20 μg/m³	N.D.
Methacrolein	< 0.11 ppm	< 0.0001 ppm	N.D.	N.D.
Alkyl Thiols	6.1 – 6.8 ppm	1.04 – 1.15 ppm	< 7.3 ppm	N.D.
Toluene	1.7 – 340 mg/m³	2.8 – 117 mg/m³	0.2 – 0.7 mg/m³	N.D.

N.D.: Not Determined or not found. Listed where contaminant is expected to be present, but concentration data was not found in the literature.

Chart Credit: Author; Data Credit: Allegue and Hinge (2012a); Asadullah (2014); California Air Resources Board and California Office of Health Hazard Assessment (2013); Eastern Research Group, Inc. (2008); Kaparaju and Rintala (2013); Petersson (2013); Ratcliff and Bain (2001); Rasi (2009); Robertson and Dunbar (2005); Wheeldon, Caners, and Karan

CHAPTER 3: Available and Emerging Biogas Utilization Technologies

The methane in biogas has chemical energy that can be used for heat, power, vehicle fuel or as a feedstock for production of other chemicals or fuels (i.e., hydrogen, methanol, etc.). If no economic use is available at the biogas source, then simply burning or flaring the gas to oxidize the methane to CO_2 and H_2O is recommended or required to minimize fugitive methane emissions

Flaring

Flares or thermal oxidizers are used to oxidize combustible waste gas to reduce VOC and methane emissions to the atmosphere. It is the simplest method of safely disposing biogas when it cannot be processed or stored. However, hydrogen sulfide is converted to SO_2, another toxic substance which contributes to acid rain. The EPA's 40 CFR 60.104 Standards for Sulfur Oxides forbids combusting gas with hydrogen sulfide concentrations above 10 grain per 100 scf (~ 0.23 g m^{-3}).

Despite the environmental benefits and low cost, no energy is recovered by flaring. The majority of biogas producers in California currently flare their biogas and/or used a flare prior to installing a biogas utilization system. The following sections discuss ways in which to positively utilize biogas's energy potential.

Distributed Generation

The simplest approach to beneficially use biogas is to use it for heat and power generation by combusting or electrochemically converting the biogas onsite (using reciprocating engines, gas turbines, fuel cells, steam boilers, etc.).

Boilers

Boilers consist of a pressure vessel containing water that is heated and evaporated by burning a fuel (Figure 11). Steam can be used to provide heat or work when expanded through a steam engine or turbine (a generator operated by the steam engine will produce electricity) for another process. When operating on biogas, boilers that are made to run on natural gas should be adjusted by altering the fuel-to-air ratio (i.e., changing the carburetor) and enlarging the fuel orifice or burner jets to handle the higher flowrate of biogas needed to ensure proper combustion. The biogas should also be tested prior to use to determine if gas pre-treatment is necessary to remove hydrogen sulfide, siloxanes, and particles that may damage the boiler. Hydrogen sulfide will form sulfuric acid with water in the condensers, causing corrosion, although the metal surfaces should be coated to help prevent that. The exhaust should also be maintained above 150 °C to minimize condensation. Siloxanes will convert to SiO_2 when burned and deposit in the boiler along with any particles in the feed gas, which can eventually clog the boiler's flame tubes if not managed. High H_2S concentrations can also cause the flame tubes to clog.

Figure 11: Steam Boiler Structure

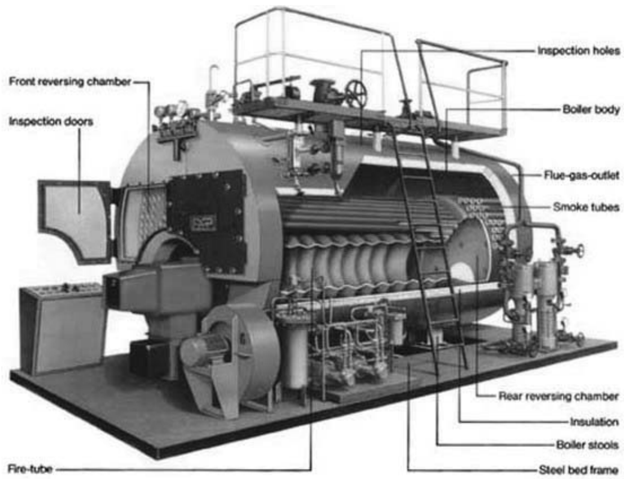


Illustration Credit: Fann Azmayan Pooyandeh Company (2002)

Boilers are relatively simple, have minimal cost and maintenance requirements. Their thermal efficiency is generally between 75 – 85%.

Reciprocating Engines

Reciprocating engines, also known as piston engines, include steam engines, Stirling engines, and gas and liquid fueled spark and compression ignition engines (often called internal combustions engines). Spark ignition gas (reciprocating) engines are the most popular application for biogas use. Depending on size, reciprocating engine-generators electrical efficiency ranges 18 – 43%. Engines are available that range from a few kW to several (10) MW. They are simple to operate and maintain and have relatively low to medium investment costs. They have higher pollutant emissions thane gas turbines or fuel cells which is an issue in some air basins in California.

Internal combustion engines can be divided into two types: rich burn and lean burn. Rich burn engines operate near the stoichiometric air-to-fuel ratio (and have low-to-zero oxygen in the exhaust), whereas lean burn engines run at higher A:F ratios (> 4% O_2 in the exhaust). Rich burn engines have higher uncontrolled NOx emissions. Lean burn engines have excess O_2 present during combustion, ensuring complete fuel combustion and lowering exhaust temperatures to inhibit the formation of NOx. Lean-burn engines are often used with for natural gas and especially for biogas applications since biogas contaminants can poison the three-way catalyst used with rich-burn engines.

Biogas should be cleaned to remove H_2S, which can lead to sulfuric acid formation, resulting in bearing failures and damage to the piston heads and cylinder sleeves. To minimize acid fume condensation, it is recommended that the engine coolant temperatures be above 87 °C. Siloxanes and particulates will cause the same problems found in boilers, and should be removed as well.

The exhaust from an internal combustion engine can be as hot as 650 °C. Waste heat can be recovered using a water jacket or exhaust gas heat exchanger. Recovered heat can be used to warm digesters or for certain biogas upgrading systems.

Microturbines

Microturbines are small gas turbines and operate on the Brayton Cycle (Figure 12). They have lower emissions compared to reciprocating engines, generally, and may have lower maintenance Microturbines have higher capital costs than reciprocating engines, but may have lower overall costs when air pollution control equipment is considered. Microturbines achieve 15 – 30% electrical efficiencies. Due to tight California air quality restrictions, commercial units for use in California are generally rated to produce less than 4 – 5 ppmvd NOx (at 15% O_2), while non-California versions generate 9 ppmvd NOx.

Microturbines generally have a capital cost of $700 – $1,100/kWh and a maintenance cost of $0.005 – $0.016/kWh (Capehart 2010).

Figure 12: Microturbine Structure

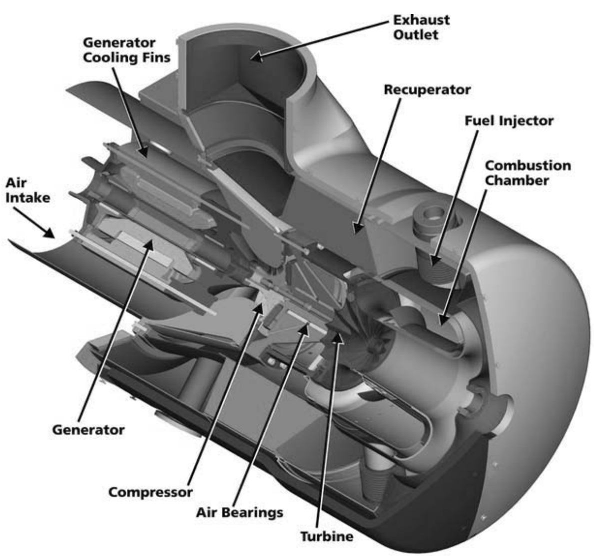


Illustration Credit: Capstone Turbine Corporation (2010)

Typically, microturbines can tolerate up to 1,000 ppm H_2S, and encounter the same problems with burning siloxane and particles. Also, since the biogas must be compressed in order to be injected into the pressurized combustion chamber, the biogas needs to be dry to avoid condensation.

Fuel Cells

Fuel cells have for several decades been the technology of space exploration, but have in recent years garnered significant attention for distributed power, transportation, and small mobile applications. They have high electrical efficiency (30 – 70%), and very low air pollutant emissions.

Fuel cells basically consist of an anode and a cathode separated by an electrolyte. Hydrogen gas catalytically splits on the anode, causing electrons to pass from anode to cathode through a circuit (electricity generation), and ions to pass from anode to cathode through the electrolyte. The hydrogen ions react withoxygen at the cathode producing water., The operation and performance of a fuel cell depend upon the anode and cathode material, electrolyte substance, and design configuration.

Methane in biogas can be used for fuel cells if it is first reformed to hydrogen and CO_2. The gas produced from reforming pure methane contains roughly 40 – 70% H_2, 15 – 25% CO_2, and 1 – 2% CO. Methane can be externally steam reformed using a catalyst (usually nickel) at high temperatures and pressures (700 – 1000 C°), or internally reformed at high-temperature fuel cell operations using the anode material as a catalyst. Hot fuel cells above 800°C can also cause CO_2 to act as an electron carrier instead of inhibiting the electrochemical process. High temperature fuel cells are more fuel flexible and more tolerant to fuel impurities. Waste heat from external reforming can be used to heat low – mid temperature fuel cells. The reformer-shift reactor sequence generally has a net efficiency of ~ 75% for large-scale installations and ~ 60% for smaller ones (< 1,000,000 scf methane/day).

There are currently five major types of fuels cells that are being researched and industrially applied: Polymer electrolyte membrane or proton exchange membrane (PEMFC), alkaline, phosphoric acid (PAFC), molten carbonate (MCFC), and solid oxide (SOFC). Each of these designs differ from one another in the materials and chemicals used in their construction, which changes their operating conditions and the reactions that occur to produce electricity (

Figure 13). MCFCs and SOFCs operate at high temperature and are internal reforming. PEMFCs and PAFCs types do not employ internal reforming so biogas or natural gas must be reformed to hydrogen before being used in the fuel cell. While biogas has been demonstrated on or experimented with internal and external reforming fuel cell types (Scholz, 2011), MCFC systems appear to be the type most often used for biogas applications systems (FuelCellToday, 2012)

Figure 13: Fuel Cell Reactions

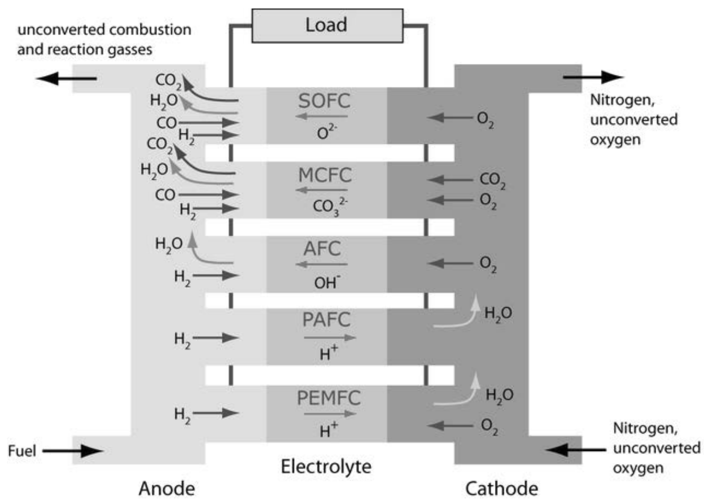


Illustration Credit: Adapted from Fray, Varga, and Mounsey (2006)

Depending upon the expected incoming gas quality, desired application, and power size, an appropriate fuel cell type can be chosen.

Table 4 provides a technical comparison of the five fuel cell types, with a breakdown of their contaminant limits. Overall, fuel cells are more electrically efficient than other gas-powered electricity generation technologies. However, they are mostly still in the research and development phase, although there are several pilot and early commercial systems available. The downside of fuel cells is their high capital costs, which are at least ten times more expensive than other electricity generating options. They are also less intolerant to contaminants, and so require superior gas cleaning.

Table 4: Fuel Cell Technology Comparison

	Polymer Electrolyte Membrane	Alkaline	Phosphoric Acid	Molten Carbonate	Solid Oxide
Application	Space; Vehicles; Mobile	Military; Space	Stationary power, Vehicles	Stationary power	Stationary power; Vehicles
Fuel gas	H_2, Methanol, Reformed gas [CH_4]	H_2, Hydrazine	H_2, Reformed gas [CH_4, Natural gas, Coal gas, Biogas]	H_2, CH_4, Natural gas, Coal gas, Biogas	H_2, CH_4, Natural gas, Coal gas, Biogas
Charge Carrier	H^+	OH^-	H^+	CO_3^{2-}	O^{2-}
Temperature	50 – 120 °C	60 – 120 °C	130 – 220 °C	600 – 700 °C	650 – 1000 °C
Stack Power Size	1 W – 500 kW	0.5 – 100 kW	10 kW – 1 MW	0.1 – 3 MW	1 kW – 2 MW
Electrical Efficiency	CH_4: 35 – 40% H_2: 60%	50 – 70%	35 – 50%	40 – 60%	45 – 60%
CO_2		100 – 500 ppm			
H_2S	< 1 ppm		< 2 – 4 ppm	0.1 – 10 ppm	≤ 1 ppm
Total Sulfur	0.1 ppm		< 4 – 50 ppm	0.01 – 10 ppm	0.1 – 10 ppm
CO	5 – 50 ppm	0.001 – 0.2%	0.5 – 1.5%		
Oxygen			< 4%	0.1%	
NH_3	10 – 200 ppm		< 0.5 – 4%	0.05 – 3%	0.5%
Halogens			< 4 ppm	0.1 – 1 ppm	< 1 – 5 ppm
Total Silicon	N.A.	N.A.	N.A.	10 – 100 ppm	< 0.01 ppm
Mercury	N.A.	N.A.	N.A.	30 – 35 mg/m^3	N.A.
Olefins	N.A.	N.A.	0.5%	0.2%	N.A.
Status	Research, Commercial	Governmental	Commercial	Research	Research

Chart Credit: Author; Data Credit: Allegue and Hinge (2012a); Deublein and Steinhauser (2011); Kaparaju and Rintala (2013); Papadias, Ahmed, and Kumar (2011)

Vehicle Fueling

Biogas can be upgraded to biomethane and used for vehicle fuel applications (as renewable compressed natural gas (CNG) or liquid natural gas (LNG). Biogas use for vehicles can be an attractive alternative to distributed power generation because air emissions are transferred to the vehicle (and local air permitting is simplified) and possibly economics.

Light-duty and heavy-duty vehicles can be fueled by natural gas (or renewable natural gas). Light-duty natural gas vehicles are often designed to run on both gasoline and CNG (with two separate tanks). Heavy-duty vehicles are normally designed to run on a single fuel type (CNG or diesel). When natural gas displaces diesel as vehicle fuel, emissions reductions of 60 – 85% for NOx, 10 – 70% for CO, and 60 – 80% for particulates can be achieved. Non-methane VOC emissions and the ozone forming potential decrease by 50%.

To produce vehicle-grade R-CNG and R-LNG, raw biogas must be cleaned and upgraded to biomethane. Moisture, siloxanes, hydrogen sulfide (and possibly other contaminants) are cleaned from the biogas which is then upgraded to biomethane (typically to >88% methane). Oxygen content will also have to be closely monitored and adjusted to avoid gas mixtures that permit explosions to occur. Unlike other systems, there is little concern about biological contamination since microbial growth does not occur under such high pressures.

Large-scale liquefaction of pipeline natural gas is commonplace around the world, but small-scale operations (5,000 – 50,000 gpd) have presented technological and economic challenges. As of October 2014, the US has 752 public CNG fueling stations and 669 private ones, and 64 public LNG fueling stations and 41 private ones. California has 156 public CNG fueling stations and 129 private ones, and 14 public LNG fueling stations and 31 private ones (US DOE 2014).

Natural Gas Pipeline Injection

Another emerging option for biogas utilization is to upgrade and inject into natural gas pipelines. This choice is ideal in situations where the biogas producer's energy and fuel demands are either not significant enough, or those demands are already met by a fraction of the total available biogas. Biogas pipeline injection takes advantage of the pre-existing network infrastructure and ideally allows 100% of the biogas to be utilized. Pipeline injection also allows for more efficient use of the biogas, since larger natural gas to electricity facilities are much more efficient than small-scale, on-site, distributed power generation systems.

High investment and operating costs, as well as complicated regulatory hurdles (e.g., gas quality standards, gas testing and monitoring requirements, permits) imposed by government agencies and utility companies , have generally constrained pipeline injection to large biogas generators with high biomass throughput (i.e., landfills, WWTPs, centralized digester plants) that have the resources to pursue such an endeavor. However, as air quality standards are recently becoming stricter in California, especially in nonattainment air districts (e.g., San Joaquin Valley and South Coast), existing and new small-scale biogas-fueled distributed generation systems such as those found on dairy farms will begin having a harder time meeting these standards. Small-scale pipeline injection provides a possible alternative. To make pipeline injection for farms more economically feasible, several nearby farms can form a co-op to send their raw biogas to a central cleaning and upgrading facility. Thus, the expensive investment costs are divided among multiple parties and it becomes less expensive on an individual basis. In addition, the equipment needed is more cost-effective (lower levelized cost of energy) at larger scales. Under this scenario, some minor contaminant removal will still be required at each source to avoid transmitting chemicals that will corrode the collection pipeline.

Another issue is that the local pipeline capacity may not be sufficient, especially in more rural locations. Even if there is a pipeline, not all sites can feasibly participate since some may not be close enough to gas transmission lines. And even if there is a pipeline close enough, it may not be able to handle the necessary throughput capacity for biogas injection.

The first biogas upgrading and pipeline injection facilities in the US were installed in the 1980s using gas from landfills and WWTPs. Currently, there are around 60 projects in the US that inject biomethane into natural gas pipelines: at least 33 landfill projects, 25 WWTP projects, and one farm-based project (California Air Resources Board and California Office of Health Hazard Assessment 2013). There is currently at least one operating biomethane pipeline injection project operating in California at the Point Loma Wastewater Treatment Plant in San Diego. A detailed description of this project can be found in Appendix B of this report.

CHAPTER 4: Regulatory and Technical Standards for Biogas Usage

Raw biogas from any source contains trace amounts of contaminants, some of which have the potential to compromise human health and safety, equipment integrity, and environmental wellbeing if at high enough concentrations. Thus, biogas needs to be cleaned and upgraded to appropriate standards. For injection to natural gas pipelines, the biogas should be upgraded to biomethane by removing the majority of carbon dioxide, producing a gas consisting of more than 95% methane.

Aside from technical requirements, there are numerous regulations that must be met. Regulations and regulatory agencies exist for nearly all facets of a biogas project, e.g., air emissions, water usage, wastewater discharge, solid waste disposal, environmental impact, construction, etc. For example, if the biogas cleaning process uses or disposes of hazardous waste chemicals, the operator must obtain a permit from the California Department of Toxic Substances Control. A permit from the State Water Resources Control Board is required for wastewater discharge and storm water runoff or construction—a new permit is needed for digester installation. Along with constructing any biogas cleaning/upgrading or digester system, there are city and county planning ordinances and zoning requirements that must be followed. The new installations need to meet building code requirements and building permits for the digesters are required. The project may additionally necessitate a California Environmental Quality Act (CEQA) or National Environmental Policy Act (NEPA) Environmental Impact Report to be completed prior to construction if an Initial Study finds that the project will have a significant impact on the environment. Because these systems have potential for air emissions, authority to construct and permits to operate must be obtained from the local air district.

One of the primary uncertainties regarding the California biogas industry is the fact that regulations have been subject to change at unpredictable times. Some changes excluded preexisting systems, while others afforded some time to achieve compliance. This means that after project completion, their remains an ongoing requirement for operators need to keep themselves informed about any future enactments that will affect their system.

Relevant regulations and technical requirements differ depending upon where and how the biogas is collected, cleaned/upgraded, and utilized. The following subsections outline the regulatory and technical standards that processed biogas generally must meet for distributed power or injection into California natural gas pipelines.

Distributed Power Generation Gas Standards

As with any energy technology, there are numerous government and corporate regulations and policies that apply to distributed power generation. However, only in recent years have rules for waste gas (i.e., biogas) been amended into existing electricity generation regulations, the most pressing being those related to air emissions. Other policies have been enacted to promote electricity generation from bioenergy resources. Technical limitations on biogas also exist because of compounds found in biogas that can damage the power generation systems. The following sections discuss the regulations, policies, and technical constraints of the distributed power generation technologies referenced in Chapter 3.

Regulations and Policies

Developing a centralized digestion processing facility requires amending waste, water, and air permits for each source facility in addition to permits for the processing facility. Co-digestion adds another level of permitting, reporting, and oversight. Permitting is often a lengthy process that can delay or even terminate projects. For example, it can take over two years to get State Water Resources Control Board permits concerning expected nitrate and salt concentration effects on groundwater. Updates to regulations can also be detrimental to biogas projects. At least one California farm digester shut down due to changes in local air district requirements for power generation equipment, i.e., San Joaquin Valley Air Pollution Controld District Rule 4702 (Sousa 2010). Keep in mind that there are only about a dozen farm digesters operating in California. Out of all the permits involved in implementing distributed generation technologies, air quality-related standards are one some of the most pertinent.

There are 35 regional air districts in California which regulate stationary air pollution sources in the state (Figure 14). Air districts that exceed the national ambient air quality standards for a pollutant are labeled as 'nonattainment' areas for that pollutant and must take action to bring the district into compliance (i.e., reduce emissions). For example, both the South Coast Air Quality Management District (SCAQMD) and the San Joaquin Valley APCD are in nonattainment for ground-level ozone, which is formed by reaction of oxides of nitrogen (NOx) and volatile organic compounds (VOCs) in the presence of sunlight (photochemical smog). As a result, SCAQMD has revised Rule 1110.2: Emissions from Gaseous- and Liquid-Fueled Engines that sets stationary and portable internal combustion engine emission standards to reduce NOx to < 11 ppmvd, CO to < 250 ppmvd, and VOCs to < 30 ppmvd for landfill and digester gas-fired engines. The San Joaquin Valley Air Pollution Control District enacted Rule 4702: Internal Combustion Engines which set more stringent air pollution emission standards for spark-ignition internal combustion engines. Specifically, for any stationary internal combustion engine rated above 50 bhp running off of biogas, emission must be limited to < 50 ppmvd NOx, < 2,000 ppmvd CO, and < 250 ppmvd VOCs. Alternatively, an engine can be compliant if it achieves an aggregate NOx emission level less than 90% of the NOx emissions achieved over a seven month period given 2,000 ppmvd NOx. This rule alone forced the closure of at least one dairy digester operation that could not meet the new specification and hinders the reinstatement of at least two other digesters that had previously been forced offline by other regulations (Sousa, 2010). Thus, when developing a biogas project in California, it is more prudent to ensure that systems be designed that are technically flexible enough within economic reason to adjust to any new regulatory changes that may occur. Over-specifying a system may cost more money initially, but can avoid future frustrations, problems, and downtime.

Figure 14: Map of California Air Districts

Illustration Credit: California Air Resources Board (2014)

Table 5 summarizes the rules pertinent to biogas utilization for the aforementioned air districts. To meet these standards, H_2S and ammonia are removed from the biogas to reduce NOx and SOx emissions. Concentration of halogens in the feed gas, which can lead to hazardous air emissions, are usually not high enough to regulate (but would be if present in sufficient concentration). Halocarbons would fall under the category of VOCs.

Table 5: List of Distributed Power Emission Requirements for Several California Air Districts

Air District	Rule	Applicability	SOx / SO_2	NOx / NO_2	CO	H_2S	NH_3	Combustion Contaminants	Particulates	Compliance Date
Butte	202	All							0.3 grain/scf	8/22/2002
	261	All				0.03 ppm				8/22/2002
	262	All	0.2% (2,000 ppm)							8/22/2002
	250	Boilers, Steam generators, Process heaters		70 ppmv (0.084 lb/MMBtu)	400 ppmv		20 ppm (at 3% O_2)			3/25/2004
	252	Stationary IC engines (lean burn, 50 - 300 bhp)		740 ppmv	4,500 ppmv					1/1/2006
		Stationary IC engines (lean burn, > 300 bhp)		150 ppmv	4,500 ppmv					
Eastern Kern	404.1	All							0.1 grain/scf	1/24/2007
	407	All	0.20%							4/18/1972
	409	Boilers, Engines, Turbines						0.1 grain/scf (at 12% CO_2)		5/7/1998
	425.2	Boilers, Steam generators, Process heaters (> 5 MMBtu/hr)		70 ppmv (0.09 lb/MMBtu) (at 3% O_2)	400 ppmv (at 3% O_2)					11/30/1997
	427	Stationary IC engines (lean burn, > 250 bhp)		125 ppm (2 g/bhp-hr) (at 15% O_2)	2,000 ppmv (at 15% O_2)					11/1/2001
	425	Cogeneration Gas Turbine Engines (> 10 MW)		RACT: 10 ppmv; BACT (20*EFF/25) ppmv						1/1/1997

Air Quality Management District	Rule	Applicability	SOx / SO_2	NOx / NO_2	CO	H_2S	Compliance Date
San Francisco Bay Area	9-1	All	300 ppm				5/20/1992
	9-2	All				0.06 ppm (3 min avg)	10/6/1999
	9-3	Heat transfer Systems		125 ppm (new); 175 (existing)			4/19/1975
	9-6	Boilers, Water heaters (0.075 - 0.4 MMBtu/hr)		14 ng/J			1/1/2013
		Boilers, Water heaters (0.4 - 2 MMBtu/hr)		20 ppm (at 3% O_2)			1/1/2013
	9-7	Boilers, Steam generators, Process heaters (> 10 MMBtu/hr)		30 ppmv (at 3% O_2)	400 ppmv (at 3% O_2)		1/1/1996
	9-8	Stationary internal combustion engines (lean burn, > 50 bhp)		70 ppmv (at 15% O_2)	2,000 ppmv (at 15% O_2)		5/31/2012
	9-9	Stationary gas turbines (0.3 - 10 MW)		42 ppmv (at 15% O_2)			1/1/1996
		Stationary gas turbines (> 10 MW w/o selective catalytic reduction)		15 ppmv (at 15% O_2)			1/1/2000
		Stationary gas turbines (> 10 MW w/ selective catalytic reduction)		9 ppmv (at 15% O_2)			1/1/2000

Air Quality Management District	Rule	Applicability	SOx / SO_2	NOx / NO_2	CO	VOCs	Combustion Contaminants	Particulates	Compliance Date
San Joaquin Valley Unified	4201	All						0.1 grain/scf	12/17/1992
	4301	All	200 lb/hr	140 lb/hr			0.1 grain/scf (at 12% CO_2)		12/17/1992
	4308	Boilers, Steam generators, Process heaters (0.075 - 0.4 MMBtu/hr)		77 ppmv (at 3% O_2)					1/1/2015
		Boilers, Steam generators, Process heaters (0.4 - 2.0 MMbtu/hr)		30 ppmv (at 3% O_2)					
	4702	Stationary IC engines (non-agricultural, lean burn, > 50 bhp)		65 ppmv (at 15% O_2)	2,000 ppmv (at 15% O_2)	750 ppmv (at 15% O_2)			1/1/14; 1/1/16; 1/1/17
		Stationary IC engines (agricultural, lean burn, > 50 bhp)		150 ppmv (at 15% O_2)	2,000 ppmv (at 15% O_2)	750 ppmv (at 15% O_2)			1/1/2010; 1/1/2015
	4701	Stationary IC engines (waste derived gaseous fuel, > 50 bhp)		125 ppmv (at 15% O_2)	2,000 ppmv (at 15% O_2)	750 ppmv (at 15% O_2)			5/31/2001
	4703	Stationary gas turbines (< 3 MW)		9 ppmvd (at 15% O_2)	200 ppmv (at 15% O_2)				1/1/2012
		Stationary gas turbines (3 - 10 MW)		8 - 12 / 9 / 5 ppmvd (at 15% O_2)	200 ppmv (at 15% O_2)				
		Stationary gas turbines (> 10 MW)		5 / 25 ppmvd (at 15% O_2)	200 ppmv (at 15% O_2)				

Air Quality Management District	Rule	Applicability	SOx / SO_2	NOx / NO_2	CO	VOCs	Combustion Contaminants	Particulates	Compliance Date
South Coast	432.1	Stationary equipment (Landfill gas)	150 ppmvd						6/12/1998; 11/17/1995
	432.1	Stationary equipment (Sewage digester gas)	40 ppmvd						
	409	IC engines					0.1 g/scf (at 12% CO_2)		7/7/1981
	407	All	500 ppmv		2,000 ppmv				7/1/1982
	404	All						≤ 450 mg/m3	2/7/1986
	474	All		125 ppm (at 3% O_2)					12/4/1981
	476	Boilers, Steam generators, Process heaters		125 ppm (at 3% O_2)			0.1 g/scf (at 3% CO_2)		5/7/1976
	475	Stationary gas turbines (New: > 10 MW, Existing: > 5 MW)					0.1 g/scf (at 3% CO_2)		8/7/1978
	1146.2	Boilers, Steam generators, Process heaters		20 ppm (at 3% O_2)					1/1/2012
	1110.2	Stationary IC engines (agricultural, lean burn, > 50 bhp)		11 ppmvd	250 ppmvd	30 ppmvd			7/1/2012
	1134	Stationary gas turbines (0.3 - 2.9 MW)		25 ppm (at 15% O_2)					8/8/1989
	1134	Stationary gas turbines (digester, 2.9 - 10 MW)		25 ppm (at 15% O_2)					

Air Quality Management District	Rule	Applicability	SOx / SO_2	NOx / NO_2	CO	VOCs	Combustion Contaminants	Particulates	Compliance Date
South Coast (cont.)	1134	Stationary gas turbines (2.9 - 10 MW w/o selective catalytic reduction)		15 ppm (at 15% O_2)					8/8/1989
		Stationary gas turbines (> 10 MW)		9 ppm (at 15% O_2)					
		Stationary gas turbines (> 10 MW w/o selective catalytic reduction)		12 ppm (at 15% O_2)					
	1135	All		0.1 lb/MWh					7/19/1991
Yolo-Solano	2.16	Heat/Power generators	200 lb/hr	140 lb/hr				40 lb/hr	
	2.37	Boilers (400k - 1M Btu/hr)		20 ppm (at 3% O_2)					1/1/2014
	2.32	Stationary IC engines (lean burn, > 50 bhp)		150 ppmv (at 15% O_2)	2,000 ppmv (at 15% O_2)				5/31/1997
	2.34	Stationary gas turbines (0.3 - 2.9 MW)		42 ppm (at 15% O_2)					7/13/1998

Chart Credit: Author; Data Credit: California Air Resources Board

Other regulations affecting distributed power generation technologies include Best Available Control Technology, District Rule 2201: New and Modified Stationary Source Review Rule, and the ARB distributed generation certification program.

Producers that generate excess electricity or do not want to use it themselves can opt to sell electricity to their local electricity utility company. The three largest electricity investor-owned utility companies in California are: Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (Figure 15). The energy price and rules for selling electricity into the grid are dictated by the utility company's electricity feed-in tariff.

Figure 15: Map of California Electricity Utility Service Areas

Illustration Credit: California Energy Commission (2014)

Relevant policies to promote renewable energy generation include the California RPS and the recently enacted Senate Bill 1122 (Rubio): Bioenergy Feed-in Tariff, which requires investor-owned electrical utilities to procure a cumulative 250 MW of new, small scale (< 3 MWe) biopower generating capacity allocated among the following categories: 110 MW to biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion; 90 MW to dairy and other agricultural bioenergy; 50 MW to bioenergy using byproducts of sustainable forest management. At the same time, Assembly Bill 2196 (Chesbro): Renewable Energy Resources, declares biomethane delivered to a generation facility via common carrier pipeline to be eligible for RPS credits if it meets certain requirements including limited applicability of out-of-state biomethane.

Technical Constraints

Distributed power generation technologies can accept a range of fuel energy content characteristic of raw biogas. Reciprocating engines and fuel cell stacks are available in large power sizes in the MW range while microturbines are limited to smaller power sizes in the hundreds of kW (Table 6).

Table 6: Features and Technical Requirements of Distributed Power Generation Technologies and CNG Vehicles

	Boilers	Reciprocating Engines	Microturbines	Fuel Cells	CNG Vehicles
Energy Content - minimum or range (BTU/scf HHV)	N.A.	400 – 1,200	350 – 1,200	450 – 1,000	900
Power Size	N.A.	5 kW – 10 MW	25 kW – 500 kW	1 kW – 3 MW	N.A.
Electrical efficiency	0%	18 – 45%	15 – 33%	30 – 70%	0%
Thermal efficiency from CHP	75 – 85%	30 – 50%	20 – 35%	30 – 40%	N.A.

Chart Credit: Author; Data Credit: Allegue and Hinge (2012a); Australian Meat Processor Corporation (2014); Krich et al. (2005); Zicari (2003)

Gas fueled power generation technologies have certain technical limitations regarding contaminants and trace compounds allowable in the fuel gas. The most prevalent contaminants and their effects on distributed power generation systems include the following:

- Sulfur compounds are corrosive when dissolved in water. When hydrogen sulfide is also combusted it is converted to sulfur dioxide which is a criteria pollutant and forms corrosive sulfuric acid when dissolved in water. Sulfur compounds can accumulate in engine oil and accelerates bearing wear, but can be somewhat mitigated with frequent oil changes. Sulfur poisons many of the metal catalysts (e.g., nickel, platinum) that used for fuel cell electrodes, methane reforming, and catalytic air pollution control devices.

- Entrained water and compressor oil droplets can damage combustion systems by injector wear, filter plugging, power loss and corrosion of engine fuel system parts. They also lead to the majority of natural gas vehicle problems, causing reduced drive performance and erratic operation. Water vapor may condense or form ice during large pressure changes.
- Siloxane converts to silicon dioxide (SiO_2) when combusted. SiO_2 can form hard deposits on the inner walls of pipes and valves, cylinder heads, pistons, turbine blades, and heat exchanger surfaces. They can also abrasively erode engine blades or block openings and seals and degrade sensors.
- Ammonia in the fuel gas contributes to NOx production when burned and should be managed or minimized if NOx is a concern.
- Halogenated compounds are corrosive in the presence of water. Combusting halogenated compounds under certain temperature and time conditions can create dioxins and furans, which are highly toxic.
- Particulate matter can wear down equipment and can plug the gas system.

Hydrogen sulfide and siloxanes are the two most significant contaminants due to the extent of damage they can cause. However, different contaminants have different effects, and even the same contaminant can affect each type of distributed generation technology differently. Thus, the feed gas contaminant restrictions will vary depending upon the generation equipment used.

Table 7 summarizes these requirements.

Table 7: Fuel Gas Requirements for Distributed Power Generation Technologies and CNG Vehicles

	Boilers	Reciprocating Engines	Microturbines	Fuel Cells	CNG Vehicles
CH_4	> 50%	> 60%	> 35%	N.D.	> 88%
Hydrocarbon Dew Point					> 10 °F
Hydrocarbons					C_2H_6: <6% C_3+: <3% C_6+: <0.2%
H_2S (ppm)	< 1,000	< 50 – 500	<1,000 – 70,000	< 0.1 – 10	N.D.
Total S (ppm)	N.D.	<542 – 1,742	N.D.	< 0.01 – 50	< 16
Total Inerts					<1.5 – 4.5%
CO_2 (ppm)				< 100 – 500	
CO (ppm)				< 0.001 – 50	< 1,000
Oxygen (%)		< 3%		< 4%	< 1%
Hydrogen (%)					< 0.1%
NH_3 (ppm)	N.D.	< 25	< 200	< 0.05 – 200	
Chlorine (ppm)	N.D.	< 40 – 491	< 200 – 250	< 0.1 – 5	< 1,000
Fluorine (ppm)	N.D.	< 40	1,500	< 0.1 – 5	
Siloxanes (ppm)	N.D.	< 2 (0.03 – 28 mg/m^3)	< 0.005	< 0.01 – 100	< 1
Mercury (mg/m^3)	N.D.	N.D.	N.D.	< 30 – 35	N.D.
Olefins	N.D.	N.D.	N.D.	< 0.2 – 0.5%	N.D.
Dust	N.D.	< 5 mg/kWh	< 20 ppm	N.D.	N.D.
Particle size	N.D.	< 3 µm	< 10 µm	< 10 µm	N.D.

N.D.: Not Determined or not found listed where values are expected to be non-negligible, but data were not found.

Chart Credit: Author; Data Credit: Allegue and Hinge (2012a); Australian Meat Processor Corporation (2014); Krich et al. (2005); Zicari (2003)

LNG is created by cooling natural gas (or biomethane) to about -160 C. Because contaminants will freeze, the gas should contain less than 0.5 ppm H_2O, 3.3 – 3.5 ppm H_2S, 50 – 125 ppm CO_2, 10% C_2 to C_4 hydrocarbons, 1 ppm C_5+ hydrocarbons, and 10% O_2 and N2, as well as have a moisture dew point less than -70 °C.

Gas Pipeline Injection Standards

Natural gas is transported and distributed in California primarily by four investor-owned natural gas utility companies that supply separate regions. In order of descending geographic size, these are: Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDGE), and Southwest Gas Corporation (SWGas).

PG&E services 4.3 million gas customers in 70,000 square mile throughout northern and central California. SoCalGas's 20,000 square miles throughout Central and Southern California, from Visalia to the Mexican border, supplies natural gas to 5.8 million customers. SDGE provides natural gas to 860,000 customers in 4,100 square miles spanning San Diego and southern Orange County. Finally, SWGas's services 187 thousand customers in 2,347 square miles covering roughly one-eighth of San Bernadino County and the area surrounding Lake Tahoe (

Figure 166). In addition to these four, there are numerous other public and private natural gas providers throughout California, but whose sum total coverage area is less than PG&E's and SoCalGas's. Gas companies operating within California are regulated by the California Public Utilities Commission (CPUC).

Figure 16: Map of California Natural Gas Utility Service Areas

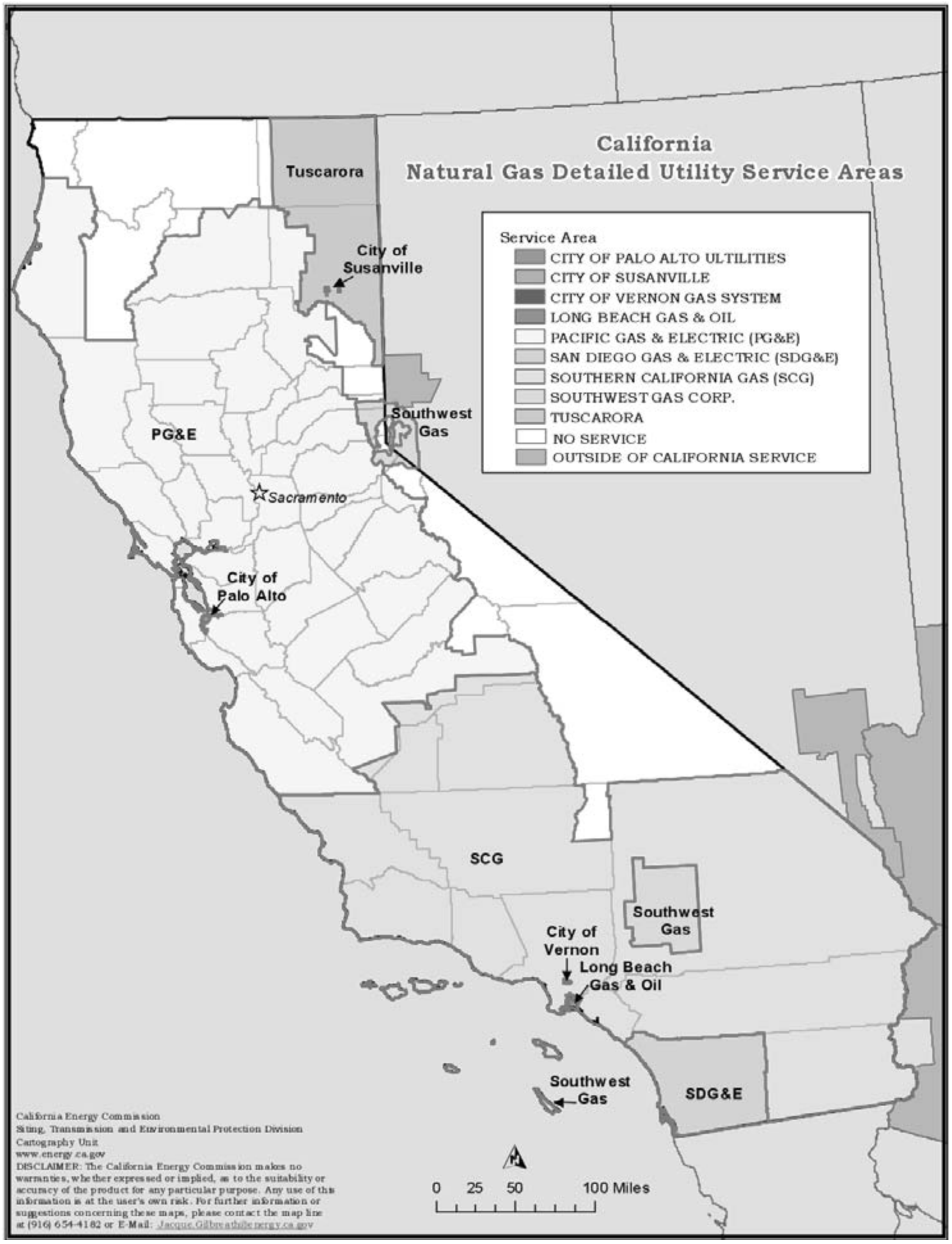


Illustration Credit: California Energy Commission (2012)

Vinyl Chloride in LFG and the Hayden Bill

In the mid-1970s, vinyl chloride was identified as a potent gaseous carcinogen that gave rise to angiosarcoma, a rare form of cancer that develops tumors in vessel walls and the liver. With the development of the plastic PVC industry, which heavily used the chemical, vinyl chloride exposure became an increasing concern throughout the U.S. during the 1980s. Studies investigating sources of vinyl chloride emissions found landfills to be a potential major source in California, emitting low concentrations of vinyl chloride into the air from anaerobic microbial action on organic chlorinated compounds (Molton, Hallen, and Pyne 1987).

As a result of these concerns, Assembly Bill 4037 (Hayden) was passed in 1988 to protect the public from potentially harmful exposure to vinyl chloride present within collected landfill gas that may be transported through natural gas pipelines. This bill specifically dictated that the maximum amount of vinyl chloride that may be found in landfill gas to be 1170 ppbv at the point of pipeline injection, mandated twice monthly sampling of landfill gas for vinyl chloride, and set a $2,500 fine to both the gas producer and pipeline owner if the vinyl chloride limit was exceeded. To avoid the risk of fines and especially forced shutoffs, all of the large gas companies in California refused to accept landfill gas into their pipelines. CPUC General Order No. 58: Standards for Gas Service in the State of California, enacted December 16, 1992, expanded upon the Hayden Amendment by adding concentration limits to hydrogen sulfide and total sulfur.

New Biomethane Standard for Pipeline Injection (Assembly Bill 1900)

Assembly Bill 1900 (Gatto)[3] amended the California Health and Safety Code Section 25420-25422, which defines health and safety limitations of biogas/biomethane use. The goals of AB 1900 were to remove existing barriers to biomethane pipeline injection and facilitate its implementation, including lifting the bans on landfill gas pipeline injection. The Bill required OEHHA, in consultation with other state agencies, to develop standards for biogas focusing on constituents of concern in order to protect human health as well as ensure pipeline integrity and safety. OEHHA and ARB identified 12 potential biogas constituents of concern: Antimony, Arsenic, Copper, p-Dichlorobenzene, Ethylbenzene, Hydrogen sulfide, Lead, Methacrolein, n-Nitroso-di-n-propylamine, Mercaptans (alkyl thiols), Toluene, and Vinyl chloride. A risk management strategy was then developed based upon Trigger, Lower Action, and Upper Action concentration levels in treated biogas (at the point of pipeline injection) for these 12 constituents (Table 8).

At concentrations above the trigger level, the constituent must be routinely monitored (quarterly or annually). The constituents required to be measured depend on the biogas source (i.e., landfill, dairy, POTW), while the frequency of monitoring is set by an initial pre-injection screening evaluation. Typically, testing is conducted annually when below the trigger level, and quarterly when above. A compound's testing interval can be extended from quarterly to annually after consecutive tests show concentrations below the trigger level, but is reset once the trigger level is exceeded. If the lower action level is exceeded three times in a 12 month period or at any time the levels exceed the upper action level, the facility must be shut-off (stop injecting into the pipeline) and repaired. To the author's knowledge, no other state or country has regulations equal or

[3] Chaptered 27 September, 2012 – Chapter 602

similar to those regarding constituents of concern and human health impacts for biomethane injected into natural gas pipeline systems. Aside from hydrogen sulfide and mercaptans, only antimony has been found to be mentioned elsewhere (see the UK Environmental Agency's Quality Protocol: Biomethane from waste).[4]

Table 8: Risk Management Levels for Constituents of Concern in Treated Biogas for Pipeline Injection

Constituent of Concern	Risk Management Levels (Health Based Standards) mg/m³ (ppmv)			Source-Specific Constituents of Concern		
	Trigger Level	Lower Action Level	Upper Action Level	Landfills	POTW	Dairy
Carcinogenic Constituents of Concern						
Arsenic	0.019 (0.006)	0.19 (0.06)	0.48 (0.15)	✔		
p-Dichlorobenzene	5.7 (0.95)	57 (9.5)	140 (24)	✔	✔	
Ethylbenzene	26 (6.0)	260 (60)	650 (150)	✔	✔	✔
n-Nitroso-di-n-propylamine	0.033 (0.006)	0.33 (0.06)	0.81 (0.15)	✔		✔
Vinyl Chloride	0.84 (0.33)	8.4 (3.3)	21 (8.3)	✔	✔	
Non-carcinogenic Constituents of Concern						
Antimony	0.60 (0.12)	6.0 (1.2)	30 (6.1)	✔		
Copper	0.060 (0.02)	0.60 (0.23)	3.0 (1.2)	✔		
Hydrogen Sulfide	30 (22)	300 (216)	1,500 (1,080)	✔	✔	✔
Lead	0.075 (0.009)	0.75 (0.09)	3.8 (0.44)	✔		
Methacrolein	0.075 (0.009)	11 (3.7)	53 (18)	✔		
Alkyl Thiols (Mercaptans)	N.A. (12)	N.A. (120)	N.A. (610)	✔	✔	✔
Toluene	904 (240)	9,000 (2,400)	45,000 (12,000)	✔	✔	✔

Chart Credit: California Air Resources Board and California Office of Health Hazard Assessment (2013)

The CPUC issued Decision (D.) 14-01-034 on January 22, 2014, which required PG&E, SDGE, SoCalGas, and SWGas to change their respective gas tariffs to allow biomethane from all organic sources other than hazardous waste landfills to be injected into the utility's gas pipeline, and develop corresponding concentration standards and monitoring, testing, reporting, and recordkeeping requirements. Subsequently, on February 18, 2014, all four gas companies submitted currently pending advice letters to the CPUC to update their gas tariffs to include the

[4] https://www.gov.uk/government/publications/quality-protocol-biomethane-from-waste

12 constituents of concern and accept non-hazardous waste landfill gas. CPUC Decision (D.) 14-01-034 still prohibits the purchase of biomethane from hazardous waste landfills. The OEHHA/ARB standards will be added to pre-existing gas quality standards set by each company, with the exception of SWGas, which is writing a new tariff document explicitly for biomethane, but will also include other gas quality standards in addition to the constituents of concern.

Prior to the establishment of the 12 constituents of concern for biomethane, the investor-owned utilities (IOUs) published individual natural gas tariffs that specified gas quality requirements. The tariffs normally addressed sulfur species (e.g., hydrogen sulfide, mercaptans) and moisture which can lead to pipeline corrosion, oxygen which promotes microbial growth and can cause explosions, and nitrogen and carbon dioxide that dilute the gas reducing energy content. Biomethane for pipeline injection must meet the specifications for the 12 constituents of concern, as well as the other (natural) gas quality requirements set by the IOUs (

Table 9).[5]

[5] Gas tariffs: PG&E Gas Rule 21; San Diego Gas & Electric Company Rule 30; Southern California Gas Company Rule 30; and Southwest Gas Corporation Rule 22

Table 9: California IOU Gas Quality Standards

Attribute or Compound	PG&E	SoCalGas	SDGE	SWGas
Energy Content (Btu/scf, HHV)	750 – 1150† (990 - 1050)‡	990 – 1150	990 -1150	950 - 1150
Temperature (°F)	60 – 100	50 – 105	50 – 105	40 - 120
Wobbe Index (Btu/scf)	N/A	1279 – 1385	1279 – 1385	≥ 1280
Water Vapor (lb/MMscf)	7	7	7	7
Hydrocarbon Dew Point	45°F at 400 psig if P < 800 psig (or 20°F at 400 psig if P > 800 psig)	45°F at 400 psig if P < 800 psig (or 20°F at 400 psig if P > 800 psig)	20°F at P > 800 psig	20°F
Hydrogen Sulfide (grain/100 scf)	0.25	0.25	0.25	
Mercaptans (grain/100 scf)	0.5	0.3	0.3	
Total Sulfur (grain/100 scf)	1	0.75	0.75	20
Total Inerts (C_1 to C_6+, CO_2, N_2, O_2, CO, H_2)	4%	4%	4%	4%
Carbon Dioxide	1%	3%	3%	2%
Nitrogen				3%
Oxygen	0.1%	0.2%	0.2%	0.2%
Hydrogen	0.1%	0.1%	0.1%	0.1%
Ammonia	0.001%	0.001%	0.001%	0.001%
Biologicals	40,000/scf, Free of < 0.2 μm filter	40,000/scf, Free of < 0.2 μm filter	40,000/scf, Free of < 0.2 μm filter	40,000/scf, Free of < 0.2 μm filter
Siloxane (mg/m³)	0.1: Lower Action 0.01: Trigger	0.1: Lower Action 0.01: Trigger	0.1: Lower Action 0.01: Trigger	0.1: Lower Action 0.01: Trigger
Mercury (mg/m³)	0.08	0.08	0.08	0.08

† Normal PG&E range of higher heating values. PG&E dictates that the interconnecting gas shall have a heating value that is consistent with the standards established by PG&E for each Receipt Point.

‡ Typical higher heating value for a PG&E receipt point.

Chart Credit: PG&E (2014); SoCalGas (2014); SDGE (2014); SWGas (2014)

The gas tariffs referenced in

Table 9 also address dust, sand, dirt, gums, oils, liquids, and other substances that would cause gas to be unmarketable or are injurious to utility facilities, employees, customers, or the general public—e.g., bacteria, pathogens, and hazardous substances including but not limited to toxic and/or carcinogenic substances and/or reproductive toxins.

Note that the OEHHA/ARB biomethane trigger levels are maximums that the IOUs must follow. The IOUs can set lower contaminant maximum concentrations. For instance, the OEHHA/ARB trigger level for hydrogen sulfide is 22 ppm, while three of the four IOUs specify hydrogen sulfide concentrations less than 4 ppm.

In addition to the various contaminants that must be tested, a significant concern among the biogas industry regards the relatively high energy content (or higher heating value [HHV]) of upgraded biomethane required by the pipeline tariffs. Unlike natural gas, biogas does not naturally contain larger hydrocarbon compounds (i.e., ethane, propane, butane, etc.) that would help increase the HHV. Unless enriched with higher energy hydrocarbon gases, biogas generally relies solely upon methane for its HHV. The gross energy content of pure methane is approximately 1012 Btu/scf, meaning that biogas would need to be upgraded to at least 97.8% methane to meet the 990 Btu/scf requirement of the three largest IOUs (Southwest Gas appears to accept 950 Btu/scf (HHV) gas (Table 9). Although technologies exist to upgrade biogas up to 98 – 99% methane, they are expensive and complex. Simple, low-cost upgrading techniques that are cost-effective for small-scale applications can only upgrade biogas to around 95 – 97% methane (e.g., 960-980 Btu/scf (HHV)). While it is allowable to add a small amount of higher energy hydrocarbon to upgraded biomethane in order to boost energy content (e.g., propane which has gross energy of 2557 Btu/scf, or mixing w/ a larger amount of natural gas before injection), biomethane advocates would like the HHV requirement be reduced from 990 Btu/scf to around 960 Btu/scf—similar to the values used in other states and countries.

A number of natural gas pipeline companies in other states and countries accept gas lower than 990 Btu/scf (HHV) (Tables 10, 11). (Foss 2004). Table 10 lists pipeline injection gas quality requirements for US gas companies that accept biomethane. Energy content requirements for other US gas companies are all lower than 990 Btu/scf with some as low as 950 Btu/scf (corresponds to methane concentration of about 94%). The standards for common gas contaminants (i.e., hydrogen sulfide, mercaptans, total sulfur, total inerts, carbon dioxide, nitrogen, oxygen, hydrogen, and moisture) are comparable.

e 10: United States Natural Gas Pipeline Companies' Gas Quality Standards for Pipeline Injection

North Pacific US	New Mexico	Texas	Southern US	Kansas	Michigan	Midwest US	New England
Williams Northwest Pipeline	New Mexico Gas Company	Atmos Energy	Gulf South Pipeline Company	Kansas Gas Service	Westcoast Energy Inc.	Northern Natural Gas	Algonquin Gas Transmission
La Plata A / La Plata B		Core Area / West Area			Raw / Processed		
≥ 985	950 – 1100	950 – 1100	950 – 1175	950 – 1100	≥ 966	≥ 950	967 – 1110
40 – 120 °F / ≤ 120 °F	40 – 120 °F	40 – 120 °F	40 – 120 °F	25 - 120 °F	≤ 49 – 54 °C / ≤ 54 °C	≤ 120 °F	
							1314 – 1400
7		7		7	4	6	7
15 °F at 100 – 1000 psia	15 °F at 100 – 1000 psia	40 °F		25 °F			15 °F
	0.20 gal / 1000 scf		0.20 gal / 1000 scf				C_2+: 12% C_4+: 1.5%
0.25	0.25	0.25	1	0.25	6.6 – 131 / 0.26	0.25	0.5
	0.3	1					
0.75 / 5	0.75	5	20	0.5	N.A. / 1	20	5
					0.7%		
3%	5%	4% / 3%					4%
2%	2%	2%	3%	2%	2%	2%	2%
			3%				
0.1% / 0.2%	0.2%	0.05%	0.2%	0.01%	N.A. / 0.4%	0.2%	0.2%
			0.04%				
			Tech. free†				
Tech. free			Tech. free				

free

Table 11: Non-U.S. Gas Quality Standards for Pipeline Injection, Part I

Country	Austria	Austria	Austria		Belgium		BC, Canada	Germany	
Organization			Gas Connect Austria		Fluxys		FortisBC	DVGW	
Year	2006	2010	2014		2014		2014	2010	
Level	Biogas		Entry-Exit	Point-to-Point	Low	High	Biomethane	Low	High
Methane content	≥ 96%		≥ 85.0%	≥ 85.0 - 89.7%					
Higher heating value (Btu/scf)		1034 – 1,237	1,034 – 1,237	956 – 1,498	920 – 1,038	1,043 – 1,234	≥ 966	811 – 1,266	811 – 1,266
Temperature (°C)			≤ 50	≤ 42 - 50	2 - 38	2 - 38	≤ 54		
Wobbe Index (Btu/scf)		1,285 – 1,517	1,304 – 1,498	1,304 – 1,498	1,179 – 1,258	1,335 – 1,495		1,016 – 1,256	1,237 – 1,517
Water vapor	≤ -8 °C at 40 bar	≤ -8 °C at 4 Mpa	≤ -8 °C at 64 bar	≤ -7 °C at 39 - 40.2 bar; ≤ -8 °C at 40 - 64 bar	≤ -8 °C up to 69 barg	≤ -8 °C up to 69 barg	≤ 65 mg/m³		
Hydrocarbon Dew Point		≤ 0 °C at max op. pressure	≤ 0 °C at 1 - 70 bar	≤ -5 °C at 39 - 69 bar; ≤ 0 °C at 1 - 70 bar	≤ -2 °C up to 69 barg	≤ -2 °C up to 69 barg			
Ethane			≤ 7.0%	≤ 6.0 - 7.0%					
Propane			≤ 3.0%	≤ 3.0%					
Hydrocarbons (C3+)				≤ 2.1%					
Butane			≤ 2.0%	≤ 2.0%					
Hydrocarbons (C5+)			≤ 1.0%	≤ 1.0%					
Hydrogen Sulfide (mg/m³)	≤ 5	< 5	≤ 6.8	≤ 5.4 - 6.8	≤ 5	≤ 5	≤ 6	≤ 5	≤ 5
Mercaptans (mg/m³)	≤ 6	< 6	≤ 16.9	≤ 15.75 - 16.9	≤ 6	≤ 6		≤ 6	≤ 6
COS (mg/m³)		< 5			≤ 30	≤ 30			
Total Sulfur (mg/m³)		< 10	≤ 120.0	≤ 105.0 - 120.0			≤ 23	≤ 30	≤ 30
Carbon Dioxide	≤ 3%	< 2%	≤ 2.0%	≤ 1.575 - 2.0%	≤ 2.5%	≤ 2.5%	≤ 2%	≤ 6%	≤ 6%
Nitrogen		< 5%	≤ 5.0%	≤ 2.1 - 5.0%					
Oxygen	≤ 0.5%	< 0.5%	≤ 0.02%	ND - 0.02%	≤ 0.1%	≤ 0.1%	≤ 0.4%	≤ 3%	≤ 3%
Ammonia	ND	ND							
Hydrogen	≤ 4%	< 4%						≤ 5 %	≤ 5 %
Halocarbons (mg/nm³)	0	ND							
Siloxanes (mg/nm³)	≤ 10						≤ 1		

Chart Credit: Author

Table 12: Non-U.S. Gas Quality Standards for Pipeline Injection, Part II

Country	Hungary		Ireland	Netherlands		Sweden	Sweden	UK	UK
Organization			Gaslink				Swedegas		Scotia Gas Networks
Year	2010		2013	2012		2011	2014	2014/1996	2014
Level	2S	2H		G-gas [Lower]	H-gas [Higher]	Biogas Fuel			
Methane content						≥ 97%			78 - 100%
Higher heating value (Btu/scf)	832 – 1,215	832 – 1,215	990 – 1,135				980 – 1,278		671 – 1,181
Temperature (°C)			1 - 38				0 – 50		0 - 20
Wobbe Index (Btu/scf)	974 – 1,116	1,225 – 1,470	1,267 – 1,380	1,166 – 1,264	1,261 – 1,543		1,315 – 1,527	1,267 – 1,380	1,208 – 1,449
Water vapor			≤ 50 mg/m³			≤ -9 °C at 200 bar	≤ -8 °C at 70 bar		-100 - 20 °C
Hydrocarbon Dew Point	≤ 4 °C at 4 Mpa	≤ 4 °C at max op. pressure	≤ -2 °C up to 85 barg						-100 - 20 °C
Ethane			< 12%						
Propane									≤ 7%
Hydrogen Sulfide (mg/m³)	≤ 20	≤ 20	≤ 5	≤ 5	≤ 5	≤ 10	≤ 5	≤ 5	≤ 10
Mercaptans (mg/m³)				≤ 10	≤ 16				
Total Sulfur (mg/m³)	≤ 100	≤ 100	≤ 50	≤ 45	≤ 45	≤ 23	≤ 10	≤ 50	
Carbon Dioxide			≤ 2.5%			≤ 3%	≤ 2.5%		≤ 7%
Nitrogen			≤ 5%						
Oxygen	≤ 0.2%		≤ 0.2%	≤ 0.5%	≤ 0.5%	≤ 1%	≤ 0.1%	≤ 0.2%	≤ 2.5%
Ammonia (mg/nm³)						≤ 20			
Hydrogen			< 0.1%			≤ 0.5%		≤ 0.1%	
Organo Halides (mg/nm³)			< 1.5						
Radioactivity (Becquerels/g)			< 5						

Chart Credit: Author

The California IOUs' 990 Btu/scf specification is a historical number for their natural gas supply. Taking into account the potential impacts on the pipeline system and end-users, the IOUs assert that although other states may have lower HHV requirements, their own HHV requirements should depend upon the historical quality of gas delivered since lowering the heating value or allowing noncompliant biomethane access to the system may have detrimental effects on end-use customer equipment and may not be compatible with many systems already in place (Inside EPA 2013). Specifically, some legacy gas equipment may not have burner geometry or controls that can be adjusted for small changes in gas purity. Consequently, this could potentially lead to equipment instabilities, flashbacks, or flameout conditions.

In practice, however, injected biomethane will constitute a small proportion of the overall gas supply under most circumstances, and would have negligible impact to bulk gas quality, assuming complete mixing. However, in some circumstances, complete mixing may not always occur. A modeling study by the National Energy Technology Lab in 2007 found that when injecting gas of different composition, steady injections would mix within a short distance of typically 100 pipe diameters, while for certain transient injections, the two gases could flow well-defined for large distances (> 100 km) before mixing. In addition, depending upon pipeline size and route at the point of injection, the biomethane may comprise the majority of gas.

For the cases where the biomethane producer purchases natural gas for blending with biomethane prior to injection in order to meet the HHV requirement, it should be noted that the gas quality standards set by AB 1900 (the 12 constituents of concern (COCs)) do not apply to natural gas. The 12 COCs were not evaluated for natural gas and it is possible that mixing natural gas with biomethane prior to injection in order to meet the energy content or other tariff requirements can introduce one or more of the COCs such that the mixture does not meet the injection quality requirements. For example the ARB report detailing the constituent of concern noted that concentrations of benzene and alkyl thiols are higher in natural gas than in biogas from all sources. To remedy this issue, the COC standards should apply before biomethane is mixed with natural gas for energy content enhancement rather than for the mixture at the point of injection.

It is also important to be aware that having a pipeline nearby does not necessarily mean that it can be used for biomethane injection. The specific pipeline's capacity must be taken into account. Not all pipelines, especially low pressure pipelines and those with low seasonal usage, can handle gas receipt.

To ensure unhindered project development, an IOU should be contacted as early as possible when exploring the option of pipeline injection. SoCalGas recommends working with them 18 – 24 months in advance of the desired in-service date. The IOUs may also have other requirements or preferences that may affect how the project is developed. For example, SoCalGas prefers that they provide the design and interconnector builds. A utility interconnection fee is considered to be one of the most expensive capital costs of pipeline biomethane implementation. However, the cost of implementing biogas cleaning and upgrading can be even more expensive. To assist with the high capital costs, SoCalGas provides an optional Biogas Conditioning and Upgrading Services Tariff (G-BCUS) in which SoCalGas will plan, design, procure, construct, own, operate and maintain the biogas conditioning and upgrading equipment on the customer's premises. The customer will be the sole owner of the treated gas before, during, and after the process until it is formally sold to SoCalGas. The customer is also responsible for ensuring that the treated biomethane meets Rule 30 standards for pipeline injection. Currently, for the second phase of AB 1900 implementation, the CPUC is addressing cost issues related to biogas pipeline injection, including those for interconnection. The economic feasibility of biomethane pipeline injection is discussed in Chapter 7 of this report.

Assembly Bill 2196

In addition to AB 1900, there are state regulations that dictate prerequisites for eligible biomethane pipeline injection. Assembly Bill 2196 (Chesbro): Renewable Energy Resources, specified requirements for RPS-eligible biomethane that is delivered to a generating facility via common carrier pipeline (Chesbro 2012). It requires:

(1) The biomethane to be injected into a common carrier pipeline that physically flows within California or toward the eligible generating facility that contracted for the biomethane;

(2) Sufficient renewable and environmental attributes of biomethane production and capture to be transferred to the retail seller or local publicly owned utility that uses that biomethane to ensure that any electric generation using the biomethane is carbon neutral, and that those attributes be retired, and not sold, as specified; and

(3) The source of biomethane to demonstrate that the reduction in emissions through capture and injection of biomethane causes a direct reduction of air or water pollution in California or alleviates a local nuisance within the state that is associated with the emission of odors (Chesbro, 2012).

In developing future policies to promote biomethane pipeline injection, the U.S. and California can look to the experience of other countries for guidance. A prime example is the German Renewable Energy Act, which established priority for the connection, purchase, and transmission of electricity produced from renewable resources while setting a fixed fee for electricity paid by grid operators for a 20-year period. Related to specifically biogas, it also established feed-in tariffs based upon power output and input materials, as well as bonuses for biogas upgrading and the use of renewable primary products or cultivated biomass. Further endorsement of biogas came with changes to Germany's Gas Network Access Ordinance (Gasnetzzugangsverordnung – GasNZV) in 2008 whereby a biomethane pipeline injection target of 6% of natural gas consumption (60 TWh) by 2020 and 10% (100 TWh) by 2030 was formed. GasNZV also gave preferred pipeline entry and access to biomethane and stated that it cannot be denied by the grid operator under the premise of an existing capacity shortage. With regards to grid access costs, the interconnection (up to 10 km), gas pressure metering plant, compressor, and calibrated measurement plant are split between the grid operator (75%) and the biomethane supplier (25%, up to €250k). The grid operator also covers the operation and maintenance costs.

Another interesting concept to consider is that Germany, Belgium, France, Hungary, the Netherlands, and Switzerland have two gas standards since gas of different qualities is supplied to different regions: one for low quality natural gas (e.g., 89% flammable gas) and another for high quality natural gas (e.g., 97% flammable gas). This would invariably require significant infrastructure changes and developments that are likely impractical for California. However, these may be possible to implement at a small scale by having dedicated biogas pipelines that send the gas to a committed end user.

CHAPTER 5: Biogas Cleaning Technologies

Raw biogas needs to be cleaned to remove toxic and harmful constituents (e.g., hydrogen sulfide, ammonia, VOCs, halides, moisture, siloxanes, particulates, AB 1900 COCs, etc.) to meet regulatory and technical standards. The principle cleaning techniques used currently include adsorption, biofiltration, water scrubbing (an absorption process), and refrigeration. Most contaminants can be removed by adsorption onto a porous material or by scrubbing the gas with water. Hydrogen sulfide can also be removed biologically by biofiltration. Moisture is typically removed by cooling the gas to condense the water which can be drained from the system.

This chapter focuses on post-production gas treatment processes, which can be applied to all biogas sources. In-situ technologies, such as sulfide precipitation, which can only be applied to digester systems, are not discussed in detail. Gas upgrading to biomethane (removal of CO_2) techniques are discussed in Chapter six.

Adsorption

Adsorption is the adhesion of compounds onto a solid surface. When biogas is flushed through an adsorbent bed, contaminant molecules will bind to the adsorbent's surface, removing the contaminants from the gas stream. Some adsorption systems induce reactions between the contaminant and adsorbent (or involve a catalyst) that creates a stable or non-harmful compound that can be removed from the adsorbent. Effective adsorbents are generally highly porous with high surface area which greatly increases their removal capacity. The pores can additionally act as physical traps for certain compounds.

Activated Carbon

The most commonly used adsorbent is activated carbon (AC), owing to its low costs, widespread availability, high surface area, and adsorptive affinity for most compounds present in biogas: hydrogen sulfide, carbon dioxide, moisture, VOCs, halides, siloxanes, etc., with the exception of ammonia. AC is a highly porous powdered or granulated carbon material created by heating carbonaceous matter—biomass or charcoal—under high temperatures of 600 – 1200 °C. With surface areas of 500 – 2500 m^3/g (usually around 1500 m^3/g), contaminants become trapped within the many micropores. Typically, 20 – 25% loading by weight of H_2S can be achieved. AC can then be thermally regenerated using the same process in which it was made. However, it is more economically favorable to simply purchase new AC material from a supplier than onsite regeneration using this method. To increase AC's adsorption capacity and affinity for certain compounds, AC can be impregnated with alkaline or oxide solids. Sodium hydroxide, sodium carbonate, potassium hydroxide, potassium iodide, and metal oxides are the most common coatings employed. However, there is greater difficulty in handling and disposing of caustic-impregnated carbon. To further assist in the adsorption of H_2S, air can be added to the biogas, causing some H_2S to convert to elementary sulfur and water.

Zeolites
Another common adsorbent are zeolites—naturally occurring or synthetic silicates with extremely uniform pore sizes and dimensions. Generally, polar compounds (e.g., water, H_2S, SO_2, NH_3, carbonyl sulfide, mercaptans) are very strongly adsorbed by zeolites. A typical zeolite's adsorption preference, from high to low, is: H_2O, mercaptans, H_2S, and CO_2. But, depending upon their chemical composition and pore size, different zeolites have greater affinities for different compounds. For example, clinoptilolite has a strong affinity for ammonia. Zeolite 13X is commonly used for the desiccation, desulphurization and purification of natural gas. With a pore size of 8 Å, it is capable of co-adsorbing H_2O, H_2S, and CO_2.

Molecular Sieves
Carbon molecular sieves are also commonly employed as an alternative to activated carbon and zeolites. As opposed to activated carbon and zeolites which are primarily equilibrium adsorbents that rely upon the capacity to adsorb more contaminants than methane, carbon molecular sieves are kinetic adsorbents that have micropores allowing contaminant molecules to penetrate faster than methane. However, note that activated carbon and zeolites can also act as molecular sieves.

Alkaline Solids
Alkaline solids can also be used for acid gas removal, relying upon chemical adsorption versus physical adsorption used by activated carbon and zeolites. Alkaline solids react with acid gases like H_2S, SO_2, CO_2, carbonyl sulfides and mercaptans in neutralization reactions, removing about 112.5 g CO_2/kg of media and 10 g H_2S/kg media. Synergistic mixtures of hydroxides can be used to improve the contaminant loading. When alkaline solids are dissolved in solution, they can be used for biogas upgrading. This is more deeply discussed in a later section about biogas upgrading on page 69.

Iron Sponge
Iron and zinc oxide/hydroxide particles can also be used to remove sulfurous compounds (iron or zinc sponge). Hydrogen sulfide endothermically reacts with these compounds to form metal sulfides and water. The optimal temperature range for this reaction is between 25 – 60 °C for iron oxides and 230 – 430 °C for zinc oxides. The metal oxide/hydroxide particles are often embedded onto wood chips. Due to the heat produced by the reaction, the material can become pyrophoric—spontaneously combust in air if allowed to dry out. Fortunately, the reaction requires water, so the biogas does not need to be dried prior to this stage. However, condensation in the sponge bed should be avoided since water can coat or "bind" metal oxide material, somewhat reducing the reactive surface area. It is therefore important to maintain proper humidity in the sponge bed.

A loading of roughly 20 kg H_2S/100 kg sorbent can be achieved with iron sponges. Iron sponges can be regenerated by aeration, by which atmospheric oxygen reattaches to the iron, and releasing the sulfur as elemental sulfur. Typically, dual or multiple reaction beds are installed, with one bed undergoing regeneration while the other is operating to remove H_2S from the biogas. Iron sponge beds can regenerated roughly 15 times before their removal efficiency drops to a level that requires replacement. Iron sponges can sometimes fuse together, requiring a high-pressure water jet for removal. Zinc oxides are more selective than iron oxides and have maximum sulfur loadings typically in the range of 30 – 40 kg sulfur/100 kg sorbent. However, they are also more expensive than iron oxides and the reaction is irreversible, meaning that zinc oxides must be replaced after each cycle. Thus, iron oxides are usually favored for their lower maintenance requirements and costs. Although metal oxides are effective at removing hydrogen sulfide, they are not very reactive with organic sulfur compounds (e.g., mercaptans). Catalytic hydrodesulfurization can be implemented to convert organic sulfur compounds into hydrogen sulfide for removal.

Iron compounds can also be used for in-situ sulfide precipitation within digester systems. Iron salts added to a digester react with H_2S and induce the precipitation of insoluble iron sulfide salt particles. This process is relatively inexpensive and will also remove ammonia, but is less effective in maintaining low and stable H_2S levels.

Silica Gel
Silica gel or aluminum oxide can remove siloxanes and moisture by trapping them within their crystalline structure. They are easily regenerated by drying at high temperatures and pressures.

General Adsorption Attributes
The adsorbent must be replaced once it is filled or can be regenerated a limited number of times. This is contributes to operational cost.

In general absorption systems are simple to operate, require minimal maintenance, have a small space requirement, and are inexpensive. Basic construction consists of the adsorbent housed inside a vessel or drum with a gas inlet and outlet. The majority of adsorbents can remove most of the contaminants found in biogas to a high degree or at least partially, though they are typically sensitive to moisture and particulates. Adsorption systems are commonly applied as a biogas pretreatment step before biogas upgrading to avoid poisoning the upgrading chemical and to lower the upgrading material's regeneration requirements.

Water Scrubbing

Water scrubbing relies upon the principle that gases will dissolve (or absorb) into a liquid to maintain a pressure-dependent equilibria (Henry's Law). Water is commonly used as the working liquid since it is readily available, inexpensive, nontoxic, and is free of the contaminants that are desired to be removed (ensuring that the contaminant gases will dissolve into it). In addition, methane has a lower water solubility than the majority of contaminants, making the process highly effective in retaining methane in the gas phase.

Water scrubbers are commonly designed to have biogas finely bubbled up through a tall vertical column of downward-flowing water. Mist eliminators at the gas outlet location minimizes water droplets from escaping the system. A variant of the common water scrubber is the atomized mist scrubbers, in which atomized water droplets are sprayed into the gas stream. These systems however have a slow response to rapid variations in gas contaminant concentrations.

Water scrubbers are cost-effective for high flow rates, and have a small space requirement. They are especially effective at removing H_2S, NH_3, VOCs, and siloxanes. However, for low pressure water scrubbing, absorbed contaminants are not easily purged so it is not effective to recycle the used water. In addition, the product gas will always be moisture-saturated. Any added water will increase drying costs, although the biogas will likely already be saturated with moisture. The primary drawback of water scrubbing is the fact that any O_2 and N_2 dissolved in the water from the atmosphere can be released into the biogas. Consequently, water scrubbing may not be optimal in applications where high HHVs are required such as R-CNG/R-LNG production or pipeline injection. Above ambient pressures, water scrubbers can also be used to effectively remove CO_2. This aspect of water scrubbing is discussed at greater lengths in a later section about biogas upgrading on Page 71.

Biofiltration

Biofiltration relies upon the natural biological metabolism of sulfur-oxidizing bacteria species to convert hydrogen sulfide into elemental sulfur or sulfate. These microbial species include *Beggiatoa* and *Paracoccus*, with the most common and utilized being *Thiobacillus*. Biofiltration systems are designed to ensure a high-density microbial community and maximize contact between the microorganisms and the feed gas.

Biofiltration systems can be set up in three different configurations: bioscrubber, biofilter, and biotrickling filter (Figure 17). In a bioscrubber, pollutants are absorbed into liquid flowing counter-currently through an absorption column, similar to a water scrubber. The liquid is then sent to a bioreactor for microbes to degrade the contaminants. A biofilter consists of a packed bed of organic material that stimulates biofilm growth through which humidified biogas is pumped. Contaminants in the biogas contact absorb and adsorb into the biofilm and interact with the microbes. Although biofilters are the most commonly used (compared to bioscrubbers and biotrickling filters), H_2S-induced acidification due to the static medium can occur, which hinders microbial activity and can render biofilters ineffective for long-term H_2S removal for gas streams with high H_2S inlet concentrations. Biotrickling filters overcome this problem by combining biofilters with bioscubbers. Biotrickling filters contain a packed bed of chemically inert materials that provide large surface area for gas contact biofilm accumulation. Biogas is injected up through the column while liquid counter-currently flows down, providing contaminant absorption, delivering nutrients to the microbes, and controlling the pH. Biogas is mixed with 4 – 6% air before entry into the filter bed to supply sulfur-oxidizing microorganisms with O_2 needed for the conversion of H_2S to S_2 and H_2S_4O.

In lieu of biofiltration, the air or oxygen can be injected directly into the digester head space, allowing sulfate-oxidizing microorganisms to naturally grow on the head space surfaces without requiring inoculation. Head space microbial H2S removal is less effective than biofiltration.

Figure 17: Biofiltration Process Schematic—A) Bioscrubber, B) Biofilter, C) Biotrickling Filter

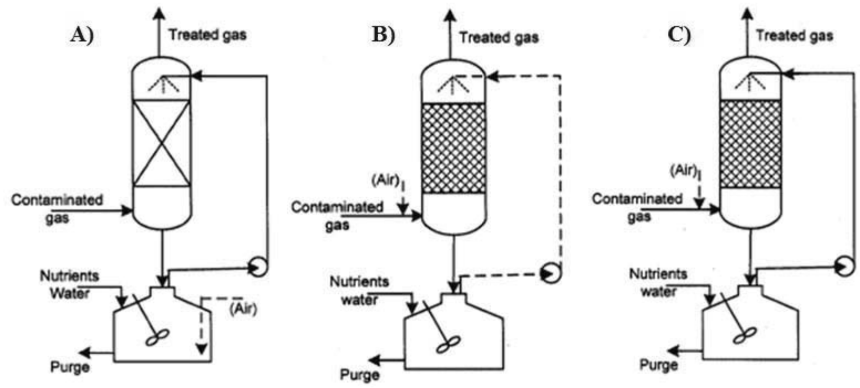


Illustration Credit: American Biogas Council (2014)

Biofiltration systems are effective at treating low and high concentrations of H_2S, from 50 – 100 ppm to 2,000 – 4,000 ppm, achieving 89 – 99.9% H_2S removal at a rate of 20 – 125 g $H_2S/m^3/h$. They can also achieve > 90 – 99% VOC removal, in addition to ~ 92% ammonia removal at low H_2S concentrations of around 200 ppm and ~ 30% ammonia removal at higher H_2S concentrations. Yet, due to being a biological process, biofiltration system performance is subject to variations depending upon environmental conditions such as temperature, pH, moisture, nutrient concentrations, and microbial community. The majority of microbes grow and function optimally near 35 °C and neutral pH. Wide deviations from these levels will negatively impact the efficiency of the biofiltration unit (Rattanapan and Ounsaneha 2012). The optimal moisture content for biofilters varies from 20 to 60 wt%.

Biofiltration units have relatively low capital costs due to its simple design with minimal control and system connections needed, requiring only a basic vessel, pumps, and inexpensive media. Biofiltration systems also benefit from low operating costs since no chemicals are needed, there are no large inorganic waste flow requiring disposal, almost no utilities are necessary, and they have high energy efficiencies.

However the characteristics of biological processes inlcude several drawbacks. Biofiltration units require a 1 – 3 month start-up time before achieving high and consistent performance, are susceptible to unforeseen performance drops by loading shocks, and can experience clogging from excessive microbial growth. The addition of air for the microbes introduces N_2 and O_2 to the gas, which are difficult to remove and this generally rules out biofiltration systems for the production of pipeline-quality or vehicle fuel gas. They also require a large space and the media must be replaced or washed (every 2 – 4 years for organic media, 10 years for inorganic media), since the pressure drop through media increases with media age. Nevertheless, biofiltration systems work synergistically with anaerobic digesters and can be applied on farms and wastewater treatment plants that plan for distributed power generation.

Refrigeration/Chilling

Refrigeration, or gas cooling, provides a simple means for removing moisture from biogas. When the gas is cooled (typically to between -18 – 2 °C), water vapor condenses on the cooling coils and can be captured in a trap. Some ammonia will also be removed given the high solubility of ammonia in water. Insignificant trace amounts of other compounds may also be absorbed into the water. At lower temperatures of < -73 °C, VOCs will condense and can be removed too. At -70 °C, 99% removal of siloxane can be achieved as well, but it is costly to operate at such low temperatures.

H_2S should be removed prior to refrigeration to significantly lengthen the life of the refrigeration unit. The power needed for refrigeration is minimal—generally less than 2% of the biogas energy content (Krich et al. 2005).

When only limited moisture removal is necessary, a rudimentary alternative to refrigeration is to bury the gas line underground over a long distance with a condensate trap attached. The cool underground temperatures will induce some moisture to condensate, but will not reach the high moisture removal achieved by refrigeration.

Biogas Cleaning Technology Comparison

Raw biogas contains a variety of compounds aside from methane. These include hydrogen sulfide (H_2S), oxygen (O_2), nitrogen (N_2), volatile organic compounds (VOCs), siloxanes, and moisture (H_2O). To remove these contaminants, adsorption, water scrubbing, biofiltration, and/or refrigeration processes are employed. Each of these technologies is able to treat different contaminants to various degrees (Table 13).

Table 13: Contaminant Treatability for Biogas Cleaning Technologies

Biogas Cleaning Process	H_2S	O_2	N_2	VOCs	NH_3	Siloxanes	H_2O
Adsorption	**	/	-	**	*	**	**
Water Scrubbing	**	--	--	**	**	**	--
Biofiltration	**	--	--	**	/	/	--
Refrigeration	/	-	-	/	**	*	**

Legend: ** High removal (intended) * High removal (pre-removal by other cleaning technology preferred) / Partial removal
- Does not remove -- Contaminant added **R** Must be pretreated

Two symbols may be in the same box if one or the other can be applicable

Chart Credit: Severn Wye Energy Agency (2013); Starr et al. (2012)

To operate effectively, each biogas cleaning technology also requires different operating conditions and specific consumables that must be replaced at regular intervals. The features of these cleaning technologies are summarized in Table 14.

Table 14: Features of Biogas Cleaning Technologies

Process	Pressure (psig)	Temperature (°C)	Sulfur Pre-Treatment	Consumables
Adsorption	0 – 100	25 – 70	Not needed	Adsorbent
Water Scrubbing	0	20 – 40	Not needed	Water; Anti-fouling agent; Drying agent
Biofiltration	0	35	Not needed	Water; Drying agent
Refrigeration	0 – 58	-29 – 5	Preferred / Required	Refrigerant

Chart Credit: Severn Wye Energy Agency (2013); Starr et al. (2012)

The primary contaminant in raw biogas, with the exception of inert compounds, is hydrogen sulfide. Hydrogen sulfide can be removed via physical adsorption by activated carbon, biofiltration, and chemical adsorption by iron and zinc oxides and hydroxides. Table 15 compares the requirements and efficiencies of these technologies.

Table 15: Comparison of Biogas H_2S Removal Technologies

	Method	Relativity to Digester	Outlet H_2S Concentration	O_2 Required	Desulphurization
Adsorption	Activated Carbon	External	50 – 250 ppm	No	Primary
	Impregnated activated carbon	External	< 1 ppm	Yes	Precision
	Iron salts	Internal	100 – 150 ppm	No	Primary
	Iron hydroxide	Internal	100 – 150 ppm	No	Primary
	Iron oxide/hydroxide	External	< 1 ppm	Yes	Precision
	Zinc oxide	External	< 1 ppm	No	Precision
Biofiltration	Biofiltration	Internal / External	50 – 200 ppm	Yes	Primary
	Biofiltration + Lye scrubber	External	20 – 100 ppm	Yes	Primary

Chart Credit: Beil and Hoffstede (2010)

All of these technologies can be applied for boilers and microturbines, which have the highest sulfur tolerances of any biogas utilization equipment. Reciprocating engines can potentially use every technology, but the removal system would need to operate near the lower end of the possible H_2S outlet range. Fuel cells require precision desulfurization techniques since the highest H_2S concentration that any fuel cell can handle is 50 ppm, while most require less than 10 ppm. As a standalone process, precision desulfurization would also be necessary for pipeline injection in California since the IOUs require 4 ppm H_2S (0.25 grain/100 scf). Zinc oxide would be recommended since it does not require O_2 addition (N_2 will also not be added since air is commonly used to add O_2), as O_2 and N_2 are difficult to remove. However, it is common to instead use a primary desulfurization system as H_2S pretreatment, and then rely upon the biogas upgrading system for precision-level H_2S removal.

Note that there can be several exceptions to the H_2S outlet concentrations listed in Table 15, as the actual performance depends upon the inlet concentration and varies from one manufacturer to another. For example, DARCO® H_2S (Cabot Norit) is an activated carbon product that is advertised to treat gas streams as low as < 10 – 20 ppm of H_2S down to undetectable levels. Thiopaq® (Paques) is a biotrickling filter with alkaline solution gas pre-treatment that can reduce H_2S concentrations to below 4 ppmv, although typical outlet concentrations range from 5 – 100 ppm.

CHAPTER 6: Biogas Upgrading Technologies

The primary function of biogas upgrading involves removing CO_2 to improve gas quality by increasing the volumetric energy content. Upgrading is usually necessary for natural gas pipeline injection or vehicle fuel applications. The most widely commercialized and used upgrading technologies are those that have been long employed by the natural gas industry—pressure swing adsorption (PSA), chemical solvent scrubbing (using amines), and pressurized water scrubbing. Newer technologies that have recently broken into the market by improving efficiencies, lowering costs, or decreasing the footprint include physical solvent scrubbing (using glycols), membrane separation, and cryogenic distillation. There are also a number emerging gas upgrading technologies in the research and pilot phase that claim lower operating costs as well as simpler and more compact process designs (e.g., rotary water scrubbing, supersonic separation, industrial lung).

Although the main purpose of biogas upgrading technologies is to remove CO_2 from the gas stream, other contaminants may also be removed. However, specific contaminant pre-treatment (especially for hydrogen sulfide) is usually recommended to improve the adsorbent's or absorbent's lifetime, lower regeneration costs, and reduce maintenance intervals. The following sections describe upgrading technologies, provide details into different operating options, and assess their advantages and disadvantages.

Pressure Swing Adsorption

Pressure swing adsorption (PSA) is a method for the separation of carbon dioxide from methane by adsorption/desorption of carbon dioxide on zeolites or activated carbon at alternating pressure levels. This technology is most prevalently applied in in the gas treatment industry as because it is also effectively removes volatile organic compounds, nitrogen and oxygen from industrial gas streams. PSA requires a pressure between 1 – 10 bar, but often 4 – 7 bar, and a temperature of 5 – 35 °C. Upon pressurization, CO_2 (and some other contaminants) preferentially adsorb onto the media. The remaining unadsorbed gas, rich in methane, is transferred out of the vessel. When pressure is reduced in the vessel, the captured gases desorb and can be vented or sent elsewhere. Typically, multiple vessels are used in parallel to smooth gas production rate and improve energy efficiency.

Figure 18 shows a four-vessel pressure swing adsorption system using carbon molecular sieves, cycling between absorption and regeneration.

Figure 18: Pressure Swing Adsorption Process Diagram

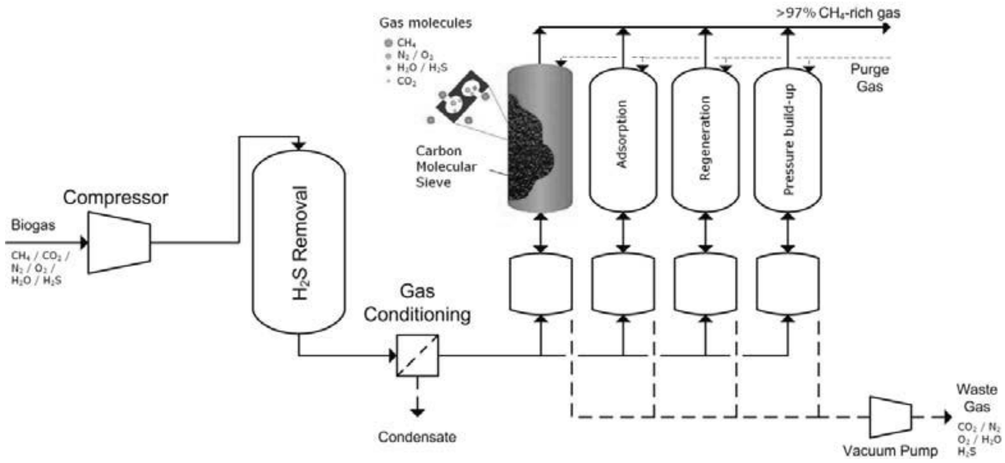


Illustration Credit: Zhao et al. (2010)

PSA systems can produce upgraded gas with methane concentrations as high as 95-98%. Methane recovery rates can range from 60 to 80%. The balance of methane leaves the system in the tail gas with the desorbed CO_2 (which would be 10-20% methane by volume). The tail gas is combusted to destroy the bypass methane with the possibility for heat recovery. Alternatively, the waste gas can be sent through another PSA cycle for additional methane recovery. By mixing the blowdown gas with the raw biogas, methane recovery can be increased by up to 5%. Carbon beds have an operating life of 4,000 to 8,000 hours, but are longer at low H_2S levels. Thus, hydrogen sulfide pretreatment may be preferred. However, moisture should always be removed prior to PSA since water would block the absorbent's micropores, reducing system performance.

Simple PSA systems can be cost-effective at small scale applications as low as 10 Nm^3/h of raw biogas. Thus, PSA systems have also been used as a follow-up polishing step for other upgrading processes, using long (several hour) cycles to remove small fractions of CO_2.

A variant of PSA is rapid cycle PSA, which operates at 5 – 20 times the cycle speed by using multi-port selector rotary valves and a multitude of smaller adsorption chambers. Rapid cycle PSA systems boast smaller sizes, lower capital costs, simple control interfaces (despite their engineering complexity), lower pressure drops, and higher throughputs. However, their high speed comes at the cost of lower methane recovery. Their complexity also makes it difficult to personally perform maintenance, and valve wearing becomes more of an issue. Nevertheless, rapid cycle PSA systems have proven their efficacy with many successful full-scale operating projects. One of the largest suppliers of rapid cycle PSA technology is Xebec Inc. (merged with QuestAir Technologies), which sells turnkey systems that can handle 150 to 5,000 Nm^3/h of raw biogas. A cost summary for the installation of a Xebec M-3100 system (300 – 3,000 Nm^3/h) at a crude oil platform is shown in Table 16. Please note that some of the costs, such as demolition, may not apply for a biogas project.

Table 16: 2010 Project Costs of Xebec M-3100 Fast-Cycle PSA System for Venoco, Inc.'s Platform Gail

Engineering	$180,000
PSA Skid	$770,000
Compressor Skid	$600,000
Demolition	$130,000
Structural Modification	$300,000
Installation	$750,000
Materials (pipes, electrical, etc.)	$100,000

Chart Credit: Toreja et al. (2014)

Chemical Solvent Scrubbing

CO_2 can also be removed from a gas stream by chemically binding it to certain dissolved compounds or liquid chemicals, i.e., alkaline salt solutions and amine solutions. After absorption, the methane rich product gas is ready for application. The solvent with CO2 (and some other contaminants) can be regenerated for reuse. The CO2 is desorbed to gaseous state.

Alkaline Salt Solution Absorption

Adding alkaline salts to water increases the physical absorption capacity of the water. Thus, the process uses less water and lower pumping demands than water scrubbing. H_2S in the biogas reacts with the dissolved alkaline salts, e.g., NaOH or KOH, to irreversibly form an insoluble alkaline sulfide salt. The alkaline salts will also react with CO_2 to form an alkaline carbonate. Because H_2S is adsorbed more rapidly than CO_2 by alkaline solutions, some partial selectivity can be achieved when both gases are present by providing fast contact times at low temperatures. The alkaline carbonates could theoretically be partially regenerated by air stripping, but in practice, the process is ineffectual and prohibitively expensive. Consequently, spent caustic solution is regularly removed from the scrubber to prevent salt precipitation. The waste is highly toxic and is difficult to handle. Overall, the complexity of these processes makes them unattractive for H_2S removal from small biogas streams.

Amine Absorption

Some of the most widely used chemical solvents for acid gas treatment are organic amines, with the most common being Diethanolamine (DEA), Monoethanolamine (MEA), and Methyl diethanolamine (MDEA). In amine absorption processes, biogas is bubbled up through a column of down-flowing organic amine solution at near atmospheric or only slightly elevated pressures—typically less than 150 psi (Figure 19). The amines exothermically react with CO_2, pulling it into the aqueous phase and bonding to it. Amines will also drive H_2S and NH_3 into solution. The amine solution is regenerated in a steam stripper column by heating (106 – 160 °C) and pressure reduction (if the biogas was pressurized) to drive off the CO_2 and H_2S.

Figure 19: Amine Absorption Process Flow Diagram

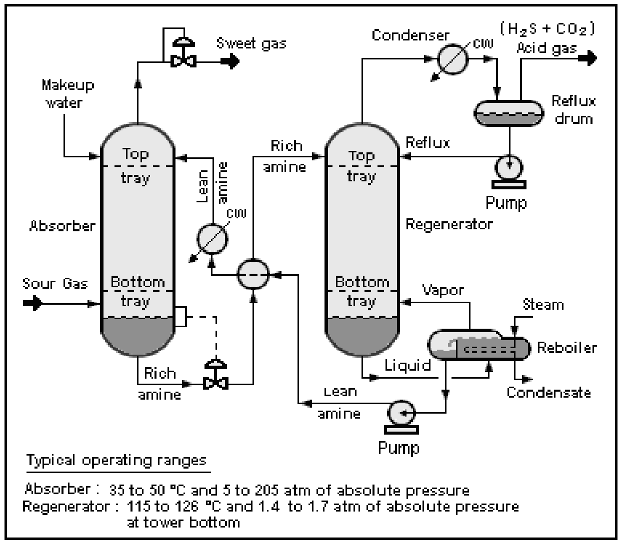


Illustration Credit: Beychok (2006)

Amines have a high selectivity and loading for CO_2 (Figure 20)—one to two orders of magnitude more CO_2 can be dissolved per unit volume in amines than in water. Low CH_4 absorption also affords a low methane slip of 0.04 – 0.1%, which is an order of magnitude less than other absorption and scrubbing technologies. To avoid equilibrium limitations, amine solution is fed at 4 – 7 times the amount of biogas CO_2 on a molecular basis. After amine absorption, the product gas is saturated with moisture and must be dried.

Figure 20: CO_2 Equilibrium Solubility in Amine Solutions

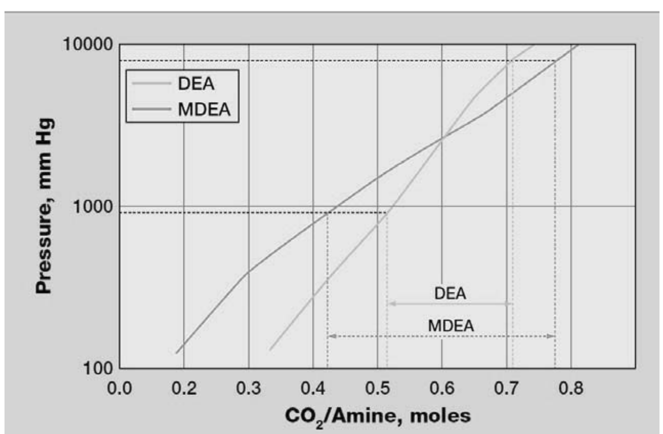


Chart Credit: Lallemand et al. (2012)

Although H_2S can be removed by amine absorption, hydrogen sulfide pretreatment is preferred to reduce regeneration energy demands. Furthermore, if H_2S is removed prior to amine absorption, CO_2 can then be recovered as an essentially pure by-product. Amine scrubbing is widely used for food-grade CO_2 production and large-scale recovery of CO_2 from natural gas wells. Oxygen must be removed prior since it reacts irreversibly with amines. Fortunately, there is little to no risk of bacterial growth because of the high pH of amines.

The most common problems that amine absorption systems experience are corrosion, amine breakdown, contaminant buildup, and foaming. In addition, some amine solution is lost when it side-reacts with other contaminants, thermally degrades above 175 °C, or evaporates. Consequently, amine solution must slowly be added and/or replaced. The overall complexity of amine systems make them difficult to apply to small-scale systems like farms, but can be effectively applied at landfills and large centralized plants. Maintenance costs are estimated to be roughly 3% of the investment cost.

Pressurized Water Scrubbing

Compounds can be physically absorbed (or dissolved) into a liquid solution. Water is commonly used due to low cost, low toxicity, and high availability.

CO_2 and H_2S preferentially dissolve into water compared to CH_4. Carbon dioxide and hydrogen sulfide are 26 and 75 times, respectively, more soluble than methane in water.[6] H_2S can also be selectively removed by water scrubbing because it is more soluble in water than CO_2. However, the H_2S desorbed after contacting can result in fugitive emissions and odor problems. Pre-removal of H_2S is considered to be a more practical and environmentally friendly approach, but is not required. Like pressure swing adsorption, water scrubbing is a popular process for gas treatment because of its ability to simultaneously remove many other contaminants: ammonia, sulfur dioxide, chlorine, hydrogen chloride, hydrogen fluoride, aldehydes, organic acids, alcohol, silicon tetrachloride, silicon tetrafluoride, and siloxanes.

Following Henry's Law, a gaseous compound's absorption into water is greater at higher pressures. When water scrubbing is used for CO_2 removal, the biogas is pressurized typically to 100 to 300 psig with a two-stage compressor, before entering the bottom of the column. The column typically contains a packed bed consisting of a high surface-area plastic media, allowing for efficient contact between the water and gas phases. The bed height and packing type determine the removal efficiency, while the bed diameter determines the gas throughput capacity. The CO_2-saturated water is continuously withdrawn from the bottom of the column and the cleaned gas exits from the top. The product gas is around 93 – 98% methane, but the process loses about 1 – 2% methane into the tail gas—more than most other systems. In an ideal system with 100% CO_2 absorption, at least 4% of the methane will also be dissolved into the water. The waste CO_2- and H_2S-laden water can be regenerated in a flash tank where the pressure is reduced, releasing the dissolved gases. Again owing to CH_4's low water solubility,

[6] Solubilities in waster: Carbon dioxide- 8.21E-4 mole fraction at 15°C, hydrogen sulfide- 2.335E-3 mole fraction at 15°C, methane- 3.122E-5 mole fraction at 15°C.

CH_4 is released first and can be recirculated to the scrubbing column, effectively increasing the biogas CH_4 concentration. Air stripping the waste water may also be done to remove H_2S since H_2S may clog pipes in the regenerative system. However, air stripping introduces oxygen into the water which will desorb into the biogas, so this may not be suitable for applications where high methane concentrations are required. The treated waste water is then recycled into the scrubber unit. The exhaust gas can be treated by regenerative thermal oxidation or flameless oxidation to avoid SO_2 emissions. Figure 21 shows the design and fluid flow through a biogas regenerative water scrubber system.

Figure 21: Biogas Water Scrubber System Design, Greenlane Biogas

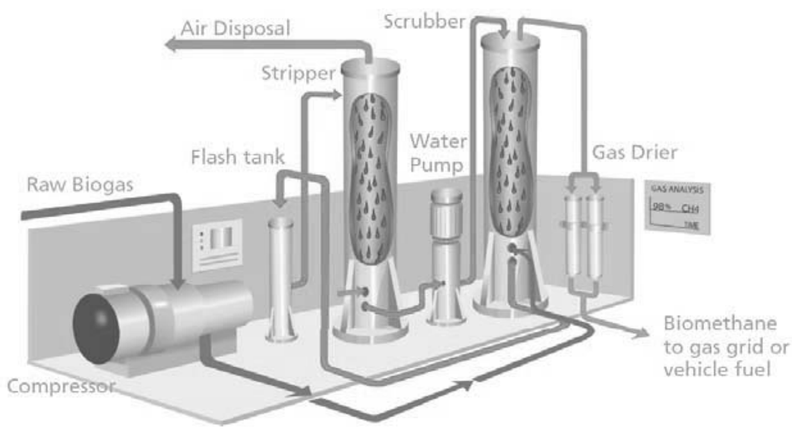


Illustration Credit: Hudde (2010)

Flashing and air stripping are incapable of completely regenerating the working water, so the water must be gradually replaced over time. Furthermore, as more CO_2 is absorbed in the scrubbing column, its partial pressure decreases, making it harder to absorb more CO_2. Thus, high water flows are needed to reach low CO_2 concentrations. Therefore, even with regeneration, water scrubbing requires a large amount of water—0.9 – 40 L discharged scrubbing water per Nm^3 of raw biogas processed (or 10% of the process water per hour) for regenerative scrubbing, and 100 – 233 L/Nm^3 for non-regenerative scrubbing (Persson 2003). Water scrubbers are more efficient and cost-effective without regeneration, when a constant supply and discharge of water is possible, such as at a wastewater treatment facility. In fact, the first time a water scrubber was used to clean biogas in the US was at a WWTP in Modestoin the 1970s. Additional cost and energy savings can be had by using secondary or tertiary treated wastewater as the scrubbing water, but this may also add microbial-related problems. The fact that there are microorganisms present in the wastewater creates the risk of introducing pathogens into the gas stream, which can contaminate the gas transmission system and pose health hazards. However, a study by Vinnerås, Schönning, and Nordin (2006) found that natural gas contained low concentrations of spore-forming bacteria such as *Bacillus* spp., and that the densities of microorganisms found did not differ much from what was found in biogas upgraded by wastewater scrubbing. At such low biological concentrations, gas intoxication and explosions were said to likely occur before ingesting a dose of pathogens high enough to cause an infection. With regards to the possible issue of plugging by biological growth, the water scrubber should be internally cleaned with detergent or externally cleaned several times a year.

Water scrubbing processes are the most prevalent upgrading technology, as they are simple, robust, flexible, proven, and have relatively low investment and operational costs. They are best implemented in medium and large applications, with competitive pricing for larger projects, and especially for higher concentration H_2S streams. Practical gas throughput capacity limits are around 2,200 Nm^3/hr. Water scrubbing can be slightly less energy efficient than most other systems, typically requiring close to 0.3 kWh/Nm^3 of cleaned gas. There are also limitations in H_2S removal. When removing large quantities of H_2S or CO_2, the tank and pipework should be made of stainless steel to avoid corrosion. In addition, not only does water scrubbing not remove inerts (e.g., O_2, N_2), but it may in fact add O_2 by desorbing O_2 that was dissolved in the incoming water. Water scrubbers can be sensitive to environmental conditions such as temperature. Maintenance costs are typically 2 – 3% of the investment cost.

A variant of conventional water scrubbers is the high pressure batch-wise water scrubber that uses pressures above 2,100 psi. It operates by first filling the scrubbing columns with compressed biogas. Pressurized water is then pumped into the columns and displaces the gas. The water is afterwards purged and regenerated by a flash tank and a desorption column. A high pressure batch-wise water scrubber system is produced and sold by Metener Ltd under the name BKP Biogas Upgrading Unit. Tailored towards raw gas flows of 30 – 100 m^3/h, the system produces a 92 – 95% methane gas with 1 – 3% methane slip. Compared to conventional systems, it uses significantly less water (0.05 – 0.1 m^3/kg of product gas, or 33.4 – 66.8 L/Nm^3 of product gas), but consumes more energy (0.4 – 0.5 kWh/Nm^3 raw biogas). It is also smaller size, but must be built to withstand much higher pressures. Metener lists the maintenance costs to be around €0.04 – 0.08/kg of upgraded pressurized gas. There are presently at least three built BKP Biogas Upgrading Units (two in Finland and one in northern China).

Another variation upon conventional water scrubbers is the rotary coil water scrubber, in which water and gas flow through a rotating coiled tubing. Water is first fed into the outermost coil turn at 29 psi (2 bar). As the coils rotates, water columns are forced inward and compress the gas in between, effectively increasing the pressure to 145 psi (10 bar) (Figure 22). This results in efficient carbon dioxide absorption, producing a gas with 94% methane with about 1% methane slip. To increase the methane content further to 97%, the rotary coil can be equipped with a post-process conventional water column. The rotary coil water scrubber technology is marketed by Arctic Nova as the Biosling and is directed at small-scale applications such as farms with 200 – 1,000 cow facilities with raw gas capacities of 14.6 – 73.1 Nm^3/h. The Biosling is claimed to be more energy efficient than conventional water scrubbers, consuming only 0.15 – 0.25 kWh/Nm^3 of raw biogas (0.26 – 0.44 kWh/Nm^3 of product gas). Although the BioSling is commercially available, there are no full-scale commercial installations at this time (Arctic Nova 2014; Bauer et al. 2013).

Figure 22: Rotary Coil Water Scrubber Design Cross-Section and Arctic Nova Biosling

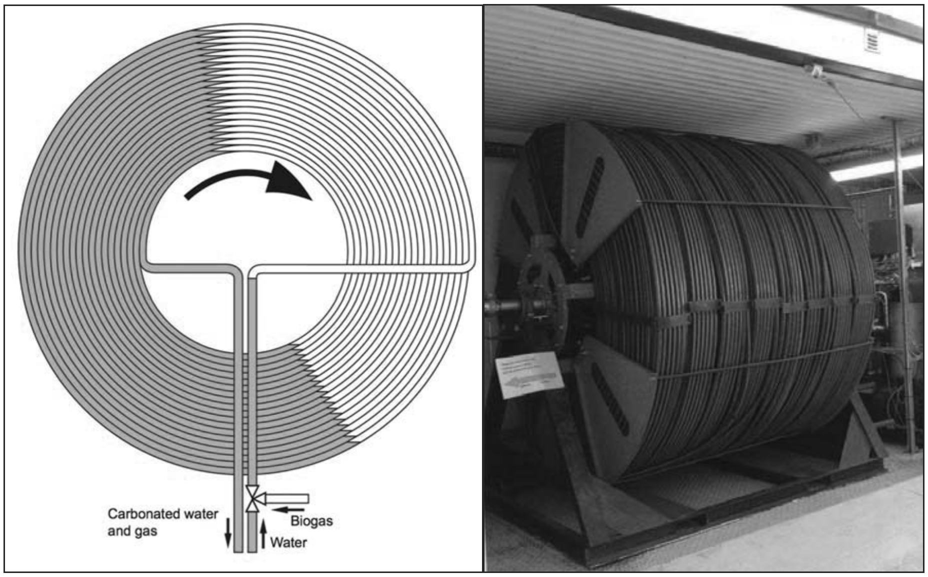


Illustration Credit: Biosling AB (2012)

Physical Solvent Scrubbing

Carbon dioxide and hydrogen sulfide can also be absorbed using liquid solvents other than water. The most industrially applied of these are organic glycols (e.g., polyethylene glycol). In return for higher cost and complexity than water scrubbing, these physical organic solvents allow for greater H_2S and CO_2 solubility than in water, allowing for lower solvent demand and reduced pumping. Glycols for scrubbing biogas can be commercially found with such names as Genosorb® 1753, SELEXOL, Purisol, Rectisol, Ifpexol, and Sepasolv.

To improve absorption, gas is compressed to 4 – 8 bar (around 60 – 115 psi) and the temperature is cooled to 10 – 20 °C. Physical solvent scrubbers operate in a similar manner to water scrubbers, using counter-current flows and a packed media bed. To regenerate the saturated solvent, it passes through a flash column, heated to 40 – 80 °C, and then run through a packed air stripper/desorption column. The product gas is normally made to consist of 95 – 98% methane with 1.5 – 4% methane slip. The physical solvent solution is afterwards regenerated by depressurization in a flash column, heating (40 – 80 °C), and steam or air stripping. Although the solvent can be regenerated, it would need eventual replacement, producing some hazardous liquid waste. However, only a minor addition of solvent roughly once a year is usually required. The stripper exhaust gas must be treated by regenerative thermal oxidation (at 800 °C) since its methane concentration is too low for flameless oxidation.

Figure 23: Physical Solvent Scrubber Process Diagram

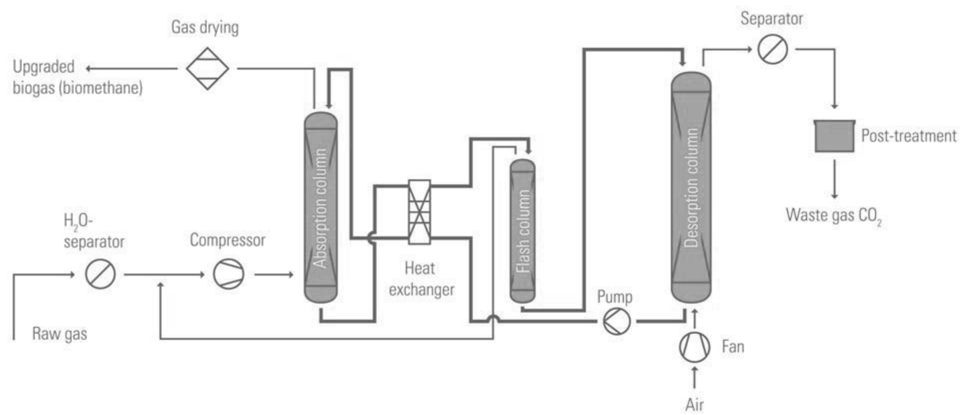


Illustration Credit: ÖKOBIT GmbH (2014)

Generally no precision desulphurization is required for glycol scrubbing. Another advantage over water scrubbing is that glycols are hygroscopic, meaning that they will absorb water by forming crystalline structures. This provides co-adsorption of H_2S, and CO_2, and H_2O. Nevertheless, moisture pretreatment by refrigeration is preferred in order to minimize the burden on glycol regeneration. Glycols will also scrub halogenated hydrocarbons and ammonia, but they will react with ammonia to form unwanted reaction products. N_2 or O_2 may only slightly be removed, but it is likely to be insignificant.

Scrubbing with organic solvents has several other advantages over using water. First of all, greater contaminant solubilization into glycols permits glycol systems to have smaller designs and lower circulation rates. Organic solvents are also anticorrosive, so pipework does not need to be made of stainless steel. Furthermore, their low freezing point allows low temperature operation, which is better for absorption. In places with water shortages, they may additional gain support from the fact that no water or antifoaming agent is consumed.

In exchange for these many benefits, physical solvents are more expensive for small-scale applications than pressurized water scrubbing or pressure swing adsorption. They also require a larger total energy demand, although this largely consists of the heat needed for solvent regeneration. The electricity requirement actually tends to be lower than most other upgrading technologies. Physical solvent scrubbing can be energy-competitive if waste heat from another process is utilized. Akin to pressurized water scrubbing, maintenance costs are close to 2 – 3% of the investment cost. Maintenance includes occasional turnovers of the organic solvent, compressor lubricant, and any adsorbent used for preliminary H_2S removal.

Membrane Separation

Membrane separation utilizes high gas pressures to create a large pressure differential across a nano-porous material (membrane) causing gas separation by several different mechanisms: molecular sieving (size exclusion), Knudsen diffusion (mean path difference), solution-diffusion (solubility difference), surface diffusion (polarity difference), and capillary condensation (adsorption). The primary transport mechanisms are dependent upon the membrane pore size, which affects the permeation rate of each type of gas (Figure 24).

Figure 24: Gas Separation Membrane Permeation Rates

Illustration Credit: Dirkse Milieutechniek (2014)

Contaminant or target molecules are forced through the membrane by pressurizing the feed gas side to somewhere between 100 – 600 psi (7 – 10 bar), depending upon the biomethane quality requirements as well as the design and manufacturer. The feed gas is passed across the membrane at an optimal velocity to allow for optimal contaminant gas permeation and minimal methane permeation. After membrane treatment, the majority of carbon dioxide, water, hydrogen, and ammonia will pass through the membrane and be removed. The feed gas will retain most of the methane, with some hydrogen sulfide, nitrogen, and oxygen. Figure 25 shows typical gas permeability through a membrane.

Figure 25: Gas Separation Membrane Permeability

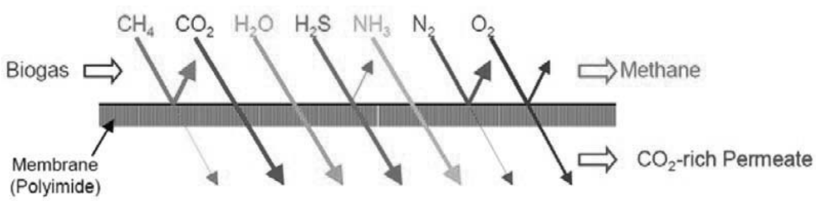


Illustration Credit: Harasek (2006)

Biogas generally requires pre-treatment to remove aggressive substances that can destroy the membrane material, in addition to the fact that the membranes do not remove H_2S or inerts (e.g., O_2, N_2) very well. Substances that can harm the membrane include water, hydrogen sulfide, ammonia, VOCs, siloxanes, particulates, and oil vapor. Water is removed to prevent condensation during compression, and hydrogen sulfide is removed since it is not sufficiently removed by membranes. Oils that are naturally present or picked up from the compressor should be removed to prevent membrane fouling. Ammonia can cause membrane swelling, while siloxanes and particles can physically damage the compressor and membrane structure.

Despite the use of gas pretreatment systems, the membranes can still suffer from plasticization, compaction, aging, competitive sorption, and fouling. Eventually, the membranes must be replaced. Typical membrane replacement intervals span > 2 years, between 5 – 10 years.

Gas separation membranes are mostly constructed from bundled polymeric (e.g., polysulfone, polyimide, polydimethylsiloxane) hollow-fiber membrane or carbon membrane, as opposed to natural organic or sheet, for superior structural integrity and higher surface-area-to-volume ratios. The hollow-fibers are bundled within small self-contained vessels, allowing for easy membrane unit replacement (Figure 26).

Figure 26: Hollow-Fiber High-Pressure Gas Separation Membrane Design and Process Configuration

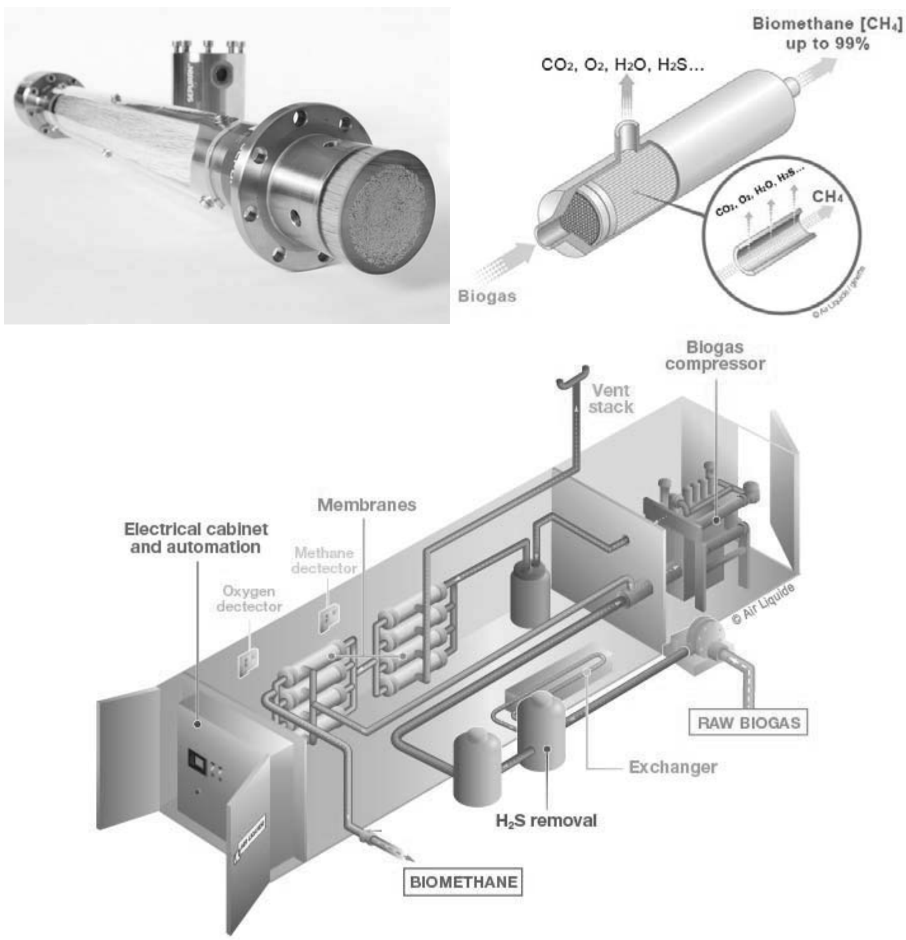


Illustration Credit: Air Liquide (2014); Fairbanks (2014)

High-pressure gas separation systems are highly reliable, easy to operate, have a simple and compact plant design, and can also be used for gas dehydration. Although these systems have relatively low capital costs, they are most competitive at the low capacity range of applications. However, to minimize the time give for methane to permeate the membrane, gas membrane separation is only reasonable at flow rates of more than 500 m^3/h. Nevertheless, this process often has more methane slip (0.5 – 15%) than other upgrading technologies, which increases with higher product gas methane requirements. The off-gas is therefore commonly either reprocessed by another membrane column or used for distributed power or heat generation.

In order to achieve higher methane content in the product, several stages may be used. For instance, biogas can be upgraded to around 92% methane content with a single membrane, or 96% with two or three membranes in series. However, the use of more membranes leads to higher methane loses and greater energy consumption. Membrane separation processes can have low or high energy consumption (0.18 – 0.77 kWh/Nm^3), with the potential for low power consumption (< 0.22 kWh/Nm^3) with highly selective membranes.

A potential enhancement to high-pressure membrane separation is gas-liquid adsorption, in which the gases are first separated by membrane permeability and then absorbed into a solution (e.g., alkaline, amine) (Figure 27). The concurrent use of absorbents significantly lowers the pressure requirements (close to atmospheric pressure) and therefore reduces power consumption. This can allow wet separation to be more economical than dry separation. Furthermore, as opposed to conventional gas-liquid contact absorption, the use of a membrane between the gas-liquid interface prevents typical problems like foaming and channeling. Gas-liquid separation can also allow highly selective separation of gases (e.g., caustic soda solution to remove H_2S, amine solution to remove CO_2), and high purity CO_2 can be sold as a product. Nevertheless, this requires not only the eventual replacement of membranes, but fluids as well.

Figure 27: Membrane Separation Techniques

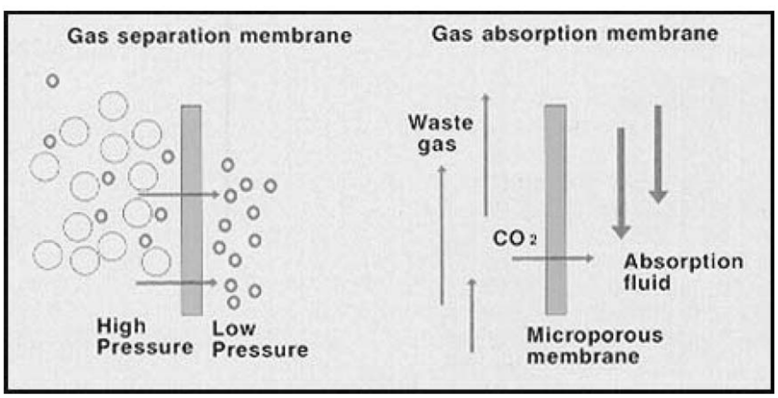


Illustration Credit: Persson and Svenskt Gastekniskt Center (2003)

Cryogenic Distillation

Cryogenic distillation takes advantage of the fact that carbon dioxide will condense and freeze before methane condenses allowing the CO2 to be removed from the gas stream as a liquid or solid.

In cryogenic distillation, biogas is compressed anywhere between 260 – 435 psi (18 – 30 bar) and cooled by heat exchangers down to -45 to -59 °C until certain gases become liquefied. High system pressures are used to ensure that carbon dioxide remains in the liquid phase and does not freeze, which would clog the pipe and heat exchanger system. The liquefied carbon dioxide is then easily separated from the remaining gas, producing highly pure biomethane. Hydrogen sulfide, which has a boiling point of -60 °C at 1 bar, can also be removed with carbon dioxide. Nitrogen and oxygen are not directly removed from the biogas since their boiling points (-196 °C and -183 °C, respectively, at 1 bar) are lower than methane's. Yet, methane can be liquefied and separated from the gaseous nitrogen and oxygen after carbon dioxide and other gas contaminants are removed. Other impurities in the gas (i.e., VOCs, halocarbons, and siloxanes) can be removed by adsorption onto molecular sieves, membranes, or by using the extracted CO_2 as a solvent scrubber. However, removing the other contaminants beforehand is preferred in order to avoid freezing over the heat exchangers and other issues. The high-pressure methane product gas can then be depressurized for pipeline injection or distributed power generation (e.g., fuel cells). Alternatively, the resulting biomethane can be cooled down further to be liquefied. Thus, cryogenic distillation can serve as an efficient method of producing compressed and liquefied natural gas, which can be used for vehicle applications.

Cryogenic distillation is able to produce a 96 – 97% methane product with 0.5 – 3% methane slip. Their primary advantage is that the gas does not contact any chemicals or moisture, meaning that there are no large recurring chemical purchase costs and no post-treatment is necessary. However, the coolant (e.g., glycol) does require infrequent replacement, so the process will still create a hazardous waste over time.

Despite savings on maintenance, cryogenic distillation systems have high capital and operating costs (i.e. high power consumption). Consequently, the process is only cost-effective at large scales. They also have complex plant designs and require higher safety standards due their operation at very low temperatures and high pressures. Operational problems may also be encountered from solid CO_2 formation on the heat exchangers. Work is ongoing at the pilot and commercial scale to overcome these issues and increase the overall system's efficiency.

A cryogenic distillation system designed by Acrion Technologies called CO_2 Wash (Figure 28) increases its performance by being combined with several other upgrading technologies. It ingeniously uses some of its waste liquid CO_2 to scrub the biogas contaminants and has MEDAL™ membranes to further reduce the product gas's CO_2 concentration. Because the scrubbing solution is made in situ, no regeneration and no solvent purchase or disposal is required. In addition to producing high-purity methane, more than 80% of the carbon dioxide is recovered as food-grade CO_2.

Figure 28: Cryogenic Distillation Process Diagram, Acrion Technologies CO_2 Wash

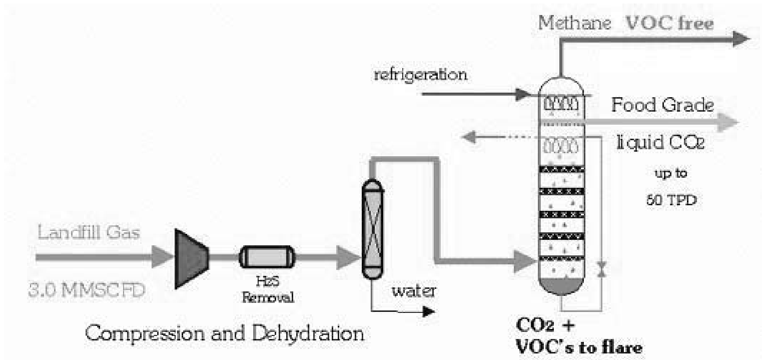


Illustration Credit: Adapted from Acrion Technologies, Inc. (2014)

Supersonic Separation

A recent, novel approach to gas clean-up is supersonic separation, consisting of a compact tubular device that effectively combines expansion, cyclonic gas/liquid separation, and re-compression. A Laval nozzle is used to expand the saturated feed gas to supersonic velocity, which results in a low temperature and pressure (Figure 29). This causes the formation water and hydrocarbon condensation droplet mist. A high vorticity swirl centrifuges the droplets to the wall, and the liquids are split from the gas using a cyclonic separator. This gas conditioning technology has been used to simultaneously condense and separate water and hydrocarbons from natural gas. Further developments allowing for the bulk removal of CO_2 and H_2S are currently underway.

Figure 29: Supersonic Separator Cross-Section

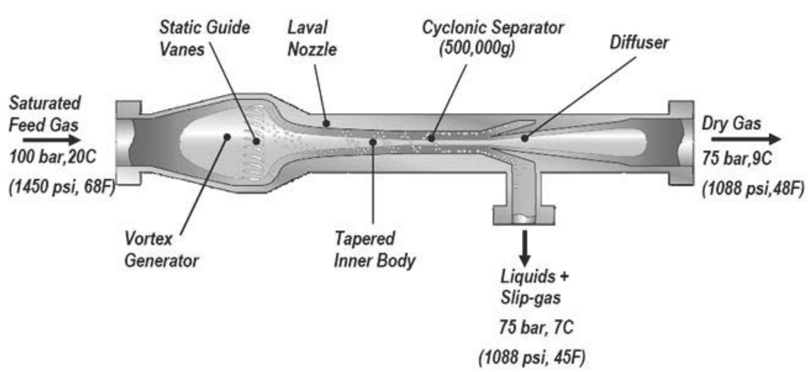


Illustration Credit: Twister BV (2014)

Similar to membrane technology, supersonic separation is simple, reliable, not susceptible to fouling or poisoning, and can offer significantly lower life cycle costs compared to conventional adsorption-based systems. Unlike all other systems, there are no downtime constraints due to utility equipment failures (e.g., glycol pumps, regeneration systems, membrane replacement, etc.), thereby providing full process automation in control systems ensuring safer and more efficient operation.

Industrial Lung

An industrial lung, also known as an ecological lung, is a bioengineered process which utilizes carbonic anhydrase—the enzyme present in our blood that catalyzes the dissolution of carbon dioxide formed from cell metabolism. Carbonic anhydrase pulls CO_2 into the aqueous phase in an absorber column where it can be picked up by an absorbent (Figure 30). The CO_2-rich absorbent is then regenerated by heat in a stripper column releasing a pure stream of > 90% CO_2.

Figure 30: Industrial Lung Process Diagram

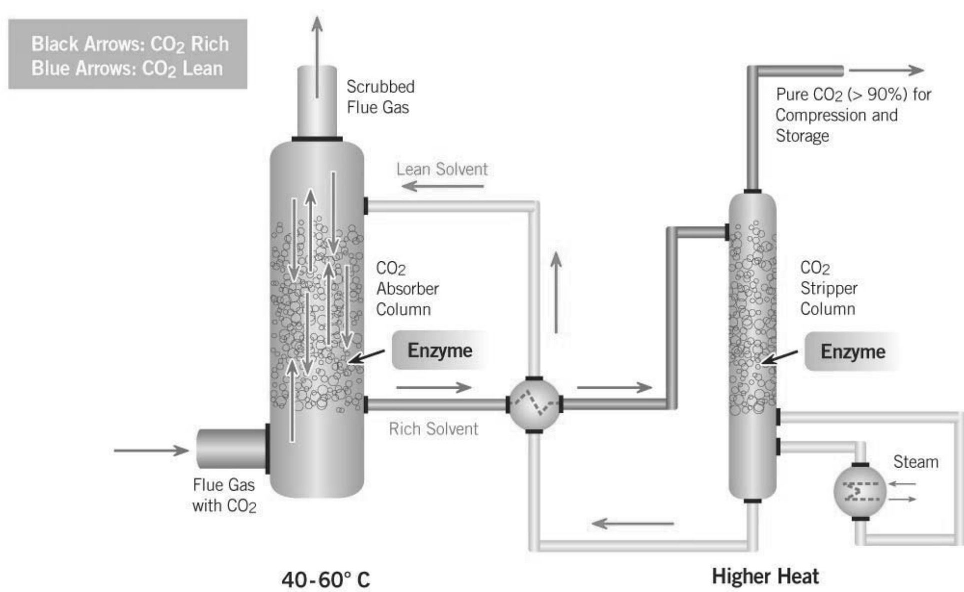


Illustration Credit: Adapted from CO_2 Solutions (2011)

This technology is patented and marketed by CO_2 Solutions, Inc. based in Quebec. CO_2 Solutions bioengineers a form of carbonic anhydrase that is 10 million times more stable than the form found in nature, and is able to withstand higher temperatures (at least 85 °C) and pH. Using just carbonic anhydrase in water, the industrial lung process is constrained by limited enzyme lifetime and high enzyme production costs. However, the special thermal and pH resistance of bioengineered carbonic anhydrase allows it to be synergistically combined with specialized absorption processes to improve removal rates. In this situation, only minute concentrations of carbonic anhydrase are required (typically 1E-5 mol/L). One of their studies showed that the addition of carbonic anhydrase increased MDEA CO_2 absorption rates by 50 times, and reduced solvent regeneration and process energy consumption by 30%. As a result, the absorption column height can be smaller by approximately 11 times (Carley 2014; Carley 2013). Laboratory experiments with biogas showed that they can purify it to 95 – 99% methane content with a CO_2 content less than 1%. CO_2 Solutions is currently operating a large bench-scale unit processing 0.5 tonne-CO_2/day, and is planning a 15 tonne-CO_2/day pilot unit in partnership with Husky Energy to start running in 2015 (Dutil and Villeneuve 2004).

Biogas Upgrading Technology Comparison

For certain applications (i.e. fuel cells, vehicle fuel, pipeline injection), biogas must be upgraded to remove CO_2 and effectively increase its methane content (volumetric energy content). The upgrading technologies discussed above have a range of operating conditions (temperature and pressure), product methane purity, methane losses (methane slip), and consumed material types. Some require pretreatment for removal of sulfur or other gas contaminants. Table 17 summarizes the operating conditions, requirements, performance and consumables required for various upgrade techniques. The industrial lung is not listed since its characteristics are dependent upon what absorbent is used in alongside the carbonic anhydrase.

Table 17: Features of Biogas Upgrading Technologies

Biogas Upgrading Process	Pressure (psig)	Temp (°C)	Product CH_4 Content	Methane Slip	Methane Recovery	Sulfur Pre-Treatment	Consumables
Pressure Swing Adsorption	14 – 145	5 – 30	95 – 98%	1 – 3.5%	60 – 98.5%	Required	Adsorbent
Alkaline Salt Solution Absorption	0	2 – 50	78 – 90%	0.78%	97 – 99%	Required / Preferred	Water; Alkaline
Amine Absorption	0 (< 150)	35 – 50	99%	0.04 – 0.1%	99.9%	Preferred / Required	Amine solution; Anti-fouling agent; Drying agent
Pressurized Water Scrubbing	100 – 300	20 – 40	93 – 98%	1 – 3%	82.0 – 99.5	Not needed / Preferred	Water; Anti-fouling agent; Drying agent
Physical Solvent Scrubbing	58 – 116	10 – 20	95 – 98%	1.5 – 4%	87 – 99%	Not needed / Preferred	Physical solvent
Membrane Separation	100 – 600	25 – 60	85 – 99%	0.5 – 20%	75 – 99.5%	Preferred	Membranes
Cryogenic Distillation	260 – 435	-59 – -45	96 – 98%	0.5 – 3%	98 – 99.9%	Preferred / Required	Glycol refrigerant
Supersonic Separation	1,088 – 1,450	45 – 68	95%	5%	95%	Not needed	

Chart Credit: Author; Data Credit: Beil and Beyrich (2013); Severn Wye Energy Agency (2013); Starr et al. (2012); Twister BV (2014)

Amine absorption produces the purest biomethane with the lowest methane slip due to how well amines select for CO_2. Conversely, alkaline salt solution absorption and pressurized water scrubbing produce the lowest methane purity as a result of non-specific CO_2 selection. Membrane separation can yield either low or high methane purity, contingent upon number of sequential membrane stages used. More stages bear higher methane quality, but incur additional methane slip loses. As a result, membrane separation can incur the highest methane slip.

Each upgrading technology is also able to remove and array of different contaminants, while some require the pre-removal of specific contaminant. Table 18 describes general ability to treat common biogas contaminants for the main upgrade techniques. Again, the industrial lung is not included because its contaminant treatability is dependent upon the absorbent used.

Table 18: Contaminant Treatability for Biogas Upgrading Technologies

Biogas Upgrading Process	CO_2	H_2S	O_2	N_2	VOCs	NH_3	Siloxanes	H_2O
Pressure Swing Adsorption	**	* **R**	/	/	*	*	*	* **R**
Alkaline Salt Solution Absorption	**	*	-	-	/ -	-	*	--
Amine Absorption	**	*	**R**	-	/ -	*	/ -	--
Pressurized Water Scrubbing	**	*	--	--	*	*	*	--
Physical Solvent Scrubbing	**	**	/	/	*	*	*	*
Membrane Separation	**	* /	* /	/	* -	*	*	*
Cryogenic Distillation	**	*	**	**	*	*	*	*
Supersonic Separation	**	**	-	-	**	*	*	**

Legend: ** Complete removal (intended)   * Complete removal (pre-removal by cleaning preferred)
/ Partial removal   - Does not remove   -- Contaminant added   **R** Must be pretreated
Two symbols may be in the same box if one or the other can be applicable

Chart Credit: Author; Data Credit: Severn Wye Energy Agency (2013); Starr et al. (2012); Twister BV (2014)

When implementing a biogas upgrading system, it is likely that one or more upstream cleaning technologies will be used for t removal of various contaminants. Thus, the upgrading system does not necessarily have to remove every contaminant. Alternatively, the cleaning steps may not need to achieve precision-level contaminant removal since that may be accomplished by the upgrading system. Upgrading systems and cleaning systems should be designed together to take into account the other's abilities and requirements with the desired product gas quality as the primary objective. Figure 31 illustrates this concept with several possible cleaning and upgrading combinations that produce high quality biomethane.

Figure 31: Combining Biogas Cleaning and Upgrading Technologies

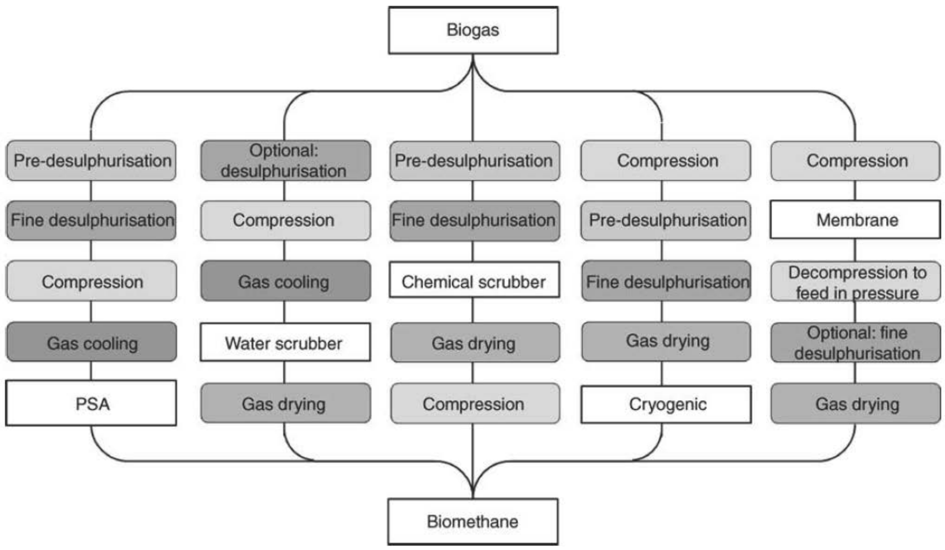


Illustration Credit: Petersson (2013)

Each upgrading technology relies upon different physical and chemical principals, and thus have different advantages and disadvantages over one another. In addition to some having higher product methane content, lower methane slip, or higher contaminant tolerance or removal, others may have lower energy requirements, smaller footprints, lower capital or maintenance costs, or greater proof of concept. These distinctions are summarized in

Table 19.

Either due to low investment price, high reliability, high removal efficiencies, or a diverse range of contaminants removal, the most commonly applied upgrading technologies are water scrubbing, PSA, and chemical scrubbing. Overall, upgrading technology selection should minimally consider the application and product gas quality requirements. However, upgrading technologies are generally expensive to purchase and can be costly to operate and maintain. As a result, the deciding factor when selecting an upgrading technology may lie with the cost (capital and O&M). Chapter 7 reviews the costs involved in employing various biogas cleaning, upgrading, and utilization technologies.

Table 19: Advantages and Disadvantages of Biogas Upgrading Technologies

	Advantages	Disadvantages
Pressure Swing Adsorption	- Low energy use - No heat demand - No chemicals - Relatively inexpensive - Compact - Applicable for small capacities - Many reference facilities	- Medium methane content - High/medium methane losses - H_2S and water pretreatment needed - Extensive process control - CH_4 loss when valves malfunction
Alkaline Salt Solution Absorption	- Removes other contaminants	- Low methane content
Amine Absorption	- Highest methane content - Low electricity demand - No gas pressurization - High CO_2 removal - Very low CH_4 losses - No moving components (except blower)	- Expensive investment costs - High heat demand for regeneration - Corrosion - Amines decompose and poison by O_2 - Salt precipitation - Foaming possible - H_2S pretreatment normally needed
Pressurized Water Scrubbing	- Simple and easy to operate - Inexpensive - Most reference facilities - Co-removal of ammonia and H_2S (H_2S > 300 – 500 ppmv) - Capacity adjustable by changing pressure or temperature	- Uses a lot of water, even w/ regeneration - H_2S damages equipment (if > 300 ppmv) - Medium methane contents - High/moderate methane losses - Clogging from bacterial growth - Foaming possible - Low flexibility for input gas variation - Biomethane drying necessary
Physical Solvent Scrubbing	- High methane content - Higher CO_2 solubility than water - Relatively low CH4 losses - Co-removal of NH_3, H_2S and other impurities, but rough pretreatment recommended.	- Expensive investment and operation - Difficult to operate - Heating required for complete regeneration
Membrane Separation	- Simple construction (lightweight and small footprint) - Simple operation (no moving components except blower) - Low maintenance - Modular configuration - No chemical or heat demand - High reliability - Small gas flows treated without proportional increase of costs	- Low membrane selectivity - Multiple steps needed for high purity - Moderate methane content - Medium to high CH_4 losses - Membrane replacement 1 – 5 years - Generally not suitable for biogas with many undefined contaminates, like landfill or WWTP biogas - Membranes can be expensive - Few reference facilities
Cryogenic Distillation	- High methane content - Low methane losses - Pure CO_2 as by product - No chemicals - Low extra energy to make LNG	- Expensive capital and O&M costs - Contaminant pretreatment needed - Technically very demanding - Full scale implantation very recent - Energy efficiency and tech not well proven
Supersonic Separation	- Simple construction and operation - No chemicals	- Expensive investment - No reference facilities - Experimental; Not well proven

Chart Credit: Allegue and Hinge (2012a)

CHAPTER 7: Economics of Biogas Technologies

Project costs include direct capital and operation and maintenance costs for each piece of biogas-related equipment, indirect costs associated with design, engineering, construction, developing supporting infrastructure, permitting, and access fees. Some of these costs for biogas technologies are discussed below.

Equipment Cost Comparison of Biogas Cleaning, Upgrading, and Utilization Technologies

Biogas Cleaning Equipment Cost

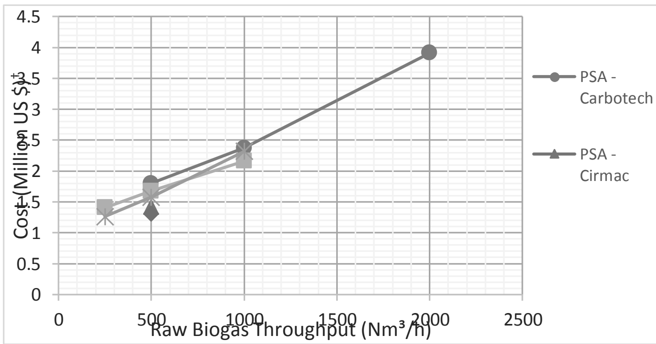
Biogas cleaning, whether by adsorption, water scrubbing, or biofiltration, requires the purchase of a reactor vessel. Water and bio scrubbers require large sized reactors and liquid pumps whereas dry absorption chambers do not. However, adsorption systems require the eventual change-out or regeneration of media. Thus, adsorption systems will have lower upfront and operating costs, but can have higher maintenance costs. Hydrogen sulfide is usually the largest contaminant in biogas, and thus a primary target for cleaning. Consequently, the cost of biogas cleaning is often listed in terms of dollars per amount of sulfur or hydrogen sulfide removed. For gas streams with 500 – 2,500 ppm H_2S, it generally costs \$1.50 – \$5.00 per pound of sulfur removed (McDonald and Mezei 2007). To remove moisture, a refrigeration or gas condensation system is often applied.

Biogas Upgrading Equipment Cost

Biogas upgrading technologies, on the other hand, are more complex and more costly. New and emerging technologies that consolidate biogas cleaning and upgrading, such as cryogenic distillation and supersonic separation, will generally be more expensive than already established technologies. Membrane separation may be an exception, providing cost savings so long as membrane replacement rates remain low. However, among the three most common upgrading technologies—pressure swing adsorption, pressurized water scrubbing, and amine absorption—there is no clear winner in terms of initial cost. As seen in

Figure 32, the lowest cost is highly dependent upon the manufacturer.

Figure 32: Biogas Upgrading Equipment Costs by Technology and Manufacturer



† Conversion using 2007 average Euro exchange rate of 1.37 USD per 1 Euro, and inflated to 2014 dollars using consumer price index; Source data was collected 2007 - 2008

Chart Credit: Urban, W. (2009)

Upgrading technologies are also affected by economies of scale. , the cost of treating biogas drops sharply with higher raw biogas throughputs up to 1,000 Nm^3/hr (

Figure 32). Small-scale biogas upgrading (0 – 100 Nm^3/h raw biogas) is usually very expensive due to high upgrading equipment investment costs. For small farms and other low volume biogas producers, biomethane production is likely not economical. In these situations, it may be more economical to transport raw biomass or biogas to a large central processing facility. However, this introduces the technical challenges associated with piping or transporting raw biogas, which is corrosive. Two solutions would be to use pipes that can withstand corrosion or to remove H_2S at each source prior to shipping.

Maintenance costs include those for periodic solid/liquid regenerative/non-regenerative media/solution changeout and membrane replacement, while operating costs include labor and energy requirements. Energy required to operate is a significant fraction of the O&M cost.

Figure 33 is a box plot showing the ranges and median electricity and heat requirements for the six most prevalent commercially available biogas upgrading technologies. For chemical and physical solvent scrubbing, a large proportion of the required energy is heat for thermal regeneration of the solvent.

Figure 33: Energy Requirements for Biogas Upgrading Technologies

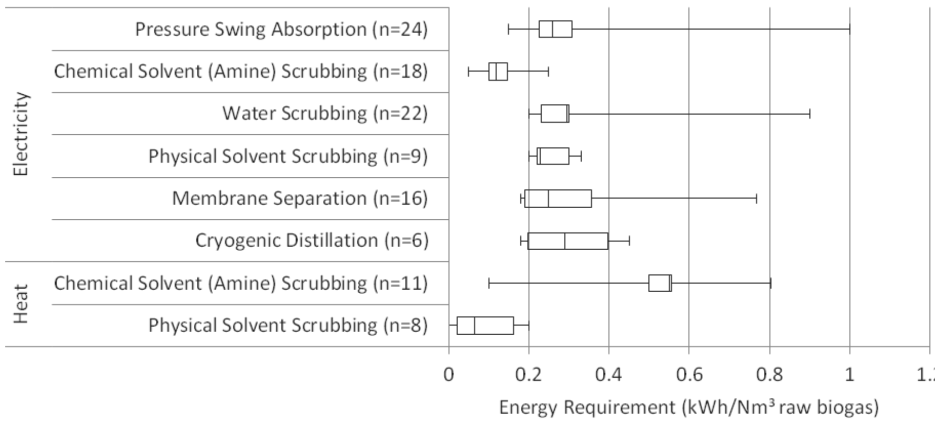


Chart Credit: Author; Data Credit: Agency for Renewable Resources (2014); Allegue and Hinge (2012b); Bauer et al. (2013); Beil and Beyrich (2013); Günther (2006); Johansson (2008); Kharrasov (2013); Niesner, Jecha, and Stehlík (2013); Patterson et al. (2011); Purac Puregas (2011); Vijay (2013)

When adding up the capital and O&M costs, there can be significant price differences between the three most common upgrading technologies at low biomethane product output rates ≤ 500 Nm^3/h (Table 20). But at higher output rates, economies of scale begin to equalize differences in capital and O&M costs such that the choice of equipment supplier again has a larger effect on the overall levelized cost of energy (

Figure 34). However, the cost of cryogenic distillation will almost always be higher than other options, but purified CO_2 and other gas streams that are produced can possibly be sold to offset some costs.

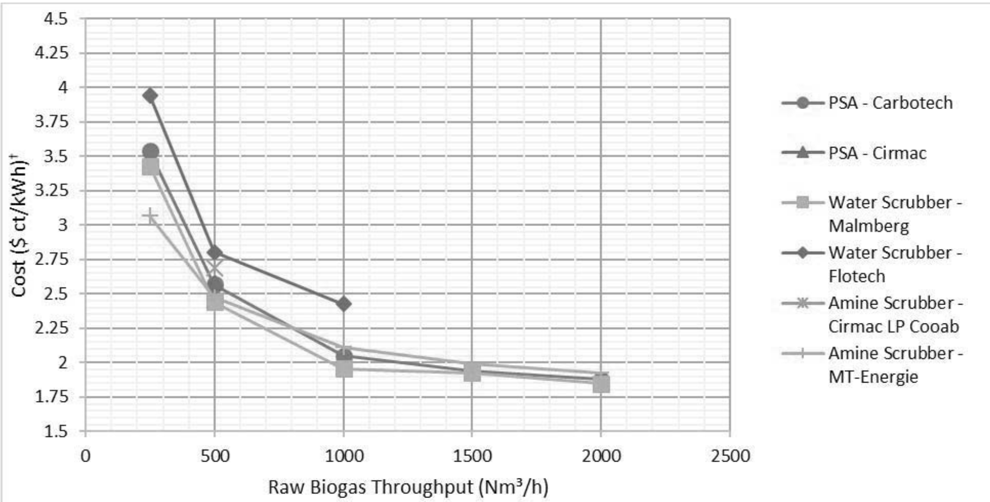
Table 20: Total Investment and Running Cost to Upgrade Biogas

Technology	US$/1000 scf biogas†
Pressure swing adsorption	9.21
Chemical absorption	6.32
Water scrubbing	4.74
Membrane separation	4.47
Cryogenic distillation	16.32

† Data for 130 – 161 Nm^3/h product gas output rate

Chart Credit: (Jensen 2013; de Hullu et al. 2008)

Figure 34: Levelized Cost of Biogas Upgrading by Technology and Manufacturer (Normalized by Biomethane Product's Energy)



† Conversion using 2007 average Euro exchange rate of 1.37 USD per 1 Euro, and inflated to 2014 dollars using consumer price index; Source data was collected 2007 - 2008

Chart Credit: Urban, W. (2009)

From reviewing several dozen biogas cleaning and upgrading companies, it is apparent that to reduce installation and construction costs and time, the industry is shifting towards turnkey solutions in which the entire upgrading system is pre-fabricated and skid-mounted onto one or more bulk units that only require piping and wiring connections when brought to the project site. It is also perceptible that the industry is focusing more on lowering energy consumption and improving contaminant removal and resistance than increasing methane product purities.

Distributed Power Generation Equipment Cost

Table 21 compares the characteristics and typical cost range for different distributed power generation and transportation applications. As with all technologies, the actual price will vary by manufacturer. However, the general relation holds that fuel cells will be more expensive than microturbines, which will be more expensive than reciprocating engines, which will be more expensive than boilers. The only exception is that microturbines can cost less to operate and maintain than reciprocating engines.

Table 21: Comparison of Distributed Power Generation and Vehicle Applications

	Boilers	Reciprocating Engines	Microturbines	Fuel Cells	CNG/LNG Vehicles
Minimum HHV (BTU/scf)	N.D.	N.D.	350	N.D.	900
Capital Cost ($/kW)	N.D.	300 – 900	300 – 1,200	3,000 – 12,000	N.D.
O&M Cost ($/kWh)	N.D.	0.008 – 0.025	0.008 – 0.022	$0.01 – $0.04	N.D.
Capacity	N.D.	5 kW – 10 MW	25 – 500 kW	1 kW – 3 MW	N.D.
Electrical efficiency	0%	18 – 45%	15 – 33%	30 – 70%	0%
Thermal efficiency with CHP	75 – 85%	30 – 50%	20 – 35%	30 – 40%	
Biogas treatment requirement	Low	Medium	Medium	High	High
HHV Requirement	Medium	Medium	Low	Any	High
NOx emissions	High	High	Low	Very low	Very low
Capital cost	Low	Medium	Medium	High	High
O&M cost	Low	Medium	Low – Medium	Low	Low

N.D.: Not Determined or not found. Listed where value should exist, but data were not found.

Chart Credit: Author; Data Credit Deublein and Steinhauser (2011); Eastern Research Group, Inc. and Resource Dynamics Corporation (2011); Environmental Science Associates (ESA) (2011); Kaparaju and Rintala (2013); US EPA (2007)

Overall Cost Discussion

Overall Cost of Injection into Natural Gas Pipelines

Due to the simplicity of biogas cleaning (conditioning) systems, they are significantly less expensive than upgrading technologies. But in terms of overall system costs (excluding biogas production and collection system costs), biogas cleaning and upgrading together represent a large part, if not the majority, of the capital and operations and maintenance costs for implementing either vehicle fueling or pipeline injection.

For example, the City of Janesville, Wisconsin's 18 – 20 MGD WWTPrecently installed a biogas upgrading and fueling station. The system currently processes 0.1 MMscfd of biogas, or about half of its total processing capacity. Prior to developing an R-CNG station, the plant had two 200 kW Waukesha reciprocating engines generating 719,600 kWh annually of electricity. Their biogas cleaning/upgrading system consists of an iron sponge chamber for H_2S removal (175 ppmv to 10 ppmv), glycol scrubbing for CO_2 removal, polymer microbeads for siloxane removal, and activated carbon to remove other contaminants. The biogas is upgraded from 60% to 90% methane in this process. The capital cost of the gas conditioning system alone was $288,320 (Table 22). R-CNG gas compressions, storage and dispensing equipment cost about $186,700 (total equipment cost $475,000). This gas conditioning system accounts for almost 61% of the total project's investment cost. Nevertheless, the final cost of R-CNG was about $0.88 per gallon gasoline equivalent.

Table 22: Gas Conditioning Skid Costs for the Janesville Wastewater Treatment Plant, WI

Capital Cost (excl. installation)	$288,320
Operations and Maintenance Costs	
Oil and Filters	$5,000/year
Microbead media	$4500/batch
Labor and Spent media disposal	$1,200
CNG compressor oil and filter change (once per year)	$1,000/year

Chart Credit: Zakovec (2014)

However, out of all currently available biogas utilization options, pipeline injection has the highest total capital and operation and maintenance (O&M) costs. Unison Solutions Inc., a supplier of biogas conditioning equipment, estimates a $3.5 million capital cost for biogas upgrading at a 350,000 scf CH_4 per day facility (Ahuja 2014). To reiterate a point made earlier, biogas cleaning and upgrading together represent a large fraction of a costs, both capital and O&M, of a pipeline injection project (more than 50% of total project cost (

Figure **35**). The City of Hamilton (Canada) WWTP spent $4 million to upgrade biogas to biomethane, while the Union Gas interconnection cost was only $300,000 (Gorrie 2012). In the 2012 SoCalGas General Rate Case Proposal, SoCalGas sought to install four biogas conditioning systems ($5.6M each) at small to midsize WWTPs (200 – 600 scfm) to produce biomethane for their facility and fleet vehicles (Goodman 2011).

Figure 35: Biomethane Pipeline Injection 15-Year Cost Breakdown

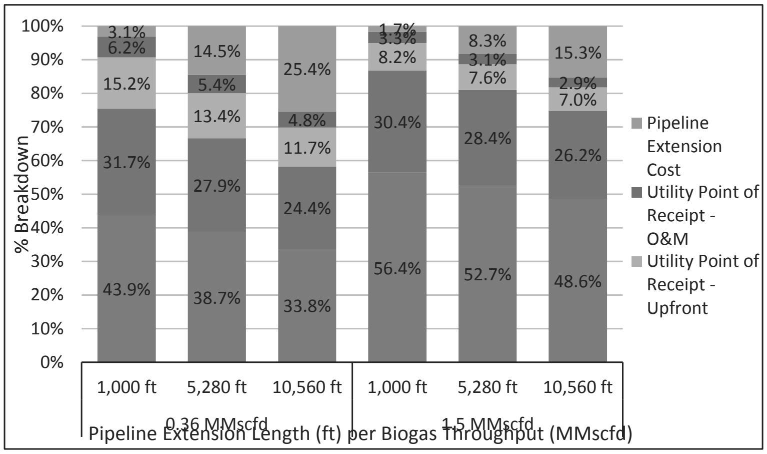


Chart Credit: Adapted from Lucas (2013b)

Pipeline interconnection costs can also be high. For the George DeRuyter and Sons Dairy in Outlook, WA, $3.4M was spent on a 3.7 mile pipeline extension to the Williams Northwest Pipeline, interconnection, and metering station. Half of the cost was funded by a Yakima County grant (Evans 2014). In California, the utilities have quoted total interconnection costs to be somewhere between $1,500,000 and $3,000,000 (Escudero 2013). SoCalGas in particular estimated the total interconnection cost in 2014 to be $2.7M. This value includes pipeline extension, point of receipt, and taxes (Lucas 2013b). Total SoCalGas interconnection capital costs have also been cited to be $1.3M – $1.9M for 1 – 10 MMscfd facilities, along with $200 – $300/ft for pipeline extension and $14,000 for pre-injection testing per Decision (D.) 14-01-034. Operating costs were estimated to be $3.5k/month for Point of Receipt facility O&M and $6k-24k/yr for periodic testing per D. 14-01-034. For the Point Loma WWTP in San Diego, CA, the cost of interconnecting with an SDGE pipeline interconnect was $1.99M (Mazanec 2013). Interconnecting also includes compressing the gas up to pipeline pressures, which adds additional cost (

Table 23). Furthermore, gas quality must be monitored, which can cost $50,000 – $100,000 for a simple monitoring system (excl. compressors), or $100k – $400k for complex systems that use chromatographs (Electrigaz Technologies Inc 2008).

Overall, interconnection costs in California are much greater than in other states. Comparatively, three projects developed outside California paid interconnections costs of $82,546, $70,816, and $272,170 as of 2013.

Table 23: Gas Compressor Costs

Model	Feed Flow Rate (scfh)	Feed Flow Pressure (psi)	Output Flow Rate (scfh)	Output Flow Pressure (psi)	Unit Cost ($/unit)	O&M Cost ($/yr)
Regression	6,000	100	5,695	800	$132,500	$9,465
GE Gemini	21,000	100	19,920	800	$200,000	$16,400
GE Gemini	42,000	100	39,780	800	$225,000	$45,500
GE Gemini	72,000	100	68,220	800	$325,000	$119,900
GE Gemini	120,000	100	113,700	800	$450,000	$193,800
GE Gemini	300,000	100	284,220	800	$600,000	$474,000

Chart Credit: Cooley et al. (2013)

To drive down total interconnection costs, proximity to a pipeline is key. When long distances are required, the cost of pipeline extension can rise to be nearly as high as the costs of the biogas upgrading equipment. From PG&E's experience, biogas injection projects more than 4 – 5 miles from a transmission pipeline are economically viable (Environmental Science Associates (ESA) 2011) Table 24 gives estimated pipeline costs. However, when land acquisition, right-of-way purchases, and difficult terrain are factored in, the total pipeline extension cost is commonly between $100,000 – $280,000 per mile, or but can be up to twice as high (Environmental Science Associates (ESA) 2011; R. Goldstein 2009; Jensen 2013). This is comparable to the cost in other countries. For example, a biomethane plant in Borås, Sweden paid $213,000 per mile for four miles of pipeline extension, while the Swedish cost of horizontally trenched pipeline is roughly $100,000 per mile (Krich et al. 2005).

Table 24: Estimated Pipeline Cost by Size and Distance

Pipe Size Diameter (in)	Flow (MMscfd)	Cost ($1000/mi)
0.5	0.007	55.643
1	0.044	58.057
2	0.268	63.334
3	0.768	68.511
4	1.585	73.890

Chart Credit: Adapted from Prasodjo et al. (2013)

Associated with the total cost of the interconnection facility and pipeline extension, there may be costs for utility facility enhancement, land acquisition, site development and construction, right-of-way, metering, gas quality, permitting, regulatory, environmental, unusual construction, and operating and maintenance of other components. Pipeline flow schedules may vary, so gas storage may also need to be purchased and installed.

When working with PG&E, they will build, own, and operate the interconnection station However, the gas supplier must obtain all rights-of-way, permits, and easements needed for a lateral pipeline, interconnection station, and access road. The supplier is also responsible for all actual capital costs and formula-based O&M costs. In 2007, PG&E's total charge for an interconnection fee, interconnection facilities, monitoring equipment, metering controls, and engineering was $265,000. If the throughput was > 0.5 MMscfd, PG&E subsidized $85,000 for interconnection, metering controls, and engineering (Anders 2007) At the same time, SoCalGas had an estimated interconnect fee of $800,000 for 1 MMscfd and $1,000,000 for 10 MMscfd (Anders 2007). In 2011, the PG&E interconnect fee was cited as being $400,000 – $600,000 (Environmental Science Associates (ESA) 2011).

For SoCalGas, there are natural gas pipeline pre-installation interconnection costs (i.e., Interconnection Capacity Study fee, Preliminary Engineering Study fee, Detailed Engineering Study fee) and post-installation interconnection costs (i.e., odorant costs of approximately $0.0003/Dth). The gas supplier pays 100% of the costs or is charged an incremental reservation rate on a going forward basis (SoCalGas 2013). To assist with the high investment cost of biomethane pipeline injection, SoCalGas developed an optional Biogas Upgrading/Conditioning Tariff Service designed for facilities that produce ≥1000 scfm raw biogas. Under this service, SoCalGas would design, install, own, operate, and maintain biogas conditioning and upgrading equipment. SoCalGas would then charge the customer a fully allocated cost under a long-term service agreement. However, the biogas producers would still own the biogas entering and exiting the biogas system, and is still responsible for ensuring that the biomethane product meets SoCalGas's Rule 30 quality standards. The biogas producer would also still need to pay for the interconnection facility. Nevertheless, using this service would largely lower a project's capital cost, but would add a running cost. Compared to using third-party subcontractors, this option is expected to expedite SoCalGas's approval process for allowing pipeline injection. Prior to the Biogas Upgrading/Conditioning Tariff Service, SoCalGas proposed a Biogas Conditioning Services and Bioenergy Production Facilities Services program, but it was rejected by the CPUC. Under this option, SoCalGas would also construct a biogas facility if one did not already exist onsite. SoCalGas would likewise own, operate, and maintain the biogas equipment. Another proposed SoCalGas program was the Sustainable SoCal Program, tailored for four small to medium wastewater treatment plants with 200 – 600 scfm raw biogas production rates, where SoCalGas would provide the same services as those mentioned above and also pay for the interconnection facility, but would own the raw and upgraded biogas (Lucas 2013a).

There are also state and federal taxes, which include sales taxes, energy taxes, property taxes, the Contributions in Aid of Construction (CIAC) tax, and the Income Tax Component of Contributions and Advances (ITCCA). The CIAC tax applies to all property, including money, received by a utility from an eligible customer to provide for the installation, improvement, replacement, or expansion of utility facilities (such as an interconnection facility). The ITCCA is a federal and state tax that the utility pays on income received as a CIAC. Effective January 1, 2014, the ITCCA rate is 35%. This thus adds 35% to the interconnect construction and supply costs. Tax exemptions may be available to certain components, such as real and personal property, and should be investigated to provide substantial cost savings. However, the largest savings are likely to come from federal, state, or local incentive programs and grants. These include competitively solicited contracts and grants from the California Energy Commission[7] and the California Air Resources Board[8]

Overall Cost of Distributed Power Generation

Small biogas power costs were estimated by Black and Veatch in support of CPUC proceedings to implement SB1122. Energy production cost (LCOE) for energy from waste water and dairy digester biogas is shown in Table 25 (does not include cost of producing the biogas).

Table 25: Levelized Cost of Energy (LCOE) for Biogas Distributed Power Generation (does not include gas production/digester cost)

Feedstock / Facility Type	Estimate	Project Size (MW)	Capital Cost ($/kW)	Operating Cost ($/kW-yr)	Tipping Fee ($/ton)	Feedstock Cost ($/dry ton)	LCOE ($/MWh)
Wastewater	Low	3	2,145	144			**51**
	Med	3	2,681	180			**63**
	High	3	3,217	216			**76**
Dairy Manure	Low	1	8,720	760			**211**
	Med	1	10,900	950			**278**
	High	1	13,080	1,140			**334**

Chart Credit: Black & Veatch (2013)

Compared to pipeline injection, the cost of distributed power generation will be less due to lower costs associated with interconnection (Table 26). Nevertheless, there are still a variety of interconnection-related fees that must be paid.

In order to interconnect with the PG&E electricity grid, there are also pre-installation costs (i.e., interconnection request fees, study/review fees/deposits, interconnection facility and system modification and ongoing maintenance costs) and post-installation costs (i.e., standby charges, non-bypassable charges) (PG&E 2014a). However, exemptions and incentives are available. For example, clean customer electricity generation, including net-metered systems, under 1 MW are eligible for CPUC's self-generation incentive program or similar CEC programs and are thereby automatically exempt from paying the PG&E's cost responsibility surcharge.

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[7] http://www.energy.ca.gov/contracts/

[8] http://www.arb.ca.gov/ba/fininfo.htm

Table 26: Cornerstone Environmental Group, LLC Cost Estimates for 165 scfm (0.24 MMscfd) Biogas Utilization Systems

Distributed Power Generation		Pipeline Injection	
Capital Cost		Capital Cost	
Engineering / Permitting	$75,000	Engineering / Permitting	$75,000
Gas conditioning system	$265,000	Gas conditioning system	$265,000
Genset turbines	$500,000	Biogas upgrading	$450,000
Grid interconnection	$50,000	Pipeline extension and Interconnection	$250,000
Construction	$100,000	Construction	$100,000
Operations and Maintenance Cost	$80,000/year	Operations and Maintenance Cost	$80,000/year

Chart Credit: Torresani (2009)

Ultra-clean and low emission customers over 1 MW and other types of customer generation subject to the statewide megawatt cap may also qualify for certain exemptions. Exemptions provided for in Decision 03-04-030 are discussed in greater detail in PG&E's Advice Letter 2375-E-B[9] and Electric Rate Schedule E-DCG[10] CPUC's Self-Generation Incentive Program, funded through December 31, 2014, provides incentives for biogas-operated fuel cells ($3.45/W), internal combustion engines ($2.08/W), microturbines ($2.08/W), gas turbines ($2.08/W), and waste heat to power technologies ($1.13/W). The incentive payout rate depends upon the energy production capacity: 100% for 0 – 1 MW, 50% for 1 – 2 MW, and 25% for 2 – 3 MW (PG&E 2014b).

With respect to Southern California Edison (SCE), projects that propose to interconnect to their distribution system must follow their Wholesale Distribution Access Tariff under the jurisdiction of the Federal Energy Regulatory Commission, as well as their Rule 21: Generating Facility Interconnections under the jurisdiction of the California Public Utilities Commission. Projects that interconnect to their transmission system must follow their CAISO tariff and are governed by and fall under the jurisdiction of the Federal Energy Regulatory Commission. SCE has several payback options available for electricity suppliers—Energy Procurement options, Renewable Energy Self-Generation Bill Credit Transfer, or Net Energy Metering. Application and interconnection study fees are charged to applicants of these programs[11]. Network Upgrades costs are also paid by the customer, but is typically refunded on a straight-line basis, including interest, over the five-year period commencing after the Project achieves commercial operation (Southern California Edison 2014).

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[9] http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_2375-E-C.pdf

[10] http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-DCG.pdf

[11] https://www.sce.com/wps/portal/home/residential/generating-your-own-power/

CHAPTER 8: Conclusions

Regulatory and Technical Standards

Distributed Power Generation

Distributed power generation is the simplest (with regards to design, permitting, and regulation) and lowest cost option for biogas utilization at existing biogas production facilities, aside from heat generation with boilers. Many facilities that are already collecting biogas and flaring it that decide to utilize their biogas opt to generate electricity. The primary biogas-powered electricity generation technologies are reciprocating engines, microturbines, and fuel cells. When biogas is used as the intake, the type of reciprocating engine typically used is a lean burn internal combustion engine. Reciprocating engines are well-established technologies and require only moderate gas pretreatment. Microturbines require less maintenance, but come in smaller power sizes and may be less efficient. Fuel cells come in five major varieties—polymer electrolyte membrane, alkaline, phosphoric acid, molten carbonate, and solid oxide. The types most commonly applied to stationary power generation are polymer electrolyte membrane, molten carbonate, and solid oxide. Fuel cells are more electrically efficient than other systems, but require greater gas contaminant pretreatment. In general, fuel cells are more expensive than microturbines, which are more expensive than reciprocating engines, which are more expensive than boilers. The only exception is that microturbines can cost less to operate and maintain than reciprocating engines.

Biomethane Pipeline Injection

An emerging application for biogas utilization is injection into natural gas pipelines. In California, the four largest natural gas transmission and distribution pipeline investor-owned utilities (IOUs) are Pacific Gas and Electric (PG&E), Southern California Gas (SoCalGas), San Diego Gas and Electric (SDGE), and Southwest Gas (SWGas). Each IOU has their own gas quality standards listed among their tariffs, but they are all fairly similar. As evident in **Error! Reference source not found.**, raw biogas from any source must undergo significant treatment to meet the IOU standards.

IOU standards for common gas contaminants are comparable to that of other states and countries. Meeting these standards is of little concern, as most cleaning and upgrading technologies are more than capable of achieving them. However, the regulations regarding the 12 constituents of concern are unique to California. It is unprecedented that California biogas pipeline injection facilities must measure up to 12 contaminants on a quarterly to annual basis per CARB's Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biomethane into the Common Carrier Pipeline in response to AB 1900 mandates.

Table 27: Partial List of Biogas Source Concentrations and IOU Standards For Biomethane Pipeline Injection

	HHV (Btu/scf)	CO_2 (%)	H_2S (ppm)	Siloxane (mg/m^3)
Landfill	208 – 644	15 – 60	0 – 20,000	0 – 50
Wastewater Treatment Plant	550 – 650	19 – 45	1 – 8,000	0 – 400
Agricultural Digester	550 – 646	15 – 50	10 – 15,800	0 – 0.2
MSW Digester	N.A.	34 – 38	70 – 650	N.A.
Gasifier	94 – 456	10 – 30	80 – 800	N.A.
PG&E	750 – 1150† (990 - 1050)‡	1	4	0.1
SoCalGas	990 – 1150	3	4	0.1
SDGE	990 -1150	3	4	0.1
SWGas	950 – 1150	2		0.1

† Normal PG&E range of higher heating values. PG&E dictates that the interconnecting gas shall have a heating value that is consistent with the standards established by PG&E for each Receipt Point.

‡ Typical higher heating value for a PG&E receipt point.

Chart Credit: Author

It is also of particular importance to note that all of the IOUs in California with the exception of SWGas require the injected gas to have a higher heating value ≥ 990 Btu/scf. This value is greater than those found in all other states and most other countries. **Error! Reference source not found.** shows that a majority of upgrading technologies are barely able to achieve the specified gas quality using a single one stage process. The only technology that is reliably capable of doing so is amine absorption. Unfortunately, amine absorption is expensive, complicated, and requires difficult/costly O_2 pre-removal. Other technologies require more than one stage (additional upgrading system in series) and/or high-end designs to reach a 990 Btu/scf product. Because single upgrading systems are already expensive, it is most likely to be economically infeasible to produce pipeline-quality biomethane at small farms and other low biogas producers.

Table 28: Partial List of Biogas Upgrading Specifications

	Product CH_4 (%)	Product HHV (Btu/scf)	Product H_2S (ppm)	Methane Slip (%)	Methane Recovery (%)	Sulfur Pre-Treatment
Pressure Swing Adsorption	95 – 98	960 – 990	< 4	1 – 3.5	60 – 98.5	Required
Amine Absorption	99	1000	< 0.2 – 8	0.04 – 0.1	99.9	Preferred / Required
Pressurized Water Scrubbing	93 – 98	940 – 990	< 1 – 2	1 – 3	92 – 99.5	Not needed / Preferred
Physical Solvent Scrubbing	95 – 98	960 – 990	< 0.1 – 20	1.5 – 4	97 – 99	Not needed / Preferred
Membrane Separation	85 – 99†	860 – 1000†	< 1 – 4	0.5 – 20	75 – 99.5	Preferred
Cryogenic Distillation	96 – 98	970 – 990	< 0.02	0.5 – 3	98 – 99.9	Preferred / Required
Supersonic Separation	95	960	N.A.	5	5	Not needed

† Multiple stages required for high CH_4 purity, but results in higher methane slip

Data Credit: Allegue and Hinge (2012a); Beil and Beyrich (2013); Persson (2003); Severn Wye Energy Agency (2013); Starr et al. (2012); Twister BV (2014)

Biogas Cleaning and Upgrading

Biogas is primarily composed of methane and carbon dioxide but can contain a large number of other compounds (in smaller amounts) some of which are detrimental to biogas appliances or contribute to unwanted air emissions.[12] Hydrogen sulfide is typically the largest concentration contaminant in biogas and is detrimental to biogas appliances, and thus a primary target for cleaning. A majority of contaminant compounds can be removed (cleaned / conditioned) by adsorption, biofiltration, or water scrubbing processes. Moisture is commonly removed by refrigeration or some other condensation process, although adsorbents can also be effective.

For certain applications, biogas must be upgraded to biomethane by removing the CO2. The most commercially deployed and available upgrading technologies are pressure swing adsorption, amine adsorption, and water scrubbing. They are highly reliable, predictable, and

[12] Hydrogen sulfide and other sulfur compounds (e.g., alkyl thiols / mercaptans), ammonia, inert compounds (e.g., nitrogen, oxygen, carbon monoxide), hydrogen, non-methane hydrocarbons, aromatics (e.g., p-Dichlorobenzene, ethylbenzene, toluene), halogenated compounds (e.g., chlorine and fluorine compunds, vinyl chloride), n-Nitroso-di-n-propylamine, methacrolein, siloxanes, arsenic, antimony, copper, lead, and moisture.

vetted technologies, having long been used in many gas industries including natural gas. Several newer technologies are starting to Including physical solvent scrubbing (using glycols), membrane separation, and cryogenic distillation. Although many biogas upgrading technologies can simultaneously clean out contaminants, specific contaminant pretreatment is typically recommended to maximize the adsorbent's or absorbent's lifetime, reduce regeneration costs, and extend maintenance intervals. Biogas upgrading technologies are more expensive to purchase, operate, and maintain than cleaning technologies due to higher complexity.

There can be significant differences between the levelized cost of energy for the three most common upgrading technologies at low biomethane product output rates of less than 500 Nm^3/h, but at higher rates, economies of scale begin to equalize differences in capital and O&M costs such that the choice of equipment supplier has a larger effect on the overall levelized cost of energy.

Recommendations

- Reduce the energy content requirement for pipeline biomethane from 990 to 960 – 980 Btu/scf (higher heating value basis);

    It is not clear that 990 Btu/scf biomethane injection is a technical requirement if injection flow is small compared to line capacity at injection point. The main reasons stated by the gas utilities, and accepted by the CPUC, for requiring 990 Btu/scf for biomethane product injection were to ensure both acceptable performance of the gas appliance and energy billing and delivery agreement. Because other states and countries allow lower energy content for biomethane injection, the concerns raised by the California utilities are apparently not encountered elsewhere. Modelling of appropriate injection rates, mixing and effect on delivered gas at point of use should be investigated.

- Collect data on levels (concentrations) of COC in the current California natural gas supply (includes instate and imported sources)

    It appears that the biomethane COCs were selected by comparing limited biogas data against limited natural gas data. While there is a current study to evaluate trace compound and biological components in more detail across a wide range of California biogas sources (e.g., study by Professor Kleeman at UC Davis), a comprehensive understanding of natural gas in California is lacking.

    If the above investigation of COCs in natural gas is not done, then amend the regulation concerning the 12 constituents of concern such that the contaminants are not measured at the point of injection, but rather before biomethane is mixed with natural gas or other higher HHV gases that are assumed to be in compliance with contaminant standards;

- Address costs and provide financial support and incentives for biogas upgrading and pipeline interconnection as well as for small-scale distributed power generation systems

    There are numerous purported societal benefits from utilization of biomass resources for biopower or biomethane (e.g., GHG reductions, nutrient management improvements at dairies, improved surface and ground water, rural jobs and economy, etc.). Investigate means to monetize these benefits (e.g., cap and trade fees for verified GHG reduction by project).

- Develop a streamlined application process with standardized interconnection application forms and agreements to minimize time and manpower spent by all parties.

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APPENDIX A: Acronyms, Definitions, and Units of Measurement

Acronyms

AB	California Assembly Bill
AC	Activated carbon
AD	Anaerobic digestion
AFC	Alkaline fuel cell
ARB	California Air Resources Board
CHP	Combined heat and power
CNG	Compressed natural gas
CPUC	California Public Utilities Commission
GHG	Greenhouse gas
HCG	Hydrothermal catalytic gasification
IOU	Investor-owned utility
LNG	Liquefied natural gas
O&M	Operations and maintenance
OEHHA	California Office of Environmental Health Hazard Assessment
LACSD	Los Angeles County Sanitation District
MCFC	Molten carbonate fuel cell
MSW	Municipal solid waste
PAFC	Phosphoric acid fuel cell
PEMFC	Polymer electrolyte membrane fuel cell
PG&E	Pacific Gas and Electric Company
POTW	Publicly Owned Treatment Works
PSA	Pressure Swing Adsorption
R-CNG	Renewable compressed natural gas
R-LNG	Renewable liquid natural gas
RPS	California Renewables Portfolio Standard
RSNG	Renewable Synthetic Natural Gas
SB	California Senate Bill
SCE	Southern California Edison
SDGE	San Diego Gas and Electric Company
SoCalGas	Southern California Gas Company
SOFC	Solid oxide fuel cell
SWGas	Southwest Gas Corporation
VOC	Volatile organic carbon
WWTP	Wastewater treatment plant

Definitions

Biogas	Gas produced by the anaerobic decomposition of organic material that is composed primarily of methane and carbon dioxide
Biomethane	Cleaned and upgraded biogas, typically > 95% methane
Cleaning	The removal of contaminants or impurities from a gas mixture
Slip	Leaked emissions from a process
Syngas	Gas produced by the thermochemical process of gasification that is composed primarily of hydrogen, carbon monoxide, and carbon dioxide
Upgrading	The removal of carbon dioxide from biogas to create biomethane

Units of Measurement

bhp	Brake horsepower
Btu	British thermal unit
cf	Cubic foot
DGE	Diesel gallon equivalent
ft	Foot
in	Inch
gal	Gallon
gr.	Grain
MGD	Million gallons per day
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
lb	Pound
mi	Mile
Nm^3	Normal cubic meter, at 0 °C and 1.01325 bar (atmospheric)
ppb	Parts per billion
ppbv	Parts per billion, by volume
ppm	Parts per million
ppmv	Parts per million, by volume
ppmvd	Parts per million, by dry volume
psi	Pounds per square inch
psig	Pounds per square inch, gauge
scf	Standard cubic foot

Unit Conversions

1 gr. sulfur compound/100 scf	=	17 ppm sulfur compound
1 mg H_2S/m^3	=	0.717 ppm H_2S
1 mg mercaptans/m^3	=	0.717 ppm mercaptans

APPENDIX B: Descriptions of Several Biogas Projects

Landfill gas is typically collected by gas blowers which pull the gas from a network of vertical extraction wells, consisting of permeable (perforated or slotted) pipes, and through covered horizontal tranches. Landfill gas can also be collected passively (without gas blowers) by taking advantage of the pressure generated by the evolving gases, but requires well-sealed gas containment. Passive systems have lower capital and O&M costs, but have higher inefficiencies and minimal collection capacity. The design and performance of US landfills is regulated by federal requirements under Subtitle D of Resource Conservation and Recovery Act for Landfill Gas Mitigation Control.

Landfill Gas Projects

The Veolia ES Greentree Landfill in Kersey, PA produces 6,000 – 6,500 scfm of 53% CH_4 landfill gas. A multi-stage Air Liquide MEDAL membrane system removes nitrogen, 98% of the carbon dioxide, and half of the oxygen present. The gas is then transported through a pipeline to a utility where it is used to generate power in combined-cycle equipment. The total cost of the system was $35 million. (Torresani 2009).

The Rodefeld Landfill in Dane County, WI, produces R-CNG to fuel 25 – 30 CNG vehicles. The system was expanded from a daily production capacity of 100 gasoline gallon equivalents per day to 250. Biogas is conditioned and upgraded through a $400,000 Bio-CNG 50 system. The station cost roughly $500,000, $150,000 of which was funded by a State of Wisconsin Office of Energy grant. The last five CNG vehicles were also funded by a $28,800 State of Wisconsin Office of Energy grant. The price of the R-CNG gas produced, as of September 2013, was $1.25 per gallon (NGV Global 2013).

The Altamont City landfill in Livermore, CA collects, cleans, upgrades, and liquefies its biogas to produce renewable liquid natural gas (R-LNG) vehicle fuel. A Guild Associate Inc.'s Molecular Gate pressure swing adsorption system is applied to clean and upgrade the landfill gas by removing sulfur compounds, water, siloxanes, halogens, non-methane hydrocarbons, N_2, and CO_2 (1 – 2% in product gas). The 96.6 – 97% CH_4 gas is then liquefied to -260 °F by a Linde mixed hydrocarbon refrigerant liquefier system. Their system produces roughly 13,500 gallons of R-LNG fuel daily for use on their fleet of 300 – 400 refuse trucks. Roughly $16M in initial capital investment was spent to build their facility. $14M was privately funded by Linde and Waste Management while the remaining $2M were provided by various grant-giving agencies— California Air Resources Board ($610,000), CalRecycle ($740,000), Southern California Air Quality Management District ($250,000) and California Energy Commission ($990,000). Subsidies and tax credits also help to offset costs (Underwood 2012).

The Los Angeles County Sanitation District (LACSD) also uses 1% of its landfill gas at the Puente Hills Materials Recovery Facility in City of Industry, CA to produce R-LNG vehicle fuel. The gas is upgraded using a multi-stage high-pressure membrane separation process, which required frequent membrane replacement—the membranes suffered from 30% losses in permeability after 1.5 years. With a capacity of 90 scfm, it produced about 1,000 gallons of gasoline equivalent daily. The greater part of Puente Hills' landfill gas is sent to a separate gas-to energy facility—a 50 MW Rankine cycle stream power plant that uses boilers to produce superheated steam which drives stream turbines/generators. The excess 46 MW of electricity is sold to Southern California Edison. In 2006, an 8 MW gas-fired internal combustion engine facility was added, consisting of three 3 MW Caterpillar 3616 engines. This facility nets 6 MW and powers the San Jose Creek Water Reclamation Plant (LACSD 2014a; LACSD 2014b).

Wastewater Treatment Plant Biogas Projects

In 2001, The Chiquita Water Reclamation Plant in Santa Margarita, CA began operating two 30 kW Capstone C30 microturbines that feed electricity to the San Diego Gas and Electric Company (SDGE). The system had cost $83,666 for construction, $1,400 for SDGE interconnection, $1,611 for South Coast Air Quality Management District permits for two turbines, and $9,520 for emissions source testing from a representative turbine. The total installation cost, excluding the equipment cost, was $114,020. This system provided $4,000 – $5,000 per month in energy savings. In March 2003, the plant added two more microturbines and a Microgen hot water generator for an installation cost of $160,582. Turbine emissions averaged 1.25 ppmv NOx and 138.5 ppmv CO. With a $77,400 grant from the South Coast Air Quality Management District, a $92,369 grant from the San Diego Regional Energy Office, and as much as $8,000 in monthly energy savings, the $372,937 invested in the project was paid back in only 2.5 years. (US DOE 2011b).

The Inland Empire Utilities Agency in Ontario, CA operates a 44 million gallons per day wastewater treatment plant that collects and purifies its biogas through an ESC CompHeet® System that removes H_2S, siloxane, and moisture. The biogas is then utilized in a 600 scfm fuel cell system that was installed in 2012 and generates 2.8 MW of electricity (Environmental Systems & Composites, Inc. 2014).

The Columbia Boulevard Wastewater Treatment Plant in Portland, OR treats 80 – 90 million gallons/day and uses its biogas on a 200 kW ONSI PC25C fuel cell and four 30 kW Capstone microturbines. Fuel cell installation cost $1,300,000, while the microturbine installation cost $340,000. The maintenance costs are around $0.02/kWh for the fuel cell and $0.015/kWh for the microturbines. The system provides more than $60,000 in energy savings and profits from selling excess energy. (US DOE).

The King County South Treatment Plant in Renton, WA scrubs the majority of its gas using high-pressure Binax scrubbers to remove hydrogen sulfide and carbon dioxide, and sells it to Puget Sound Energy as pipeline quality biomethane. For a two-year demonstration project from 2004 to 2006, a portion of the raw digester gas was diverted to a SulfaTreat and two activated carbon absorbers to reduce H_2S concentration to 0.1 ppmv before being sent to a 1 MW molten carbonate fuel cell (the world's largest). A waste heat recovery unit for the fuel cell's exhaust was sized for 1.7 MMBtu/hour and brought the fuel cell system's efficiency up from 45% to 67.5%. Fuel cell emissions of ≤ 0.2 ppm NOx, ≤ 13 ppm CO, and no detectable NMHC, were far under the region's air quality standards (Bloomquist 2006). Methane breakthrough was only about 290 ppm and the electrical efficiency was around 45%. However, numerous components required frequent maintenance, further burdened by high replacement costs. The fuel cell was also highly sensitive to gas quality, leading to shutdowns, the majority of which were caused by spikes in methane content. The fuel cell stack was estimated to have a lifetime of < 3 years, while the gas catalysts should last 5 years. SulfaTreat was replaced every 7 – 8 months and the activated carbon absorbers every 3 – 4 months. Fuel cell start time was approximately 10 hours. The King County WWTP currently operates an 8 MW plant running dual-gas turbines.

Point Loma Wastewater Treatment Facility in San Diego, CA is the only project currently operating in CA that injects biomethane into a common-carrier natural gas pipeline. BioFuels Energy, LLC holds a long-term rights agreement to Point Loma's biogas. 900 – 1,100 scfm of 59% methane biogas coming out of the digesters has hydrogen sulfide removed by a Sulfatreat unit and then is upgraded by a two-stage Air Liquide membrane system. The gas is afterwards polished by passing through activated carbon to produce a 98% methane product gas with approximately 0.5% CO_2, 0.1% O_2, and 1.3% N_2. Part of the biomethane is diverted to an onsite 300 kW DFC fuel cell that powers the biogas purification system. In total, the plant consumes 2 MW. The remaining biomethane is transported by San Diego Gas and Electric pipelines to the University of California, San Diego which operates a 1.4 MW DFC1500 fuel cell, and the City of San Diego South Bay Water Reclamation Plant which feeds a 2.8 MW DFC3000 fuel cell. A 300 kW DFC fuel cell powers the biogas purification system. In total, 5.5 – 5.8 MW of electricity is generated from the biogas. Of the total $45M investment cost, $1.99M went to interconnection. The project used $14.4M in Self-Generation Incentive Program incentives along with federal Investment Tax Credits (30% of net project cost) and New Market Tax Credits (39% of the qualified equity investment, after applying the Self-Generation Incentive Program, over a seven year period). The California Pollution Control Financing Authority provided $12M in tax-exempt bonds. Revenue is earned by selling fuel cell electricity and renewable energy credits. BioFuels Energy shares the credits with the City of San Diego and the University of California, San Diego, except for the last five years in which University of California, San Diego owns their portion (Greer 2011; Mazanec 2013).

Agricultural Waste and Manure Digester Biogas Projects

Joseph Gallo Farms' 5,000 cow Cottonwood site in Atwater, CA generates 300,000 cf/day of biogas from a lagoon digester system. The biogas is fed into a 300 kW Caterpillar 3412 and a 400 kW Caterpillar G399 reciprocating engine, which together output 5.9 GWh/year of electricity. The engines require oil changes every 500 hours, tune-ups every 1,000 hours, and major overhauls every 16,000 hours. The entire digester system costs $150,000/year to maintain. The total investment cost including interconnection, but excluding the 400 kW engine, was $2.7 million. Partial project funding was received from California state grants for alternative energy programs administered by Western United Resource Development and Pacific Gas and Electric Company (US DOE 2010).

With the assistance of Sacramento Municipal Utility District (SMUD), New Hope Dairy's 1,200 cow dairy in Galt, CA uses a covered lagoon digester to produce biogas that is used to generate 450 kW or power. SMUD also provided assistance in the construction of another digester system in Galt, CA at the Van Warmerdam Dairy. Both of these digesters were helped funded by $5.5 million in grants from the U.S. Department of Energy and the California Energy Commission (Sacramento Municipal Utility District 2013).

In 2008, Tollenaar Holsteins Dairy in Elk Grove, CA began generating 113,000 ft^3/day of biogas in a complete-mix lagoon digester designed by RCM International. Biogas is fed into a 250 kW genset that cycles for three days on and one day off. The total turnkey cost of the digester was around $1.7 million. $500,000 were covered by a conventional bank loan at 5.3% interest, while the rest was supplied by $1.2 million in grants: $500,000 from the United States Department of Agriculture's (USDA) Rural Energy for America Program (REAP), $250,000 from a cost-share agreement with the USDA's Natural Resources Conservation Service's (NRCS) Environmental Quality Incentives Program (EQIP), $250,000 from the Sacramento Municipal Utility District (SMUD), and $200,000 from the California Energy Commission (US EPA 2012a).

Starting in late 2006, the Sierra Nevada Brewing Company in Chico, CA began running four 250 kW FuelCell Energy DFC300A molten carbonate fuel cells on 25 – 40% biogas from brewery's wastewater anaerobic digester. Residual thermal energy is used for facility heating and to produce steam for their brewing process (US DOE 2011a).

In 2005, the 6,000 – 10,000 milking cow Hilarides Dairy in Lindsay, CA began collecting biogas from two covered lagoon digesters that were producing 300 – 500 cf/min of biogas. Biogas was cleaned using Sulfatreat and then used to run four 125 kW Caterpillar G324 reciprocating engines for electricity production. Two more engines were later added in 2008, but there was still excess biogas available. Around that time, more stringent restrictions on stationary power emissions were enacted, which made the owner, Rob Hilarides, reconsider the idea of just adding more biogas engines. Hilarides considered upgrading his gas for biomethane pipeline injection, but decided against it due to the complexities of the process in California. He determined that he would rather continue offsetting his retail costs and be able to apply his own gas quality standards, and so chose to install a system to produce compressed biomethane that would be used as fuel for his milk trucks and farm equipment. This was an especially attractive option because diesel prices at the time were around $4.50/gallon and the estimated cost of biogas CNG was $2/DGE. The system, which began operation in 2009, first pressurizes the biogas to 175 psi (12 bar) before sending it to a Xebec M-3200 pressure swing adsorption system to produce 970 BTU/cf biomethane. The 200 BTU/cf off-gas is mixed with biogas and sent to the generators. Vilter compressors then further pressurize the biomethane into CNG at 3,600 psi. At least two semi-trucks, a pickup truck, and four hot water heaters have been converted on the farm to run on the biomethane. (Greer 2009; Western United Resource Development, Inc. 2006).

Vintage Dairy in Riverdale, CA, was established by David Albers, who also founded BioEnergy Solutions LLC, a company that designed, built and maintained biogas systems on farms and processing facilities. On the farm, biogas produced from the manure of 3,000 – 5,000 dairy cows in a 38,140,000 gallon lagoon digester was scrubbed in a Natco bioreactor to remove H_2S (to < 4 ppm) and then processed in a pressure swing adsorption system to remove CO_2 (to < 1%) and moisture. The 99% pure biomethane product was injected into Pacific Gas and Electric Company's common-carrier pipelines (at 650 psi) from October 2008 to December 2009, providing 2.39 GWh/year. Plans were in order to develop a central biogas upgrading facility and collection network that would take biogas from nine surrounding farms. However, BioEnergy Solutions declared bankruptcy in December 2011. This may in part be due to the high investment cost of the facility—$3.7 million. Further economic hardship came with the suspension on biomethane RPS eligibility that lasted from March 2012 to April 2013. To recoup costs, Vintage Dairy was listed for sale at $21.5 million (Harvey 2012; PG&E 2008; D. W. Williams 2009).

Scenic View Dairy in Fenville, Michigan was the first commercial facility in the US to produce both pipeline quality methane and electricity from animal waste. With 3,450 head of cattle, the dairy produces 324,000 cf/day of biogas from three 870,000 gallon complete mix digesters. In 2006, the dairy began generating 4.5 GWh/year using two 400 kW Caterpillar G3412 Co-Generator reciprocating engines. Excess electricity is sold to Consumers Electric Company. The generators cost $35,000 while the electric panel was $25,000. Including an oil change every 600 hours, the engine system's O&M cost is $1,000/month. In 2007, the dairy began upgrading its gas in a $200,000 Xebec M-3200 PSA system to be sent to 2,000 Michigan Gas Utilities customers. Total system costs were around $2.75 million, including $1.2 million for the digesters, $400,000 for the biogas upgrading system, $1 million for the engines and interconnection to the utility grid, and $150,000 on other costs related to solids separation and new buildings (N. Goldstein 2007; US EPA 2012b).

The Huckabay Ridge Anaerobic Digestion Project, owned by Elements Markets in Stephenville, TX, is the largest anaerobic digestion facility in North America. Its 6,800,000 gallons of working volume is used to convert manure collected from dairy farms within a 20 mile radius and grease-trap wastes from Dallas–Fort Worth restaurants. The facility generates 2,700,000 cf/day of raw biogas and upgrades it to pipeline quality biomethane, contractually sending up to 8,000 MMBtu/day to PG&E pipelines until 2018. The facility was purchased from Environmental Power Corporation in 2010, and had recently been put up for auction on Nov. 21, 2013. Huckabay Ridge's aggregate design considerably saves on construction costs, but may not be as simple to implement in CA where dairies already have individual permits for their wastes and if the wastes are comingled, then the product would fall under a different permitting classification (US EPA 2012c).

Municipal Solid Waste Digester Biogas Projects

Zero Waste Energy LLC, based in Lafayette, CA, is a global project developer utilizing patented SMARTFERM anaerobic digestion technology. To date, Zero Waste Energy has designed and developed three dry anaerobic digestion facilities in California that digest food and green waste in Marina (Monterey Regional Waste Management District), San Jose (ZWEDC), and South San Francisco (SSF Scavenger). Each of these systems produce 3,000 – 3,200 ft^3 of biogas per ton of waste. The Marina facility began operation in February 2013 and treats up to 5,000 tons of waste per year, generating 100 kW of CHP electricity. The ZWEDC plant, the largest commercial dry anaerobic digestion facility in the US, treats 90,000 tons of waste per year and generates 1.6 MW of CHP electricity. The SSF Scavenger site treats 11,200 tons of waste per year and generates > 100,000 DGE/year of compressed natural gas.

CleanWorld, based in Gold River, CA, markets high-solids anaerobic digestion technology. On December 14, 2012, CLeanWorld unveiled a high-solids BioDigester at the South Area Transfer Station in Sacramento, CA. It is the largest commercial high-solid anaerobic digester, currently processing nearly 40,000 tons/year of food waste. The biogas that is collected runs through a 190 kW 2G Cenergy gas conditioner and engine to generate 3.17 million kWh/year, enough power for 400 California homes. The facility also produces 700,000 DGE/year using a BioCNG 100 gas conditioning and upgrading system for removal of hydrogen sulfide, VOCs, siloxanes, moisture, and carbon dioxide. The CNG is used by Atlas Disposal to fuel its trucks. CleanWorld has a partnership with EcoScraps to produce liquid fertilizer from the digester effluent. The liquid and solid residues are processed to make 10 million gallons/year of fertilizer and soil amendments.

On April 22, 2014, CleanWorld opened the UC Davis Renewable Energy Anaerobic Digester which converts 20,000 tons of the university's food waste per year. Gas from the thermophilic three-stage digester system is mixed with gas from a nearby landfill at a 2:1 ratio, and then treated by a Unison Solutions biogas cleaning system to remove hydrogen sulfide, siloxanes, and moisture. A Capstone C800 800 kW microturbine package and a 125 kW organic Rankine cycle generator together create 5.6 million kWh/year. To overall investment costs to build the UC Davis system was $8.5 million.

To save costs on infrastructure development, municipal solid waste can be digested using the excess capacity already available at existing WWTPs. The EPA estimates CA's excess capacity to be 15 – 30% (US EPA 2013). By adding wastes from outside sources, WWTPs will benefit from greater biogas production and can earn revenue from tipping fees. The downsides to this consist of the potential for process upsets, additional new permits must be obtained, and infrastructure (e.g., storage, pretreatment to remove debris and other indigestible material) must be added to handle the incoming waste.

The East Bay Municipal Utility District in Oakland, CA was the first wastewater treatment plant in the US to anaerobically digest post-consumer food scraps. Investment costs included $125,000 for system design, $1.1 million for ten 60 kW Capstone C60 microturbines, $410,00 for turbine installation, $360,000 for a 633 kW York absorption chiller, $130,000 for gas and electrical connections, $100,000 for a service contract, $30,000 for air permits, and $255,000 for other costs (US DOE 2011c). After installing a new 4.6 MW turbine in 2012, it became the first WWTP to be a net energy producer in North America, producing 130% of plant demand in 2013. The residual biosolids are used for land application at non-food crop sites in Merced and for alternative daily cover at nearby landfills (East Bay Municipal Utility District 2014).

Wood-to-RSNG Demonstration Projects

There is a wood-to-RSNG demonstration project in California partially funded by the Energy Commission. This project is headed by G4 Insights of Canada partnering with Placer County. The demonstration project plans to use forest biomass as feedstock and will employ a hydro-pyrolysis technology (hydrogen enriched gasification/pyrolysis) to create a methane rich product gas. Standard gas upgrading equipment is used to clean the product gas. Some of the product methane is recycled to a steam-methane reformer (SMR) to produce the hydrogen needed for the hydropyrolyzer (though the demonstration test unit planned for the project will omit the SMR and use bottled hydrogen instead). This will be a small facility with capacity for about 50 lbs of biomass per batch run with two to four runs per week (with 2 – 3 gasoline gallon equivalents of RSNG production per run) (Ng 2010).

The Paul Scherrer Institute (PSI) has developed a fluidized bed methanation reactor (based on the Comflux technology) for use on a portion of the product gas at the Güssing, Austria allothermal gasification CHP plant. Initial demonstration with a 10 kW_{SNG} reactor took place between 2003 and 2008 which included a run of more than 1,000 continuous hours. The 10 kW_{SNG} demonstration led to development of a 1 MW_{SNG} process development unit (PDU), complete with gas upgrading, at the Güssing site. In 2009, a 250-hour run of the 1 MW_{SNG} PDU was completed producing about 100 m^3/h of SNG (Kopyscinski 2010).

In the Netherlands, ECN (a research lab) and the utility HVC are building a 10MW_{th} wood fueled gasification CHP facility that will include demonstration of RSNG production (Bush 2012). There are plans for a follow-on 50 -100 MWSNG commercial scale demo (Aranda, 2014).

The GAYA Project in France would build and demonstrate a 20-60 MWSNG commercial scale demonstraton facility possibly as early as 2017 (Aranda, 2014). GAYA is a research consortium composed of technology providers and academic institutions.

Announced Commercial Wood-to-RSNG Projects

The GoBiGas project in Sweden, has built and is commissioning a 20 MWSNG wood-to-RSNG facility with an 80 -100 MW SNG Phase II facility planned (~ 2017 start?). Allothermal gasification technology by Repotec (that is used at the Güssing facility mentioned above) was selected for the GoBiGas project (Göteborg Energi 2012).

The European utility company E.ON is siting a 200 MW SNG wood-to-RSNG facility in Sweden. Named “Bio2G” (second-generation biogas) E.ON, in partnership with the Gas Technology Institute (GTI) and others has tested methanation reactors and are developing designs for up to 600 MWSNG capacity (Bush 2012; Ståhl 2011).

APPENDIX C: Fuel Cell Descriptions

Polymer electrolyte membrane fuel cells (PEMFCs), also known as a proton exchange membrane fuel cells, have a membrane serving as the electrolyte which allow protons to permeate while keeping hydrogen on the anode side and oxygen on the cathode side. The membrane electrolyte must be water saturated to avoid membrane dehydration and provide suitable ion conductivity. The electrodes are made of porous, platinum-impregnated carbon paper. Compared to other fuel cell technologies, PEMFCs operate at lower temperatures, are lighter and more compact, can fast-start due to high operating current densities, and use no corrosive liquid. Researchers envision PEMFC use in small mobile applications and electric vehicles since they have a higher energy density and recharge faster than batteries. With respects to larger applications such as biogas utilization, PEMFCs are sensitive to impurities, have low power sizes, and their operating temperatures (50 – 120 °C) are too low for cogeneration.

Alkaline fuel cells (AFCs) use an aqueous alkaline solution, such as KOH, as the electrolyte. The electrodes can be made from a number of different inexpensive materials (e.g., graphite, carbon blacks, carbon paper, PTFE). Consequently, AFCs are the cheapest to manufacture while still having high performance. However, carbon dioxide easily poisons the electrolyte because the alkaline chemicals are highly reactive with CO_2. Consequently, pure hydrogen or CO_2-scrubbed gas must be used. For this reason, AFCs are not the best candidate to use in conjunction with biogas technologies, which yield up 50% CO_2. There is also the hazard of using a caustic medium.

Phosphoric acid fuel cells (PAFCs) use highly concentrated or pure phosphoric acid saturated in a silicon carbide matrix as the electrolyte. Like PEMFCs, PAFC electrodes are also made of porous, platinum-impregnated carbon paper. However, the higher operating temperatures of PAFCs slows down CO poisoning of the platinum catalyst so that higher CO concentrations can be withstood. PAFCs are not as sensitive as PEMFCs to most fuel impurities and can also tolerate CO_2 unlike PEMs. Their operating temperature (130 – 220 °C) is also high enough for the expelled water to be converted to steam and used for CHP applications. The primary drawbacks to PAFCs are that they use a very corrosive electrolyte and have a low power density.

In a molten carbonate fuel cell (MCFC), the high operating temperature causes carbonate salts to melt in a ceramic matrix of $LiAlO_2$ and conduct carbonate ions to serve as the electrolyte. MCFCs use a nickel anode and a nickel oxide cathode. The high MCFC operating temperatures of above 600 °C provide an environment for several synergistic chemical reactions to occur, producing additional H_2. Firstly, CO reacts with water following the water gas shift reaction pathway to produce H_2 and CO_2. Secondly, CH_4 may be internally reformed to H_2 at high temperature using the anode as a catalyst. Although MCFCs also use a very corrosive electrolyte and are sensitive to even more impurities, their ability to directly use methane, CO_2 and siloxane tolerance, and potential for large power sizes make MCFCs a prime candidate for use with biogas.

Solid oxide fuel cells (SOFCs) use an electrolyte consisting of a solid, nonporous metal oxide (e.g., Y_2O_2-stabilized ZrO_2). High temperatures of 650 – 1000 °C permit the conduction of oxygen ions from cathode to anode through the electrolyte. The anode is made of $CoZrO_2$ or $NiZrO_2$ cermet while the cathode is made of Sr-doped $LaMnO_3$. Even though SOFCs do not require precious metal catalysts, the materials can still be expensive, but the use of a solid electrolyte avoids the corrosion problems that most other fuel cells have. Like MCFCs, high operating temperatures allow for internal methane reformation, but in addition to the water gas shift and internal reforming reactions, methane can undergo the steam reforming reaction ($CH_4 + H_2O \rightarrow CO + 3H_2$) and be converted into hydrogen without a catalyst. SOFCs are generally designed for small applications of a few kW. However, tubular, flat plate, and monolithic cell stacking configurations can be used to increase voltage and power.

APPENDIX D: Supplementary Figures and Tables

Table 29: Natural Gas Pipeline Quality Standards for Other Gas Pipeline Operators in California

Company	City of Long Beach, Gas & Oil Department	City of Vernon Natural Gas Department	El Paso Natural Gas Company / Kinder Morgan	Kern River Gas Transmission Company	Mojave Pipeline Company / Kinder Morgan	North Baja Pipeline LLC / TransCanada	Tuscarora Gas Transmission Company / TransCanada
Higher Heating Value (Btu/cf)	990 – 1,150	990 – 1,150	≥ 967	≥ 970	≥ 970	990 – 1,150	≥ 975
Temperature (°F)	50 – 105	50 – 105	50 – 120	40 – 120	50 – 105	50 – 105	100
Wobbe Index	1,279 – 1,385	1,279 – 1,385				1,279 – 1,385	
Water Vapor (lb/MMscf)	7	7		7	7	7	4
Hydrocarbon Dew Point		45°F at 400 psi if P<400 psi (or 20°F at 400 psi if P>800 psi)	20°F at normal pipeline psig	15°F at < 800 psig	20°F at < 600 psig	20°F at < 600 psig	
Hydrogen Sulfide (grain/100 scf)	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Mercaptans (grain/100 scf)	0.3	0.3	0.75	0.3	0.3	0.3	
Total Sulfur (grain/100 scf)	0.75	0.75	5	0.75	0.75	0.75	10
Total Inerts	4%	4%	3%	4%	4%	3%	
Carbon Dioxide			2%	3%	3%	2%	2%
Oxygen	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.4%
California ARB Constituents of Concern	Yes	No	No	No	No	No	No

Chart Credit: Author

Table 30: List of Nonattainment Air District in California

	Ozone	PM2.5	PM10	H_2S
Amador	✔		✔	
Antelope Valley	✔		✔	
Butte	✔	✔	✔	
Calaveras	✔		✔	
Colusa			✔	
Eastern Kern	✔		✔	
El Dorado	✔		✔	
Feather River	**T**		✔	
Glenn			✔	
Great Basin Unified	✔		✔	
Imperial	✔		✔	
Lake				
Lassen			✔	
Mariposa	✔		**P**	
Mendocino	✔		✔	
Modoc			✔	
Mojave Desert	✔	**P**	✔	**P**
Monterey Bay Unified	✔		✔	
North Coast United			**P**	
Northern Sierra	**P**	**P**	✔	
Northern Sonoma				
Placer	✔		✔	
Sacramento	✔		✔	
San Diego	✔	✔	✔	
San Francisco Bay Area	✔	✔	✔	
San Joaquin Valley Unified	✔	✔	✔	
San Luis Obispo	✔		✔	
Santa Barbara	✔		✔	
Shasta	✔		✔	
Siskiyou				
South Coast	✔	**P**	✔	
Tehama	✔		✔	
Tuolumne	✔			
Ventura	✔		✔	
Yolo-Solano	✔		✔	

P: Region is partially nonattainment T: Region is transitioning to nonattainment

† All California air districts are either classified as attainment or unclassified for carbon monoxide, nitrogen dioxide, sulfur dioxide, sulfates, lead, and visibility reducing particles

Chart Credit: Author; Data Credit: California Air Resources Board (2014a)

Table 31: Operating Conditions, Features, and Requirements of Biogas Cleaning and Upgrading Technologies

	Biogas Cleaning / Upgrading Process	Pressure (psig)	Temperature (°C)	Product CH_4 Content	Methane Slip/Loss	Sulfur Pre-Treatment	Consumables
Cleaning†	Adsorption	0 – 100	25 – 70			Not needed	Adsorbent
Cleaning†	Water Scrubbing	0	20 – 40			Not needed	Water; Anti-fouling agent; Drying agent
Cleaning†	Biofiltration	0	35			Not needed	Water; Drying agent
Cleaning†	Refrigeration	0 – 58	-29 – 5			Preferred / Required	Refrigerant
Upgrading†	Pressure Swing Adsorption	14 – 145	5 – 30	95 – 97.5%	1 – 3.5%	Required	Adsorbent
Upgrading†	Alkaline Salt Solution Absorption	0	2 – 50	78 – 90%	0.78%	Required / Preferred	Water; Alkaline
Upgrading†	Amine Absorption	0 (< 150)	35 – 50	99%	0.04 – 0.1%	Preferred / Required	Amine solution; Anti-fouling agent; Drying agent
Upgrading†	Pressurized Water Scrubbing	100 – 300	20 – 40	93 – 98%	1 – 3%	Not needed / Preferred	Water; Anti-fouling agent; Drying agent
Upgrading†	Physical Solvent Scrubbing	58 – 116	10 – 20	95 – 98%	1.5 – 4%	Not needed / Preferred	Physical solvent
Upgrading†	Membrane Separation	100 – 600	25 – 60	85 – 99%	0.5 – 20%	Preferred	Membranes
Upgrading†	Cryogenic Distillation	260 – 435	-59 – -45	96 – 98%	0.5 – 3%	Preferred / Required	Glycol refrigerant
Upgrading†	Supersonic Separation	1,088 – 1,450	45 – 68	95%	5%	Not needed	

† Cleaning refers to the removal of miscellaneous contaminants, while upgrading specifically focuses on the removal of carbon dioxide

Chart Credit: Author; Data Credit: (Beil and Beyrich 2013; Severn Wye Energy Agency 2013; Starr et al. 2012; Twister BV 2014)

Table 32: Contaminant Treatability for Biogas Cleaning and Upgrading Technologies

	Biogas Cleaning / Upgrading Process	CO_2	H_2S	O_2	N_2	VOCs	NH_3	Siloxanes	H_2O
Cleaning†	Adsorption	/	**	/	– –	**	*	**	**
	Water Scrubbing	/	**	– –	– –	**	**	**	– –
	Biofiltration	/	**	– –	– –	**	/	/	– –
	Refrigeration	–	/	–	–	/	**	*	**
Upgrading†	Pressure Swing Adsorption	**	* R	/	/	*	*	*	* R
	Alkaline Salt Solution Absorption	**	*	–	–	/ –	–	*	– –
	Amine Absorption	**	*	R	–	/ –	*	/ –	– –
	Pressurized Water Scrubbing	**	*	– –	– –	*	*	*	– –
	Physical Solvent Scrubbing	**	**	/	/	*	*	*	*
	Membrane Separation	**	* /	* /	/	* –	*	*	*
	Cryogenic Distillation	**	*	**	**	*	*	*	*
	Supersonic Separation	**	**	–	–	**	*	*	**

Legend: ** Complete removal (intended)   * Complete removal (pretreatment preferred)   / Partial removal
– Does not remove   – – Contaminant added   **R** Must be pretreated

Two symbols may be in the same box if one or the other can be applicable

† Cleaning refers to the removal of miscellaneous contaminants, while upgrading specifically focuses on the removal of carbon dioxide

Chart Credit: Author; Data Credit: (Severn Wye Energy Agency 2013; Starr et al. 2012; Twister BV 2014)

Figure 36: Total Energy Requirements for Biogas Upgrading Technologies

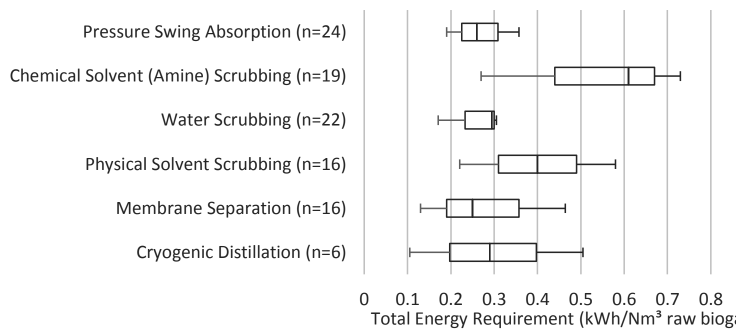

Chart Credit: Author; Data Credit: (Agency for Renewable Resources 2014; Allegue and Hinge 2012b; Bauer et al. 2013; Beil and Beyrich 2013; Günther 2006; Johansson 2008; Kharrasov 2013; Niesner, Jecha, and Stehlík 2013; Patterson et al. 2011; Purac Puregas 2011; Vijay 2013)

Figure 37: Electricity Requirements for Biogas Upgrading Technologies

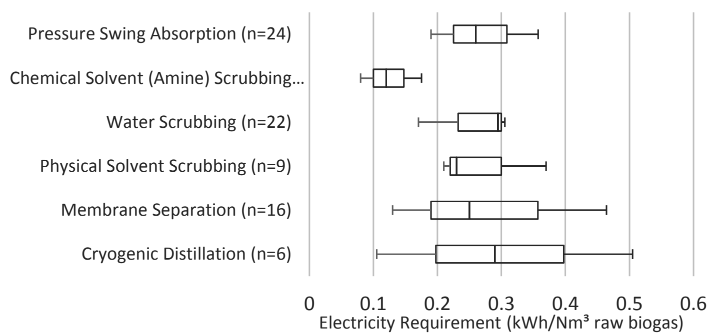

Chart Credit: Author; Data Credit (Agency for Renewable Resources 2014; Allegue and Hinge 2012b; Bauer et al. 2013; Beil and Beyrich 2013; Günther 2006; Johansson 2008; Kharrasov 2013; Niesner, Jecha, and Stehlík 2013; Patterson et al. 2011; Purac Puregas 2011; Vijay 2013)

Table 33: Review of Commercially Available Products

ess	Brand Name	Capacity	Regen	Specific to Biogas	US Biogas Plants	Turn Key	Company	Location
arbon				Y		N	Bosch KWK Systeme	Lollar, Germany
arbon	DARCO® BG/BGH, NORIT® RB 30M/RB 40M, SORBONORIT® B 4			N		N	Cabot Norit	Marshall, TX
arbon	DARCO® H2S			N		N	Cabot Norit	Marshall, TX
arbon	DARCO® VOC			N		N	Cabot Norit	Marshall, TX
arbon ed with	NORIT® ROZ 3			N		N	Cabot Norit	Marshall, TX
arbon ed)	Type FCA®			N		N	Calgon Carbon Corporation	Stockton, CA
arbon ed with 3% KI)	Chemsorb® 1202			N		N	Molecular Products Ltd.	Boulder, CO
arbon ed)	Sofnocarb KC®			N		N	Molecular Products Ltd.	Boulder, CO
arbon ed)	Westates Carbon		N	N		N	Evoqua Water Technologies	Vernon, CA
arbon ed)	OdorClean™					Y	Enduro Composites	Houston, TX
d	Sofnolime® RG Grade			N		N	Molecular Products	Boulder, CO
ide	Media G2®		Y, 15x	Y		N	ADI Systems Inc.	Denver, CO
	Iron Sponge		Y, 3x	Y		N	Connelly-GPM Inc	Chicago, IL

Adsorption	Iron Oxide (Iron-oxide-impregnated wood chips)	OdorFilter™ / BAM™	< 10,000 cfm		Y	Y	Y	MV Technologies	Golden, CO
	Iron Oxide (Iron-oxide-impregnated wood chips)	H2SPlus™ / BAM™	150 - 15,000 cfm		Y	Y	Y	MV Technologies	Golden, CO
	Iron Oxide (Iron-impregnated wood chips)	SulfrPack CIS			Y		Y	Robinson Group LLC	Bothell, WA
	Iron Oxide (Iron-impregnated clay pellets)	SulfrPack ST			Y		Y	Robinson Group LLC	Bothell, WA
	Iron Oxide	SulfaTreat® (Standard, HP, 410HP, XLP)		N	N	Y	N	M-I SWACO / Schlumberger	Bakersfield, CA (Global)
	Iron Oxide (Fe_2O_3)	SOXSIA®			Y		N	Gastreatment Services	Bergambacht, Netherlands
	Iron Oxide	Sulfur-Rite®		N	N		N	Merichem Company	Houston, TX
	Iron Oxide (Fe_2O_3)	GTP Filter	10 – 2,500 Nm^3/h		Y		Y	Gastreatment Services	Bergambacht, Netherlands
	Mixed Metal Oxide	Select HP®			N		N	M-I SWACO / Schlumberger	Bakersfield, CA (Global)
	Mixed media	GES 350/400/600/900/1500	300 – 2,500 scfm		Y		Y	Parker Hannifin Corporation	Haverhill, MA
	Mixed media (Activated alumina, activated carbon, molecular sieves, silica gels)	Gas Conditioning System Skid	1,000 scfm	Y	Y		Y	Venture Engineering and Construction	Las Vegas, NV
	Multi-layer graded & pleated nanofiber filtration media	GES S4 Biogas Filter			Y		Y	Parker Hannifin Corporation	Haverhill, MA

Adsorption	Polymer Media	SRT System		Y	Y		Y	DCL International Inc.	Oak Ridge North, TX
	Polymeric Media	BGAK Siloxane Reduction System		Y	Y	Y	Y	Willexa Energy, LLC / PpTek Limited	Charlotte, NC
	Segmented activated gradient media and HOX silica gel-based media	SAGPack			Y		Y	Robinson Group LLC (acquired Applied Filter Technology, Inc.)	Bothell, WA
	Zeolite (13X)	Z10-03		Y	N		N	Zeochem	Louisville, KY
	Zeolite (13X)	Sofnosiv™			N		N	Molecular Products Ltd.	Boulder, CO
	Zinc Oxide	Puraspec®		N	N		N	Johnson Matthey Process Technologies	Pasadena, TX
	?	CJC Filtersorb AC64, CJC VOC Deep Bed Series	100 – 1,500 m³/h		N		Y	C.C.JENSEN A/S	Newnan, GA
	?	CJC Filtersorb AC64, CJC VOC Annular Bed Series	500 – 6,000 m³/h		N		Y	C.C.JENSEN A/S	Newnan, GA
	?	CJC™ Biogas Filter Medium	100 - 6,000 m³/h		Y		Y	C.C.JENSEN A/S	Newnan, GA
	?	CompHeet®		Y	Y	Y	Y	ESC Energy Systems	Redmond, WA
	?	SRS Siloxane Reduction System		Y	Y	Y	N	Willexa Energy, LLC	Charlotte, NC

Biofiltration	Biofilter	BioSulfurex®	12 – 2,000	Y	Y		Y	DMT Environmental Technology	Joure, Netherlands
	?	OdorClean™ Biofilter Systems		Y	Y		Y/N	Enduro Composites	Houston, TX
	Biotrickling filter with activated carbon	OdorClean™ 250/500	425 – 850 m³/hr	Y	Y		Y	Enduro Composites	Houston, TX
	Biotrickling filter	BioStrip	150 - 3,000 scfm	Y	Y		Y	Robinson Group LLC	Bothell, WA
	Biotrickling filter with alkaline solution gas pre-treatment	Biopuric™		Y	Y		N	Veolia Water Technologies	Pennsauken, NJ
	Biotrickling filter with alkaline solution gas pre-treatment	Sulfothane™		Y	Y		N	Veolia Water Technologies	Pennsauken, NJ
	Biotrickling filter with alkaline solution gas pre-treatment	Thiopaq®	10 – 50,000 Nm³/h	Y	Y		N	Paques	Wilmington, DE
Chemical Solvent Scrubbing	Alkaline Salt Solution	LRS 10		Y	N		N	British Gas Company	Rotherham, England
	Alkaline Salt Solution	Sulfurex®	200 – 1,320 Nm³/h		Y	N	N	DMT Environmental Technology	Joure, Netherlands
	Alkaline Salt Solution	MECS® DynaWave®			N		N	MECS, Inc.	Chesterfield, MO (Global)
	Alkaline Salt Solution	DGE-BCM 2	100 – 5,000 Nm³/h		Y		Y	DGE GmbH	Lutherstadt Wittenberg, Germany

Chemical Solvent Scrubbing	Amine absorption	AdvAmine™	0.0125 – 1.05 Nm³/h		N		N	PROSERNAT	Puteaux, France
	Amine absorption	HySWEET®			N		N	PROSERNAT	Puteaux, France
	Amine absorption	Sulfa-Bind G100		Y	N		N	NuGreen	Mansfield, TX
	Amine absorption	Sulfa-Bind G200		Y	N		N	NuGreen	Mansfield, TX
	Amine absorption	Sulfa-Bind G201		Y	N		N	NuGreen	Mansfield, TX
	Amine absorption (Methyl diethanolamine, Tetrahydrothiophene dioxide)	Sulfinol®			N		N	Shell	Houston, TX
	Amine absorption	ADIP-X			N		N	Shell	Houston, TX
	Amine absorption	Sulfa-Scrub® (Hexahydrotriazine)			N		N	Quaker Chemical	Conshohocke n, PA
	Amine absorption	The Eliminator			N		N	Gas Technology Products	Schaumburg, IL
	Amine absorption	LP Cooab®	50 – 5,000 Nm³/h		Y		N	Cirmac	Apeldoorn, Netherlands
	Amine absorption	LP Cooab®	450 – 3,400 Nm³/h		Y		N	Purac (Läckeby Water Group)	Lund, Sweeden
	Amine absorption	LI'LTEX™ / BIGTEX™ / MIGHTYTEX™ / MIGHTYTEX™		Y	N		Y	SouthTex Treaters, Inc.	Odessa, Texas
	Amine absorption	AminSelect			Y		Y	Dreyer & Bosse	Gorleben, Germany
	Amine absorption	MT-Amine Scrubbing	150 – 2,000 Nm³/h		Y		Y	MT-BioMethan GmbH	Zeven, Germany

Chemical Solvent Scrubbing	Amine absorption	PuraTreat™ / PuraTreat® R+	< 1,500		Y		N	Bilfinger Berger Industrial Services GmbH	Cloppenburg, Germany
	Amine absorption	Sulf-X			Y	Y	N	ChemE Solutions	Lake Stevens, WA
	Amine absorption	Sulfa-Clear®			N		N	Weatherford International	Addison, Texas (Global)
	Iron Solution (Chelated-Iron)	LO-CAT		Y	N		N	Merichem Company	Houston, TX
	Iron Solution (Chelated-Iron)	MINI-CAT		Y	N		N	Merichem Company	Houston, TX
	Iron Solution (Chelated-Iron)	SulFerox		Y	N		N	Le Gaz Integral	Nanterre, France
	Iron Solution (Chelated-Iron)	SulfInt			N		N	Le Gaz Integral	Nanterre, France
	Iron Solution	SweetSulf™			N		N	PROSERNAT	Puteaux, France
	Sodium Nitrite Solution	Sulfa-Check®			N		N	NALCO	Burlingame, CA (Global)
	Styrene-divinyl benzene-based ion-exchange resin	BioGas AutoKleen (600, 1200, 2000, 2400, 3000, 4000, 5000)	350 – 5,000 m^3/h	Y	Y		Y	PpTek Limited	West Sussex, United Kingdom
	Styrene-divinyl benzene-based ion-exchange resin	BioGas ManualKleen (50, 150, 300)	50 – 350 m^3/h	Y	Y		Y	PpTek Limited	West Sussex, United Kingdom
	Hydrocarbon (Heavy) Liquid	CrystaSulf®			N		N	URS Corporation	Sacramento, CA (Global)
	Unknown	MECS® SULFOX™ NK/HK/MET/SAR			N		N	DuPont	Chesterfield, MO (Global)
	Unknown + Adsorption	IBCS 300	100 – 1,600 scfm		Y	Y	Y	Quadrogen Power Systems	Vancouver, British Columbia, Canada

Cryogenic Distillation		CO_2 Wash®		N	Y	Y	N	Acrion Technologies	Cleveland, OH
		Sprex® / Sprex® CO_2			N		N	PROSERNAT	Puteaux, France
		GPP® / GPP®plus			Y	N	Y/N	Gastreatment Services BV	Bergambacht, Netherlands
Industrial Lung					Y	N	N	CO_2 Solutions Inc.	Québec, Canada
Membrane Separation	High-pressure gas separation	PRISM® PB6050-P3	60 – 120 Nm^3/h	N	Y	Y	N	Air Products	Allentown, PA
	High-pressure gas separation	Sepuran® Green membranes	10 – 1,000 Nm^3/h	N	Y	Y	N	Evonik	Portland, OR
	High-pressure gas separation	Carborex® MS	50 – 750 Nm^3/h	N	Y	N	Y	DMT Environmental Technology	Joure, Netherlands
	High-pressure gas separation	Cynara®			N	N	Y/N	Cameron	Antioch,CA (Global)
	High-pressure gas separation	Separex™			N	N	Y	UOP LLC (Honeywell)	Anaheim, CA
	High-pressure gas separation	Medal™	100 – 11,200 Nm^3/h		Y	Y	N	Air Liquide	Houston, TX
	High-pressure gas separation	MT-Membrane Technology (Uses Evonik SEPURAN®Green membrane modules)	250 – 700 Nm^3/h		Y	N	Y	MT-BioMethan GmbH	Zeven, Germany
	High-pressure gas separation	EnviThan (Uses Evonik SEPURAN®Green membrane modules)			Y	N	Y	EnviTec Biogas	Saerbeck, Germany
	High-pressure gas separation	AE-Membrane (Uses Air Products PRISM® Membranes)	100 – 1,000 Nm^3/h		Y	N	Y	Arol Energy	Le Bourget-du-Lac, France

Membrane Separation	High-pressure gas separation	MemfoACT AS Keyless Biogas Upgrading Solution	50 – 2,500 Nm³/h		Y	N	Y	MemfoACT AS	Heimdal, Norway
	High-pressure gas separation		> 80 – 500 Nm³/h		Y	N	N	Axiom (Axiom Angewandte Prozesstechnik Ges.m.b.H.)	Ebreichsdorf, Austria
	High-pressure gas separation/Cryogenic		250 – 700 Nm³/h		Y	Y	N	Pentair Haffmans	Delavan, WI (Global)
	High-pressure gas separation/Cryogenic	BioCNG™ 50/100/200	50 – 200 scfm		Y	Y	Y	BioCNG	Dublin, CA
	Gas-liquid adsorption		10 – 1,000 scfm		Y	N	Y	Nrgtek Inc.	Orange, CA
Physical Liquid Scrubbing	Propylene Carbonate	Fluor Solvent™			N		N	Fluor Corporation	Dublin, CA
	N-Methyl-2-Pyrrolidone	Purisol			N		N	Air Liquide	Houston, TX
	Selexol (dialkyl ethers of polyethylene glycol, mixed tetraethylene glycol dimethyl ethers)	Genosorb® 1753	250 – 2,000 Nm³/h (up to 600,000)	Y	Y		N	Clariant GmbH	Sulzbach (Taunus), Germany
	Selexol (dimethyl ethers of polyethylene glycol)	SELEXOL™		Y	N		N	UOP LLC (Honeywell)	Anaheim, CA
	Methanol	Rectisol®			N		Y/N	Air Liquide	Houston, TX
	Methanol	Ifpexol	< 353,961 Nm³/h		N		N	PROSERNAT	Puteaux, France
	Methyl isopropyl ether	Sepasolv®			N		N	BASF Global	Orange, CA
	Polyethylene glycol	BGAA	200 – 700 Nm³/h		Y		Y	Schwelm Anlagentechnik GmbH	Schwelm, Germany

Physical Liquid Scrubbing	Polyglycol	Biogas-Upgrader	310 – 2,000 Nm³/h		Y		Y	BMF HAASE Energietechnik GmbH	Neumünster, Germany
	Triethylene glycol	TEG Regenerator Unit			N		Y	SouthTex Treaters, Inc.	Odessa, Texas
	Water	Kanuka / Rimu / Matal / Torara / Torara+	50 – 2,500 Nm³/h	Y	Y		Y	Greenlane Biogas	Burnaby, British Columbia, Canada
	Water	COMPACT®	100 – 3,000 Nm³/h		Y		Y	Malmberg Water	Yngsjö, Sweden
	Water	Carborex® PWS		Y	Y	N	Y	DMT Environmental Technology	Joure, Netherlands
	Water	OdorClean™ Wet Scrubbers		Y	Y	Y	Y/N	Enduro Composites	Houston, TX
	Water	(Uses Greenlane Biogas System)	850 Nm³/h	Y	Y		Y	Anaergia	Carlsbad, CA
	Water	CO_2Strip			Y		Y	Robinson Group LLC	Bothell, WA
	Water (Rotary Coil)	BioSling			Y	N	Y	Arctic Nova	Vittangi, Sweden
Pressure Swing Adsorption		Molecular Gate®			Y	Y	Y/N	Guild Associates	Dublin, OH
		FirmGreen			Y	Y	Y	FirmGreen	Newport Beach, CA
		M-3200	100 – 300 Nm³/h		Y	Y	Y	Xebec Adsorption Inc.	Houston,TX
		M-3100	300 – 3,000 Nm³/h		Y	Y	Y	Xebec Adsorption Inc.	Houston,TX

Pressure Swing Adsorption		M-3200*	3,000 – 10,000 Nm³/h		Y	Y	Y	Xebec Adsorption Inc.	Houston,TX
		DGE-BCM 4	100 – 5,000 Nm³/h		Y	N	Y	DGE GmbH (Dr.-Ing. Günther Engineering GmbH)	Lutherstadt Wittenberg, Germany
		ZETECH$_4$© (BGAA250 - BGAA1400)	250 – 1,400 Nm³/h		Y	N	Y	Schmack Carbotech GmbH	Essen, Germany
		BIOSWING	500 – 5,000 Nm³/h		Y		Y	Mahler AGS GmbH	Stuttgart, Germany
		Methane purification plant	800 scfm		Y	Y	Y	ARC Technologies	Yukon, PA
Refrigeration		DriPack			Y		Y	Robinson Group LLC	Bothell, WA
		Air Cooled Dehydration Module			Y		Y	Willexa Energy, LLC	Charlotte, NC
	Glycol chiller	TCR system			Y		Y/N	Gastreatment Services	Bergambacht, Netherlands
	Glycol chiller	E Series	100 – 2,500 scfm		Y		Y	Pioneer Air Systems Inc.	Monroeville, PA
	Glycol chiller	TCR Series	100 – 3,600 scfm		Y		Y	Pioneer Air Systems Inc.	Monroeville, PA
Supersonic Separation		Twister® Supersonic Separator	60,000 Nm³/h		N	N	Y/N	Twister BV	Rijswijk, Netherlands

Temperature Swing Adsorption		ADAPT (Advanced Adsorption Process Technology)		Y	N	N	N	GL Noble Denton / DNV GL	Houston, TX

Notes: Robinson Group LLC acquired Applied Filter Technology, Inc.

Xebec Adsorption Inc. merged with QuestAir Technologies

Gas Technology Products is a division of Merichem Chemicals & Refinery Services LLC

Greenlane Biogas was formerly known as Flotech

Air Liquide acquired Lurgi AG

Please contact the author for more details on these technologies, including advertised and actual removal efficiencies for various contaminants and pricing

Chart Credit: Author

QUESTION:
FCG says in its response to staff's first data request question 8 that "FCG anticipates that the annual operations and maintenance costs for biogas conditioning equipment could be in the range of 4% to 7% of the original capital cost of the equipment." In the company's response to staff's first data request, question 12, the utility states "FCG will ensure creditworthiness by requiring the customer to remit a deposit in the amount of two months estimated billing or to provide an irrevocable letter of credit or surety bond." (a)Please explain how FCG would address the cost recovery process, if a customer served under this tariff goes into default. (b) Please explain how FCG would ensure that the general body of rate payers would not be affected by an RNG customer defaulting on its contract.

RESPONSE:
The proposed new Rate Schedule RNGS contains important customer safeguards that will ensure non-participants are not subsidizing the RNG customers. The proposed Rate Schedule RNGS tariff provides that the costs associated with the biogas conditioning equipment, plus the carrying costs at FCG's overall cost of capital, will be fully recovered from the RNG customer. The proposed new tariff also provides that the negotiated monthly rate must be set at an amount sufficient to ensure that service provided under Rate Schedule RNGS does not cause any additional cost to FCG's other rate classes. Because the costs associated with the biogas conditioning equipment will be fully paid by the RNG customers pursuant to a contract, the capital expenditures will not be included in rate base recovered from customers (similar to customer contributions in aid of construction).

In the event an RNG customer defaults on its contract, FCG will pursue all legal remedies available to collect any amounts then outstanding under the contract from the defaulting RNG customer, its parent company, and/or its guarantor, as applicable. FCG will not recover any amounts outstanding under the RNG contract from its general body of rate payers unless otherwise approved by the Commission upon a petition by FCG.

Importantly, the proposed new Rate Schedule RNGS contains a number of different measures to help insulate FCG in the event an RNG customer defaults on its contract. Under the proposed Rate Schedule RNGS tariff, FCG may require the RNG customer to furnish a guarantee, such as a surety bond, letter of credit or other means of establishing credit, and/or to comply with other provisions as determined appropriate by the Company. Each of these measures provide some assurance of recourse in the event an RNG customer defaults on its contract. Prior to entering into a contract with an RNG producer, FCG will perform an in-depth credit analysis of the potential customer. FCG may require commercial credit references, banking references, and authorization to examine the potential RNG customer's creditworthiness using commercially available services. Based on this review, FCG will incorporate appropriate measures in the contract to help insulate FCG from a potential default by the RNG customer.

Additionally, FCG will require the RNG customer to execute an agreement granting FCG an easement with rights of ingress and egress providing full and unencumbered access to the biogas conditioning equipment. FCG's interests as a creditor in the biogas conditioning equipment will also be secured by filing a Uniform Commercial Code-1 financing statement, which gives notice that FCG has an interest or lien against the biogas conditioning equipment to secure the financing under the RNG contract. In the case of a default by the RNG customer, FCG would seek recovery of the biogas conditioning equipment in order to protect its investment in the assets.