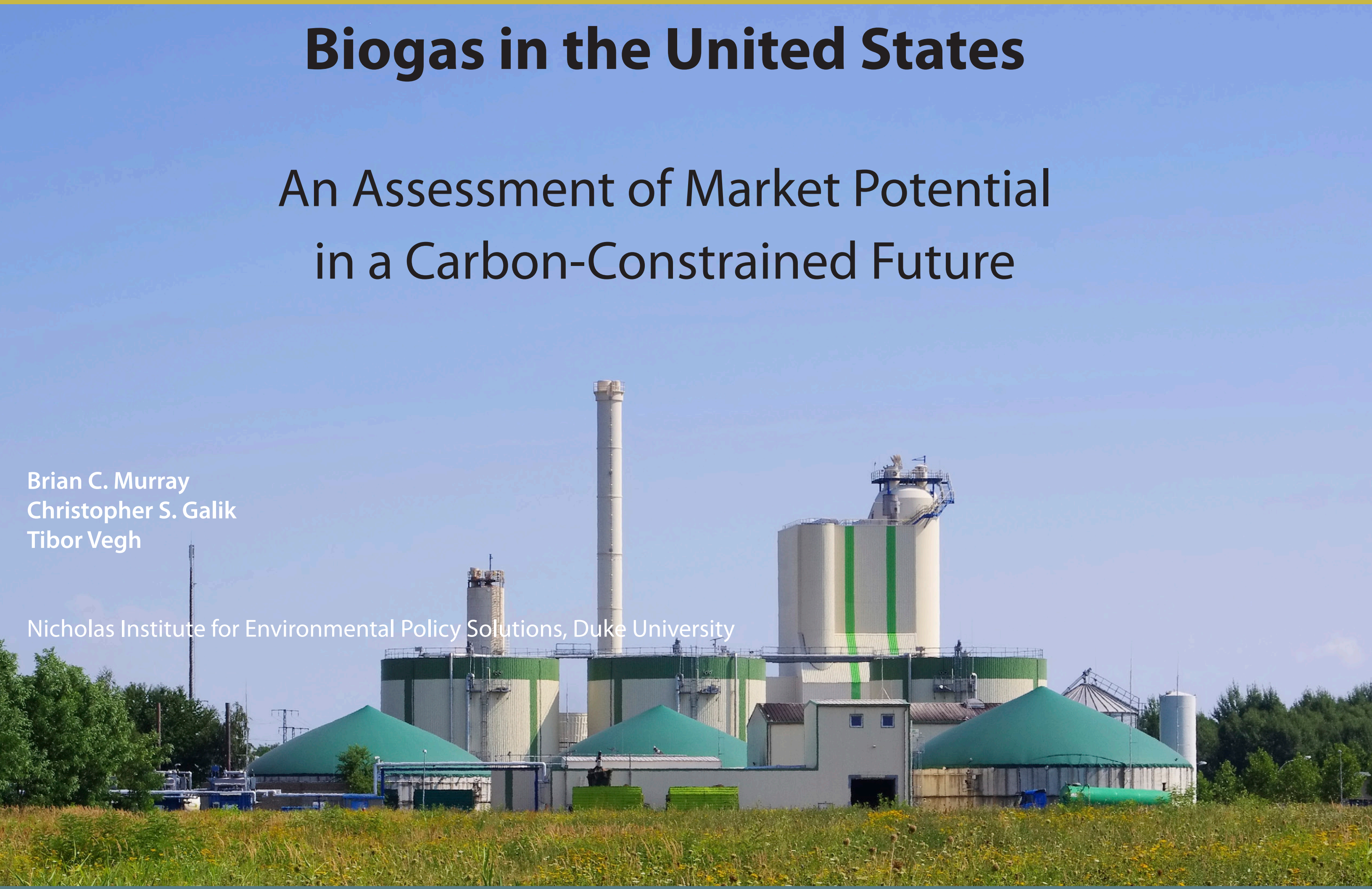
NICHOLAS INSTITUTE REPORT

Biogas in the United States

An Assessment of Market Potential in a Carbon-Constrained Future



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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.

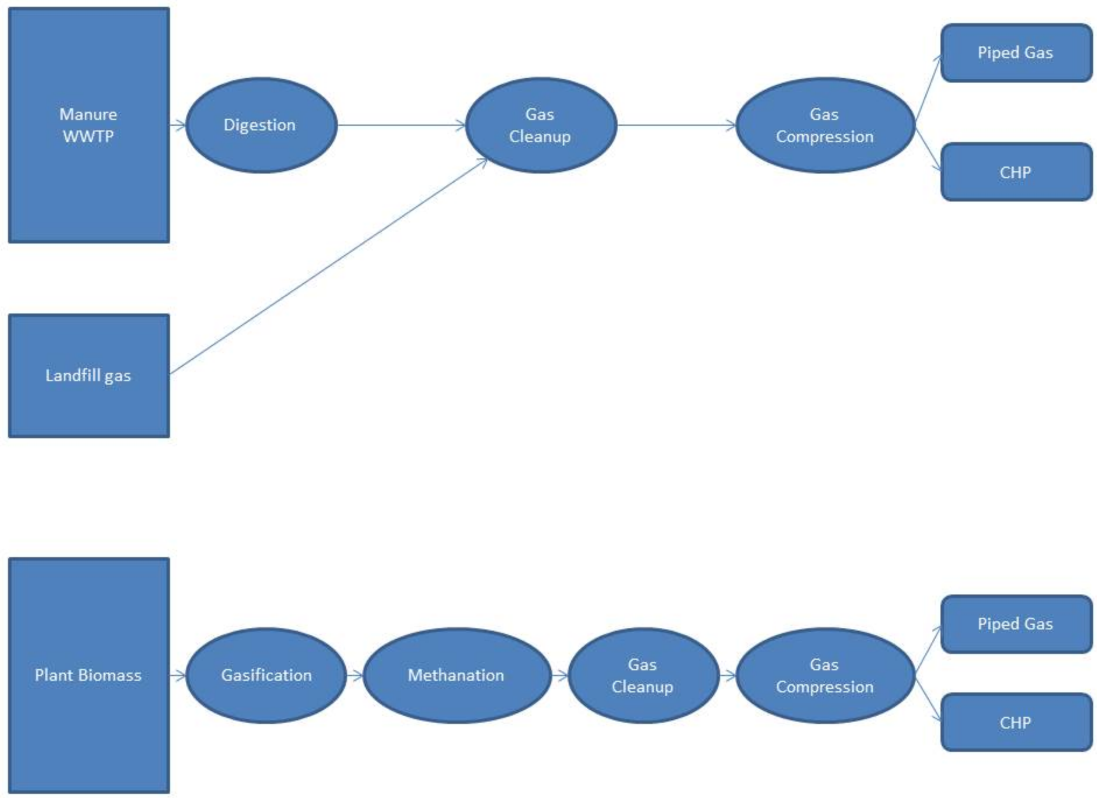
A key question, however, is whether a deep and decentralized market could develop for biogas, thereby allowing that energy source to become a viable substitute for fossil natural gas, and under what conditions? This study explores this question from a supply-and-demand perspective. Because infrastructure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

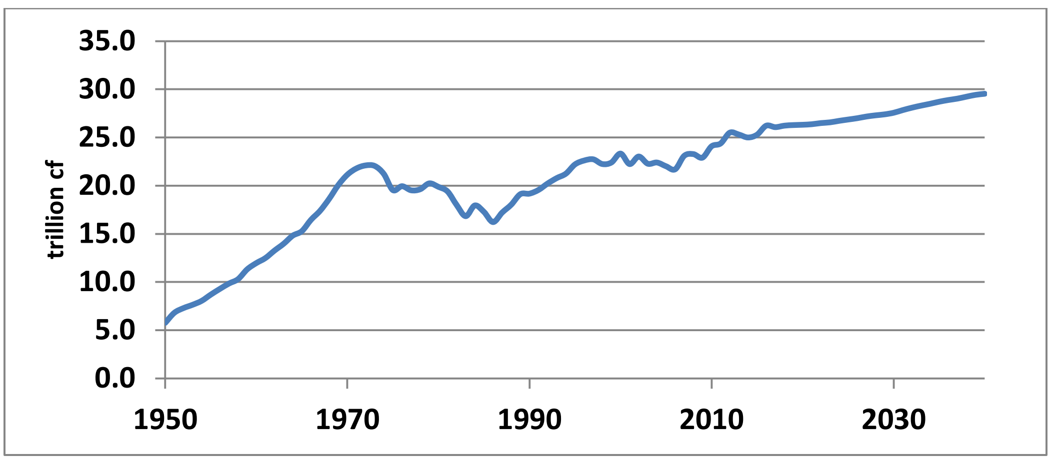
Table 1. U.S. natural gas consumption by end use in 2012.

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 \$/MMBűdz 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

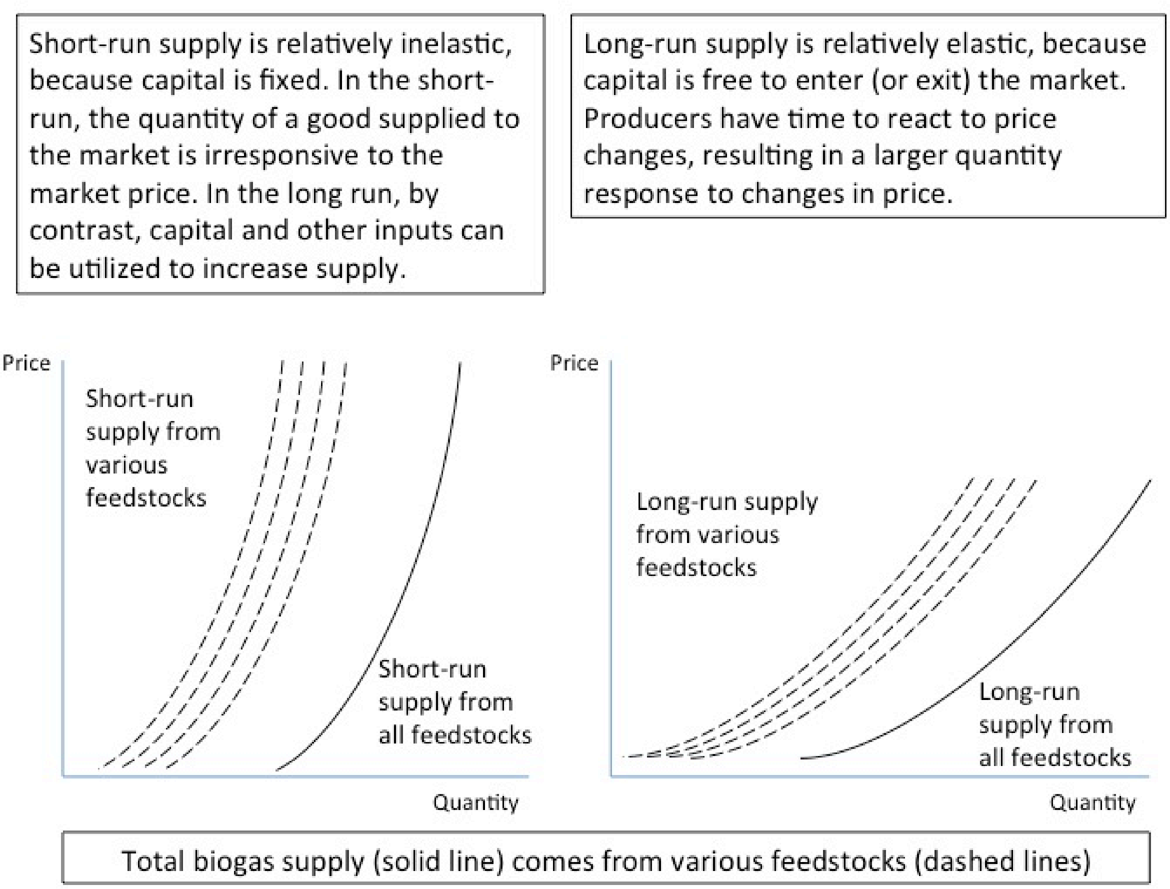
Demand for biogas may also be created by individual facility or corporate objectives. For example, an increasing emphasis on corporate social responsibility (CSR) may create a preference for low-carbon, renewable energy sources such as biogas. Biogas can also play a role in diversifying energy generation 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:

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

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.

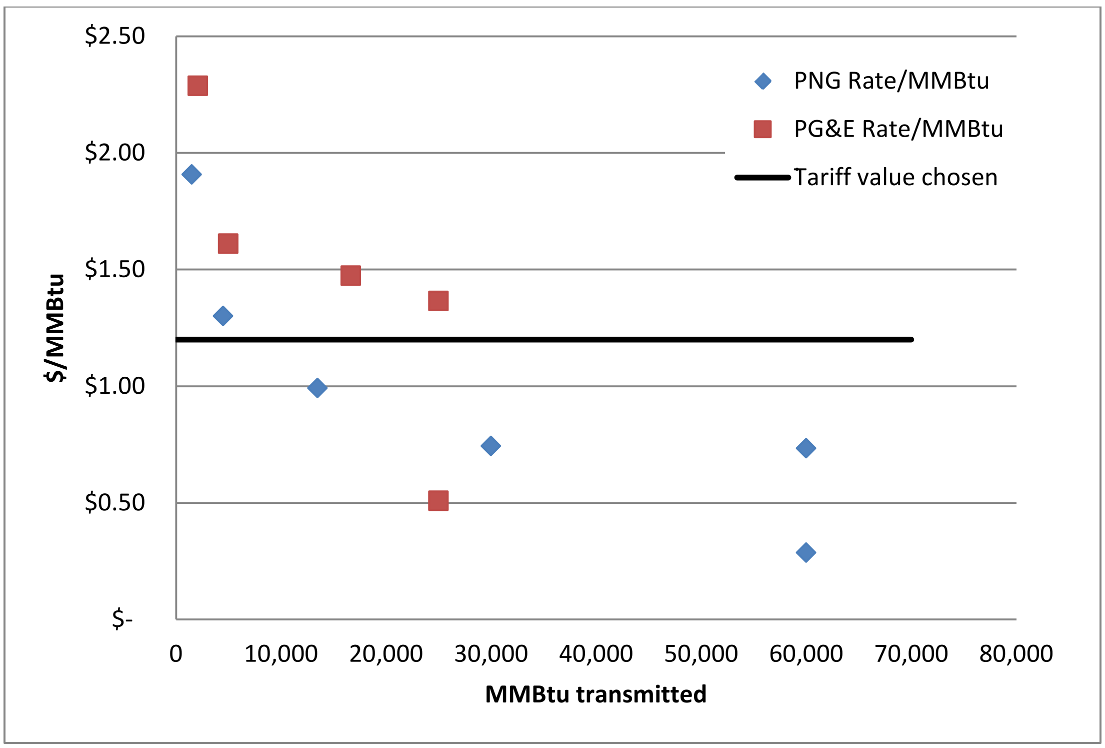
To calculate annual costs, data on the upfront (capital) cost and the annual (operating and maintenance) cost for the 20-year equipment life were gathered. These cost estimates for wastewater treatment plants and landfill gas were based on Prasodjo et al. (2013) and Cooley et al. (2013). Costs specific 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.

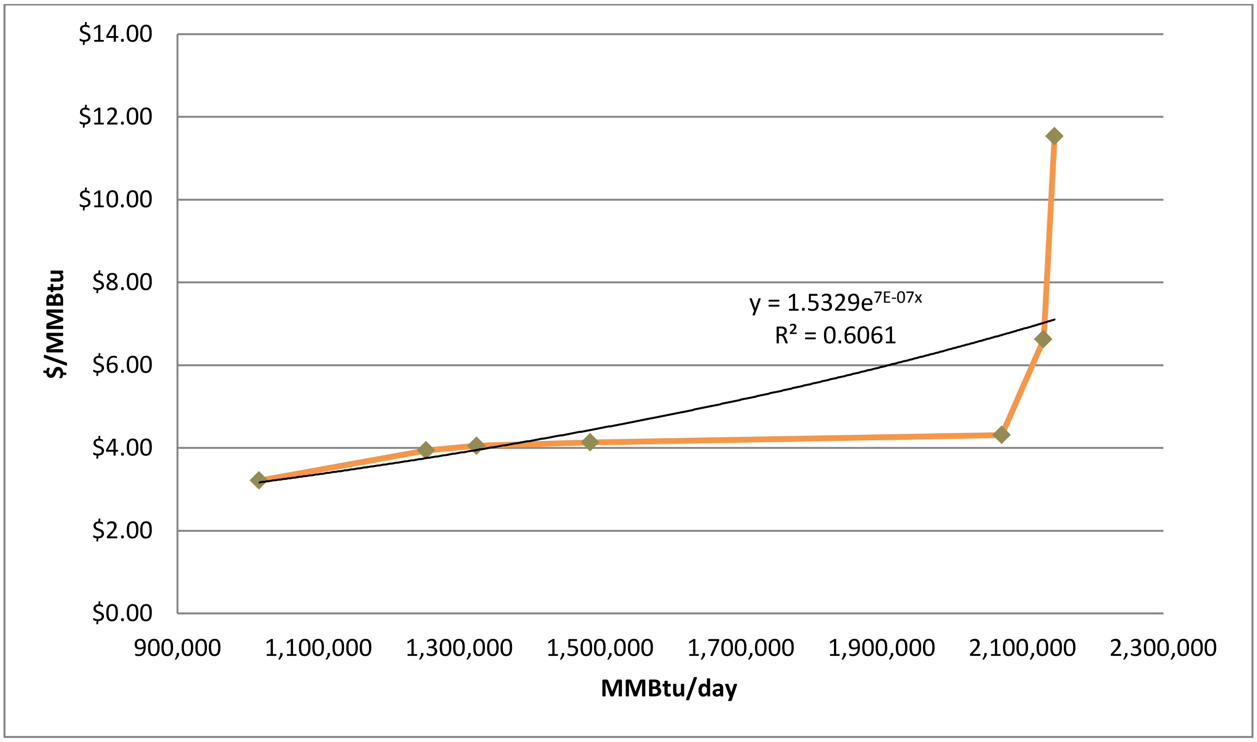
LF category	Size category: landfill output (scfh)	Generation unit used	Number of landfills	Total methane generation in LF category (scfh)	Total methane generation in LF category (MMBtu/day)
1	<6000	Recipr. engine	417	655,148	15,724
2	6,000–21,000	Steam turbine	320	2,471,423	59,314
3	21,000–42,000	Steam 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)

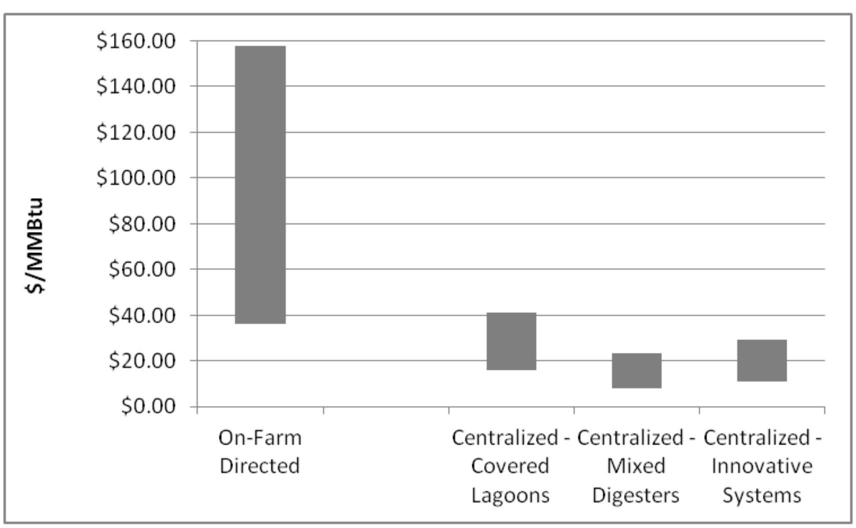
Complete mix capital cost = $320,864 + $563/cow (last term scaled by 0.31 for swine and beef)

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.

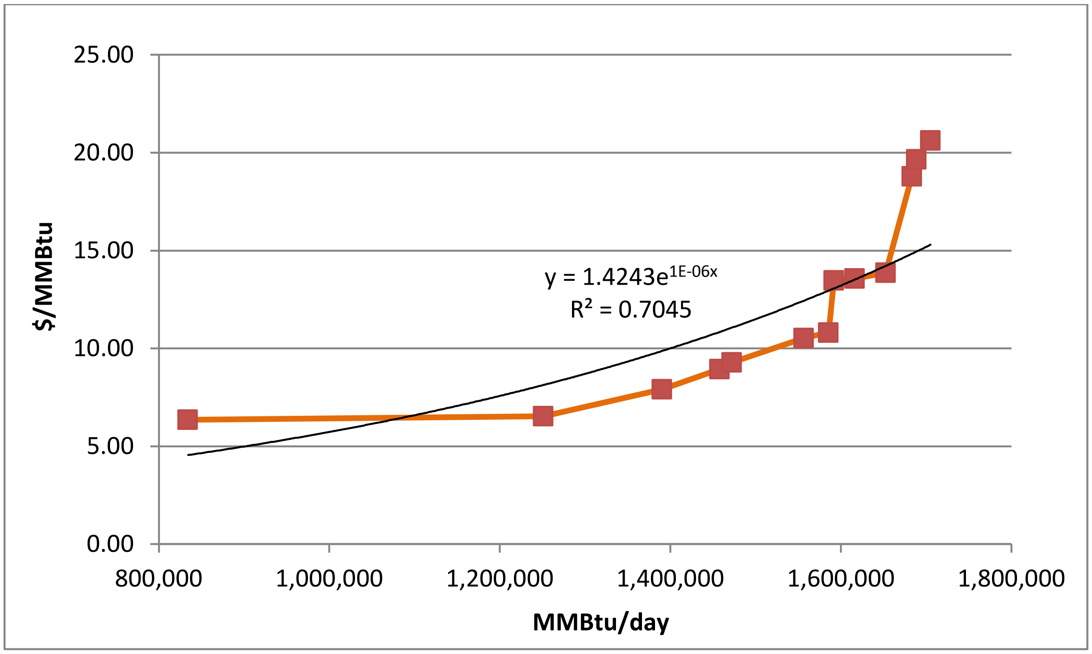
Table 6. Costs associated with biogas production from anaerobic digestion of dairy, swine, and beef manure.

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).

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

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[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.

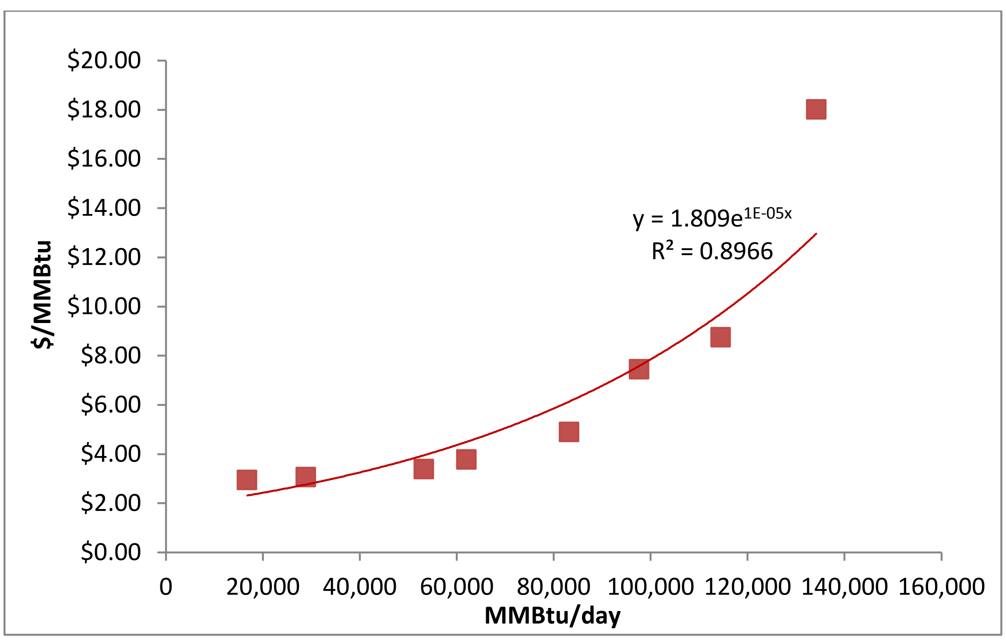
Table 8. Installation and O&M costs associated with biogas conditioning and compression.

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).

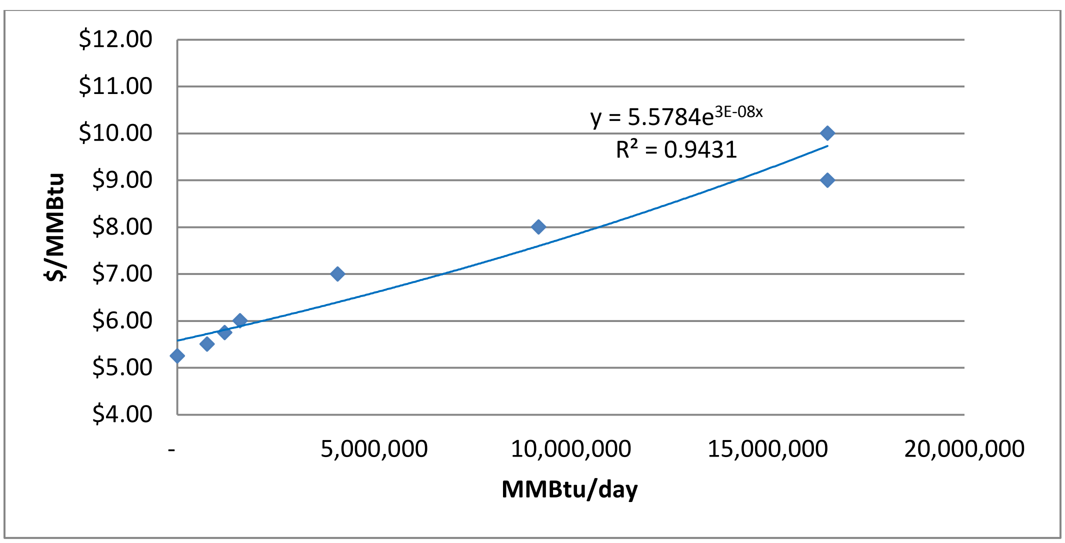
Table 9: Gas yield, capital, and O&M costs for biomass gasification facilities.

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.

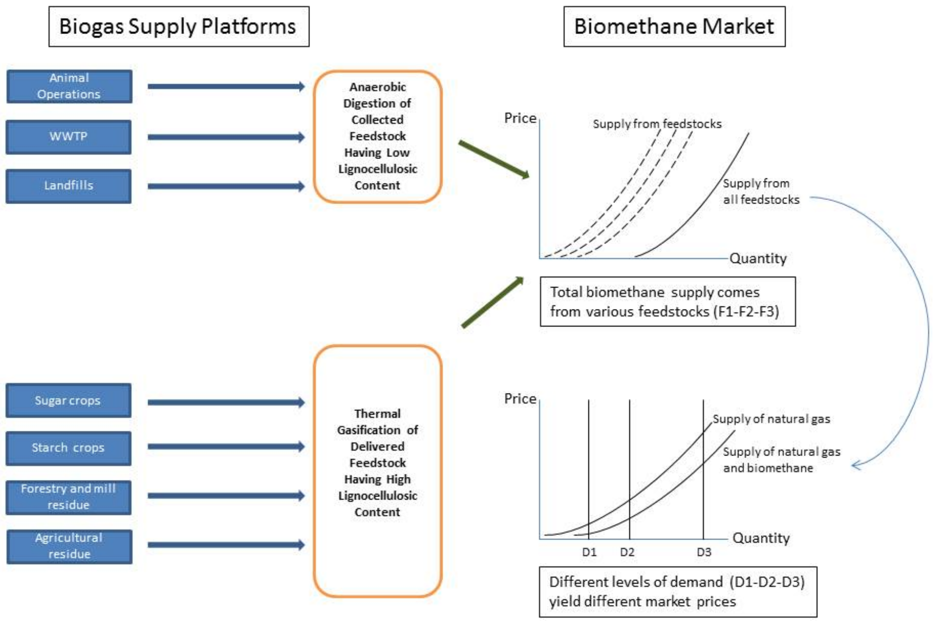
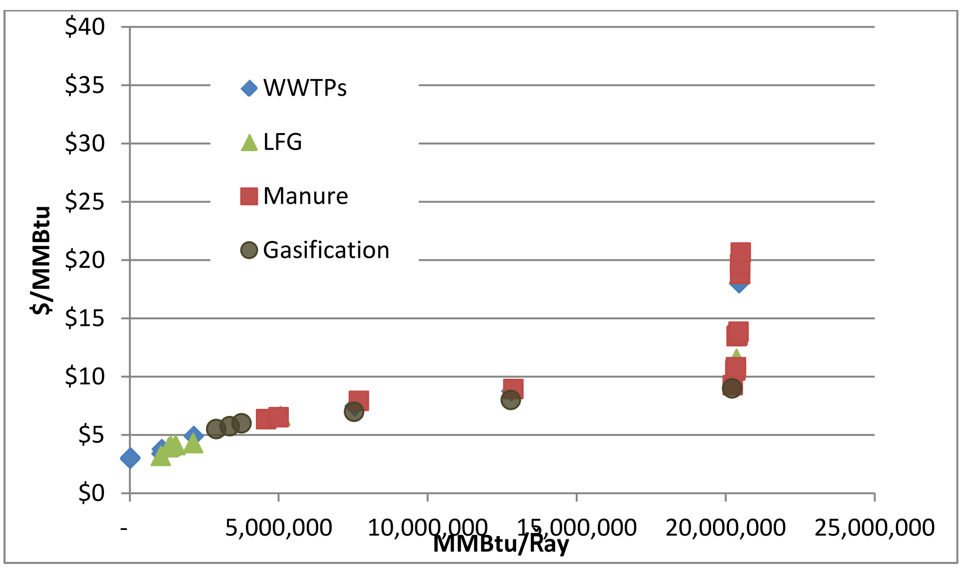


Figure 11. Combined supply function for four biogas sources.



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.

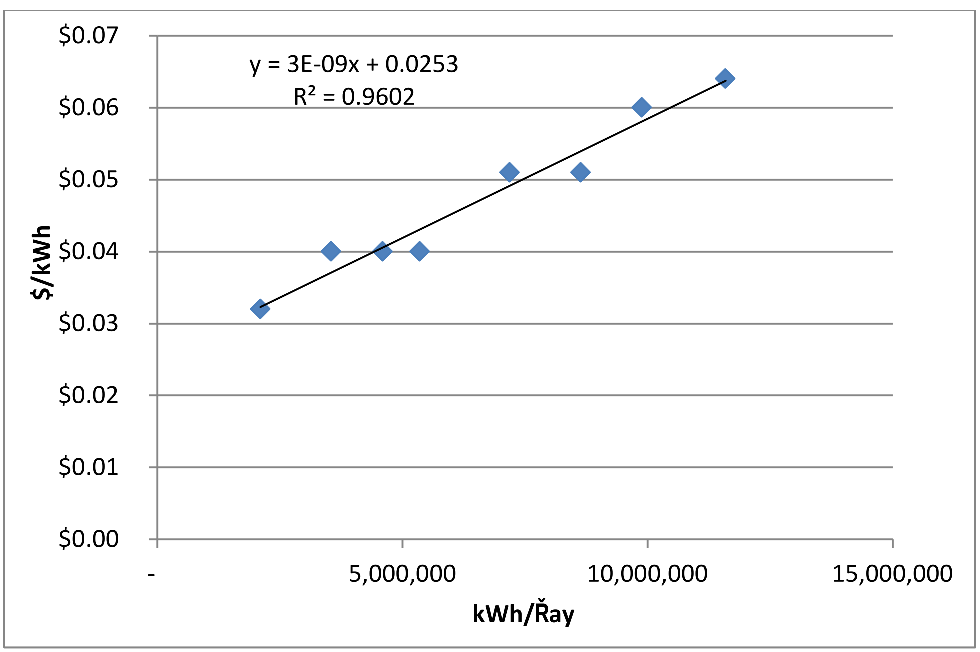
stream of electricity generation from that unit.[15] The electricity supply function across all potential units is shown in Figure 14. This process of matching biogas generation in cubic foot per hour with the needed electricity generator units was repeated for LFG and animal operations. Installation 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.

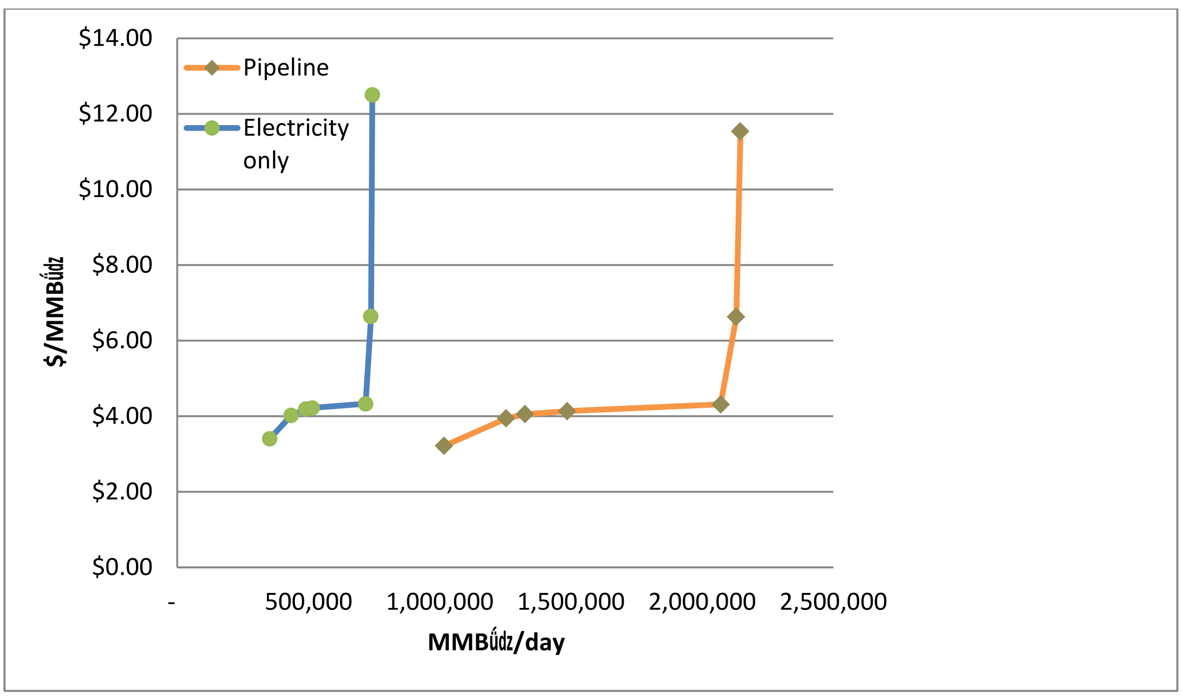


15 Here, installation and maintenance costs include conditioning of digester gas; these costs are not added separately as they are in the WWTP pipeline biogas example above.

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.

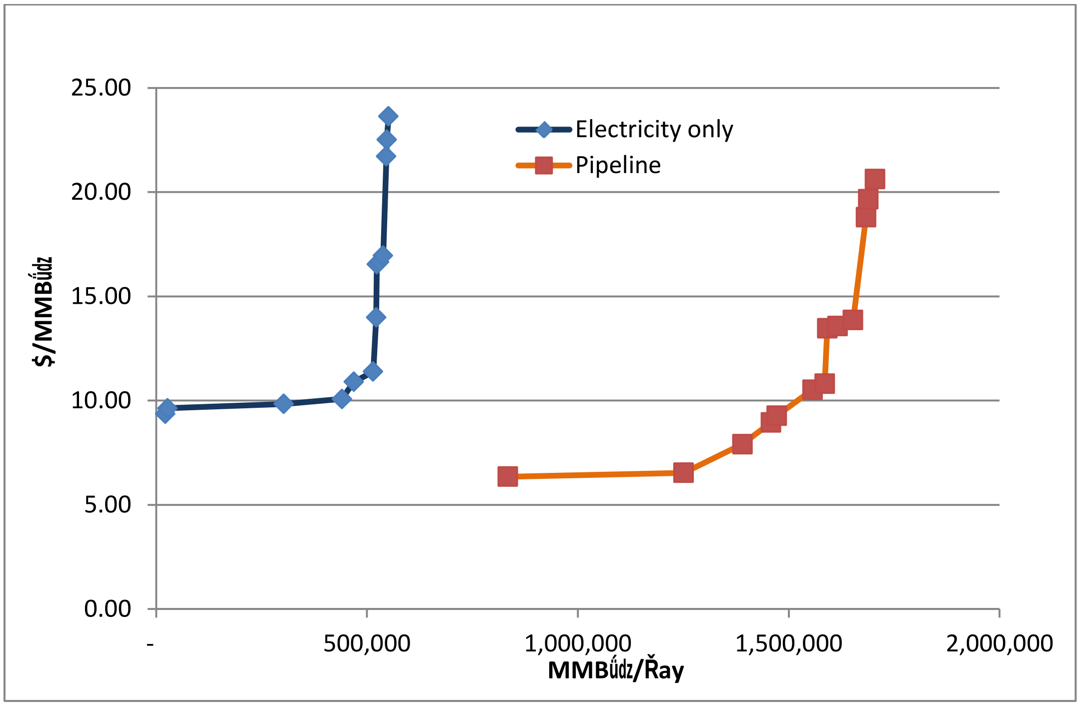


Figure 15. Comparison of pipeline biogas, electricity, and CHP supply functions for WWTP facilities already possessing anaerobic digesters.

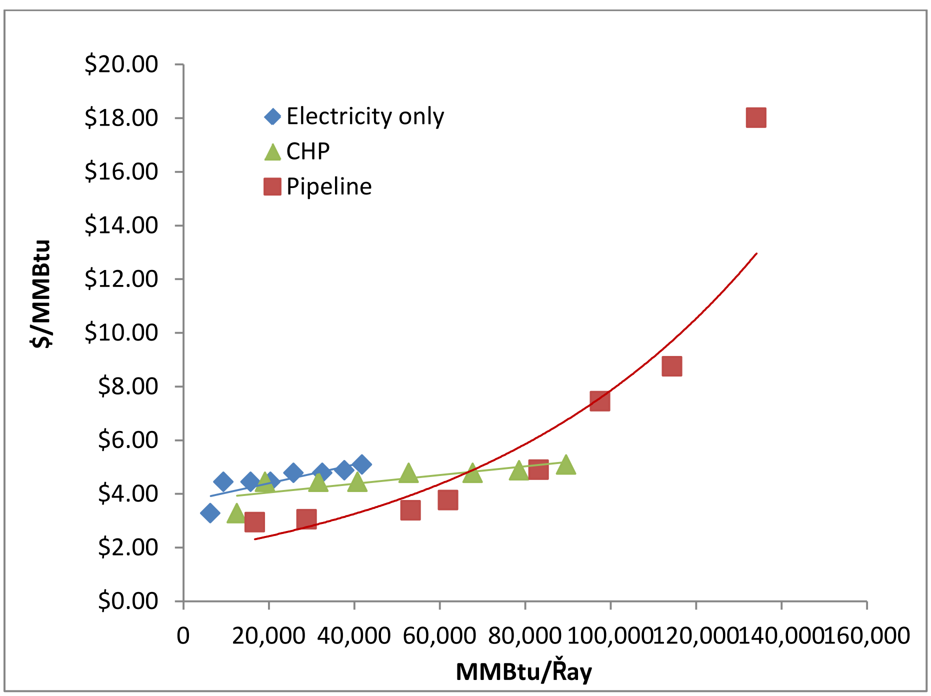
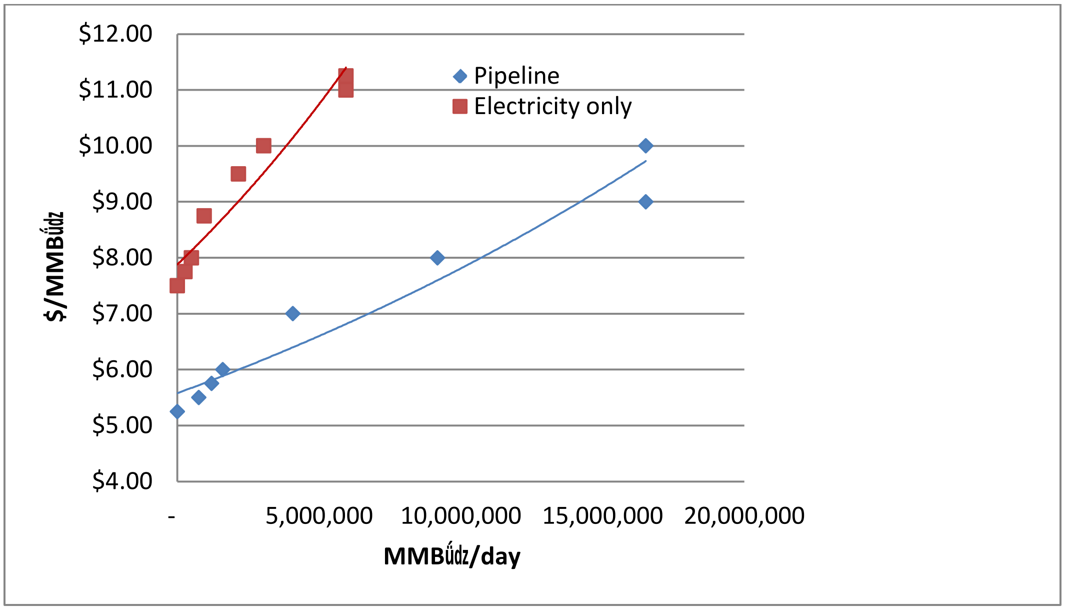


Figure 16: Comparison of pipeline biogas and electricity supply functions for biomass gasification.

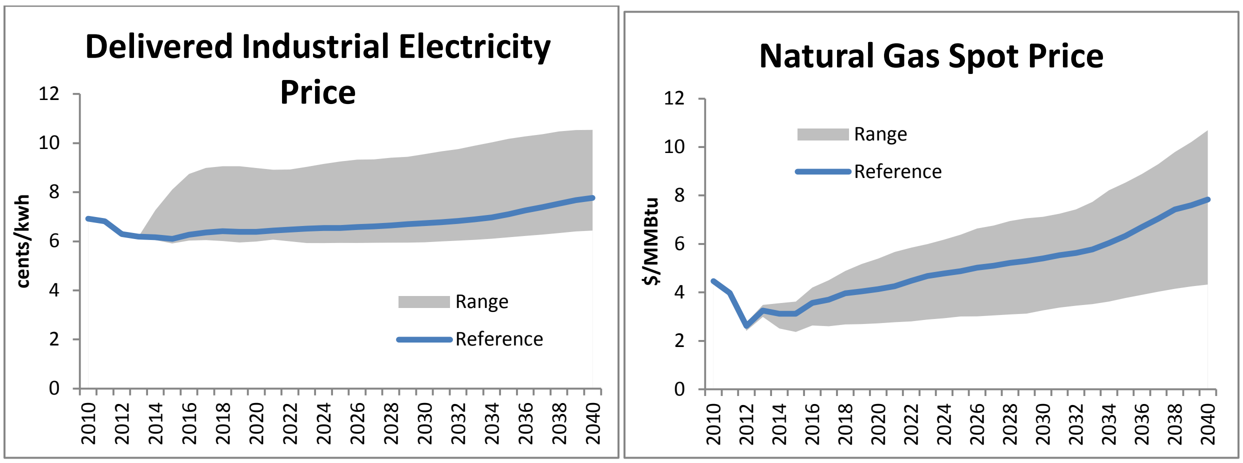


The figures above show that electricity generation is typically more expensive on a per MMBtu basis than pipeline biogas. Therefore, pipeline biogas might be expected to outcompete direct power production in most cases. However, the costs represented in the functions are unlikely to be the only basis 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.

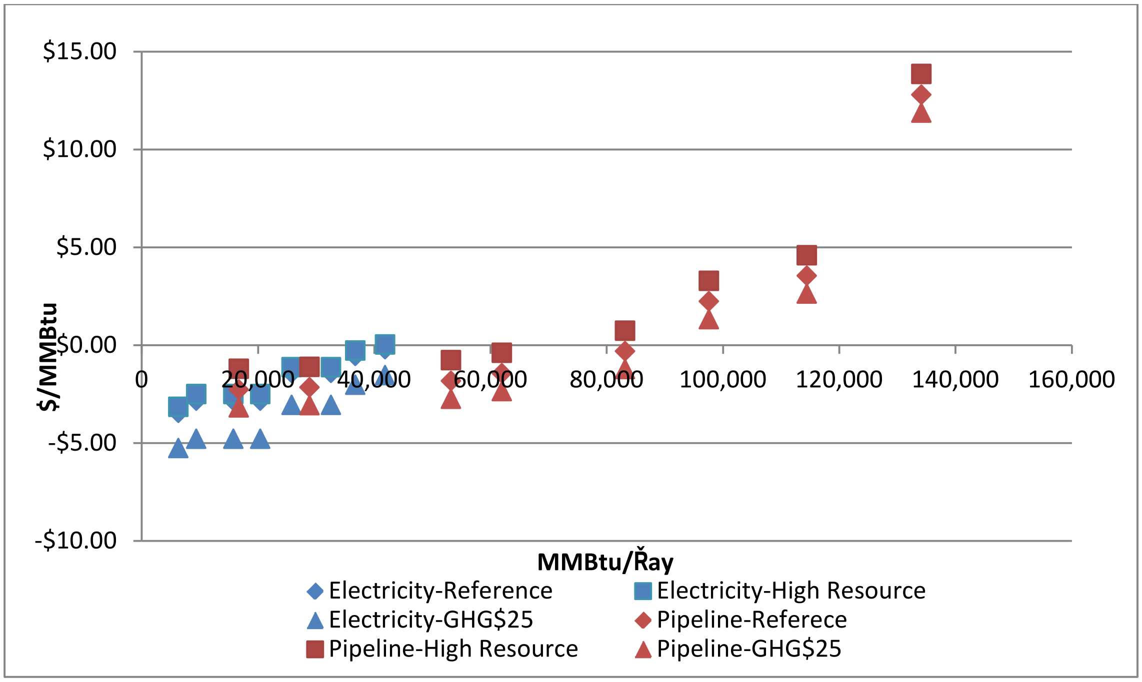
Figure 18 shows the net costs of WWTP electricity and pipeline biogas, respectively. Negative costs indicate a net benefit to that particular use relative to a "do nothing" scenario, wherein no biogas is captured and produced for use or sale. Figure 18 shows that, once electricity credits and biogas 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.

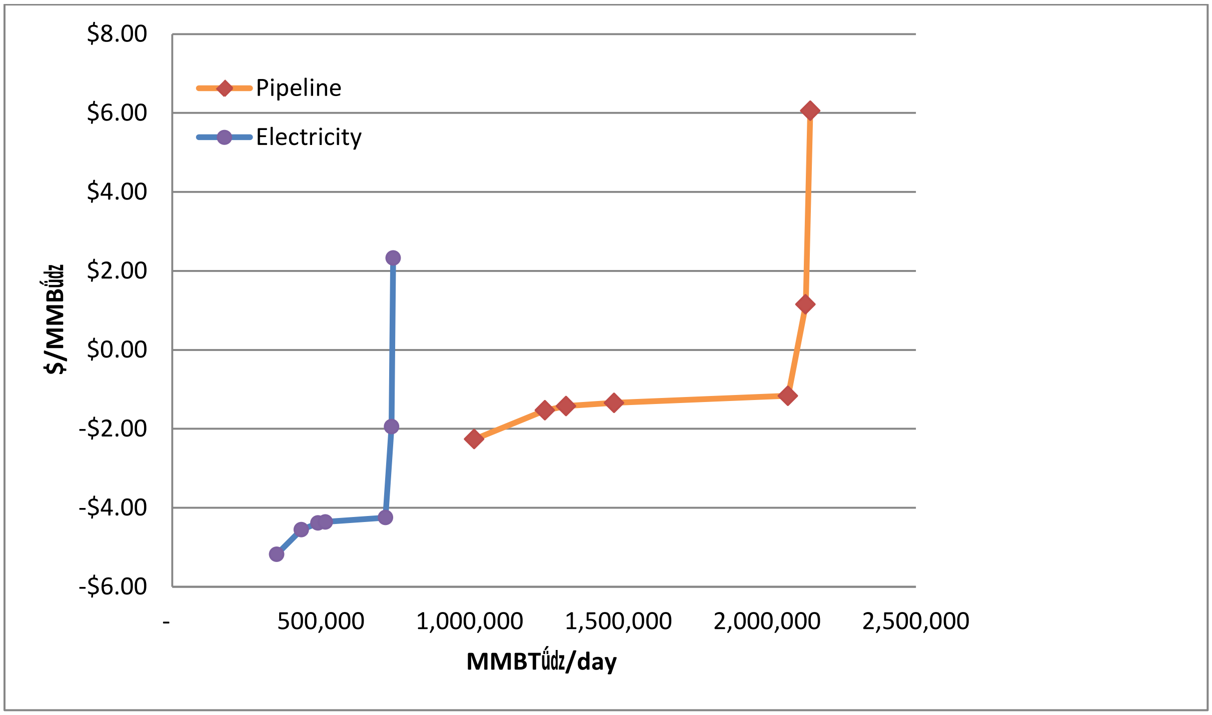
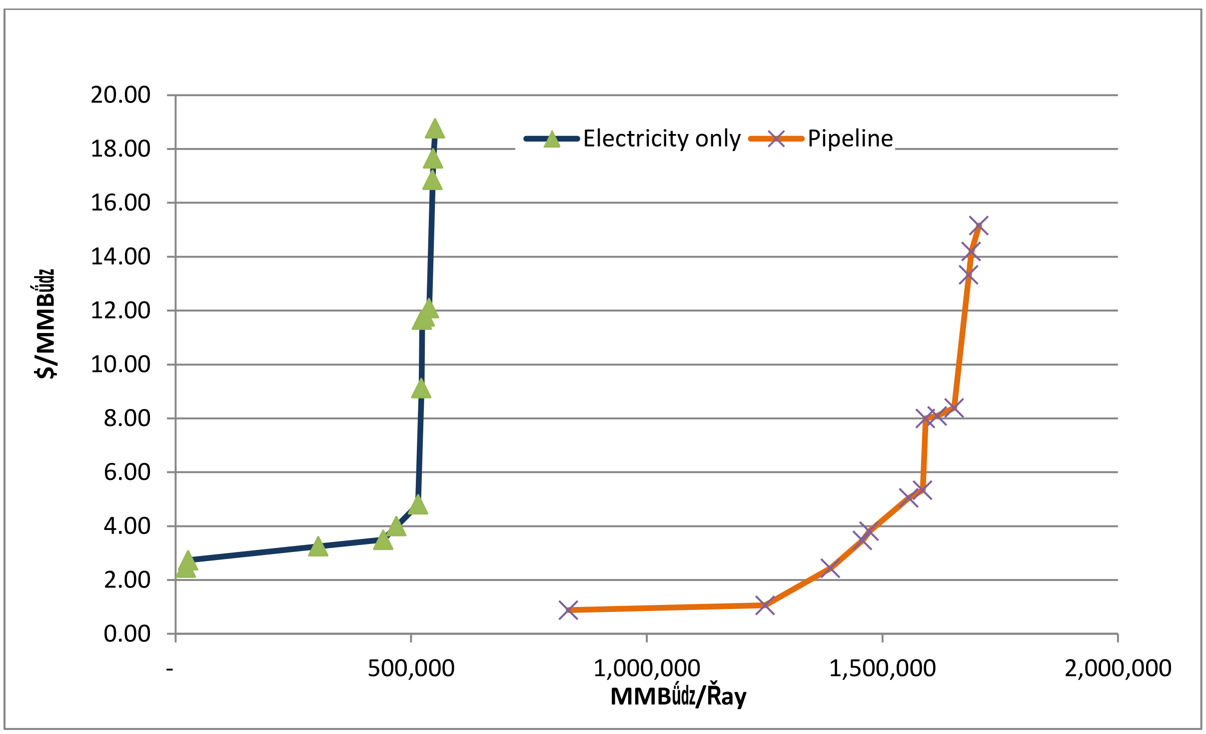


Figure 20. Comparison of net costs of electricity and pipeline biogas for animal operations.



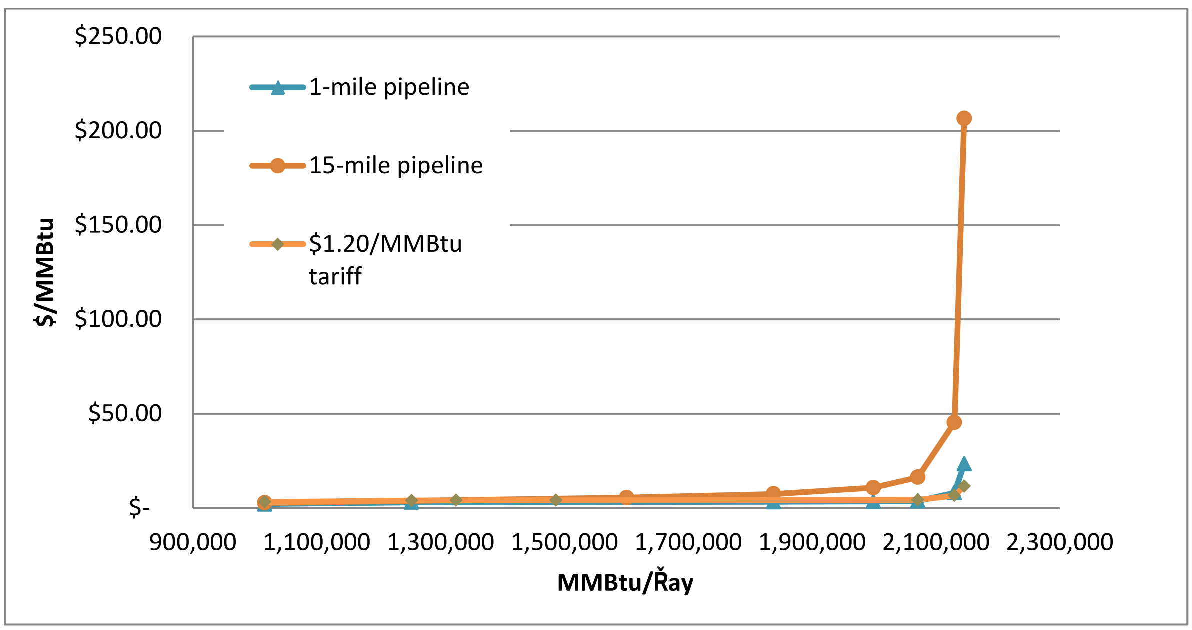
The Role of Facility Configuration and Transmission Financing

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.

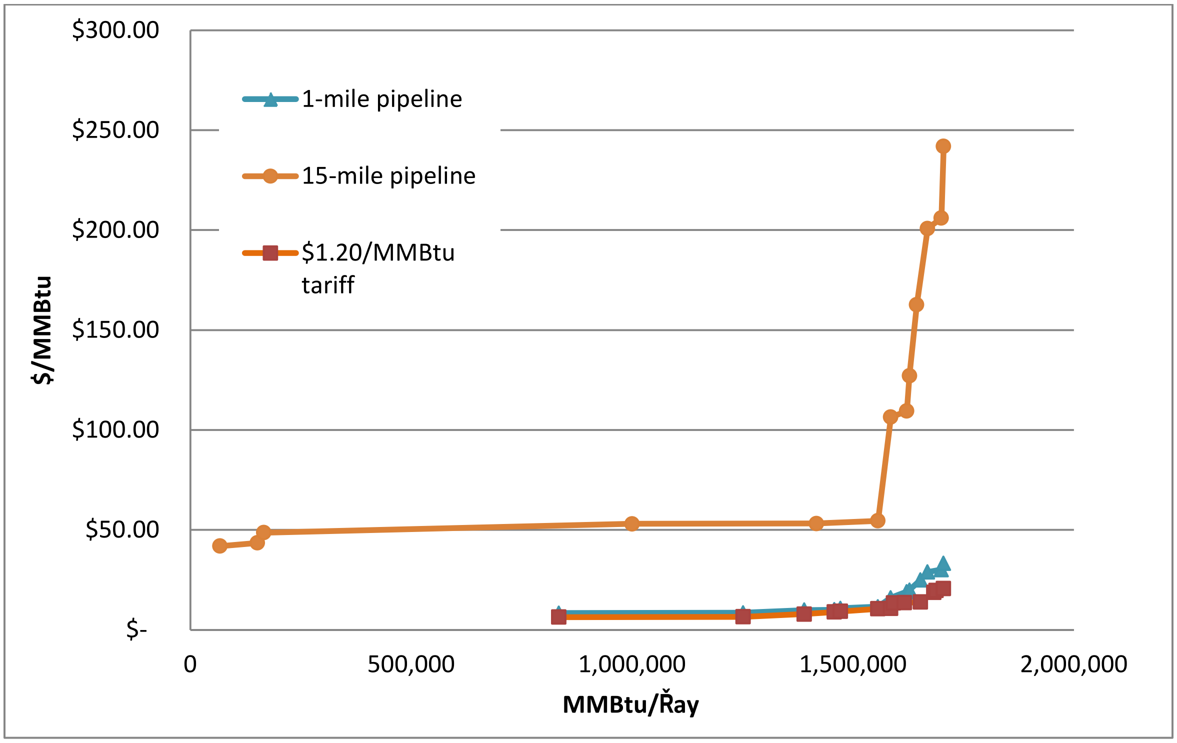


Figure 23. Comparison of LCOE under three piping-cost assumptions for wastewater treatment plants.

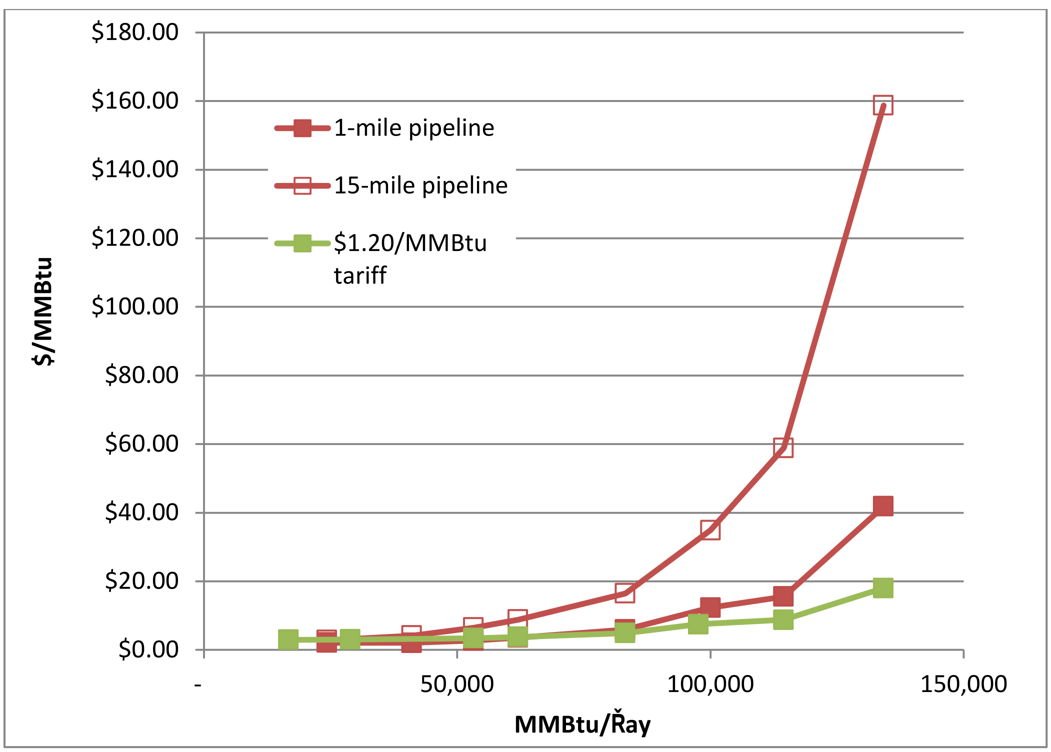
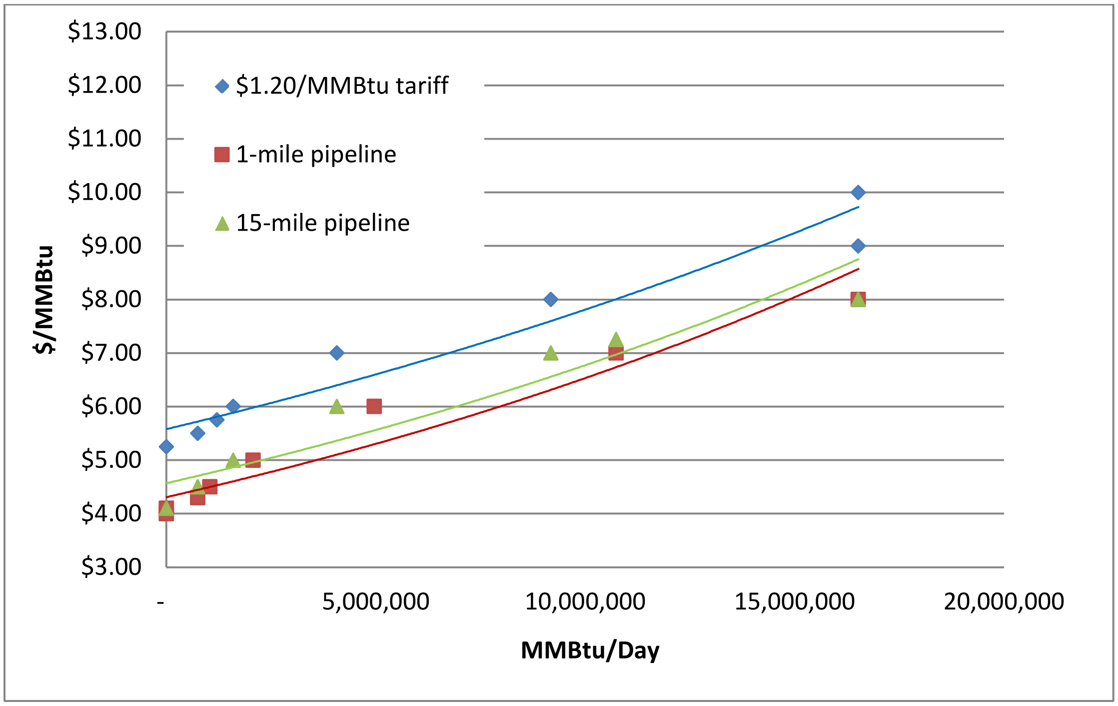


Figure 24. Comparison of LCOE under two piping-cost assumptions for biomass gasification



Biogas Market Dynamics, Barriers, and Opportunities

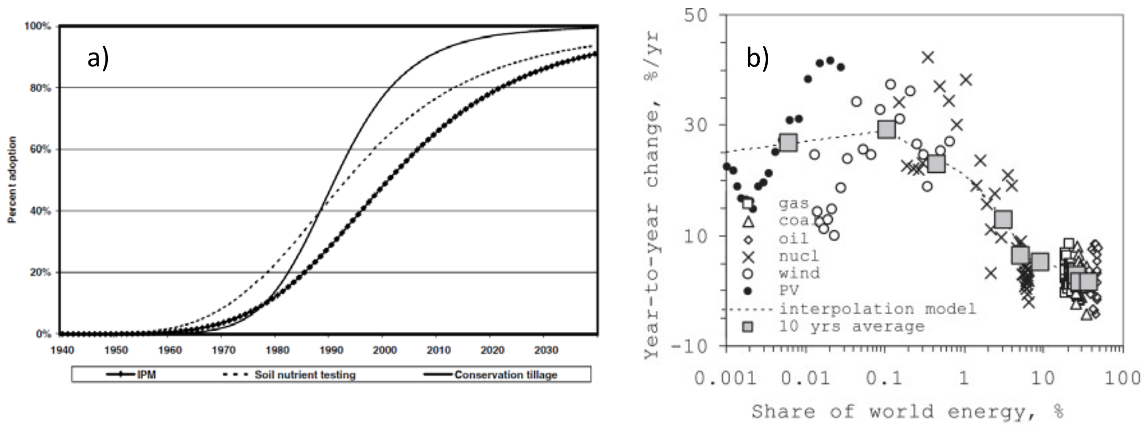
The supply analyses above implicitly assume the emergence of factors that enable or impede long-run growth in the market. Having examined the long-run economic potential of biogas at different prices, the study turned to the question of how that potential can be realized. It identified key barriers to 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,

[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.

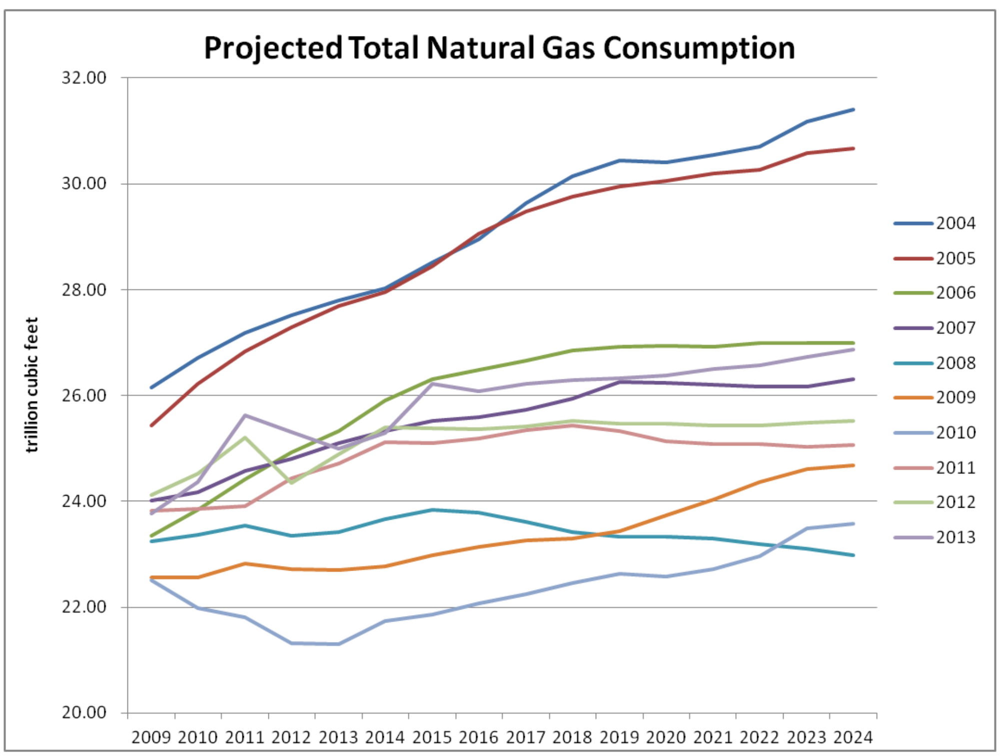
- **In addition to economic hurdles, full-scale appreciation of biogas potential faces technological, market, and institutional hurdles**. Technology diffusion is an open-ended process subject to many institutional factors that are hard to predict. Accordingly, this analysis cannot definitively speak 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]

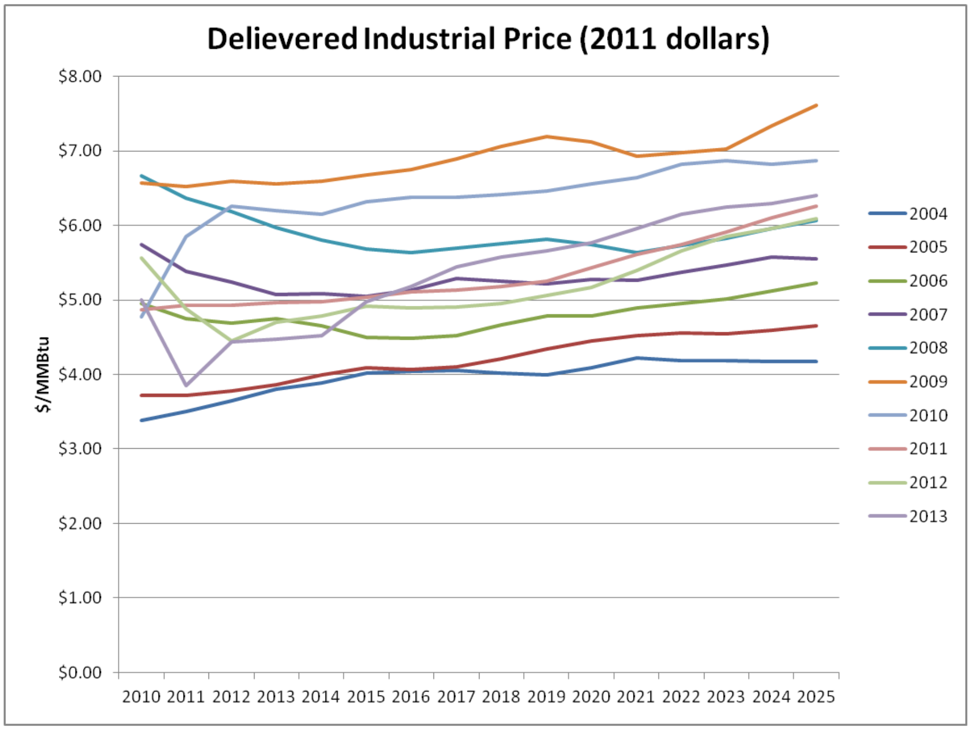
Figure A1. Reference-case-projected total natural gas consumption as reported in the United States.



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

[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).

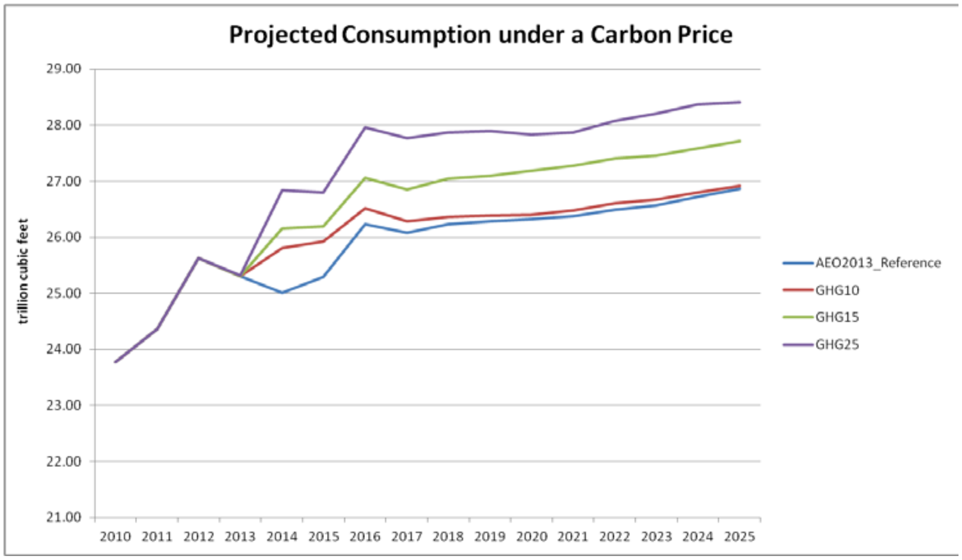
Figure A2. Reference-case-projected natural gas price (2011 dollars) as reported in the United States.



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

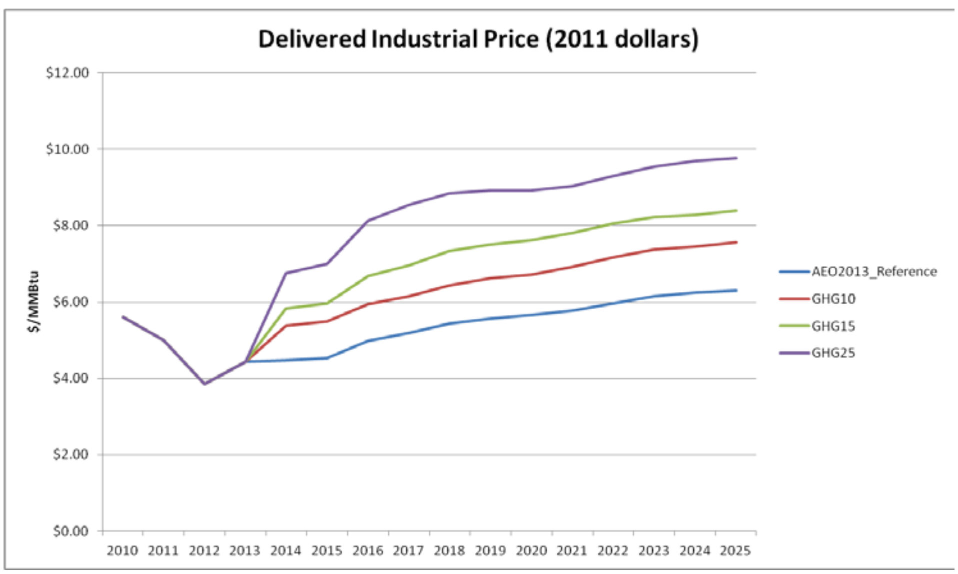
How imposition of a carbon price could affect consumption of natural gas is uncertain. So, too, are the likelihood and eventual magnitude of a carbon price. Shown below are total U.S. natural gas consumption (Figure A3) and the price of delivered natural gas to industrial users (Figure A4) under several 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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