




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

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NREL/TP-5600-49009
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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		
Methane (CH4) LHV	0.052	GJ/kg methane
LHV Biogas	0.0223	GJ/Nm3 biogas
LHV Biomethane	0.0361	GJ/Nm3 biomethane

Biogas Cleanup Plant Utility Usage		
Electricity Consumption	0.230	kWh/nm3 biogas

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 ≤ q < 700	400	$1.16 M	0.250
700 ≤ q ≤ 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].

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

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

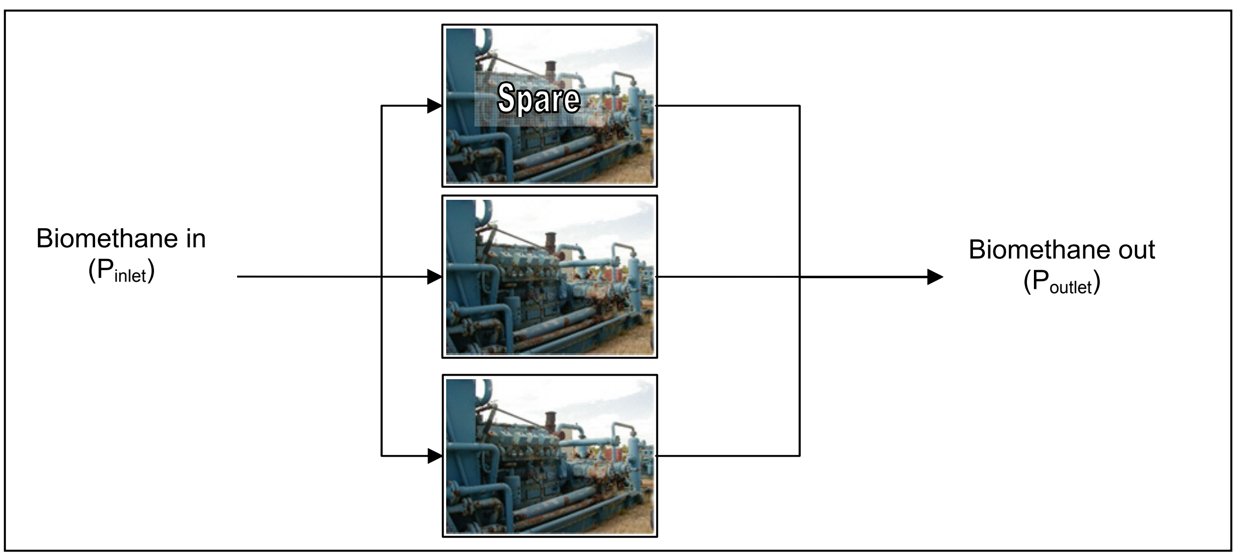


Figure 6. Compressor layout for external compression
(from DOE, *H2A Delivery Components Model Version 1.1: Users Guide*, April 7, 2006)

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

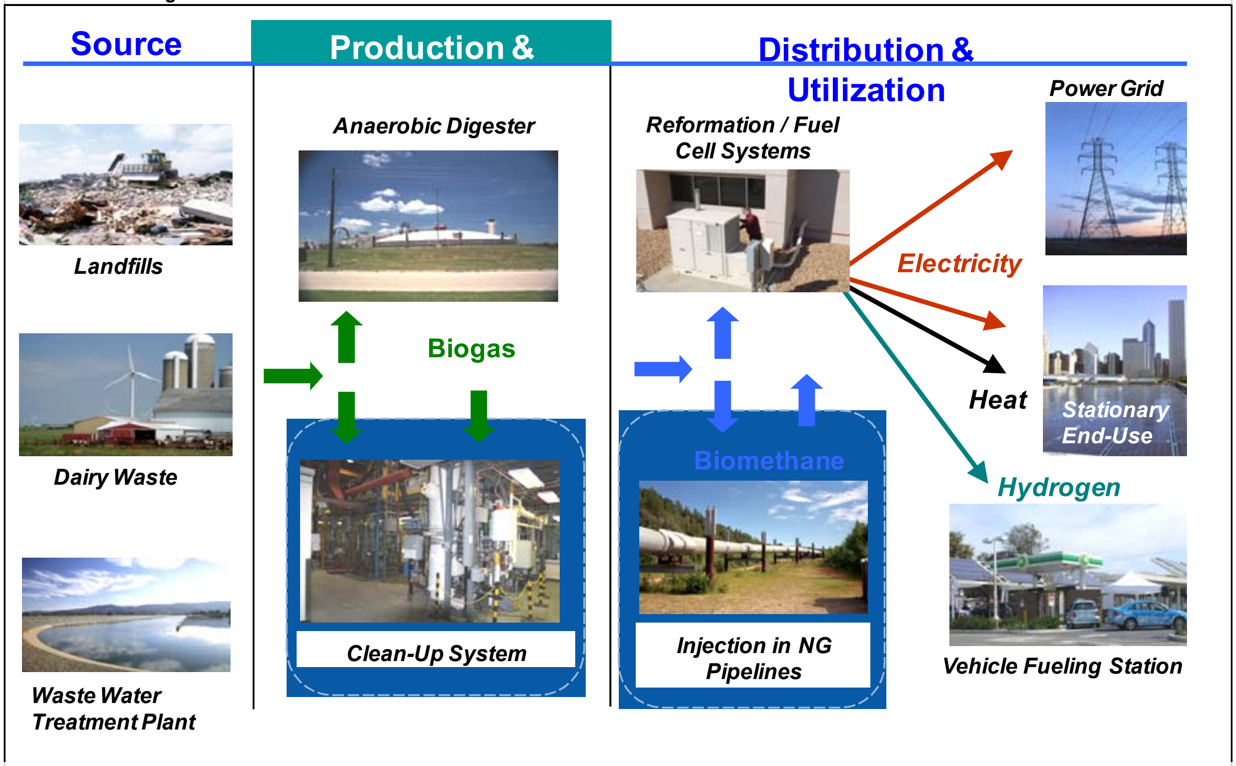
Upstream energy and emissions data for the biogas feedstock are calculated using a newly released report by the California Air Resources Board (CARB) [10]. This can be seen in Figure 13, an excerpt of Table C1 in the 'HyARC Physical Property Data' tab. The CARB report is based on a modified version of 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 (H2S, CO2, 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:
CH4: 96% - 98% by volume
CO2: Less than 2%
H2S: 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].

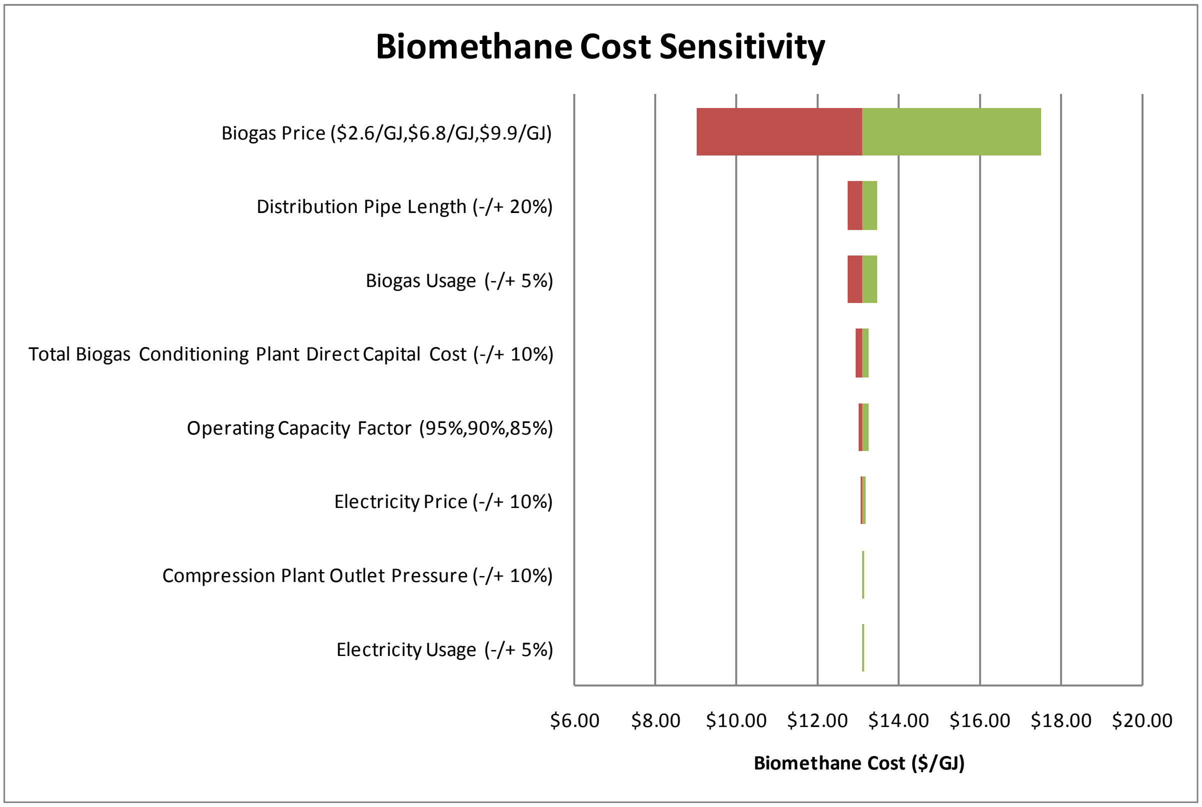


Figure 17. Sensitivity of several parameters on the cost of biomethane

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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