Biomethane for Transportation

Opportunities for Washington State

A report for the Western Washington Clean Cities Coalition

November 2011

Revised January 2013

WESTERN WASHINGTON CLEAN CITIES

WASHINGTON STATE UNIVERSITY
EXTENSION ENERGY PROGRAM

RECOVERY.GOV
American Recovery and Reinvestment Act

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A report for the Western Washington Clean Cities Coalition,
prepared by Jim Jensen, Senior Bioenergy and Alternative Fuels Specialist at the
Washington State University Extension Energy Program, and
funded by the American Recovery and Reinvestment Act through
a grant from the U.S. Department of Energy.

November 2011
Revised January 2013

An electronic version of this document is available for downloading at
www.wwcleancities.org/ and *www.energy.wsu.edu*.

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WSUEEP11-052 Rev 1 • January 2013

Acknowledgements

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-EE0002020.

The author would like to thank the following people who reviewed and provided comments for the development of this report:

- Mark Fuchs, Washington State Department of Ecology;
- Mary Beth Lang, Washington State Department of Agriculture;
- Peter Moulton, Washington State Department of Commerce; and
- Dave Sjoding, Washington State University Extension Energy Program.

The author would also like to thank the following Washington State University Extension Energy Program staff for their support and assistance:

- Gil McCoy, Pauline Jensen and Caryl Gold for their valuable research;
- Melinda Spencer for editing; and
- Gerry Rasmussen for the artwork and design/layout of the publication.

– *Jim Jensen*
Senior Bioenergy and Alternative Fuels Specialist
Washington State University Extension Energy Program

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Symbols, Abbreviations and Acronyms

AD ....Anaerobic digestion
AFDC ....Advanced Fuels Data Center
AFV ....Alternative fuel vehicle
ARRA ....American Recovery and Reinvestment Act
bio-CNG ....Compressed natural gas from biomethane
bio-LNG...........Liquified natural gas from biomethane
Btu ....British thermal unit (1 Btu = 1.055 kilojoules)
°C ....Degrees Celsius (°F = 9/5 °C+32)
CARB ....California Air Resources Board
CAR ....Climate Action Reserve
cf......................cubic feet
CH_4 ....Methane
CHP ....Combined heat and power
CNG ....Compressed natural gas
Commerce ....Washington State Department of Commerce
CO_2 ....Carbon dioxide
CTE..................Center for Transportation and the Environment
DGE ....Gallons of diesel-equivalent
DOE .................U.S. Department of Energy
Ecology............Washington State Department of Ecology
EISA ....Energy Security and Independency Act, also known as RFS
EPA ..................U.S. Environmental Protection Agency
°F ....Degrees Fahrenheit [°C = 5/9 (°F-32)]
FOG ....Fats, oil, and grease
ft ....Foot or feet (1 ft = 0.3048 meter)
gal ....Gallon (1 gal = 3.785 liters)
GGE ....Gallons of gasoline-equivalent
GHG ....Greenhouse gas
gpd ....Gallons per day
GREET ....Greenhouse Gases, Regulated Emissions and Energy Use in Transportation
GRI ....Gas Research Institute
GTI ....Gas Technology Institute
H_2O ....Water
hr ....Hour
H_2S ....Hydrogen sulfide
HSAD...............High solids anaerobic digestion
kW ....Kilowatt
kWh ....Kilowatt-hour
L ....Liter (1 L = 0.2642 gallon)
Land GEM ....EPA's Landfill Gas Emissions Model
lb ....Pound (1 lb = 0.4536 kilogram)
LCFS ....Low-carbon fuel standard
LFG ....Landfill gas
LMOP ....Landfill Methane Outreach Program
LNG ....Liquefied natural gas
LPG..................Liquefied petroleum gas

MBtu ....Million Btu
MMBtu ....Million Btu (as in a thousand thousand Btu)
mg ....Milligram (1 mg = 0.0154 grain)
MGD...............Million gallons per day
MJ ....Megajoule
Mpg ....Miles per gallon
MSW................Municipal solid waste
MW ....Megawatt
MWh ....Megawatt-hour
Nm^3 ....Normal (dry standard) cubic meter (1 Nm^3 = 35.31 normal cubic feet)
NO_x ....Nitrogen oxides
O_2 ....Oxygen
O&M ....Operations and maintenance
PG&E..............Pacific Gas and Electric
PM ....Particulate matter
PM_{10}.................Particulate matter less than 10 micrometers in diameter
POTW.............Publicly Owned Treatment Works
ppm ....Parts per million
psi ....Pounds per square inch (1 psi = 0.06804 atmosphere)
PTW.................Pump-to-wheel
REC..................Renewable energy credits
RGGI................Regional Greenhouse Gas Initiative
RLNG...............Renewable liquefied natural gas
RNG.................Renewable natural gas
RFS...................Renewable Fuel Standard
RIN ....Renewable Identification Number
RPS...................Renewable Portfolio Standard
scf ....Standard cubic foot or feet (1 scf = 0.0283 standard cubic meter)
scfm ....Standard cubic foot or feet per minute
SO_2...................Sulfur dioxide
STP...................Sewage treatment plant
tpd ....Tons per day (1 tpd = 0.9072 megagram per day)
VRI...................Vehicle Research Institute
WERF..............Water Environment Research Foundation
WSU ....Washington State University
WTP.................Wheel-to-pump
WTW ....Well-to-wheel
WWTP.............Wastewater treatment plant
WWU ....Western Washington University

Executive Summary

Biomethane refers to the gas produced by cleaning and upgrading biogas produced through anaerobic digestion of organic by-products, such as wastewater solids, livestock manure, food wastes, and yard debris. After removing carbon dioxide (CO_2) and other gases, the remaining methane is essentially the same as natural gas and can be used in all the ways natural gas is used. For this reason, biomethane is also called renewable natural gas or green gas.

This report looks at the potential opportunities for producing biomethane for transportation uses in Washington. This assessment supports the goals and objectives of the Western Washington Clean Cities Coalition to reduce petroleum use, reduce air pollution, reduce greenhouse gas pollution, and support local economic development in the process.

This analysis provides a high-level review of the possible sources of biogas, likely end users for this alternative fuel, technologies needed to produce and compress biomethane, and results of economic analyses of these technologies. This analysis was designed to define the range of uses/products for biomethane and the competition it faces from natural gas and other alternative fuels.

The primary sources for producing biomethane in Washington include biogas produced:

- At landfills, wastewater treatment plants, dairies, and other livestock operations;
- By anaerobic treatment of the organic fraction of municipal solid waste (MSW); and
- Through thermal gasification of crop residue and woody wastes.

In total, excluding any gas production from thermal gasification, this assessment estimates that the different feedstocks available in Washington could produce as much as 512,418 gas gallon equivalents (GGE) of biomethane per day, as presented in Table 1.

In considering biomethane potential from different sources, it is important to remember that the potential biomethane from landfills is produced from organic wastes landfilled over decades of time and will not be constant throughout the future. This assessment is based on the estimated potential in the next 10-15 years. Biomethane potential from WWTPs, livestock producers, and municipal solid wastes is more constant and may be expected to increase due to increases in population and in collection and processing efficiency.

The end uses compared in the assessment include biogas/biomethane for heat and power, for direct use as transportation fuel, and for injection into the natural gas pipeline network for either power or transportation. All of these possible uses have different costs and benefits that developers and policymakers must consider.
This report presents reviews of the technology choices and economics of preparing

Table 1. Potential GGE of Biomethane Produced from Various Feedstocks

Feedstock Sources	Gas Gallon Equivalents per Day (GGE/d)	Evaluation
Landfills	354,960 GGE/d	The gas at landfills and wastewater treatment plants (WWTPs) is largely already being produced and used partially or flared. For this reason, landfills and WWTPs are a good first target for using biogas for transportation.
Wastewater Treatment Plants	36,829 GGE/d	The LRI Landfill and the Tacoma-Central and University Place-Chambers Creek WWTPs were identified as early candidates that are ready to receive technical assistance and support.
Dairies	61,344 GGE/d	Estimates for dairies and MSW digesters are considered "potential" at this time, meaning that a lot of investment in plants and equipment needs to occur to capture some of that potential. The regions around Yakima and Whatcom counties provide the largest opportunities to develop projects for direct use of biomethane or for pipeline injection of biomethane for transportation end uses.
MSW Digesters	59,285 GGE/d	MSW digesters planned at Cedar Grove Composting in Everett and Barr-Tech in Spokane may benefit from a transportation component.

biomethane for transportation. Biomethane is roughly half the cost of diesel; however, in comparison with natural gas as a source of compressed natural gas (CNG) for vehicles, biomethane is about twice the cost. For this reason, at this time, quantifying and supporting mechanisms that value or monetize the renewable attributes of biomethane are crucial to its success in the market.

The mechanisms that already exist include the federal Renewable Fuel Standard and California's Low Carbon Fuel Standard. Policies that could further support the value of biomethane in relation to other fuels include adoption of a federal and/or state low carbon fuel standard, carbon taxes, or cap-and-trade mechanism to create market incentives for greenhouse gas reduction.

The report concludes with a series of recommendations to support further development of transportation, starting with support for basic investments in natural gas infrastructure and natural gas vehicles. Investing in CNG fueling stations and vehicles anywhere enlarges the access that biomethane producers have to markets through natural gas pipelines. Co-locating public CNG fueling stations near sources of biomethane in urban areas or at transportation nodes in rural areas provides even greater benefit. Finally, it is important to provide direct support for plants and the equipment needed to produce biogas from agricultural and municipal organic wastes. It would be helpful if federal grants treated transportation end uses equitably with heat and power end uses.

Introduction

In the absence of oxygen, decomposing organic materials produce biogas – a combination of methane (CH_4), carbon dioxide (CO_2), and other gases. Biogas produced from different sources will have varying concentrations of methane. Biogas is most often found to have between 50 and 65 percent methane, with corresponding energy values of 500 to 650 British thermal unit (BTU) per cubic foot. Natural gas delivered to customers is effectively 100 percent methane and has an energy value of about 1,000 BTU per cubic foot. If raw biogas is processed and cleaned to remove moisture, CO_2, hydrogen sulfide and other gases from the methane, we call the end product "biomethane" or "renewable natural gas." The BTU content can be made equivalent to that of natural gas.

Natural gas ("fossil biogas") is found in underground reserves formed millions of years ago. Biogas continues to form naturally in bogs and swamps (hence its historic name, "swamp gas"). Biogas is also a natural by-product of burying organic materials in landfills and keeping liquid manure in storage lagoons. In the last century, scientists and engineers found economic value in treating sewage wastewater solids using the same anaerobic digestion principles that produce biogas. More recently, engineered anaerobic digestion systems have begun to be used to convert a wider range of organic waste resources, such as dairy and other livestock manures and food processing wastes, into biogas and a range of valuable co-products.

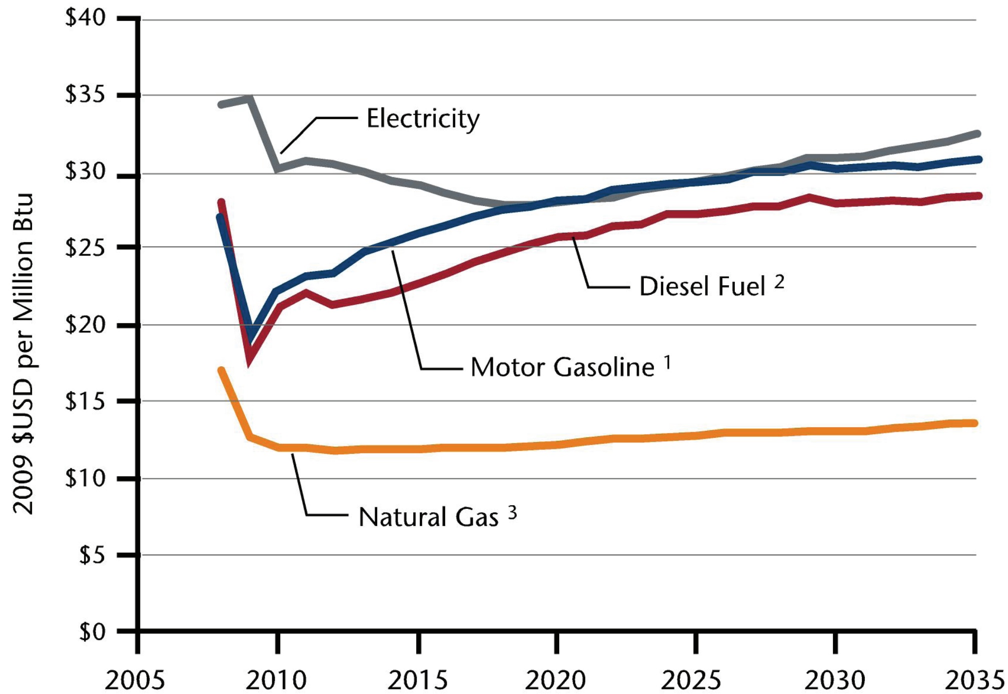
While initial interest in anaerobic digestion may have been prompted by the need to manage wastewaters for odor control, public health, and environmental safety, the similarity of biogas and natural gas was not lost. As a result of much experimentation and innovation, biogas has been used in the same ways one might use natural gas – to fire stoves, boilers, furnaces, engines, and generators, and as transportation fuel. Each end use has its own challenges and barriers, which are being addressed by those who actively support these uses.

How Has Biogas Been Used in Washington State?

Residents and businesses in the state have enjoyed very low energy prices for many years. As a result, many landfills in the state simply managed the biogas they collected by burning it in flares. At wastewater treatment plants (WWTPs), operators typically used biogas to fuel boilers for the heat needed by their digesters but otherwise flared their surplus biogas.

This historic pattern has changed recently (see Figure 1). The cost of petroleum products and electricity has risen, while natural gas prices have dropped due to shale gas fracking technology. In addition, greater emphasis is being given to renewable forms of energy. Now the largest landfills and WWTPs, and some of the smaller ones, look for productive, cost-effective uses for the biogas they produce. The most common uses include producing electricity, heat, combined heat and power (CHP), or cleaning the gas for delivery into natural gas pipelines. An additional use as transportation fuel is now gaining attention.

Figure 1. Transportation Energy Price Projections
(EIA Reference Case)



[1] Sales weighted-average price for all grades. Includes federal, state and local taxes.
[2] Diesel fuel for on-road use. Includes federal and state taxes while excluding county and local taxes.
[3] Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.

Source: DOE EIA Annual Energy Outlook 2011 with Projections to 2035

Benefits and Challenges of Using Biomethane for Transportation

Major reasons to focus on biomethane as a transportation fuel include:

- The rising price of gasoline and diesel fuel, which is intensifying the search for cheaper alternatives;
- The need to improve air quality; and
- The need to reduce greenhouse gas (GHG) emissions.

Worldwide, as many as 12 million natural gas vehicles are in use *(Yborra, 2011)*. In the United States, the number of natural gas vehicles in operation changed from 105,000 in 2000 to 110,000 in 2009. That represents just 0.06 percent of all vehicles. The number of CNG refueling stations in the United States reached 1,300 in 2009 *(CNGVA, 2010)*.

Using biogas as a replacement fuel for diesel provides important benefits:

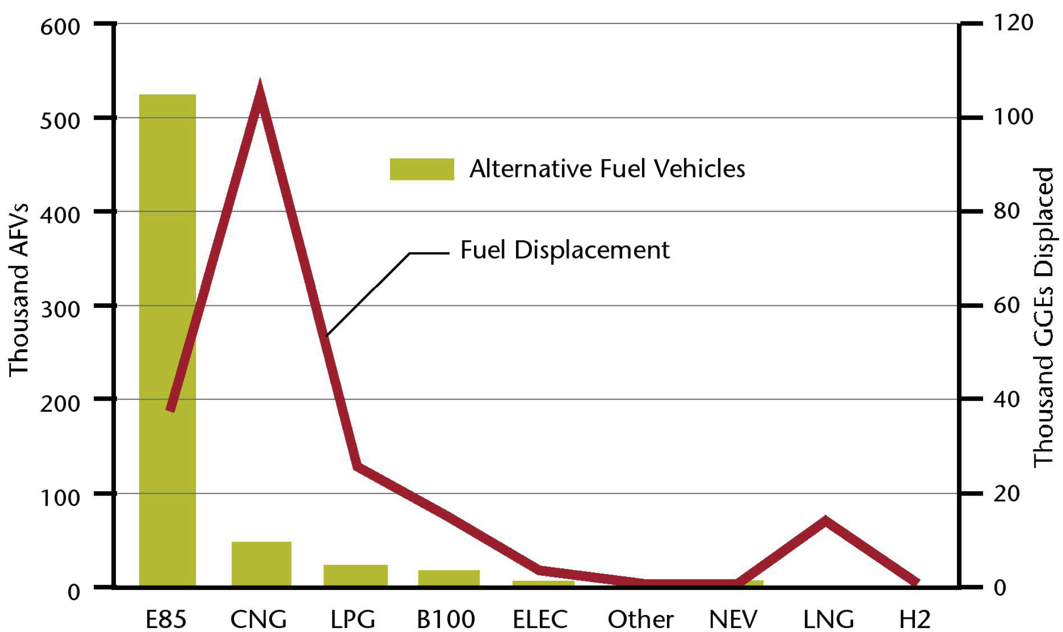
- Reduce air pollution, including particulate matter.
- Reduce dependence on fossil fuels and foreign sources of petroleum because biomethane is a renewable form of domestic fuel.
- Reduce GHG pollution by capturing and using biogas from fugitive sources, such as landfills and manure lagoons.

The U.S. Department of Energy supports energy efficiency and renewable energy development through a variety of programs:

- CHP is supported through the Industrial Technologies Program.
- Biofuels get support through the Office of Biomass Programs.
- Vehicle efficiency gets support through the Vehicle Technologies Program.
- Biomethane transportation infrastructure and deploying vehicles using CNG and liquefied natural gas (LNG) from renewable sources are supported through the Clean Cities Program.

In 2008, CNG- and LNG-powered vehicles accounted for most of the GGEs of petroleum displaced by the 624,000 alternative fuel vehicles sponsored by Clean Cities programs (see Figure 2), even though they accounted for only 9 percent of these vehicles. CNG and LNG vehicles accounted for more than 40 percent of total reported petroleum displacement by ***all*** measures *(Richardson, 2010)*.

Figure 2. Number of Alternative Fuel Vehicles and Fuel Displacement by the Department of Energy's Clean Cities Program



A recent report entitled, *"The Potential for Renewable Gas,"* (*Gas Technology Institute, 2011*), summarized the advantages and national benefits of biomethane:

- It is another source of domestically produced energy. Under the two practical long-term scenarios that were considered for this study, the market potential of renewable gas is from 1.0 to 2.5 quadrillion BTUs per year. The technical potential, representing complete utilization of all available feedstocks, is approximately 9.5 quadrillion BTUs per year.
- The job creation potential of renewable biogas projects is significant. The number of direct jobs created ranges up to 83,000, depending on the depth of the market penetration. Using an average multiplier of 3.1 for indirect and induced jobs, the total number of jobs created ranges up to 257,000.
- Depending on the model of deployment, renewable biogas production could result in 146 million metric tons of CO_2 removed from the air annually – the equivalent of taking 29 million cars off the road.
- The California Air Resources Board (CARB) in a 2009 report determined that biomethane is the lowest carbon transportation fuel available today.
- Almost every state in the United States has the resources to participate in the production of renewable gas and, along with it, the potential to create new green jobs.
- Biomethane from renewable sources, including animal manure, forest residues, and agricultural wastes, can be produced at efficiencies ranging from 60 to 70 percent, which uses renewable resources in a responsible and efficient manner.
- All of the technology components needed to produce renewable biogas from this variety of biomass sources exist today.
- Biogas production in digesters provides the agricultural sector additional environmental benefits by improving waste management and nutrient control, and by dramatically reducing carbon emissions through the control of methane by placing manure in enclosed vessels instead of open lagoons.
- Biomethane is an interchangeable fuel that can be delivered to customers via the existing U.S. pipeline infrastructure and can provide a renewable energy option in the natural gas energy market, which represents 25 percent of overall U.S. energy use.
- Biomethane is, in many instances, the low-cost option among renewable products.

The Clean Cities-sponsored report on biomethane entitled, *"Renewable Natural Gas: Current Status, Challenges, and Issues,"* listed the following major obstacles to the widespread development and use of biomethane, or renewable natural gas (RNG):

> For **RNG**, the major barriers to significant deployment are a lack of customers (i.e., demand) for the produced fuel, the cost and logistics

of delivering it, immature and unproven technologies, and restrictions mandating what can and cannot be a part of the project.

- **Customers.** Demand is critical for all aspects of the project, from the initial design and sizing of components and processes, to maintaining efficient operations, to generating acceptable profits and cash flow.

- **Distribution.** New pipelines are the preferred mode for transporting gaseous RNG from the production facility to the pipeline system (in the case of pipeline injection) or to the final user (in the case of motor vehicle fleets). However, pipeline construction is expensive and the additional investment may not be feasible. This is especially true if the market consists of a handful of vehicle fleets not readily accessible via a single pipeline. Since liquid RNG is more readily transported, liquefaction is sometimes used to aid distribution, even if demand is for gaseous product.

- **Technologies.** Small-scale liquefaction is not an established technology. Developers are making progress in the design and integration of refrigeration into process flows and in improving reliability and efficiency.

- **Permitting and legal restrictions.** Most RNG projects incorporate a biogas-fueled generator to provide electricity for process needs and refrigeration/compression. Permitting can be difficult for this "new source," especially in California. Similarly, restrictions on pipeline injection can limit this type of project to certain biogas sources.

- **Refueling facilities.** Because producers of RNG require markets for their product, a lack of refueling facilities is also a barrier to the deployment of RNG. Here, however, refueling facilities are viewed less as part of the infrastructure needed to support deployment and more as customers of the produced fuel.

This analysis looks at these and other issues affecting the viability of producing and using biomethane for transportation in Washington. It looks broadly at potential sources of renewable biogas, the technologies used to upgrade raw biogas into biomethane, the potential end-user fleets and the challenge of getting the gas to them. It also considers the economics of using biomethane and the importance of putting a value on the clean, renewable attributes of biomethane. A series of recommendations are offered at the conclusion.

Chapter 1: Sources of Biogas for Biomethane

Raw biogas, capable of being processed into biomethane, may be produced by a variety of processes that receive or manage organic waste streams.

Key sources in Washington include, in no particular order: landfills, municipal and industrial wastewater treatment plants (WWTPs), and anaerobic digesters using agricultural, food processing, and/or municipal organic wastes. Biomethane for transportation fuel can also be an end product of thermal gasification of more fiberous or woody waste byproducts.

The resulting biogas may have varying energy values (as measured in British thermal units [BTU]) and complex mixes of other trace gases, reflecting the wide range of byproducts, or feedstocks, used in its production. These variations can complicate end use options. Table 2 shows the different gases that may be found in biogas from different sources.

The end use for the biomethane guides the degree of gas cleaning or upgrading that is required. In general, the energy value of gas is measured in BTU. Commercial natural gas is effectively 100 percent methane with some water vapor, with an energy value of 1,000 (+/- 50) BTU per cubic foot. Specifications among natural gas companies can vary, but to mix with other gas in transmission pipelines, a biomethane product would need to have nearly 985 BTU and little to no trace gases. For vehicle use, the gas would still have to be scrubbed of hydrogen sulfide, siloxane, and other trace gases, but engines can tolerate as much as 10 percent CO_2, so the upgrade required may only be to 900 BTU per cubic foot.

Landfills

Landfills generate raw biogas through anaerobic decomposition of organic waste materials, such as food waste and yard and garden debris found in mixed municipal waste streams. There was a time not long ago when biogas seeped out of unlined

Table 2. Typical Sources and Characteristics of Biogas Generation

Sources	Common Characteristics
Landfills	Methane (CH_4), carbon dioxide (CO_2), hydrogen sulfide (H_2S), water vapor, other sulfides and mercaptans, siloxane, nonmethane organic compounds, oxygen, nitrogen, ammonia, and other trace gases
Wastewater treatment plants	CH_4, CO_2, H_2S, water vapor, siloxanes, and possibly traces of nitrogen and ammonia
Dairy manure	CH_4, CO_2, H_2S, and water vapor
Food processing byproducts	CH_4, CO_2, H_2S, and water vapor
Municipal organic wastes	CH_4, CO_2, H_2S, water vapor, siloxanes, other gases in trace amounts

landfills and caused problems in surrounding neighborhoods. Today, engineered landfills are located away from metropolitan areas, and they are more enclosed, with thick plastic liners along the sides, bottoms, and tops of a series of landfill "cells." Garbage is deposited in layers and covered each day. Biogas begins forming right away. As individual cells reach capacity, federal regulations require operators of most landfills to install gas collection systems to remove the landfill gas to prevent it from migrating. However, most of this gas is still burned in flares.

The Roosevelt Regional Landfill is the fourth largest permitted landfill in the United States.
Source: Klickitat PUD

According to the U.S. Environmental Protection Agency (EPA) Landfill Methane Outreach Program (LMOP), there are 558 operational landfill energy projects in the United States. The vast majority of these generate electricity. The next largest group uses the biogas for direct thermal applications and cogeneration of electricity and heat. Roughly 30 projects produce biomethane, mostly for pipeline uses. Only a handful of landfills produce biomethane directly for transportation uses (*EPA, LMOP, 2011*).

The EPA identifies about 500 more landfills that have the size and characteristics to be "candidate landfills" for energy projects. This potential for energy production nationwide (perhaps as biomethane) was discussed during the U.S. Department of Energy (DOE) *Waste to Wheels Workshop* in 2010. It reported the following:

> In 2008, according to the annual BioCycle/Columbia University survey of state data on solid waste management, 270 out of 389 million tons (69 percent) of mixed solid waste generated were deposited in landfills. Between 50 and 60 percent of this amount consisted of organic materials. [DOE claims] if just 1 million tons of these mixed wastes – a typical amount for a mid-sized city in a region having average rainfall – were deposited in the same landfill over a 20-year period, these wastes would emit, at peak yield, enough biogas annually to make the equivalent of 15 million diesel gallons *(Richardson, 2010).* [For comparison, Washington drivers can use 15 million gallons of diesel in a few days.]

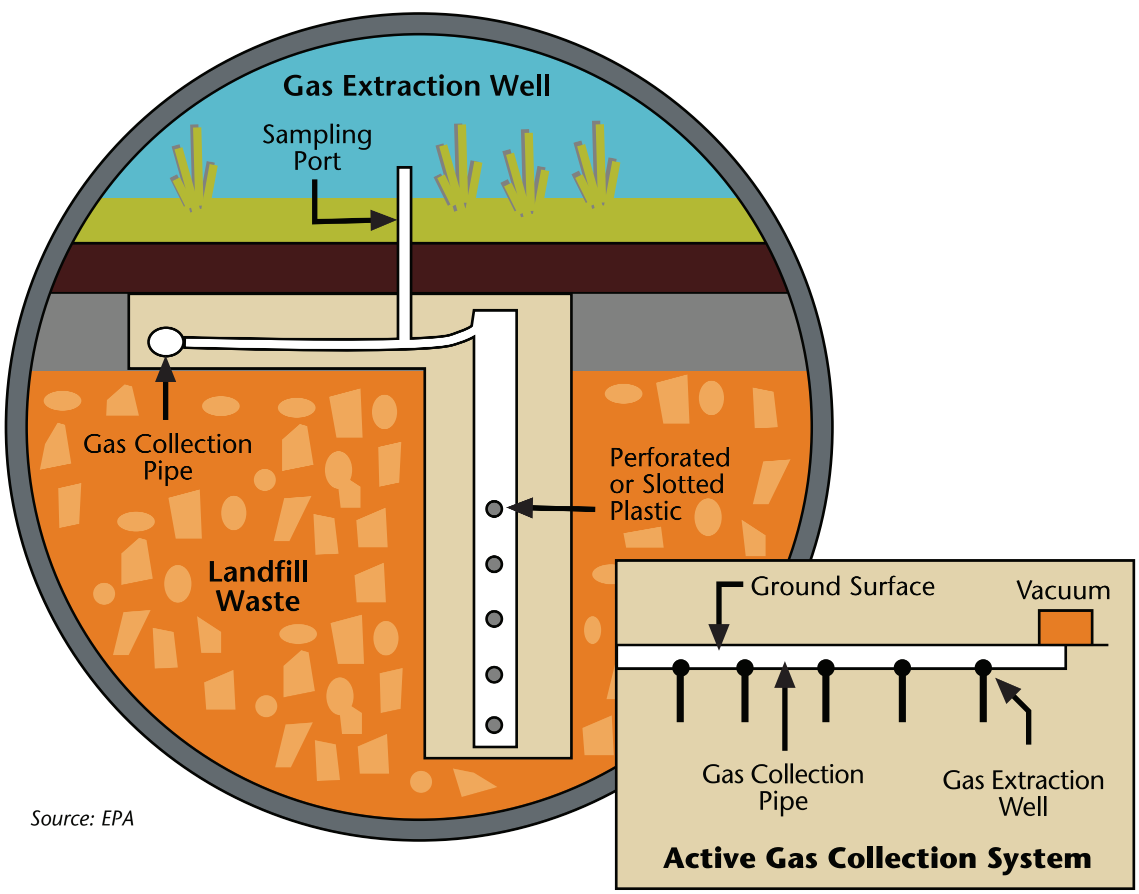
While today's larger, more highly engineered landfills can produce sufficient biogas to make electricity or transportation fuel, landfills are not considered the most efficient way to capture biogas from municipal solid waste (MSW). Critics point out that landfills have a limited lifespan, and they lose a significant fraction of biogas potential because decomposition occurs prior to gas collection. They also point to pollution problems related to the contaminants in landfill gas *(Ewall, 2007)*. Using landfill gas has some significant challenges, as it often contains a wider array of contaminant gases, including siloxanes, oxygen nitrogen, and even toxic gases not found in biogas from other sources.

Washington State law established a hierarchy for solid waste management that puts landfilling at the bottom of the best practices for waste handling. The Washington State Department of Ecology Waste 2 Resources Program (*www.ecy.wa.gov/programs/swfa*) works to keep non-contaminated organic material out of the state's landfills and to identify new management technologies and new markets for products made from this organic material.

Project Assessment

For this assessment of biomethane potential from Washington landfills, the project team consulted a wide variety of data resources, especially reports and databases maintained by the EPA and the Washington State Department of Ecology, to develop a database of Washington landfills. The data was analyzed to identify landfills of sufficient size and age. Landfills that were closed prior to 1999 were excluded.

Figure 3. Diagram of Typical Landfill Gas Capture Installation



Source: EPA

Table 3. Washington State Landfills with Biomethane Potential

County	Facility Name	Location	Year Opened	Closure Year	Waste per Year tons	Waste in Place tons
Klickitat	Roosevelt Reg. Landfill	Roosevelt	1991	**2041**	2,088,177	53,000,000
King	Cedar Hills Reg. Landfill	Maple Valley	1965	**2018**	867,482	33,000,000
Pierce	LRI Landfill (304th St.)	Graham	2000	**2050**	1,031,084	11,341,000
Douglas	Greater Wenatchee Reg. Landfill	East Wenatchee	1975	**2020**	181,075	2,008,248
Yakima	Terrace Heights Landfill	Yakima	1974	**2019**	161,330	3,727,219
Cowlitz	Cowlitz County Landfill B	Longview	1974	**2014**	96,165	2,100,000
Pierce	Hidden Valley	Puyallup	1965	1998	435,632	17,425,280
Kitsap	Olympic View	Port Orchard	1960	2002	166,768	7,004,248
Asotin	Asotin County	Clarkston	1975	**2025**	47,290	848,342
Pierce	City of Tacoma Landfill	Tacoma	1960	1998	124,683	5,610,756
Grant	Ephrata Landfill	Ephrata	1942	2005	90,517	NA
Benton	Richland Horn Rapids	Richland	1975	2018	53,000	NA
Yakima	Cheyne Road LF Cell 2	Zillah	2010	**2035**	71,104	1,198,976
Walla Walla	Sudbury Road Landfill	Walla Walla	1972	2007	52,929	1,102,917
Thurston	Hawks Prairie Landfill*	Olympia	1970	2000	71,192	2,135,753
Yakima	Cheyne Rd LF Cell 1 (unlined)	Zillah	1968	2010	29,974	1,198,976
Pierce	Fort Lewis Landfill #5	Fort Lewis	1969	2004	34,255	1,198, 910
Clallam	Port Angeles SLF	Port Angeles	1972	2006	30,176	1,026,000
Okanogan	Okanogan Central	Okanogan	1994	2030	27,498	407,820
Stevens	Stevens County	Kettle Falls	1979	2054	24,000	NA

**Operated by the Thurston County Waste & Recovery Center*

Table 3. Washington State Landfills with Biomethane Potential*, continued*

Facility Name	Biomethane Potential EST m3/yr	Biomethane Potential EST cf/d	Gas Trend	GGE Potential EST GGE/d	Current Gas Use
Roosevelt Reg. Landfill	140,000,000	13,545,479	Increasing	108,364	Reciprocating Engine, Klickitat PUD Power
Cedar Hills Reg. Landfill	120,000,000	11,610,411	Peaking	92,883	Bioenergy Washington, High-BTU to Pipeline to Puget Sound Energy
LRI Landfill (304th St.)	100,000,000	9,675,342	Increasing	77,403	***EPA Candidate***; Contract for use with Biofuels Energy, LLC
Greater Wenatchee Reg. Landfill	15,000,000	1,451,301	Peaking	11,610	Flare; ***EPA Candidate***; Considering Power Project
Terrace Heights Landfill	13,300,000	1,286,821	Peaking	10,295	Flare; ***EPA Candidate***
Cowlitz County Landfill B	12,000,000	1,161,041	Peaking	9,288	Flare; ***EPA Candidate***; Possible Pud Project
Hidden Valley	10,000,000	967,534	Decreasing	7,740	Reciprocating Engine (Puyallup Energy Recovery)
Olympic View	9,500,000	919,158	Decreasing	7,353	Leachate Evaporation-Project Shutdown 2009
Asotin County	4,300,000	416,040	Increasing	3,328	Flare; Desires Future Energy Project
City of Tacoma Landfill	5,500,000	532,144	Decreasing	4,257	Reciprocating Engine; NEO Corp
Ephrata Landfill	5,250,000	507,955	Decreasing	4,064	Flare
Horn Rapids	3,902,000	377,532	Peaking	3,020	Flare
Cheyne Road LF Cell 2	2,000,000	193,507	Increasing	1,548	Flare; ***EPA Candidate***
Sudbury Road Landfill	3,200,000	309,611	Decreasing	2,477	Flare; ***EPA Candidate***
Hawks Prairie Landfill	3,000,000	290,260	Decreasing	2,322	Flare; Closed; No Evidence of Gas Use
Cheyne Rd LF Cell 1 (unlined)	2,100,000	203,182	Decreasing	1,625	Flare; ***EPA Candidate***
Fort Lewis Landfill #5	2,000,000	193,507	Decreasing	1,548	No Flare; ***EPA Candidate***
Port Angeles SLF	2,000,000	193,507	Decreasing	1,548	Flare; ***EPA Candidate***
Okanogan Central	2,532,000	244,980	Increasing	1,960	Flare
Stevens County	3,004,000	290,647	Increasing	2,325	Flare
Total		44,369,960		354,960	

Table 3 presents the results of the assessment. It provides data about 20 active or recently closed landfills located around the state – 11 of these are still receiving waste. Data is included for the estimated volumes of waste received per year and the total waste in place at the landfills. The project team used the EPA's Landfill Gas Emissions Model (LandGEM)(version 3.02) to calculate the biomethane potential. LandGEM generates an arc of gas outputs for future years based on the volumes of solid waste disposed over time. Based on the annual gas outputs estimated, the team looked forward 10 to 15 years for a reasonable figure to use for annual potential. The team also considered whether the gas output trend was increasing, peaking, or decreasing. This is noted in the table. Using these annual data, estimates for daily gas output were calculated,followed by the potential displacement in gasoline gallons equivalent (GGE).

The landfill source assessment also includes a column that highlights what is known about current gas uses. It also shows if a landfill has been identified by EPA's LMOP as a candidate site, meaning it has sufficient waste in place to be considered for energy project development.

Discussion

One of the bigger challenges of assessing landfill gas (LFG) potential is that gas production is not consistent from one site to another. For example, over the last two decades, communities around the state, especially larger urban areas in western Washington, have made great strides in removing organic waste materials from their municipal waste streams, which can reduce the yield of biogas produced at these sites. The data developed for this assessment

SPOTLIGHT

LRI Landfill Biomethane Opportunity

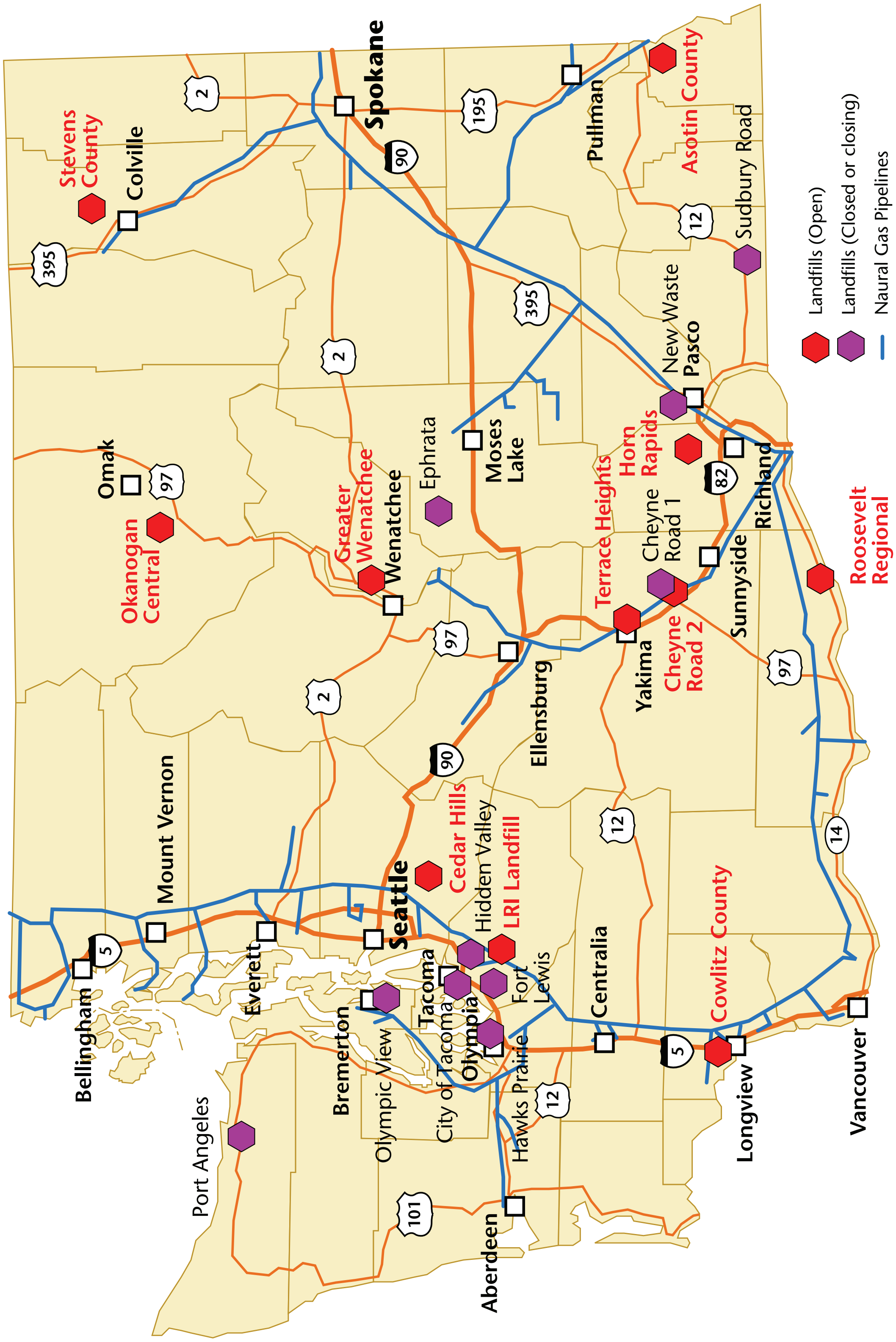
The LRI Landfill in Pierce County, owned by Waste Connections, has signed a long-term agreement with Biofuels Energy, LLC, to manage the landfill gas stream for energy production. At the LRI Landfill, Biofuels Energy reports current biogas production of more than 3,000 standard cubic feet per minute (scfm). Their gas projection models suggest that output could increase to 5,000 scfm in 10 years and 8,000 scfm in 15 years.

Planning and development for the project is occurring at a brisk pace. The first phase of development will use about two-thirds of current gas production for a hybrid electricity-compressed natural gas (CNG) project. On-site electricity production will support operations and future development. The landfill gas will be upgraded using AirLiquide's membrane conditioning process – like the process used at the Cedar Hills Landfill in King County.

The first phase of CNG development will use cleaned gas to produce more than 800,000 diesel gallon equivalents (DGEs) per year of CNG for transportation uses, enough fuel for more than 150 heavy-duty diesel trucks per year. Company representatives indicate that while transportation uses are a high priority for the Pierce County project, they are looking to see if the region embraces the opportunity to use bio-CNG before deciding how much of the second phase of development is used for transportation fuels.

With sufficient interest, the second phase could add more than 2.5 million DGEs annually, supporting close to 450 heavy-duty trucks *(Mazanec, 2011).*

Map 1. Landfills with Biomethane Potential



is useful generally for identifying potential targets for further project development; to develop more precise figures for project development, more detailed feasibility studies are warranted.

Another challenge of estimating the potential size of landfill energy projects is that gas production is not constant over time. In each landfill cell, there is an extended ramp-up period, followed by a period of peak output, followed by a long decline. This phenomenon is illustrated in Figure 4 from a study reported by the DOE Clean Cities Program.

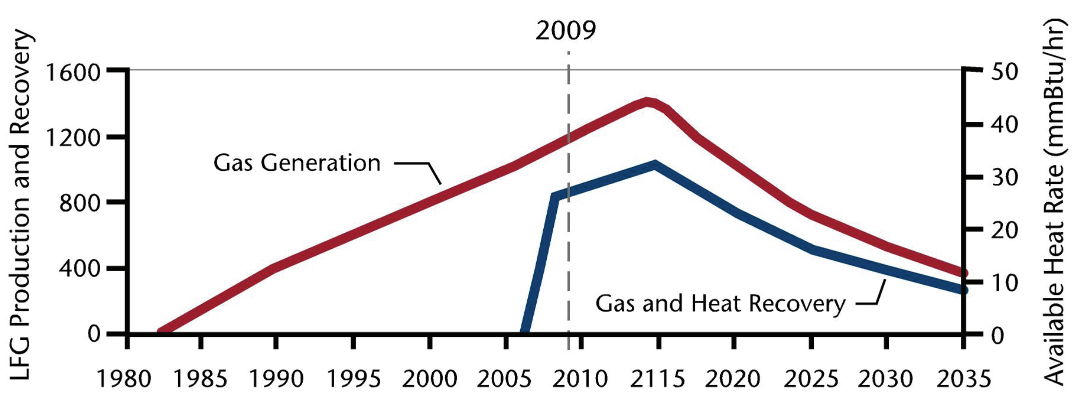
This figure illustrates a typical LFG generation and recovery profile for a site opened in 1980 at which peak recovery occurs in 2014. In conventional landfills, gas recovery typically begins slowly, 10 to 15 years after the waste is deposited, and continues for several decades. In newer designs (e.g., conventional cells with leachate circulation), accelerated waste stabilization permits economic recovery to begin much earlier, typically within five years of waste deposition (*EPA, 2011*).

A final concern of some critics of landfill gas projects is the potential for harmful emissions from the combustion of landfill gas containing toxic contaminants (*Ewall, 2007*). The challenge is to thoroughly analyze the available gas for all substances; install clean-up technology that also removes any toxic compounds; and effectively dispose of, not burn, any hazardous material.

Project Candidates

The landfill assessment found that five landfills have actively used biogas for productive purposes, ranging from leachate evaporation to electricity production. One site, the Cedar Hills Landfill in King County, cleans the gas for delivery into the natural gas pipeline. Puget Sound Energy (PSE) uses the pipeline gas to produce electricity at a natural gas generating station. To date, there are no dedicated vehicle fueling projects using landfill gas in Washington.

Figure 4. Typical Flow of Landfill Gas Over Time



Source: Clean Cities, 2010

The assessment also found that EPA identifies nine landfills as “candidate” sites, meaning that their analysis suggests that these sites have good potential for profitable gas-to-energy projects. The EPA published briefs on two of these candidate sites, the Port Angeles Landfill and the Fort Lewis Landfill.

In addition to these opportunities, Waste Connections has signed an agreement with Biofuels Energy, LLC, to manage the landfill gas stream for energy production at the LRI Landfill in Pierce County. Biofuels Energy brings relevant experience to the project, having recently completed a large-scale biomethane project at the Point Loma Wastewater Treatment Plant near San Diego *(Mazanec, 2011)*.

Wastewater Treatment Plants

Wastewater treatment plants (WWTPs) are another significant source of biogas. These facilities include municipal or county WWTPs that manage sewage wastewater from homes and businesses. They can also include industrial wastewater treatment at food processing and beverage facilities. The United States has thousands of WWTPs that use a vast array of mechanical, biological, and chemical processes to treat the wastewater and the wastewater solids that result.

The DOE reported the following information about wastewater treatment facility energy potential during its 2010 Waste to Wheels Workshop:

> Of the more than 16,000 wastewater treatment plants in the U.S., approximately 3,500 of the largest already have anaerobic digesters on site, along with the expertise needed to operate them. The primary functions of these digesters are to reduce the volume of sludges by 40 to 60 percent (which makes their final disposal less costly) and to control pathogens and odor in compliance with regulations. About half of these digesters simply burn the gas off. Plants seeking to increase the energy content of digester gas can "co-digest" additional organic wastes along with the sludges – typically fats, oils, and grease (FOG) and food processing wastes – following the example of the East Bay Municipal Utility District. This strategy can increase gas production by up to 40 percent with as little as a 10 percent increase in feedstock volume *(Richardson, 2010)*.

Chambers Creek Wastewater Treatment Plant serves Pierce County residents.
Source: Pierce County

Project Assessment

For the WWTP assessment, various sources were evaluated, especially reports and databases maintained by the EPA and the Washington State Department of Ecology. Ecology maintains a public database of wastewater discharge permits that provides valuable information about the hundreds of WWTPs in the state.

A database of Washington's municipal WWTPs was created for this report. The data were analyzed to identify projects that had anaerobic digesters that produce biogas and that were of sufficient size to have development potential. Several sources point to the 5 million gallon-per-day (MGD) threshold that EPA identified as being necessary to justify evaluation for profitable use of the energy in the biogas (*Eastern Research Group, 2007)*.

Table 4 shows the results of the assessment. It provides data about 31 facilities in the state that have anaerobic digesters and average flows near or above 4 MGD. Facilities smaller than the EPA threshold were included on the chance that they might expand in the future. Average daily flow data from public sources is included. From these data, calculations were made of the biomethane potential; from that, the potential displacement in GGEs was estimated.

A gap in our research to date involves biogas production from anaerobic digestion of high-strength industrial wastes, such as at food and drink processing facilities. Records of the municipal WWTPs indicate that substantial quantities of this food processing material are managed at municipal facilities. Even those facilities that do digest on-site may still use the municipal treatment system for their final wastewater disposal, thus they would not require a discharge permit from Ecology. More research is required to determine the extent of on-site digestion at industrial facilities and the potential it represents as a source for biomethane.

SPOTLIGHT

Simplot's Biogas Project

As the nation's leading supplier of potato products to consumers, J.R. Simplot Company has numerous processing plants located around the Pacific Northwest. Each facility generates millions of gallons of wastewater daily from washing, peeling, and sizing potatoes into french fries and other products.

In 2007, Simplot began operating an anaerobic digestion system at its processing plant in Moses Lake, WA. It is a simple system, consisting of a covered anaerobic lagoon capable of storing and digesting 20 million gallons of wastewater. Named "Bertha" by the employees, the covered lagoon produces biogas that is used directly in the processing plant's boiler system. As a result, the company has significantly reduced its demand for natural gas, reducing annual GHG production equivalent to 15,000 tons of CO_2. The project received early development support through an agreement with a company to create and market the GHG reductions as carbon credits *(Simplot, 2010).*

Discussion

The assessment found examples of at least four municipal WWTP energy projects in Washington. King County leads the way with energy recovery at two WWTPs (West Point and South). These two facilities with biogas-to-energy projects account for more than half of the estimated biogas production output from major metropolitan facilities. Energy production at the just-completed Brightwater WTTP in north King County is being considered.

Two other projects are at the Budd Inlet WWTP, part of the LOTT wastewater group in Thurston County and the Redondo WWTP in Des Moines (King County). These are smaller electricity generation projects, ranging from 60 kW to 330 kW capacities. They are WWTP biogas projects of a size suitable for some electricity

Table 4. Wastewater Treatment Plants with Biomethane Potential

County	Facility Name	Location	Average Flow (MGD)	Biomethane Potential EST cf/d	GGE Potential EST GGE/d
King	King County West Point WWTP	Seattle	215 *(not avg)*	1,290,000	10,320
King	King County South WWTP	Renton	144 *(not avg)*	864,000	6,912
Spokane	Spokane AWWTP	Spokane	59.6 - 79.8	420,000	3,360
Pierce	Tacoma Central No. 1	Tacoma	60.00	360,000	2,880
Snohomish	King Cty Bright-water WWTP	Woodinville	36.00	216,000	1,728
Pierce	Chambers Creek STP	University Place	28.70	172,200	1,378
Thurston	LOTT	Olympia	28.00	168,000	1,344
Yakima	Yakima POTW	Yakima	21.50	129,000	1,032
Clark	Salmon Creek STP	Vancouver	14.95	89,700	718
Benton	Richland POTW	Richland	11.40	68,400	547
Kitsap	Bremerton STP	Bremerton	10.10	60,600	485
King	Lakota WWTP/ Lakehaven Utility Dist.	Federal Way	10.00	60,000	480
Skagit	Mt Vernon WWTP	Mount Vernon	7.6 - 15 *(not avg)*	60,000	480
Grays Harbor	Aberdeen STP	Aberdeen	9.90	59,400	475
Walla Walla	Walla Walla STP	Walla Walla	9.60	57,600	461
King	Midway Sewer District WWTP	Des Moines	9 *(not avg)*	54,000	432
King	Salmon Creek WWTP/SW Suburban Sewer Dist.	Burien	8.10	48,600	389

Table continued on next page

production, but they could not likely satisfy the return on investment required to develop advanced gas cleanup and compression capabilities.

Project Candidates

As mentioned, EPA set 5 MGD average flow as the threshold for consideration as a potential energy project. To define pipeline-quality biomethane further, National

Table 4. Wastewater Treatment Plants with Biomethane Potential, *continued*

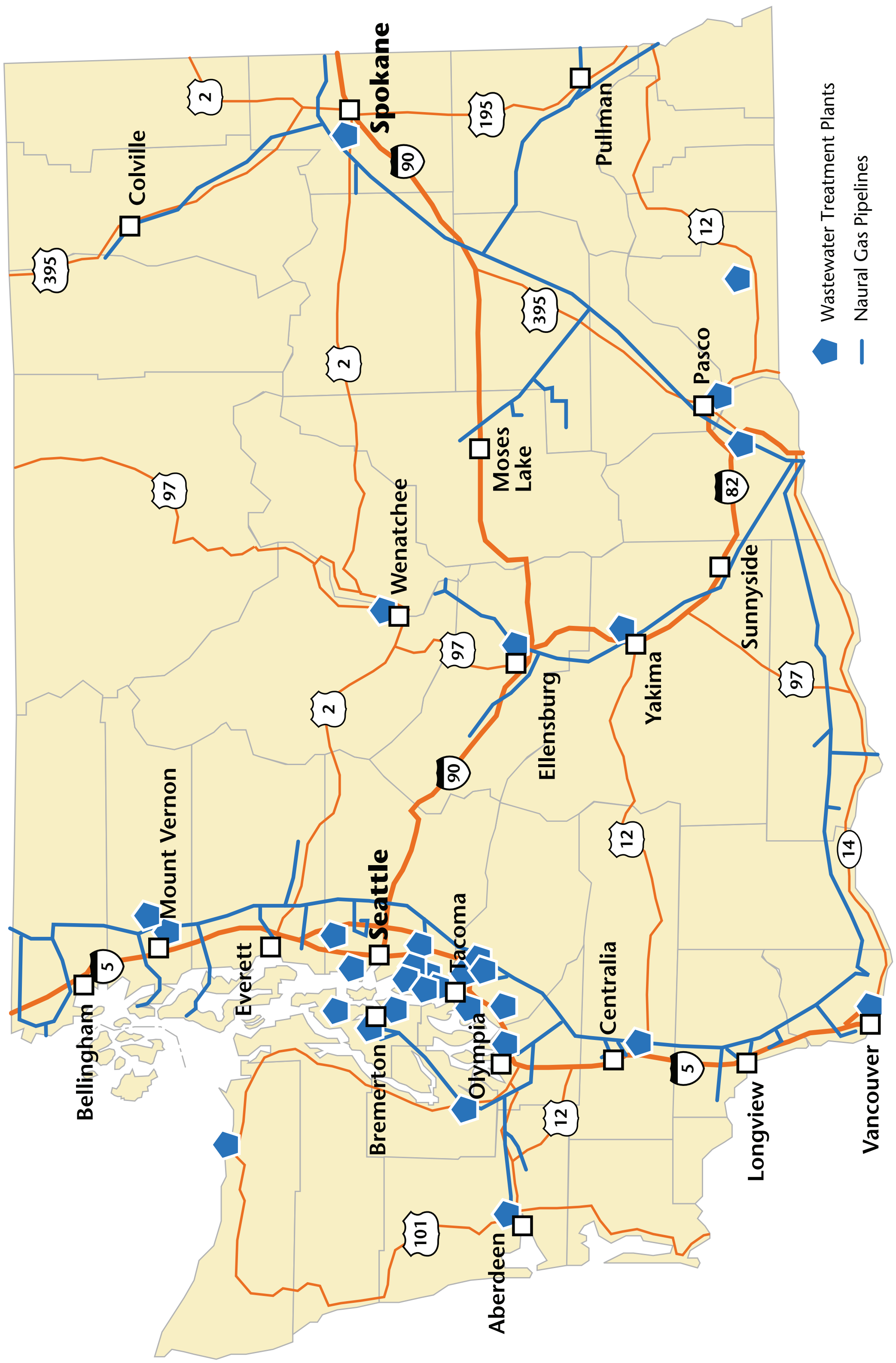
County	Facility Name	Location	Average Flow (MGD)	Biomethane Potential EST cf/d	GGE Potential EST GGE/d
Kittitas	Ellensburg POTW	Ellensburg	8.00	48,000	384
King	Miller Creek WWTP	Normandy Park	7.10	42,600	341
Clallam	Port Angeles STP	Port Angeles	6.70	40,200	322
Lewis	Chehalis STP	Chehalis	6.00	36,000	288
Kitsap	Kitsap County - Central WWTP	Poulsbo	6.00	36,000	288
King	Redondo WWTP/ Lakehaven Utility Dist.	Redondo	5.60	33,600	268.8
Chelan	Wenatchee POTW	Wenatchee	5.50	33,000	264
Pierce	Puyallup WPCP	Puyallup	5.00	30,000	240
Pierce	Sumner STP	Sumner	4.59	27,540	220.32
Franklin	Pasco WWTP	Pasco	4.52	27,120	216.96
Kitsap	Port Orchard WWTP	Port Orchard	4.20	25,200	201.6
Mason	Shelton STP	Shelton	4.02	24,120	192.96
Skagit	Burlington WWTP	Burlington	3.79	22,740	181.92
Pierce	Fort Lewis	Tacoma	NA	NA	
Total				4,603,620	36,829

Sources: Current EPA websites, WA Dept. of Ecology data resources, and assorted news articles and reports (Kerstetter, 2001).

Grid, a natural gas utility, sets the threshold at 17 MGD, though this figure will likely change as technology improves *(Chahbazpour, 2010)*.

The assessment shows four additional candidates that fit the 17 MGD threshold: Spokane, Tacoma, Chambers Creek (University Place), and Yakima. The Western Washington Clean Cities Coalition has begun discussions with Tacoma city officials and is currently providing technical assistance to evaluate a potential project. Chambers Creek, also in western Washington, may offer an excellent opportunity following a more in-depth feasibility study.

Map 2. Selected Wastewater Treatment Plants with Biomethane Potential



Livestock Producers – Dairies

Livestock operations create a variety of organic wastes that may be suitable for digestion into biogas, but so far manure from dairy and hog operations has been the major focus. In Washington, the dairy industry is a much more significant candidate than other livestock operations.

The EPA estimates that 6,900 farms present a reasonable potential for methane capture or generation. Currently, the EPA AgSTAR program is tracking around 160 existing livestock digester projects in the United States. The vast majority of these projects produce heat and electricity. Two CNG vehicle projects at dairies are currently underway, and more may be in the works. The first is located at the Hilarides Dairy in California's Central Valley; the second project just kicked off at the Fair Oaks Dairy in west central Indiana.

The scene surrounding biomethane project development at the Vanderhaak Dairy in Whatcom County.

Six digester projects are currently operational in the state: one in eastern Washington and the rest in Whatcom and Skagit counties in northwest Washington. The Vanderhaak Dairy in Lynden is participating in a pilot biomethane vehicle project in development by Western Washington University with support from Western Washington Clean Cities.

Project Assessment

The assessment of dairy biomethane potential is calculated from the gross numbers of dairy cows in each county and using a conservative figure of 30 cubic feet of methane generated per cow per day. This estimate shows more technical then market potential. Many of the smallest dairies will not invest in digestion technology. However, while industry observers may mark the threshold for viability at 500 cows or more, even a 200-cow dairy may benefit from digestion if it cooperates with multiple dairies in a larger project.

This assessment provides guidance about desirable dairy geography and size to help target dairy producers who are more likely to benefit from digestion technology. Table 5 shows the results of the assessment and the potential GGEs generated per day if all of the manure was converted to biomethane.

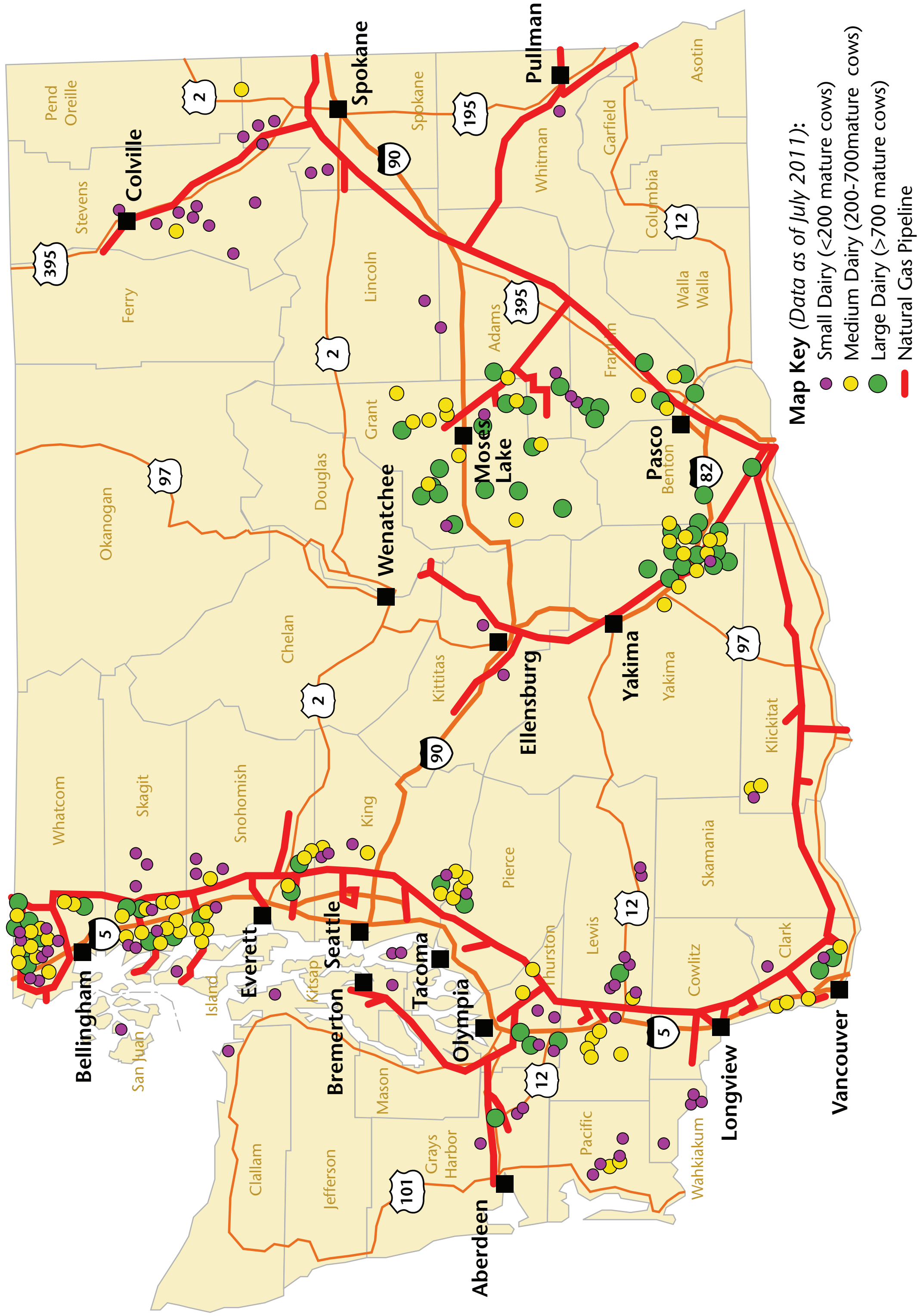
Discussion

Observers of digester developments in the state point to financing, regulations, and markets as key obstacles that need to be addressed to make digesters at dairies more viable. Key factors involved in the viability of anaerobic digestion on dairy farms also include the volume and characteristics of the manure available for digestion

Table 5. Washington State Dairies and Their Biomethane Potential

County	Number of Dairy Farm Herds					Total Cows	Bio-methane Output EST cf/d	GGE Potential EST GGE/d
	1 to 199 Cows	200 to 499 Cows	500 to 999 Cows	1,000 - 2,499 Cows	2,500 or More Cows			
Yakima	2	9	19	28	9	93,606	2,808,180	22,465
Whatcom	55	38	24	7	1	46,588	1,397,640	11,181
Grant	2	9	4	7	3	29,652	889,560	7,116
Franklin	1	2	2	5	2	19,666	589,980	4,720
Skagit	8	17	6	1	0	12,273	368,190	2,946
Snohomish	13	7	6	2	0	9,575	287,250	2,298
King	14	15	2	0	0	7,926	237,780	1,902
Adams	1	2	0	5	0	7,453	223,590	1,789
Lewis	21	6	2	1	0	6,250	187,500	1,500
Thurston	9	1	2	2	0	4,813	144,390	1,155
Benton	1	1	1	0	1	4,261	127,830	1,023
Clark	3	3	2	0	0	3,346	100,380	803
Grays Harbor	7	2	0	1	0	2,476	74,280	594
Pacific	6	1	1	0	0	1,417	42,510	340
Stevens	8	1	0	0	0	1,050	31,500	252
Pierce	2	0	1	0	0	1,004	30,120	241
Klickitat	1	2	0	0	0	895	26,850	215
Spokane	7	1	0	0	0	816	24,480	196
Clallam, Cowlitz, Island, Jefferson, Kitsap, Kittitas, Lincoln, San Juan, Wahkiakum, Whitman	14	4	0	0	0	2,532	75,960	608
Total	175	121	72	59	16	255,599	7,667,970	61,344
The following counties have no dairy facilities registered with WSDA: Asotin, Chelan, Columbia, Douglas, Ferry, Garfield, Mason, Okanogan, Pend Oreille, Skamania, Walla Walla								

Map 3. Washington State Dairies, Digesters, and Natural Gas Pipelines



and the capacity to co-digest the manure with other agricultural or industrial waste streams (e.g., preconsumer food waste) that have higher relative biogas potential. The EPA and others may point to viability thresholds for 500 to 1,000 milk cow equivalents, but that is only part of the story. Community digesters that bring together multiple farms and multiple feedstocks offer exciting opportunities for energy development. The Rainier digester project under development near Enumclaw in King County is an example of such an opportunity.

Project Candidates

Yakima, Grant, Franklin, and Adams counties in eastern Washington are home to the numbers of cows and larger dairies necessary to justify consideration for significant biomethane development. They represent 59 percent of the dairy biomethane potential in the state. Map 3 shows the locations of registered dairy farms and the locations of major utilities and natural gas transmission pipelines (shown as blue lines). Whether for direct vehicle use or for injection into the natural gas pipeline, the proximity of natural gas transmission pipelines to major dairy centers in eastern Washington may offer an alternative market to the low electricity purchase rates offered to project developers by utilities in that area.

In western Washington, Whatcom, Skagit, and Snohomish counties – representing 27 percent of the state's biomethane potential – offer the most immediate opportunities for digester development. Proximity to major urban centers, interstate highways, and major natural gas pipelines could make biomethane projects attractive for developers.

Municipal Solid Waste Organics

Communities throughout Washington have a strong recycling ethic, as demonstrated by the impressive recycling rates reported from Bellingham to Vancouver and from Seattle to Spokane. The organic materials contained in municipal solid waste (MSW) streams are energy-rich materials that offer valuable opportunities to produce renewable power or fuel.

Source-separation and processing have not only been cost effective in comparison to landfilling, but the potential emissions reduction benefits are also important. Based on EPA models, between a quarter to a third of the biogas potential is lost in landfills because of the lag time from when garbage is dumped to when biogas collection systems are operational. During this lag time, decomposition still occurs and the resulting methane – a potent greenhouse gas – is emitted to the atmosphere *(U.S. Composting Council, 2009)*.

Including food scraps in yard debris collection expands opportunities for capturing bioenergy.
Source: City of Portland

Washington communities have a two-decade track record of source-separating yard and garden debris for composting. And as the cost of transporting and landfilling garbage increases and concern about greenhouse gases grows, communities continue to look for opportunities to separate more organic waste from their MSW. For the purposes of this assessment, the organics portion of the solid waste stream is divided into two parts: one that is suitable for biogas production through high-solids anaerobic digestion (i.e., food wastes, yard debris, and soiled paper packaging and products) and another that is suited to thermal gasification (i.e., wood wastes).

High-Solids Anaerobic Digestion

One common strategy for diverting more organic materials is allowing the addition of food waste, and sometimes soiled paper packaging, to yard waste containers. The former yard debris cart becomes an all-organics collection cart. In Europe, the materials combined in an organic materials collection bin are often sent to facilities that practice high-solids anaerobic digestion. Composting or fertilizer production still follows the digestion process, but this new stage of processing captures the energy value in the volatile solids of the organic materials and helps control odors. This technology for high-solids anaerobic digestion is now developing in North America.

High-solids anaerobic digestion can happen in a couple ways – wet or dry – depending on what parts of the non-woody organics fraction is collected. Source-separated organics may be ground or processed together with liquid wastes such as wastewater solids or dairy manure for co-digestion. Even as solids levels increase in the mixed feedstock, the process can be considered a form of "wet" digestion as long as these co-digestion materials can be pumped (greater than 70 percent moisture).

Co-digesting food processing wastes, dairy processing liquids, and even fats, oils and grease (FOG) with dairy manure occurs at many wastewater and livestock digester projects in Washington and around the country. In eastern Washington, the Barr-Tech facility outside of Spokane plans to incorporate source-separated food wastes with animal wastes for use in a plug-flow type digester.

The European technologies that are gaining new attention mostly use batch dry digestion methods. Batch methods process the source-separated organics to keep the solids-liquids density at a level that allows operators to stack the material in piles inside airtight containers (greater than 30 percent solids). These moisture levels are higher than would be appropriate for aerobic composting. As leachate forms, it is collected from under the piles and is recirculated to maintain anaerobic conditions. Biogas is produced over a three- to four-week period, after which the digested materials are taken from the digester containers and moved to an aerobic composting process for conversion to soil amendments *(Spencer, 2010)*.

Currently, dry-batch digestion technologies from Bekon, BIOFerm, Gicon, Kompoferm, and Solum are being marketed in the United States. Research at Washington State University, sponsored by the Department of Ecology, is looking for ways to enhance high-solids anaerobic digestion technology.

Project Assessment

To assess the biogas potential from the food-yard-paper fraction of MSW, the research team used records maintained annually by the Washington State Department of Ecology on the fate of a wide variety of MSW materials. Ecology tracks whether materials are recycled, diverted or disposed of, and conducts regular waste characterization studies, which separate and weigh different categories of waste at disposal facilities around the state. The most recent all-state solid waste characterization study was done in 2009.

While absolute tonnages may vary somewhat, these reports confirm the concentration of organic MSW materials around metropolitan areas. Table 6 shows the availability of these materials by county. Biomethane potential is calculated based on methane yield of 60 cubic meters per metric ton of mixed municipal organics *(Allen, 2011)*.

Discussion

The food-yard-paper fraction of MSW is a relatively new target for anaerobic digestion in the United States. An August 2010 article in the trade magazine

BioCycle identified four projects in development using dry, high-solids methods (including two from the Pacific Northwest) *(Spencer, 2010)*:

- **Cedar Grove Composting**, Everett, WA (BIOFerm Energy Systems) – 50,000 tons per year of food-yard-paper materials from Puget Sound area communities.
- **Fraser-Richmond Soil & Fibre**, Richmond, BC (Harvest Power) – 30,000 tons per year of food waste from the Vancouver, BC, area, plus yard trimmings.
- **Zero Waste Energy Development Company** (ZWED), San Jose, CA (Kompoferm) – 50,000 tons per year of mixed organic waste from the City of San Jose and other regional generators, and the organic fraction left after processing recyclables and garbage at the GreenWaste Recovery facility in San Jose.
- **University of Wisconsin**, Oshkosh, WI (BIOFerm Energy Systems)— 6,000 tons per year of food waste from campus, plus yard trimmings from the community.

Project Candidates

As described above, at least two facilities are in the preconstruction stage in Washington – the Cedar Grove Composting facility outside Everett (dry style) and the Barr-Tech plant outside Spokane (wet style).

Harvest Power, with offices in Waltham, MA, Seattle, WA, and Richmond, BC, has begun construction of a high-solids anaerobic digestion system in British Columbia. They are actively developing projects in other areas of North America and are watching for opportunities in Washington.

Many Washington communities looking for opportunities to increase diversion of organics from landfills will consider high-solids anaerobic digestion to recover energy prior to composting.

Thermal Gasification

Thermal gasification processes produce synthesis gas (syngas), which is composed mostly of hydrogen, carbon monoxide, CO_2, water vapor, methane, and trace gases. Syngas can be upgraded to biomethane by converting hydrogen and carbon monoxide through a process called methanation and removing CO_2 and other gases.

Thermal gasification uses gasifier technology to break down feedstock that has lower moisture and typically higher fiber. Thermal gasification processes have used feedstocks such as wood chips, woody biomass, crop residues, and even purpose-grown energy crops.

While commercial-scale thermal gasification plants are still being developed, technologies required to clean and upgrade the syngas are commercially available and can recover up to 98 percent of the methane from the syngas *(Chahbazpour, 2010)*.

Table 6. Mixed MSW Organics with Biomethane Potential by County

County	MSW Total tons	MSW Mixed Organics tons	Biomethane Potential EST cf/d	GGE Potential EST GGE/d
King	1,875,519	401,924	2,121,118	16,969
Pierce	785,639	168,362	888,518	7,108
Snohomish	683,655	146,507	773,180	6,185
Spokane	462,677	99,152	523,265	4,186
Clark	424,733	91,020	480,352	3,843
Thurston	245,181	52,542	277,287	2,218
Kitsap	239,769	51,382	271,167	2,169
Yakima	234,564	50,273	265,313	2,123
Whatcom	196,529	42,116	222,264	1,778
Benton	163,058	35,652	188,152	1,505
Skagit	118,000	25,287	133,452	1,068
Cowlitz	101,254	21,699	114,513	916
Grant	84,697	18,151	95,788	766
Island	81,424	17,449	92,086	737
Lewis	74,132	15,886	83,840	671
Franklin	72,783	15,597	82,314	659
Chelan	71,540	15,331	80,908	647
Grays Harbor	71,342	15,289	80,684	645
Clallam	71,021	15,220	80,321	643
Mason	57,846	12,396	65,421	523
Walla Walla	57,788	12,385	65,359	523
Stevens	42,050	9,011	47,556	380
Whitman	41,664	8,929	47,120	377
Okanogan	40,033	8,579	45,275	362
Kittitas	38,951	8,347	44,052	352
Douglas	36,653	7,855	41,453	332
Jefferson	29,542	6,331	33,411	267
Asotin	21,420	4,590	24,225	194
Pacific	21,271	4,558	24,056	192
Klickitat	20,377	4,367	23,045	184
Adams	17,285	3,704	19,548	156
San Juan	15,294	3,278	17,297	138
Pend Oreille	12,859	2,756	14,543	116
Skamania	10,794	2,313	12,207	98
Lincoln	10,344	2,217	11,699	94
Ferry	7,353	1,576	8,316	67
Wahkaikum	4,133	886	4,674	37
Columbia	3,990	855	4,512	36
Garfield	2,060	441	2,327	19
Total			7,410,621	59,285

This assessment provides a look at the woody fraction of MSW in Washington by county. Though commercial development may be some years away, the data is provided to give as broad a look at biomethane potential as possible. Table 7 shows the availability of woody MSW and agricultural field residues by county. It does not show availability of forest residuals or mill residues, which represent another significant resource that may be available for energy development. The University of Washington, under contract with the Washington State Department of Natural Resources, is currently calculating the volumes of forest harvest residues generated on all public and private timberlands in the state. That report is expected toward the end of 2011.

Table 7. Selected Feedstocks for Thermal Gasification by County

County	MSW Total tons	MSW Mixed Woody tons	AG Field Residue tons	Total Thermal Gas Feedstocks tons
Adams	17,285	1,156	195,508	196,664
Asotin	21,420	1,433	7,034	8,467
Benton	163,058	10,909	113,986	124,895
Chelan	71,540	4,786	0	4,786
Clallam	71,021	4,751	0	4,751
Clark	424,733	28,415	0	28,415
Columbia	3,990	267	109,047	109,314
Cowlitz	101,254	6,774	0	6,774
Douglas	36,653	2,452	74,358	76,810
Ferry	7,353	492	0	492
Franklin	72,783	4,869	119,113	123,982
Garfield	2,060	138	61,592	61,730
Grant	84,697	5,666	268,297	273,963
Grays Harbor	71,342	4,773	0	4,773
Island	81,424	5,447	0	5,447
Jefferson	29,542	1,976	0	1,976
King	1,875,519	125,472	0	125,472
Kitsap	239,769	16,041	0	16,041
Kittitas	38,951	2,606	0	2,606
Klickitat	20,377	1,363	9,682	11,045
Lewis	74,132	4,959	0	4,959
Lincoln	10,344	692	229,962	230,654
Mason	57,846	3,870	0	3,870
Okanogan	40,033	2,678	4,305	6,983
Pacific	21,271	1,423	0	1,423
Pend Oreille	12,859	860	0	860
Pierce	785,639	52,559	0	52,559
San Juan	15,294	1,023	0	1,023
Skagit	118,000	7,894	0	7,894
Skamania	10,794	722	0	722
Snohomish	683,655	45,737	0	45,737
Spokane	462,677	30,953	169,101	200,054
Stevens	42,050	2,813	5,208	8,021
Thurston	245,181	16,403	0	16,403
Wahkaikum	4,133	276	0	276
Walla Walla	57,788	3,866	270,175	274,041
Whatcom	196,529	13,148	0	13,148
Whitman	41,664	2,787	636,150	638,937
Yakima	234,564	15,692	63,527	79,219
Grand Total:	6,549,224	438,143	2,337,045	2,775,188

Chapter 2: End Uses for Biomethane

At least three major end uses or market opportunities are discussed in this assessment. These include:

- Heat and power production,
- Biomethane use as transportation fuel, and
- Distribution into the interstate pipeline system.

This last use would allow source providers to market their gas as "renewable natural gas" to buyers who are willing to pay premiums for the environmental attributes of biomethane. The dominant actors in this market currently are California utilities and refineries that want to increase their production of renewable power or low-carbon fuel to meet government mandates.

The market for natural gas has changed dramatically in recent years with the discovery of new, more economically viable methods of recovering natural gas from shale deposits around the United States. The Henry Hub spot price of natural gas has dropped significantly from a summer 2008 peak over $12/MBTU to between $2.50 to $5.00/MBTU throughout most of the past three years *(EIA, 2011)*. As a result, a critical factor in all the end uses of biomethane is the value the market gives to the environmental and renewable attributes of the gas. The value of clean, renewable biomethane in displacing high-cost petroleum fuels has appeal for businesses and government agencies that are looking to improve their economic and environmental balance sheets. This value can be pushed further by government policies that require adaptation to more renewable power or low-carbon fuels. For more on this topic, see Chapter 5.

The ultimate end use of the biogas from a landfill or digester has a major impact on the extent to which the biogas must be upgraded or treated. Figure 5 shows shows how different end uses can fit along a line of increasing levels of gas clean up.

Boilers and combined heat and power (CHP) generators can use gas with lower BTU values (meaning more CO_2). The primary step for purifying biogas after removing water vapor is desulfurization, which is reducing the level of hydrogen sulfide to less than 1,000 parts per million (ppm). The next step is gas treatment to remove sulfides, CO_2, siloxanes, and any other contaminant gases.

For use in fuel cells, the next step is reforming the biomethane into hydrogen. For transportation- or pipeline-grade fuel, biomethane must be compressed after gas treatment and put in pressure tanks or pipelines for distribution.

As technology evolves, new end uses will be discovered. For example, advances are being made in fuel cells beyond power production. Fuel cell/battery hybrid buses and short-haul trucks are nearing commercial scale.

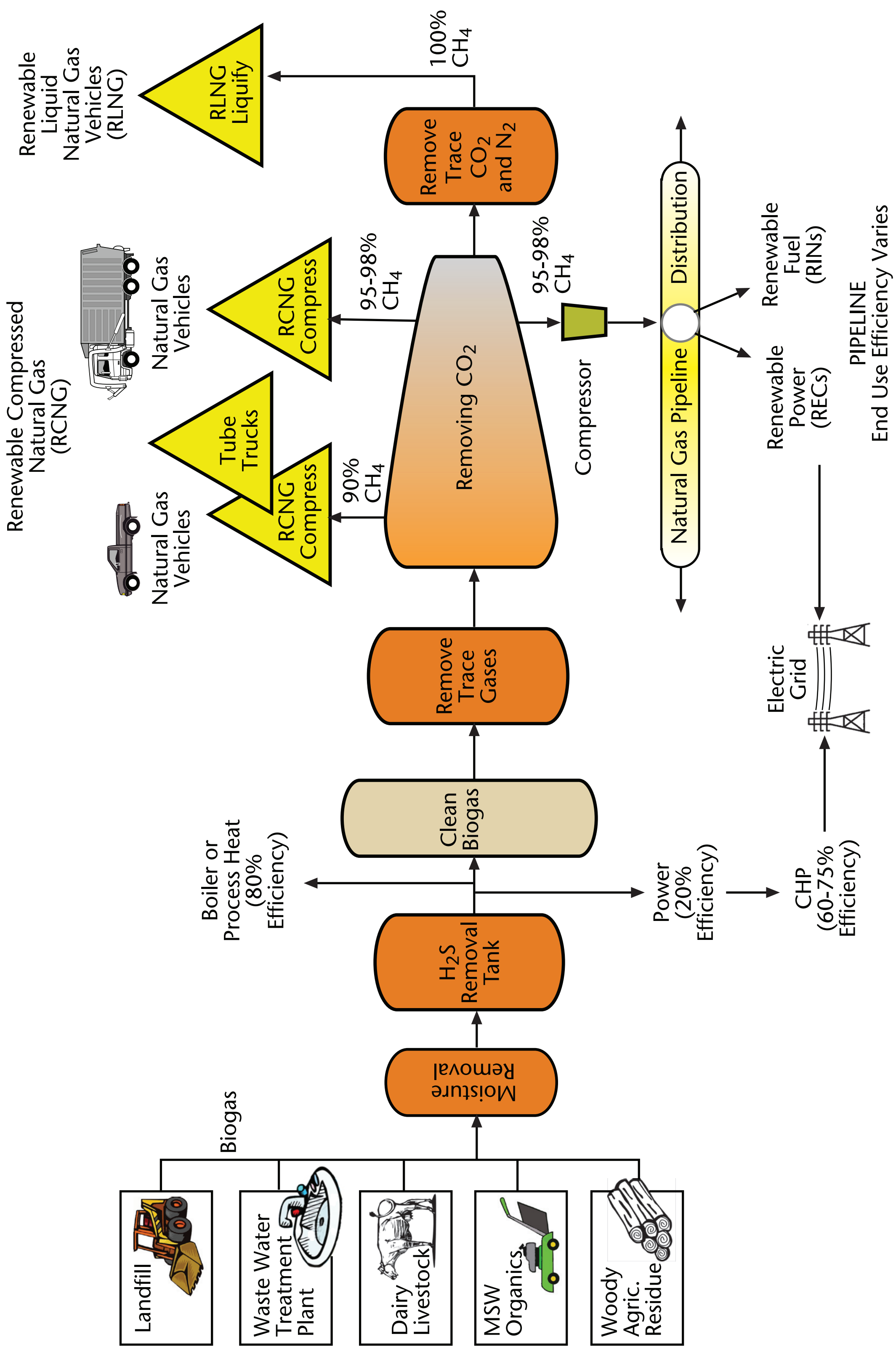
Heat and Power Production

In Washington state and elsewhere, the first entry into renewable energy production for operators of landfills, wastewater treatment plants (WWTPs), and agricultural digesters has been heat and power production. Some projects, especially smaller projects, simply use the biogas as a direct substitute for propane or natural gas in boilers to produce process heat for digesters or other equipment.

For larger facilities, CHP production or stand-alone electricity generation has emerged as a dominant use. The market for renewable power has improved in some areas of the state, where utilities are offering upwards of 8 to 10 cents per kilowatt hour (kWh) produced. However, issues such as interconnection requirements and costs, power purchase agreements, price of power sold, and occasional utility resistance to distributed energy continues to restrict more widespread development of CHP technology in general.

The technology for biogas-to-power systems is steadily improving. For example, Stirling engine CHP systems that can handle biogas that has not been purified are now available. In addition, a number of commercial power generation systems have been developed to handle biogas, even at very low BTU levels. These technology improvements are expanding the range of viable biogas opportunities. The wastewater treatment facility in Helena, MT, has installed two Stirling engine systems and Lakehaven Sewer District in Washington is in the process of installing a system at Redondo Beach.

Figure 5. Biogas Upgrading and End Use Pathways



SPOTLIGHT

WWTP CHP Projects in Washington

Here are descriptions of existing biogas-to-energy projects published in a report by the Northwest Clean Energy Application Center

Wastewater Treatment Facility, Renton – A 1.5 megawatt (MWc) molten carbonate fuel cell is located at the South Treatment Plant in Renton. It was the original commercial-scale demonstration project for FuelCell Energy. The demonstration period ended in September 2006 and the system is now mothballed, but it could be brought back online with new fuel cell stacks (the technology has significantly progressed), a new interconnection agreement with Puget Sound Energy (PSE), and probably a new revenue stream of hydrogen gas (an add-on system). The project benefitted from a series of lessons learned, upgrades such as scrubbing the biogas, and adjustments. Currently, the plant cleans its biogas using a pressurized water-scrubbing technology and delivers the cleaned biomethane into a natural gas distribution pipeline under a contract with PSE.

West Point Treatment Plant, Seattle – This CHP facility, operational since 1985, is rebuilding and enlarging existing CHP operations (2.4 MWc to 4.6 MWc). Digester gas is also used to run influent pumps (1.6 MW). The rebuilt system will have two reciprocating engines of 2.3 MW each, plus the 1.6 MW, for a total system capacity of 6.2 MW. Average operations will be at the 3.9 MWa level with peak operation when necessary. West Point shows the value of reinvesting in new systems as technology improves.

Brightwater Wastewater Treatment Facility, Woodinville – A new WWTP began operation in 2011 and will continue to ramp up in 2012. Brightwater uses membrane bioreactor technology for final treatment of the liquid effluent. Wastewater solids are digested anaerobically. Plant size will start at 36 million gallons per day (MGD) with room for expansion. Biogas will be produced that could generate about 1 MW of electricity. A feasibility study on using Brightwater as a test bed facility for CHP applications was conducted by King County in cooperation with the Northwest Energy Technology Collaborative. Snohomish PUD has agreed to fund the test bed.

Budd Inlet Treatment Plant, Olympia – This is a 330 kWc biogas CHP and district energy project at the LOTT Alliance wastewater treatment facility that came online in November 2009. It received an energy conservation grant of $1.7 million from PSE. Total project cost was $2.4 million, including a district heating loop. The biogas powers a GE Jenbacher JMS 208 engine. The project development team included TRANE, Cascade Power and Smith Power Products.

Redondo Wastewater Treatment Plant, Des Moines – This 60 kWc Stirling engine CHP system is a collaborative project between Lakehaven Utility District and PSE. The project's two Stirling Flexgen engines use digester gas from the plant's

Continued on next page...

WWTP CHP Projects in Washington
Continued

solids handling system (approximately 50,000 cubic feet per day). When complete, it will allow the district to offset approximately 20 percent of the plant's daily electrical requirement. Thermal energy will be used to reduce natural gas as a heating source for the plant. This project will be the first in Washington to use this state-of-the-art technology.

More information is available from the Northwest Clean Energy Application Center: *www.chpcenternw.org*.

Transportation Fuel

Natural gas is not yet a major fuel for transportation, but the use of compressed natural gas (CNG) or liquefied natural gas (LNG) is a key step toward the goal of using biomethane in place of natural gas in transportation.

Since the first attempts to increase the use of natural gas vehicles during the 1980s, the market for natural gas vehicles has shifted up and down with changes in the natural gas markets. Attention has focused primarily on "captive fleets," that is, fleets of vehicles that operate in a localized area and return to the same home base each day. Fleets in urban areas with higher fuel usage per vehicle mile have had the most success *(CNGVA, 2010)*. Examples of such fleets include taxis, school and municipal buses, and refuse/recycling trucks.

One potential advantage of direct use of biomethane over pipeline injection is that natural gas vehicles can tolerate somewhat higher levels of CO_2, which can have a significant impact on gas cleanup costs. For injection into the pipeline, the biogas must be purified to about 98-99 percent methane. For direct use as a vehicle fuel, biogas may be cleaned to around 90 percent methane. For example, the California Air Resources Board (CARB) established the following natural gas fuel specification *(Rutledge, 2005)*:

- Methane: 88 percent minimum
- Ethane: 6 percent maximum
- Propane: 3 percent maximum
- Oxygen: 1 percent maximum
- Inert gases (CO_2 + N_2): 1.5 - 4.5 percent
- Total sulfur: 16 ppm
- Dewpoint: ≥10°F below 99 percent applicable local winter design temperature

Fleets are Key

The Clean Vehicle Education Foundation describes the use of natural gas vehicles in public and private fleets using these relative numbers *(Yborra, 2011)*:

- Transit buses: 11,000 (one of every five on order)
- Refuse trucks: 5,000
- School buses: 3,600 to 3,800
- Medium-duty vehicles (shuttles, vans and other work trucks): 20,000+
- Light-duty vehicles (public and private fleets): 25,000 to 30,000 and growing

When converting a fleet to natural gas, the relative benefits and costs must be considered. The benefits start with a major advantage in fuel cost savings. The cost of wholesale CNG can be as low as $1.00 per gasoline gallon equivalent (GGE). Even at retail, the cost of CNG is currently $1.79 per GGE, which is significantly less than the price of the alternative. These savings add up fast for fleet vehicles that may only get 4 to 10 miles per gallon (mpg). CNG from biomethane can be a competitive choice compared to diesel costs.

Other issues to consider are if the fleet owner is installing compression and storage equipment from the pipeline connection and the price premium for new natural gas vehicles versus existing vehicle conversions. If fleet owners accept that conversion to natural gas makes economic sense, then the next step is to convince them of the superiority of CNG made from biomethane. In the current market, this argument has to be based on the value of societal or environmental attributes, which clearly motivate some companies.

The "Green-Clean" Factor

In western Washington, refuse and recycling hauling fleets have joined the Pierce County transit system as successful users of CNG for their vehicles. These fleets meet two important criteria: their vehicles have low mileage ratings (meaning they use a lot of fuel) and they return to the same fleet base each day. Their conversion to CNG was pushed along by two "green" factors:

1. The cities of Seattle and Issaquah, for example, required refuse and recycling haulers to reduce the carbon intensity of their collection systems as a factor in winning new contracts with the city. For Waste Management and CleanScapes (the winning bidders), that meant switching from diesel to CNG.
2. A change in air pollution regulations affected diesel vehicles, especially heavy-duty vehicles.

Fuel cost savings and these green factors influenced these companies to commit in big ways to convert their heavy-duty collection vehicles to CNG. They are increasingly converting other parts of their fleets to CNG, too. This has, in turn, influenced other haulers, such as Allied Waste, to look into CNG conversion to stay competitive.

Waste Management, with support from the Western Washington Clean Cities Coalition and Saybr Contractors, went the extra step of establishing a public fast-fill station next to their fleet facility in south Seattle. Saybr has worked on many of the CNG fueling stations in the area, including the construction of the public fast-fill fuel station near SeaTac Airport for the Port of Seattle and Clean Energy Fuels Corporation.

The Port of Seattle's SeaTac Airport is another example of where incorporating value for environmental benefits supports the expansion of CNG use in transportation. Taxi cabs that serve the airport are increasingly lower-carbon, lower-emission vehicles, such as hybrid and natural gas cars. The addition of natural gas vehicles in such a visible location and the nearby refueling infrastructure support use by other fleets and the public.

Identifying and monetizing the value attached to green factors will further move the market beyond conversion to natural gas to the eventual use of more biomethane.

Direct Use Simplifies Distribution

As a company, Waste Management also has experience using biomethane in vehicles. Their first project used LNG from a landfill gas project in California. The fact that their trucks return regularly to the source of the gas points to the main advantage of the direct use of biomethane for transportation. It eliminates the distribution challenge of getting the gas from the source to the end user. The alternatives – trucking CNG in dedicated cylinders to an end user or injecting biomethane into the pipeline grid – both involve significant costs that can threaten a project's viability.

Waste Management and CleanScapes have contracts for waste collection services around the region and throughout the state. With in-house experience managing CNG fleets and the ability to take advantage of the green factor, they could be a major partner for future biomethane projects.

Marine Vessels and State Ferries

In addition to road vehicles, large marine vessels are another potential target for use of natural gas and biomethane, in particular LNG and bio-LNG. An important driver in the consideration of LNG for ships was the creation in 2010 by the International Maritime Organization, an agency of the United Nations, of the North America Emissions Control Area (ECA). The control area was created for the purpose of reducing sulfur dioxide (SO_2) and nitrous oxide (NO_X) pollution from burning diesel.

Though the State ferries already use ultra-low-sulfur diesel, other large marine vessels that historically use bunker fuel will be challenged to meet the new restrictions, which become enforceable in 2012. To meet the new air quality requirements, and, in the case of the State ferries, to save significant costs on fuel, LNG is in serious consideration as an alternative fuel.

The Washington Legislature's Joint Committee on Transportation is sponsoring a consultant study on the costs and benefits of a switch to LNG. In early feedback WSDOT estimates that the ferry system could save nearly $300 million in fuel costs, with a net present value (at 5 percent) of $75.9 million, measured against estimated upfront costs of $65 million to retrofit six Issaquah class vessels. Though Norway has extensive experience with LNG to fuel ships, this would be the first use of LNG on vessels in the United States *(Moseley, 2011)*.

Pipeline Distribution of Biomethane

One of the challenges of biomethane use for transportation is getting the gas to end users. Direct use at or near the source is the most economical and may represent the most value if the producer can make use of all the biogas. When that is not possible, the alternative is to clean the gas and deliver it to the network of natural gas distribution pipelines across Washington and around the country.

The natural gas pipeline system is comprised of large interstate transmission lines and smaller, more numerous intrastate distribution lines. At costs that can exceed a million dollars per mile to bury new gas pipeline, this option works primarily for producers who are very close to a pipeline that can accept the biomethane into the larger transmission lines.

Pipeline Gas Standards

While no single standard for natural gas or biomethane quality exists, we can use guidance from Europe, which has more facilities producing biomethane

SPOTLIGHT

Dairy Biomethane Direct Use Projects

Hilarides Dairy

Rob Hilarides produces milk on a large dairy near Lindsay, in California's Central Valley. In 2005, Hilarides installed his first energy project – a covered digester on the manure lagoon serving his 6,000-head heifer ranch. That digester produced enough gas to feed four 125 kW generators to make power for the local utility. Hilarides saw the success and value of his investments, which lead him in 2008 to add digestion capacity at his main dairy, which had 9,000 head and sat next to the heifer ranch. He added two more generators, reaching the maximum permitted under California regulations. This left a surplus of biogas, leading Hilarides to explore its use as a transportation fuel.

Hilarides owns and operates his own fleet of tanker trucks to deliver fluid milk to the nearby processing plant in Hilmar. To build his biomethane project, Hilarides partnered with interested public and private organizations, including dairy, environmental, and technical interests. Together they won a $600,000 grant to demonstrate the use of biomethane in his farm's trucking fleet. The project was operating in time for the 2009 World Dairy Expo kick-off in Tulare.

The project cost about $1.6 million to install. It combines a SulfaTreat (iron sponge) process to remove hydrogen sulfide, followed by pressure-swing adsorbtion technology to scrub the CO_2. It has a fast-fill pump on site to fill the four converted milk trucks and a small fleet of pickup trucks. At full capacity, the facility is designed to offset 650 to 800 gallons per day of diesel and gasoline *(McDonald, 2011)*.

SPOTLIGHT

Dairy Biomethane Direct Use Projects
Continued

Fair Oaks Dairy
In mid-2011, a second major dairy signed contracts to embark on their own biomethane to transportation project. With multiple farms and more than 10,000 cows, the Fair Oaks Farms dairy group in Fair Oaks, Indiana, is a major producer of milk, which they market to processing facilities in three Midwestern states. The dairies are located near the Fair Oaks interchange off Interstate 65, about 70 miles south of Chicago.

The dairy group partnered with Clean Energy, a leading CNG supplier. The first step involved establishing a connection to the natural gas pipeline and creating private and public CNG fueling facilities. The group then partnered with Paccar Leasing to lease the 42 Kenworth natural gas trucks needed to move milk. The fleet is projected to use upwards of 1.5 million diesel gallon equivalents (DGE) of natural gas per year.

Soon they will build the facilities to clean the biogas from one of the dairy's multiple anaerobic digesters to use in their fueling facilities. The dairy is motivated by the desire to save money, make money, and produce milk with the lowest possible carbon footprint, which has become a demand of milk product buyers like Walmart.

for pipeline injection and vehicle use. In the United States, Pacific Gas & Electric (PG&E) and Southern California Gas (SoCalGas, a Sempra company), both major gas utilities based in California, have published standards in response to interest and development of biomethane projects in their service territories. Key default requirements are summarized in Table 8.

Renewable Attributes
Simply selling upgraded biomethane as natural gas would not be economical given the low value for natural gas in today's market. Its real value is as renewable gas. Once the biomethane is in the transmission lines, a producer should be able to sell it in much the same way that a renewable electricity provider sells renewable power – the gas commodity should be valued separately from the renewable attributes of the biomethane in separate transactions. The different values of the biomethane might be sold to the utility that accepts it into the pipeline or to any end user in exchange for a transit or wheeling charge from the gas utility. With strict, accurate metering and recordkeeping, it may be possible to sell the renewable attributes separately. This type of market transaction may allow entities in other locations to take credit for the renewable gas in order to meet state or federal mandates for renewable energy.

Marketing renewable attributes from biomethane is not as well developed as the market that operates for renewable energy credits (RECs) in the power sector. The major gas utilities in California – PG&E and SoCal Gas – have extensive experience making these transactions successful.

In states where the biomethane is used to produce electricity, the appropriate

Table 8. Biomethane Gas Quality Specifications from California Utilities

Gas Quality	PG&E	SoCalGas
CO_2	≤ 1 percent	≤ 3 percent
Oxygen	≤ 0.1 percent	≤ 0.2 percent
Hydrogen sulfide	≤ 0.25 grains/100 scf	≤ 0.25 grains/100 scf
Mercaptan sulfur	≤ 0.5 grains/100 scf	≤ 0.3 grains/100 scf
Total sulfur	≤ 1 grain/100 scf	≤ 0.75 grains/100 scf
Water/moisture	≤ 7 lbs/million scf	≤ 7 lbs/million scf
Total inerts	No requirement	≤ 4 percent
Heating value	Specific to receipt point	970-1150 BTU/scf
Landfill gas	Not allowed	No requirement
Temperature	60 – 100°F	50 – 105°F
Gas interchangeability	Per AGA Bulletin 36[a]	Per AGA Bulletin 36[a]
Wobbe number	Specific to receipt point	Specific to receipt point
Lifting Index	Specific to receipt point	Specific to receipt point
Flashback index	Specific to receipt point	Specific to receipt point

[a] American Gas Association, Research Bulletin 36, *Interchangeability of Other Fuel Gases with Natural Gases.*
Source: *Rutledge, 2005*

mechanism may be the creation of RECs or other certificates required to meet Renewable Portfolio Standards (RPS). This is a possibility in Washington and California, but there remains a question in California if renewable gas from out of state will get the same credit value as in-state renewable gas.

SPOTLIGHT

Washington Biomethane Pipeline Projects

Cedar Hills Landfill

In 2009, Bio Energy Washington, a subsidiary of Virginia-based Ingenco, began operating one of the largest landfill gas processing facilities in the U.S. at the Cedar Hills Landfill in King County. Employing 12 staff, the project cleans landfill gas using a membrane filter technology supplied by Air Liquide. Within a year, the facility reached about 80 percent of its rated capacity.

From the landfill, the gas is injected into a natural gas distribution pipeline and sold to Puget Sound Energy. Because of the gas cleaning system used at the landfill, the biomethane is actually cleaner than natural gas coming from conventional wells.

Once in the pipeline, PSE uses this gas to produce electricity at one of its nearby natural gas generating stations. According to PSE, the power produced is equivalent to a 35 MW natural gas power plant – enough to power 24,000 homes. They also estimate that the renewable attributes of the biomethane will reduce the utility's carbon footprint for that power by two-thirds. Because renewable energy credits from the project may be generated and sold, PSE and the county have agreed to share in any proceeds.

South Treatment Plant

King County's South Treatment Plant in Renton is one of three in the county and one of the largest in the state. This plant has been purifying its digester gas for decades using a highly effective water scrubbing technique. Much of the digester gas is used internally as fuel to meet thermal or power needs of the facility.

The plant participated in a commercial-scale demonstration of a molten carbonate fuel cell, producing 1.5 MW of power. The demonstration period ended in 2006. Now mothballed, the fuel cell system could be brought back on line with new fuel cell stacks (the technology has significantly progressed), a new interconnection agreement with PSE and probably a new revenue stream of hydrogen gas (an add-on system). The Northwest Clean Energy Center produced a case study on the project.

For several years, the plant has delivered excess biomethane via pipeline under an agreement with PSE. But because of the age of the project, PSE cannot use this source for compliance with the Renewable Portfolio Standard established under Washington Initiative 937.

The PSE agreement is currently up for renewal, so King County officials are reviewing additional opportunities for this biomethane. They may use more of it internally to reduce operation costs or sell it through the pipeline to California fuel providers impacted by the state's low-carbon fuel standard (LCFS). A key factor is if time limits affect renewable status of the gas under the California LCFS. Officials are also considering local transportation uses, but they do not have sufficient vehicles on site to use all the biomethane, their long-haul biosolids trucks could not make their round trips using low-energy-density CNG, and capital expenditures for CNG or LNG infrastructure and vehicle conversions for their use or public use would be challenging. A decision is expected in late 2011 *(Hensman, 2011).*

Chapter 3: Converting Biomethane for Transportation Fuel

After biogas is produced and collected from a landfill or digester, three major steps are required before it can be used as a fuel for transportation:

- First, the unwanted gases and moisture must be removed. This process converts the biogas into biomethane, or renewable natural gas.
- Second, the cleaned gas must be pressurized into compressed or liquefied gas (CNG or LNG) to be used by vehicles.
- Finally, the gas has to get from the source to an end user, so the third step involves distributing the gas or arranging for its delivery or pick up for use in vehicles.

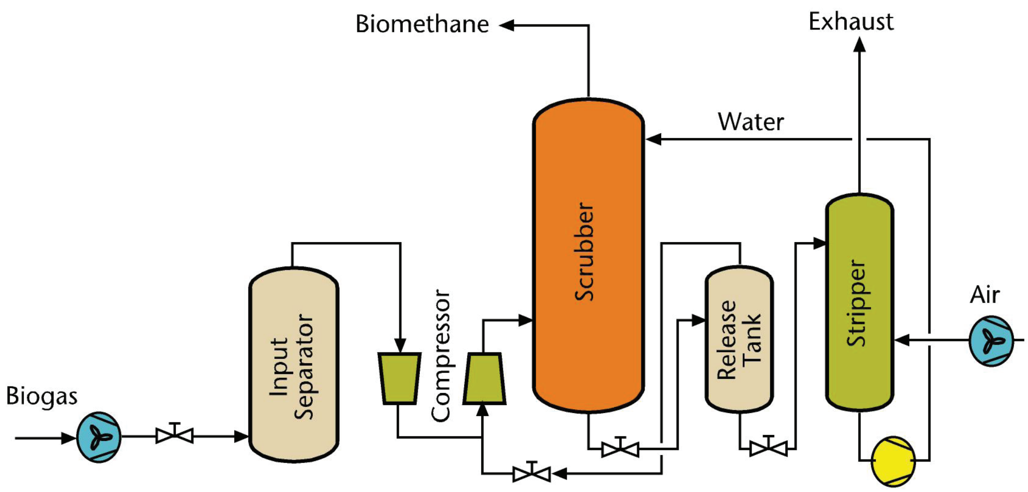
Cleaning/Upgrading Biogas

Facility operators have many options for cleaning biogas into biomethane. The list goes by many names and, of course, by many brand names used by equipment suppliers to set apart their specific combination of technology. The basic gas cleaning steps include:

- Water vapor removal
- Hydrogen sulfide (H_2S) removal
- Carbon dioxide (CO_2) removal
- Siloxane and trace gas removal

For a research project about the pros and cons of different biogas treatment technologies, Washington State University (WSU) scientists evaluated various methods available to produce biomethane at facilities in the state. They also developed and tested adsorption tower technology for possible use in farm digester projects. Among the sources that the WSU researchers reviewed was a Dutch study of biogas cleanup technologies used in Europe and the costs of installing and operating biogas cleanup systems. In addition, a major study entitled, "State of Science on Biogas," by the Water Environment Research Foundation (WERF), looked at the treatment and utilization of biogas and provided an in-depth analysis of the available technologies for cleaning biogas for high-energy-value uses. Details of these three technology studies are summarized in Figures 6 through 12.

Figure 6. Biomethane Upgrading Technology: Water Scrubbing



Water scrubbing is a well-proven technology. Because CO_2 and H_2S are more soluble in water than CH_4, they are relatively easy to separate in this physical process. Typically, pressurized gas is fed into the bottom of the scrubber while water is fed on top. The water exits with the CO_2 and H_2S, while moisture-laden methane exits the top. The CO_2 and H_2S are stripped as exhaust gases from the water, which is often used again. Fresh water may be used if readily available.

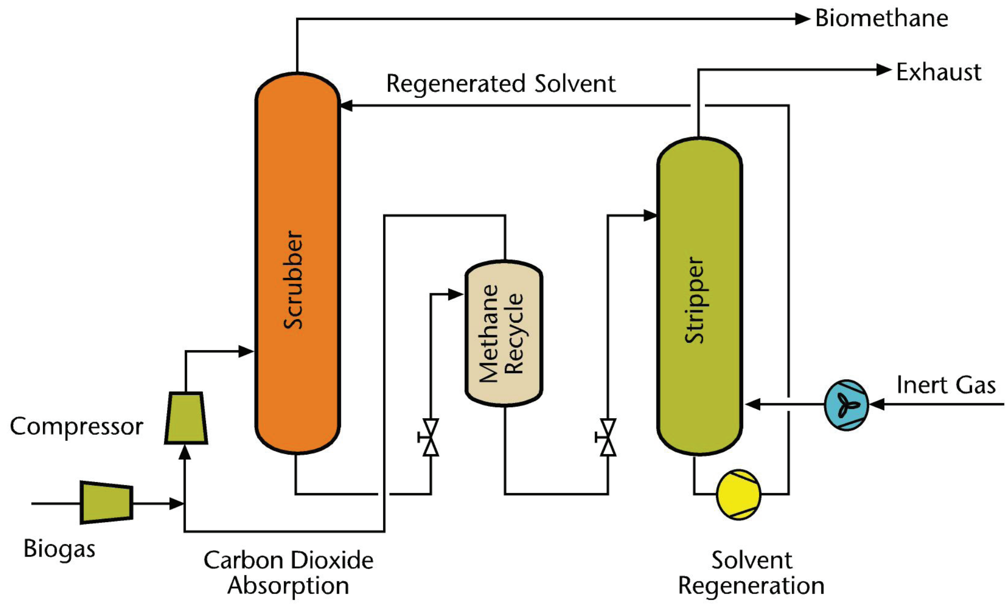
Advantages:

- Mature technology
- Reliable and simple to maintain
- No special chemicals required
- Achieves removal of both CO_2 and H_2S
- Good methane content at outlet (>97 percent)
- Low cost to operate and maintain

Disadvantages:

- Requires a lot of water even with regeneration
- High-quality water required
- Corrosion problems due to H_2S
- Limitation of H_2S removal because the CO_2 decreases pH of the solution

Figure 7. Biomethane Upgrading Technology: Physical Scrubbing



Physical scrubbing with polyethylene glycol is similar to water scrubbing. CO_2 and H_2S are more soluble than methane in this solvent. Because they are more soluble in this solution than water, this method has the advantage of less pumping and reduced demand for solvent. Selexol is one of the trade names for this method, which always involves regeneration and recirculation of the solvent.

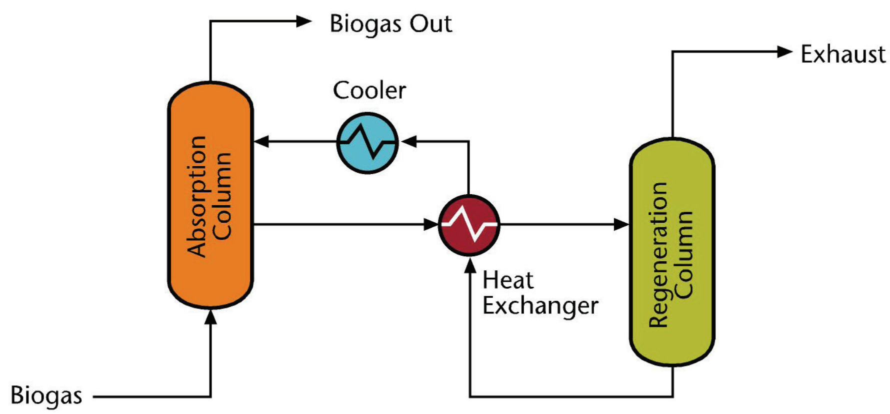
Advantages:

- Biomethane does not require further drying
- Higher absorption rate than water (smaller columns)

Disadvantages:

- Solvent regeneration is complex if H_2S is not removed first
- Solvent is expensive and difficult to handle

Figure 8. Biomethane Upgrading Technology: Chemical Scrubbing/Chemical Absorption



Chemical absorption also uses an absorption column through which biogas is pumped. In this method, reversible chemical bonds are formed between the solute and the solvent. The exhaust gases are released when the solvent is regenerated. When amines are used as the solvent, the regeneration is done with heat.

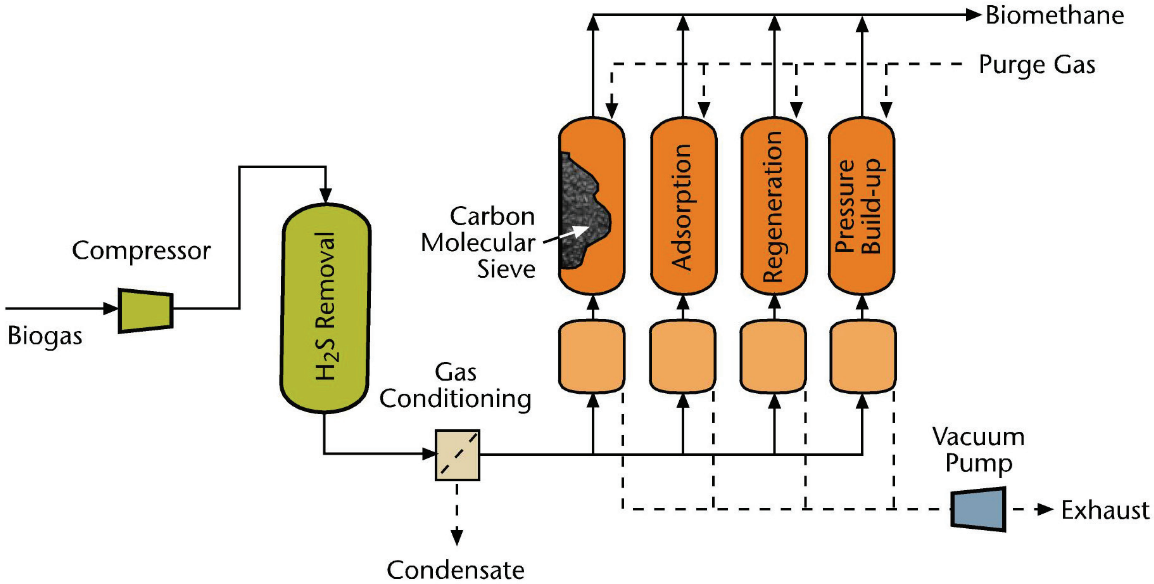
Advantages:

- Operates at atmospheric pressure
- High efficiency and reaction rate for higher absorption rate than water (smaller columns)
- Complete H_2S removal

Disadvantages:

- Solvent is difficult to handle
- Amine breakdown requires significant heat to regenerate
- Corrosion problems
- Additional chemical input
- Wasted chemicals may require treatment
- Historically used only in larger facilities

Figure 9. Biomethane Upgrading Technology: Pressure Swing Adsorption



This method uses variations in pressures to separate gases based on their molecular characteristics and affinity for an absorbent material. Under pressure, gases tend to be attracted to solid surfaces, or adsorbed. Higher pressures result in more adsorption. Special adsorptive materials (e.g., zeolites and active carbon) are used as a molecular sieve, preferentially adsorbing the target gas species at high pressure. When the process swings to low pressure, the gases are desorbed from the adsorbent material.

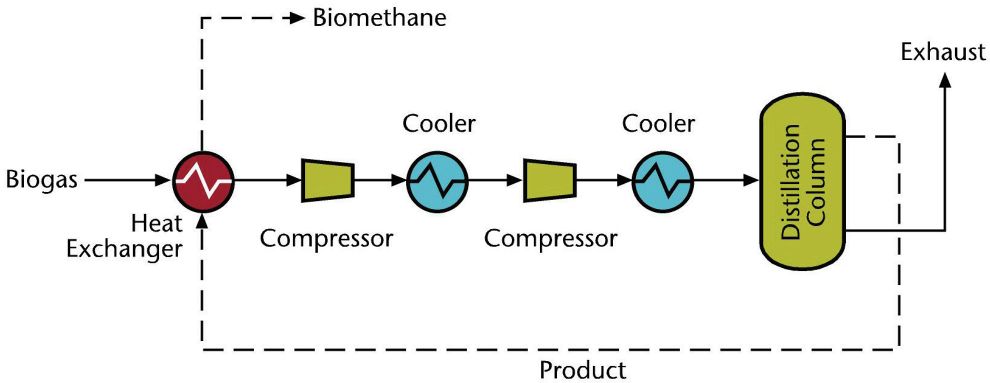
Advantages:

- Suitable for smaller flows
- No heat or chemicals required
- Low power demand
- Low cost to operate and maintain
- Low emission
- Allows removal of nitrogen and oxygen

Disadvantages:

- High capital cost (affected by number of columns of the PSA unit
- Lower methane content at output (<97 percent)
- Incomplete scrubbing (an additional H_2S removal step needed first and other treatment required afterwards)

Figure 10. Biomethane Upgrading Technology: Cryogenic Separation



Cryogenic separation is based on the principle that different gases liquefy at different temperature-pressure domains. This method demands significant energy inputs to operate at very low temperatures and at high pressures.

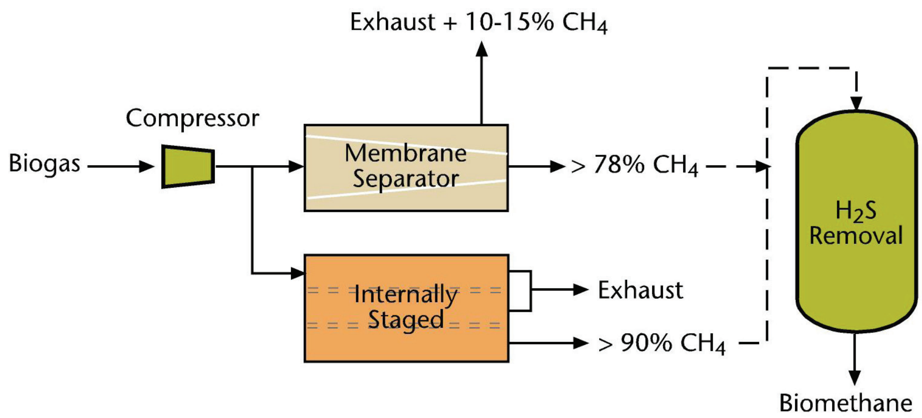
Advantages:

- Achieves large quantities of high purity biomethane (>99 percent)
- Produces CO_2 in marketable form
- Better technology for producing LNG

Disadvantages:

- High capital costs
- Uses lots of process equipment, mainly compressors, turbines and heat exchangers
- Requires low temps and high pressures
- Higher operating and maintenance costs

Figure 11. Biomethane Upgrading Technology: Membrane Systems



Membrane systems work on the principle that some gases can penetrate a thin membrane while others cannot. The permeability is a direct function of the chemical solubility of the target component. Hollow fiber modules are used to give a large membrane surface per volume, making the unit very compact. Operating pressures are typically in the range of 25 to 40 bar.

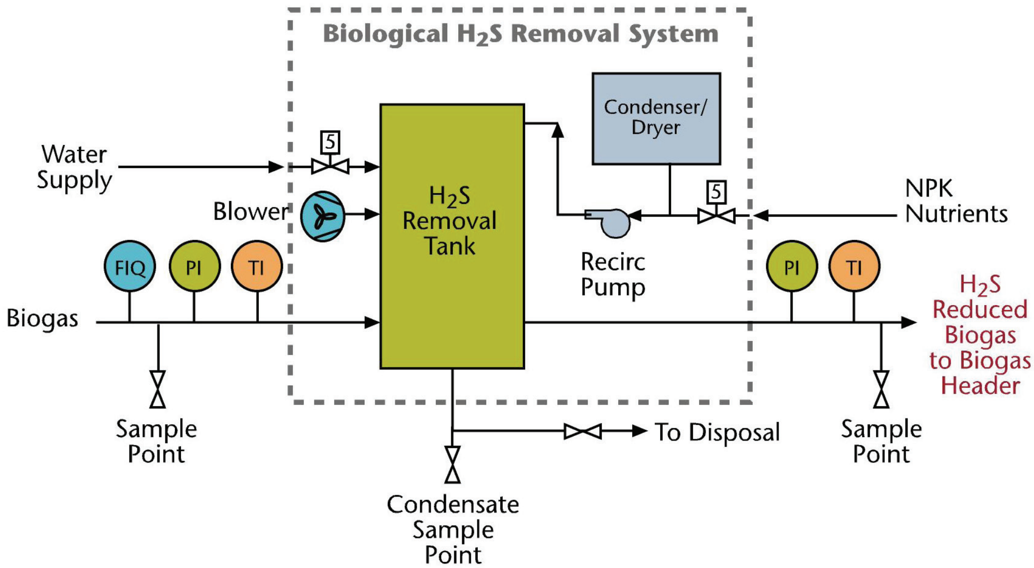
Advantages:

- Compact, easy to use
- Fast start up
- Light in weight
- Low energy required
- Low maintenance

Disadvantages:

- Often yields lower methane concentration though high purity is possible (between 95-99 percent)
- Renewal of high-cost membrane required
- Must remove H_2S prior to treatment

Figure 12. Biomethane Upgrading Technology: Biological Filters



Bio-filters that use a variety of media to support populations of select micro-organisms are increasingly used to clean many types of gases. They are widely used to remove H_2S. Further development to use them for removing other components of biogas show promise.

Advantages:

- Low energy requirement, mild conditions and byproducts (e.g., elemental sulfur)

Disadvantages:

- Additional nutrients are required for bacterial growth
- Small amount of O_2 and N_2 left in treated biogas
- The H_2S removal efficiency depends on the activity of bacteria

Sources: WSU (Zhao, et al., 2010); Dutch study (de Hullu, et al., 2008); WERF (Arespacochaga, 2010)

A study of biogas upgrading technologies worldwide provides a comparison of effectiveness for selected parameters, as shown in Table 9.

Table 9. Effectiveness of Different Gas Cleanup Technologies

Parameter	Pressure Swing Adsorption	Water Scrubbing	Organic Physical Scrubbing	Chemical Scrubbing
Pre-cleaning needed[a]	Yes	No	No	Yes
Working pressure (bar)	4-7	4-7	4-7	No pressure
Methane loss[b]	<3% / 6-10% [f]	<1% / <2% [g]	2-4%	<0.1%
Methane content in upgraded gas[c]	>96%	>97%	>96%	>99%
Electricity consumption[d] (kWh/Nm^3)	0.25	<0.25	0.24-0.33	<0.15
Heat requirement (^{O}C)	No	No	55-80	160
Controllability compared to nominal load	+/- 10-15%	50-100%	10-100%	50-100%
References[e]	>20	>20	2	3

[a] Refers to raw biogas with less than 500 mg/m^3 of H_2S. For higher concentrations, pre-cleaning is recommended.
[b] The methane loss is dependent on operating conditions. The figures given here refer to figures guaranteed by the manufacturer or provided by operators.
[c] The quality of the biomethane is a function of operational parameters. Figures given refer to those guaranteed by the manufacturer or provided by operators, based on air-free biogas.
[d] Given in kWh/Nm^3 of raw biogas, compressed to 7 bar.
[e] Number of references reviewed. Some are pilot plants.
[f] <3% CarboTech / 6-10% questAir
[g] <1% malmberg / <2% Flotech
Source: Urban, et al., 2008, as quoted in Petersson, et al., 2009

Relative Costs

The Dutch study described above investigated the capital and operating costs of biogas cleanup technologies. Though based on European project technology and expressed initially in euros, the cost comparisons they developed provide a helpful look at the relative costs of these technologies, as shown in Table 10.

Table 10. Economics of Different Cleanup Technologies

Biomethane Technology	Economics	
	Euros/ Nm^3 biogas	US$/1000 scf biogas
Membrane	0.12	4.47
Water scrubbing	0.13	4.74
Chemical absorption	0.17	6.32
Pressure swing adsorption	0.25	9.21
Bio-filter	NA	NA
Cryogenic separation	0.44	16.32

Source: de Hullu, et al., 2008

Conclusions

The findings of the WSU evaluation of biogas-cleaning technologies suggests the following: For small-scale anaerobic digesters, if the upgraded biogas is used for electricity generation, the membrane method is preferred because of its lower cost. If the biogas needs to be upgraded to natural gas quality, chemical absorption is selected. For large-scale biogas purification, the combination of water scrubbing and biological method is preferred for the sulfur recovery and low environmental impacts.

A review of the use of gas cleaning technologies in Europe, where the practice is more mature commercially, suggests that market competition among technologies and companies is more open and fluid. A survey of 120 gas upgrading facilities in 13 countries across Europe, Asia, and the United States compared technologies currently in use by plant size, different sources of biogas, and intended end use. No particular pattern in selection could be found and no one type of technology is dominant among these projects, not according to plant size, nor the source of the biogas, nor the intended end use. This survey suggests this is a wide open market. Many of the European equipment suppliers have started marketing their systems to operators in the United States *(Petersson, et al., 2009)*.

Compressing Biomethane

The second major component of preparing biomethane for use as transportation fuel involves compressing the processed biomethane into the equivalent of CNG or LNG. This makes the biomethane usable by existing or converted natural gas vehicles. The decision to develop CNG or LNG capacity is driven by market opportunities and economies of scale.

Compressed Natural Gas

CNG is pressurized in storage tanks to a standard of 3,000 to 3,600 pounds per square inch (psi). The cylinders were historically made of steel, but are now made of many different materials. Recently, cylinders have been made of metal liners wrapped with composite fiber material to reduce weight while increasing strength.

Compressing gas to CNG standards is less costly than compressing LNG, which is higher density. However, because of its lower energy density relative to LNG, diesel, or gasoline, cars and trucks that use CNG have a reduced range. The availability of refueling stations is limited, so fleet owners are less assured of their ability to refuel for a return trip. This fact favors its use in short-haul vehicles or fleets that return to a home base each day for refueling.

The CNG cylinders are located in different places in different vehicles; they may be in the trunks of cars, on the frame of trucks, or on the roofs of buses. Refueling is done in one of two ways: on a time-fill or fast-fill basis. Time-fill fueling occurs through gradual pressurization. It is lower in cost, but can take several hours to fill a vehicle. This is not a problem for fleets with vehicles that park overnight. The fast-fill option is more expensive and uses more energy to run compressor pumps. It also requires a high-pressure storage system of sufficient size to assure that demands on the system can be supplied at the fast-fill speed.

Liquified Natural Gas

Natural gas is liquefied to achieve very high energy densities; that is, more energy in smaller volumes. This makes it more economical to transport. To make LNG, natural gas is cooled cryogenically to a liquid (roughly -260°F). It is stored in this cold liquid form in large cylinders. To use in vehicles, the liquid gas is warmed back into a gaseous state.

LNG is preferred by many heavy-duty vehicle fleets because of its higher

SPOTLIGHT

Alternative Vehicle Fueling Stations

The locations of public CNG and LNG fueling stations are maintained in a database available to the public through the Alternative Fuels Data Center (AFDC) of the U.S. Department of Energy. Look for the "Alternative Fuel Station Locator" at *www.afdc.energy.gov/afdc/*.

energy density, which allows the vehicles to reduce the space required for fuel storage so they can carry bigger payloads and travel farther between fill-ups. The United States has a limited number of facilities that produce LNG for vehicles. LNG is commonly shipped from these facilities and stored at fleet-based storage facilities around the country, so transportation costs between the source and the end user is a major economic consideration *(Yborra, 2011)*.

Until recently, LNG was an import market, with a few major import terminals in the southern United States. However, as U.S. natural gas supplies increase due to exploitation of recently opened shale gas deposits, talks about the development of LNG for export, especially to Asia, have begun. Natural gas that may sell for $4 per million British thermal unit (MBTU) in the United States or Canada can be piped to the West Coast, liquefied, and shipped via tanker to Japan at a total cost of $9 per MBTU. The spot price in Asia for natural gas can be $11 or $12 per MBTU. This favorable situation has prompted discussion on the West Coast, especially in Oregon, about developing an LNG export terminal *(Sickinger, 2011)*.

The production of bio-LNG or renewable LNG (RLNG) requires very large volumes of biomethane. For example, because of the requirement to keep LNG very cold, it is not convenient or economical to fill a 10,000-gallon delivery truck over a period of days. Realistically, a facility needs to produce at least a truckload each day. For this reason, LNG has been economical on very large projects at landfills, but is a less realistic option for WWTPs or dairies *(Wegrzyn, 2011)*.

Distributing Compressed Biomethane

When considering a project to produce biomethane for transportation, developers need to consider the costs to deliver the biomethane from its source to the end user. This large hidden cost can pose problems if not considered carefully.

The distribution of compressed biomethane may be simple if the end user is on or next to the source facility or visits there regularly. It is likely not a coincidence that the two successful bio-CNG projects undertaken by dairy producers have their own fleets of trucks that were converted to use the fuel directly from fuel pumps at the dairies. Some projects to convert landfill gas to vehicle fuel have succeeded because the refuse trucks that use the biomethane regularly visit the landfill.
On the other hand, a biomethane source on one side of a state would have to use the natural gas pipeline system to get biomethane to an end user on the other side of the state or to users in another state. This connection works if the pipeline is close by. Otherwise, the source needs to lay additional pipeline to make the connection to the distribution line.

The New York State Energy Research and Development Authority completed a study in 2006 that included a detailed analysis of the added cost of burying different sizes of gas pipe to connect a biomethane source to a natural gas distribution line. They looked at different sizes of pipe to allow for smaller or larger gas flows over time. They also looked at costs by length, up to one mile. The cost of pipe and installation, plus an additional 50 percent for fittings, is provided in Table 11.

SPOTLIGHT

Altamont Landfill LNG Project

The Altamont Landfill LNG Project in Livermore, CA, has received a lot of attention as one of the first biomethane projects to focus on transportation. Waste Management completed the project in 2009 with support from the California Energy Commission, Cornerstone Environmental Group, Guild Associates, and Linde. Linde built the gas processing plant based on patented designs from the Gas Technology Institute (GTI).

In 2004, the landfill had more than 36 million tons of waste in place. The biomethane project processes about 3 million cubic feet of landfill gas daily, yielding 13,000 gallons of LNG that is used by 300 Waste Management garbage trucks. The company estimates the project displaces more than 2.5 million gallons of diesel fuel annually and reduces their greenhouse gas emissions by 85 percent.

SPOTLIGHT

Vehicle Research Institute's Biomethane Project

The Vehicle Research Institute (VRI) at Western Washington University (WWU) has for many years promoted vehicle efficiency and the use of alternative vehicle fuels. Located in one of the major dairy-producing regions of the state and not far from the site of the first dairy digester in Washington, they turned their attention to the potential to produce biomethane for transportation.

In cooperation with the VanderHaak Dairy and Bellair Airporter Shuttle, a local provider of shuttle and charter bus services, VRI developed a project to demonstrate the value of CNG for fleet companies and the potential for cleaning biogas from the dairy digester using a modified chemical (amine) scrubbing technology.

With grant support from the American Recovery and Reinvestment Act provided through the Western Washington Clean Cities Coalition, VRI has installed a facility that compresses natural gas into CNG and a card-operated fast-fill dispensing unit at the dairy, which is just on the American side of the State Route 539 border crossing with Canada. VRI continues to work to create a gas scrubbing system, which they expect to begin operating in 2012 *(Leonhardt, 2010, 2011).*

Another alternative being tried in Whatcom County requires the end user, a company that runs shuttle buses to SeaTac Airport, to drive to the VanderHaak Dairy where WWU has installed a fast-fill CNG station. It takes the shuttle driver an extra 15 to 20 minutes each way to go to the farm for fuel. This is an acceptable expense only to the extent that the company saves enough on fuel and other costs to make up the difference.

Another option requires the biomethane source to inject CNG into cylinders that are delivered by truck to the end user. This system could use one large tank or several smaller cylinders. As one "tube truck" is delivered, another is taken back to the source to be refilled. This option requires that multiple tube trucks be purchased or leased so drivers can move trucks back and forth from the bio-CNG source to end users.

CNG tube trailer delivers gas directly to the end user.
Photo: Alibaba.com

Table 11. Cost of Pipeline Connects to Natural Gas Network

Diameter	Length	Cost with Fittings
1/4 inch	0.25 miles	$28,611
	0.5 miles	$57,222
	1.0 miles	$114,444
1/2 inch	0.25 miles	$36,630
	0.5 miles	$73,260
	1.0 miles	$146,520
1 inch	0.25 miles	$51,480
	0.5 miles	$102,960
	1.0 miles	$205,920
2 inch	0.25 miles	$94,050
	0.5 miles	$188,100
	1.0 miles	$376,200

(Roloson, et al., 2006)

SPOTLIGHT

Biomethane-Hydrogen Transportation Link, Joint Base Lewis-McChord

The U.S. Armed Forces Command at Joint Base Lewis-McChord (JBLM, formerly Fort Lewis) near Tacoma, WA, is hosting a major project innovation through a contract with the Center for Transportation and the Environment (CTE). Project partners include Air Products, Gas Technology Institute (GTI), Plug Power, and Proterra.

The project will use biomethane from the on-base wastewater treatment plant biogas to produce hydrogen as fuel for base vehicles. According to CTE, the project "includes all of the key elements of a clean hydrogen energy cycle:

- A renewable energy supply in the form of recovered wastewater treatment plant digester gas
- Local hydrogen generation via digester gas cleanup and reformation
- Bulk hydrogen storage, transport, and dispensing
- Hydrogen load in the form of 19 fuel cell-powered electric forklifts and one fuel cell-powered shuttle bus, with an option for a stationary fuel cell system."

GTI will supply the hydrogen generation system, which has three parts: digester gas clean-up, biomethane reformation, and hydrogen purification. Once complete, the system will generate over 50 kg of hydrogen daily – enough to fuel a shuttle bus and 19 warehouse lift trucks fitted with fuel cells. Proterra will design and build the 35-foot composite-body, plug-in battery-dominant fuel-cell hybrid electric bus. The bus will transport staff around Joint Base Lewis-McChord. The gas will be distributed from the source to the dispensing units using two tube trucks, which will take turns delivering compressed hydrogen to the dispensing unit and refilling at the generation site. On-site power generation is also an option that can be done by diverting a separate stream of hydrogen to a stationary fuel cell system *(Hanlin, 2009).*

Biomethane Technology Vendors

Some of the many companies that provide technology for cleaning biogas are listed in Table 12. Some of these companies also provide project development and financing capabilities.

Table 12. Technology Providers

Technology Provider	Summary	Notable Projects
Acrion Technologies Cleveland, OH *www.Acrion.com/*	Provider of a water-scrubbing technology named "CO_2 Wash Process."	• Burlington County Resource Recovery Complex and New Jersey EcoComplex, Columbus, NJ • Novo Gramacho Landfill, Rio de Janeiro, Brazil
Air Liquide – US Houston, TX *www.AirLiquide.com*	Supplies gas-handling equipment to customers in 80 countries. In this sector they supply the "MEDAL Biogas Membrane System" for biogas and landfill gas.	More than a dozen projects, including: • Cedar Hills landfill, King County, WA • Point Loma WWTP, San Diego, CA • Fresno WWTP, Fresno, CA
Applied Filter Technology Bothell, WA *www.AppliedFilter Technology.com/*	Custom-designed biogas-to-energy systems for many industries, including chilling, compressing, and removal of sulfur, CO_2 and siloxane. Uses a proprietary graphite molecular sieve to adsorb siloxane.	• South Carolina Landfill No. 1 & No. 2 • Paris Landfill, France • Dozens of additional projects for simple siloxane or H_2S removal
Cornerstone Environmental Group LLC Middletown, NY *www.Cornerstoneeg. com/*	Complete biogas to CNG systems, from 50 to 200+ scfm production.	• Rodefeld Landfill, Dane County, WI
Greenlane Biogas NA Ltd Burnaby, BC *www.Greenlane Biogas.com/en/home*	Part of the Flotech Group, a supplier of natural gas and gas upgrading equipment. Greenlane offers six standard modular designs, featuring an advanced energy-efficient pressurized water-scrubbing system to remove CO_2 and H_2S. Capacity from 50 to more than 3,000 scfm biogas.	• Landfill Gas Project, Detroit, MI, with Canton Renewables/ Clean Energy • Fair Oaks Dairy, Fair Oaks, IN, with UTS Residual Processing and Clean Energy

Continued on nexr page.

Table 12. Technology Providers, *continued*

Technology Provider	Summary	Notable Projects
Prometheus Energy Redmond, WA *www.Prometheus Energy.com*	Biogas to LNG technology, including purification and liquefaction of various methane-bearing gas streams on a small scale to a unique method for the bulk separation of CO_2 from waste gas streams. Process utilizes filters, phase separators, selective reactions, physiadsorption, freezing and cryogenic refrigeration techniques to purify and liquefy the biogas.	• Municipal Landfill, Victoria, BC • Stranded gas well, Sacramento, CA • Frank R. Bowerman Landfill, Orange County, CA with Applied LNG Technologies
Quasar Energy Group Cleveland, OH *www.QuasarEnergy Group.com*	Quasar Energy Group builds, owns, and operates digester projects using municipal organics, food processing byproducts and agricultural wastes. Its subsidiary company, Biogas Technology Unlimited, provides gas cleanup systems for their projects	• Ohio Ag R&D Center, Wooster, OH • Zanesville Organic Waste Project, Zanesville, OH • PPG Industries Reclamation Project, Barberton, OH
Ros Roca Envirotec Lleida, Spain *www.RosRoca Envirotec.com*	A European provider of advanced waste collection, biomass energy, and composting projects. They provide gas cleanup systems using pressure water-scrubbing technology.	• Biffa Waste Services AD plant, Cannock, United Kingdom
Xebec Adsorption Inc. (merged with QuestAir) Blainville, Quebec *www.xebecinc.com/*	Xebec's expertise in natural gas drying and CNG fueling combined with QuestAir's excellent pressure swing adsorption technology to treat biogas for distribution in pipelines or as transportation fuel. Capacity ranges from 150 to 5,000 Nm3/h.	• Hilarides Dairy Farm, Lindsay, CA • Also SEMPRA, Montauk Energy, Halla Engineering, Terasen Gas

Chapter 4: Economics of Biomethane for Transportation

The research completed for this Washington state biomethane assessment found more than a dozen active renewable gas projects in the United States, only a few of which use biomethane for transportation. There are currently no operational transportation projects in Washington. As a result, very little actual cost-benefit data can be compiled or analyzed. More complicated still, the projects that do exist range over a wide time span and involve different sources of biogas, different types of clean-up technology, and a range of end users and geography.

Nonetheless, several studies completed in recent years as well as data from equipment manufacturers provide some helpful perspectives on the relative costs of biomethane projects and of various clean-up technologies.

California Dairy Biomethane Study

One of the first detailed examinations of the economics of producing biomethane was completed in 2005 by a group of California researchers. Working on behalf of the Western United Dairymen, the research team looked in detail at the costs, benefits, challenges and opportunities for developing biomethane projects based on dairy digesters. California has the largest number of dairy cows of any state, often concentrated on large dairies. In addition, because California has an increasing number and complexity of regulations affecting electricity generation by internal combustion generators, biomethane looked promising. Though their focus was on biomethane for pipeline injection, their research is applicable to transportation end uses as well.

Based on experience around the country and in California, the team estimated the costs of a dairy anaerobic digester facility while isolating the costs of electricity-generating plants at those facilities. Because no biomethane projects existed in the United States, they estimated the costs of biogas upgrading based on actual operating parameters and associated costs from four Swedish biogas-to-biomethane plants.

The analyses they conducted combined to produce estimated costs for three hypothetical dairy anaerobic digestion and biogas-to-biomethane facilities. The results are shown in Table 13.

This evaluation shows that the added cost of installing and operating an upgrading facility at a small dairy facility (45,000 cf per day) could be $8.12 per 1,000 cf of biomethane. For a larger dairy facility (240,000 cf per day), which might be comparable to a medium-sized wastewater treatment plant (WWTP) or landfill, the costs could range from $5.45 to $8.56 per 1,000 cf *(Krich, et al., 2005)*.

Table 13. Estimated Costs for Hypothetical Dairy Biogas-to-Biomethane Projects

Facility	No. of Cows or Cow Equiva-lents	Methane[a] cf/day	Dollars per 1,000 cf Biomethane				
			Estimated Cost for Anaerobic Digester $/1,000 cf		Estimated Cost for Biogas Upgrading $/1,000 cf		Estimated Total Cost
			Capital	O&M	Capital	O&M	$/1,000 cf
Small Dairy[b]	1,500	45,000	3.10	0.60	3.10	5.02	11.82
Large Dairy A[c]	8,000	240,000	2.48	0.50	1.74	3.71	8.44
Large Dairy B[d]	8,000	240,000	2.48	0.50	1.74	6.82	11.54

[a] Based on an approximate methane yield of 30 cf/cow/day.
[b] Small Dairy: Operating costs based on average of three Swedish plants; capital costs based on Kalmar plant.
[c] Large Dairy A: Operating costs and capital based on Boras plant in Sweden.
[d] Large Dairy B: Operating cost based on Linkoping plant in Sweden; capital costs based on Boras plant.
Source: Krich, et al., 2005

New York Biogas Processing Study

A team of researchers from New York State Electric & Gas Corporation and Cornell University completed a study of biogas from dairies in 2006. They focused on biogas characterization and biogas processing and upgrading. They also completed a detailed economic assessment of injecting dairy biomethane into the natural gas pipeline *(Roloson, 2006)*.

The team looked at overall capital costs for projects based on various cow herd sizes: 500, 1,000, 3,000, 5,000, and 10,000. For capital cost data, they used information provided by two companies with long histories of involvement in this space – Applied Filter Technologies (AFT) and Cogeneration Technologies. They also included operation and maintenance (O&M) costs using AFT data for cleanup systems used at landfills. Reflecting economies of scale in gas cleanup, AFT estimates that capital and O&M costs for 500- and 1,000-head projects are approximately the same.

Next the team looked at the potential impact of distribution costs in the form of added costs for installing pipeline to reach the natural gas distribution line from ¼-mile, ½-mile, and 1 mile. *(One part of the equation that appears to be lacking is the expense of the intertie connection to the distribution pipeline. This can be a large expense, which they rightly indicate is site specific.)* Once these capital and O&M costs were compiled, the team explored the sensitivity of the economics to interest rates, at levels of 3 percent, 5 percent, and 7 percent. These various costs over a 10-year project period were compared against possible gas sales revenue based on prices of $4/MBTU to $14/MBTU, in $2 increments. Results of their analysis follow.

500-cow dairy

- $12/MBTU is needed to "break even," assuming there is no added pipeline cost and the interest rate is 3 percent.
- $14/MBTU is the sales price required if ½ mile of pipe is added to the capital cost and assuming the interest rate remains low.

1,000-cow dairy

- At least $6/MBTU is necessary to be profitable under any circumstance.
- At $8/MBTU, a profit is possible as long as the pipe connection is ½ mile or less.
- At $10/MBTU, a profit is possible even with 1 mile of pipeline and higher interest rates.

3,000-cow dairy

- Even at $4/MBTU, the project can make a profit with no added pipeline and a low interest rate.
- $6/MBTU is needed if added pipeline is required, but it will still be profitable with even 1 mile of added pipe and higher interest rates.

5,000-cow dairy

- Even at $4/MBTU, the project can make a profit with no added pipeline and a low interest rate.
- At $6/MBTU, the project can make considerable profit over the 10-year period: over $1 million at low interest rates, even with ½ mile of added pipe.

10,000-cow dairy

- $3.50/MBTU is the "break even" sales price for a project of this size.
- At $4/MBTU (no pipe added and low rates), more than $1 million in profit is possible.

CalStart

A white paper published by CalStart in 2010 analyzed the cost of producing biogas from dairy waste and of upgrading that gas to pipeline quality biomethane. The paper concludes that "biomethane has the potential to be produced cost-competitively with conventional natural gas using feedstocks and processes available today" *(Chen, 2010)*.

The paper's authors used a broad variety of published data, articles, and interviews to calculate relative costs for producing biogas. They analyzed the capital, operating, and maintenance costs of producing biogas from 20 individual dairy projects around the country using four different digestion methods. Project sizes ranged from 11,333 to more than 250,000 cubic feet per day. The authors found that the cost per cubic foot of biogas ranged widely from $0.38 to $8.00. The average cost of production was $2.11 per cubic foot. The median value from their analysis was about $1.50 per cubic foot. Three quarters of the projects produced biogas for less than $2.16 per cubic foot. The four largest facilities had an average cost of production of $0.99 per cubic foot.

Similarly, the authors evaluated the relative costs of upgrading biogas to biomethane by looking at 33 farms, landfills and other facilities. They discovered that facilities may scrub gas for hydrogen sulfide (H_2S), carbon dioxide (CO_2), and water vapor. Not all facilities did all three upgrading steps. They also found that the potential for competitive upgrading costs is very sensitive to scale.

Using the data in the white paper, it is possible to go a step further to develop total cost scenarios in three general size categories. To make comparisons for all three sizes of facilities, we used the biomethane upgrading costs shown in Table 14. For the biogas production cost at small facilities, we used the average cost for all facilities; for medium-sized facilities we used the median cost; and for the large facility we used the average of the costs for the four largest facilities in the data set. Results are shown in Table 15. This analysis confirms the importance of scale in the relative cost of making biomethane.

Table 14. CalStart – Estimated Costs for Upgrading to Biomethane

Facility Size	Biomethane produced cf/d	Calculated cost of upgrading to biomethane $/1,000 cf
Small	< 100,000	7.12
Medium	100,000 to 1,000,000	3.92
Large	>1,000,000	0.0489

Table 15. CalStart – Estimated Total Costs for Upgraded Biomethane

Facility Size	Biogas Production Cost $/1,000 cf	Biomethane Upgrading Cost $/1,000 cf	Total Cost $/1,000 cf	Total Cost* $/MMBTU
Small	2.11	7.12	9.23	8.99
Medium	1.50	3.92	5.42	5.28
Large	0.97	0.0489	1.02	0.99
*Calculated as 1 cubic foot = 1,027 BTU				

Tillamook County Bioenergy Feasibility Study

In 2011, the Tillamook County, Oregon, Solid Waste Authority sponsored a study to assess the feasibility of converting additional municipal and agricultural waste and byproducts into biogas for power or fuel. The project was completed by TetraTech with several goals in mind: control local liabilities, develop clean energy resources, create new job potential, and reduce the County's carbon footprint.

The project team evaluated a wide range of feedstocks, including dairy manure and dairy mortalities; fats, oils, and grease (FOG) from local businesses; meat processing byproducts; and brewery wastewater. Anaerobic digestion, followed by composting of the digested solids, was determined to be the most viable technology at this time. Though the brewery wastewater was eventually left out of the mix, the project team developed three scenarios for development of conceptual designs and lifecycle financial analyses. These are outlined as follows:

1. Manure from 3,000 cows, plus cow mortalities, FOG, and meat byproducts, producing biogas to power a 0.9 MW CHP system for renewable electricity.
2. Manure from 6,000 cows, plus cow mortalities, FOG, and meat byproducts, producing biogas to power a 1.8 MW CHP system for renewable electricity.
3. Manure from 6,000 cows, plus cow mortalities, FOG, and meat byproducts, producing biomethane for a 700,000 DGE/year CNG for transportation system. The analysis for this scenario included vehicle conversion costs in the capital expense to build local vehicle capacity. It also assumed a 25 percent discount from diesel costs for the bio-CNG.

Table 16 shows the results of TetraTech's financial analysis for the three scenarios.

As reported to the Solid Waste Authority, the smaller scenario does not produce sufficient revenue to generate a profit without significant grants or subsidies to offset loan repayment costs. Scenario 2 is better able to take advantage of economies of scale and is essentially a cost-neutral project. The costs per wet ton processed go down from $87/ton in Scenario 1 to $77/ton in Scenario 2.

Scenario 3 is the most capital intensive of the three, with capital expenses of nearly $15 million. This reflects the high capital requirements for biogas clean up,

Table 16. Tillamook Bioenergy Feasibility Study – Financial Modeling Projections

Performance Metric	Scenario 1	Scenario 2	Scenario 3
	3,000-Head AD + CHP	6,000-Head AD + CHP	6,000-Head AD + CNG
Total Construction Cost	$7,405,276	$12,467,500	$14,069,400
Construction Cost / Wet Ton Processed	$87.32	$77.20	$88.77
Annual Total Revenues	$872,977	$1,700,449	$2,629,421
Annual O&M Cost	$408,226	$560,204	$692,640
Annual Capital Repayment	$652,457	$1,111,074	$1,300,525
Annual Net Profit (Loss)	($187,706)	$29,171	$636,255
20-Year Net Present Value (NPV)	($39,843,295)	($25,349,500)	$37,529,585
Annualized NPV	($3,197,129)	($2,034,109)	$3,011,471
20-Year Internal Return on Investment (IRR)	5 percent	9 percent	13 percent
Simple payback	Year 15	Year 12	Year 8

compression and fueling, and vehicle conversions. On the other hand, this scenario offers the highest project returns, based on the value of bio-CNG relative to diesel fuel.

Summary

Compared with diesel, compressed natural gas (CNG) from natural gas is significantly less expensive, with wholesale prices near $1.00 per diesel gallon equivalent (DGE) and recent retail prices reported at $1.75 per DGE. The economics of biomethane can be summarized as somewhere in the middle, between natural gas and diesel fuel. In other words, producers contend that bio-CNG can be produced for around $2.00/DGE. That would place it at about twice the cost of natural gas and half the cost of diesel fuel. This description is supported by conclusions made by other sources about the comparative values of biomethane and other fuels *(Baragetti, 2011)*:

- Diesel = $22.00 per MMBTU
- Natural gas = $6.70 per MMBTU
- Biomethane = $12.00 per MMBTU
- Electricity = $26.60 per MMBTU

The project team developed Figure 13 to illustrate the position of biomethane opportunities among various alternatives on an MBTU equivalent basis. The cost of producing biomethane falls with the benefits of economies of scale. Once they pass the reported thresholds for project size, the estimated costs drop below those reported for electricity production.

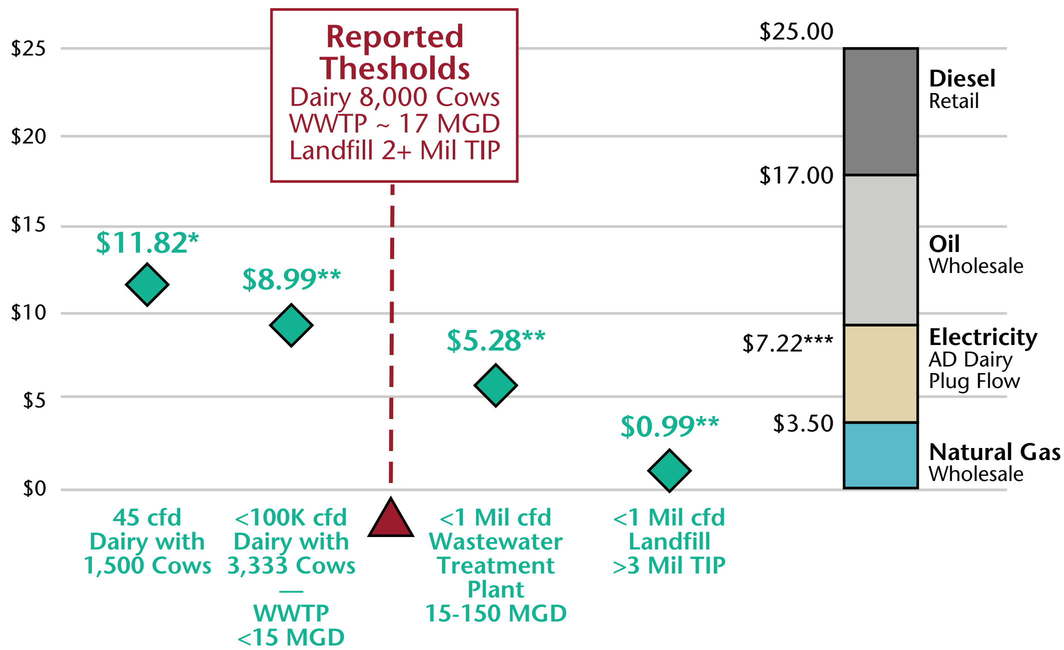
Only the largest landfill projects currently have the size and scale to compete directly with natural gas as CNG. They can produce bio-CNG for retail sale at roughly $2.00 per DGE *(Mazanec, 2011)*. More modest projects, at or near the reported thesholds, find the comparison to diesel more attractive. As described earlier, large dairy projects have also found that economic sweet spot by using biomethane directly to offset purchases of diesel.

Beyond the straight fuel-to-fuel comparison, it is important to remember that biomethane is a renewable gas and has extra value to the environment and society as a renewable fuel. Historically, these large environmental or societal values have not always translated well in monetary terms. This is the topic of the next chapter.

Finally, biomethane is not the only renewable transportation fuel or the only renewable substitute for diesel. As the markets develop, biomethane will have to compete with biodiesel, cellulosic ethanol, hydrogen and other emerging alternative vehicle fuels.

Figure 13. Biomethane Costs

$/mmBtu = $/1,000 scf



** Krich, et al., 2005   ** Chen, 2010   *** USDA, NRCS, 2007*

Chapter 5: The Value of Environmental Attributes

While natural gas is cleaner than gasoline or diesel, biomethane is cleaner still than natural gas. The question is: What monetary value can be attributed to and gained from the environmental benefits of these fuels?

Natural gas reduces air pollution and particulate pollution and emits less carbon dioxide (CO_2) than its petroleum competition. Because biomethane is chemically the same as natural gas, its additional environmental benefits occur "upstream" of the vehicle. The production of biomethane often involves the capture of existing sources of biogas that release methane – a potent greenhouse gas (GHG) – into the atmosphere. Methane released to the air has 23 times greater global warming potential than CO_2.

Biomethane is also a locally derived renewable fuel, so it also generates local economic and societal benefits that are not clearly monetized except as a matter of government policy.

Because the sweet spot for biomethane economics is so often tied to the environmental benefits of the source project and the fuel, environmental regulations and incentives play an important role in advancing biomethane projects. These environmental effects fall into two main categories: renewable energy and renewable fuel incentives, andGHG reductions.

Renewable Energy Incentives

Renewable energy incentives often take the form of a preference for renewable fuel sources in corporate or government purchasing decisions. They may also take the form of mandates, as is the case for Washington State and many local government agencies. They can also take the form of renewable portfolio standards imposed on utility providers. In Washington, the applicable law – developed through the passage of Initiative 937 – requires certain power utilities to have 15 percent renewable electricity in their power portfolios by 2020. However, Initiative 937 only applies to the development of renewable electricity, so it currently favors the use of biogas for renewable electricity over the use of biomethane for alternative vehicle fuel.

Renewable Fuel Standards

As a renewable gas, biomethane used as alternative vehicle fuel, whether directly or after transportation by pipeline, may be a way to comply with the federal Renewable Fuel Standard (RFS) or California's state-mandated Low Carbon Fuel Standard (LCFS).

The federal RFS was created by Congress through the Energy Policy Act of 2005. It was updated in the Energy Independence and Security Act of 2007 (EISA). The new standard, known as RFS2, sets annual mandates for four types of alternative fuels, based on lifecycle GHG emissions levels relative to a 2005 baseline of petroleum.

The four alternative fuel types include: renewable fuel, advanced biofuel, biomass-based diesel, and cellulosic biofuel. The final rule was published in 2010 and contains mandates through 2022.

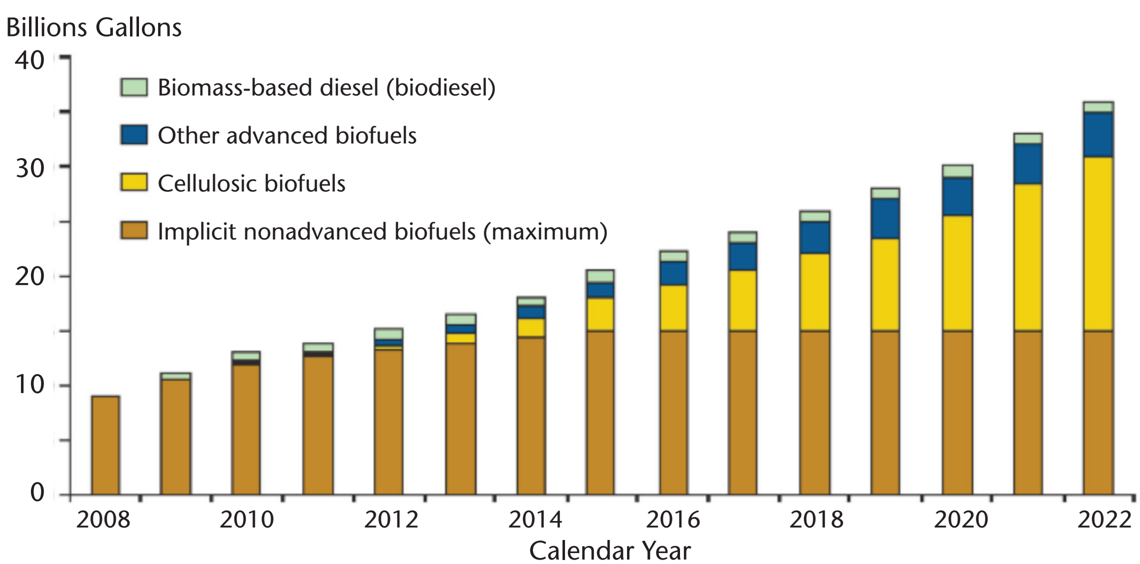
EPA manages the RFS rule and assures compliance. Renewable fuel types and mandates are given in Table 17.

Table 17. Renewable Fuel Types in RFS2

Fuel Type	Percent reduction from displaced gas/diesel (2005 baseline)	**Comments**
Renewable fuel	20 percent	Produced from renewable biomass
Advanced biofuel	50 percent	Renewable fuel other than ethanol from corn starch
Biomass-based diesel	50 percent	Includes biodiesel and non-ester renewable diesel
Cellulosic biofuel	60 percent	Fuel derived from cellulose, hemicelluloses or lignin from renewable biomass
Source: Pew Center		

The RFS2 mandates translate into specific targets for gallons of fuel as shown in Figure 14.

Figure 14. Renewable Fuel Standard Mandates, by Type, 2008-2022



Note: Biofuel RFS specified through 2012; subsequent years "shall not be less than the applicable volume... for calendar year 2012."

These national level RFS2 mandates shown in Figure 14 are prorated, according to relative annual production or import levels, to individual gasoline or diesel fuel producers, known as “obligated parties.” The EPA monitors compliance by obligated parties through the use of Renewable Identification Numbers (RINs), which EPA uses to track the production and distribution of alternative vehicle fuels for RFS2. Producers of renewable fuels assign individual serial numbers to every gallon of alternative fuel produced, and they report these numbers to EPA. Through this tracking mechanism, RINs can be distributed and traded among certified users. This allows the fuel commodity to be separated from the renewable attributes, which means the fuel commodity and the RINs can be sold together or separately, as the market players choose.

Biomethane qualifies as an Advanced Biofuel under the RFS. However, while RINs for ethanol and biodiesel have developed multi-year transaction histories, no known transactions for bio-CNG or bio-LNG have been made to date. This makes it challenging to assign any monetary value to these attributes.

For their bioenergy feasibility study for Tillamook County, Tetra Tech did some valuable research into the use of RINs in the near future. As of July 2011, the Tetra Tech team found biodiesel RINs trading at around $1.30/gallon and Advanced Biofuels RINs trading at around $0.75/gallon equivalent (for biogas, 77,000 BTUs is equal to 1 gallon equivalent or 1 RIN). They found ethanol RINs had been trading at near $0.03/gallon for several months. The difference in these prices are a function of the balance of demand (the level of mandated targets) versus the supply of RINs, with a dash of speculation added to the equation. Based on their research and analysis, Tetra Tech set three prices for comparison:

low = $0.20/gal equivalent;
medium = $0.50/gal equivalent; and
high = $0.75/gal equivalent.

The high-level mark reflected the value of Advanced Biofuel RINs at that time.

The Oregon project team concluded, “Although the value of RINs are fully dependent on the annual fluctuations of fuel mandates decided by the US Congress, industry insiders are confident that RINs will be a valuable tool going forward.”

California Low-Carbon Fuel Standard

Another California policy that is having an incentive effect is the LCFS. Established by Executive Order in 2007, the LCFS establishes a statewide goal of reducing the carbon intensity of California’s transportation fuels by at least 10 percent by 2020. It applies to all refiners, blenders, producers and importers of transportation fuels and is measured on a full fuels cycle basis. It can be met through market-based methods, meaning providers that exceed their performance requirement can receive credits that can be applied toward future obligations or traded to providers that have not met the standard.

Biomethane benefits from the California RFS in two ways. First, biomethane itself is a very low-carbon fuel. It reduces GHG emissions roughly 80 percent. The

California Air Resources Board (CARB) recognizes bio-CNG as one of the lowest carbon fuels available.

Second, any other transportation fuel provider using low-carbon renewable power or fuels in the manufacture or distribution of fuel lowers the carbon intensity of that fuel. This has the effect of rewarding biomethane injected into the pipeline and sold in California for use in various fuel industries. It could be used in the production of ethanol or as bio-CNG in gasoline tanker trucks, and provide a benefit under the LCFS.

These and other opportunities have been discussed widely in the natural gas and renewable gas sectors, but they remain untested. Washington biogas producers report being approached by representatives from California transportation fuel providers, but there remains a huge gap between the concept of a California market and reality. As a result, it is difficult, if not impossible, to estimate the value of this option as a market opportunity. One of the significant risks is the politics surrounding California mandates and the desire of some advocates to protect in-state production through preferential treatment.

Washington Low-Carbon Fuel Standard

Washington State officials have also discussed the potential value of a LCFS. The Governor in 2009 directed the Department of Ecology, in coordination with the departments of Transportation and Commerce, to assess the impacts of a LCFS. Ecology, working with TIAX, evaluated a standard for reducing the carbon intensity of transportation fuels by 10 percent from 2007 levels by 2023. The analysis looked at the range of alternative vehicle fuels, with particular focus on ethanol and biodiesel. Renewable CNG derived from waste feedstocks was included in the possible fuel mix.

The evaluators summarize their findings as follows:

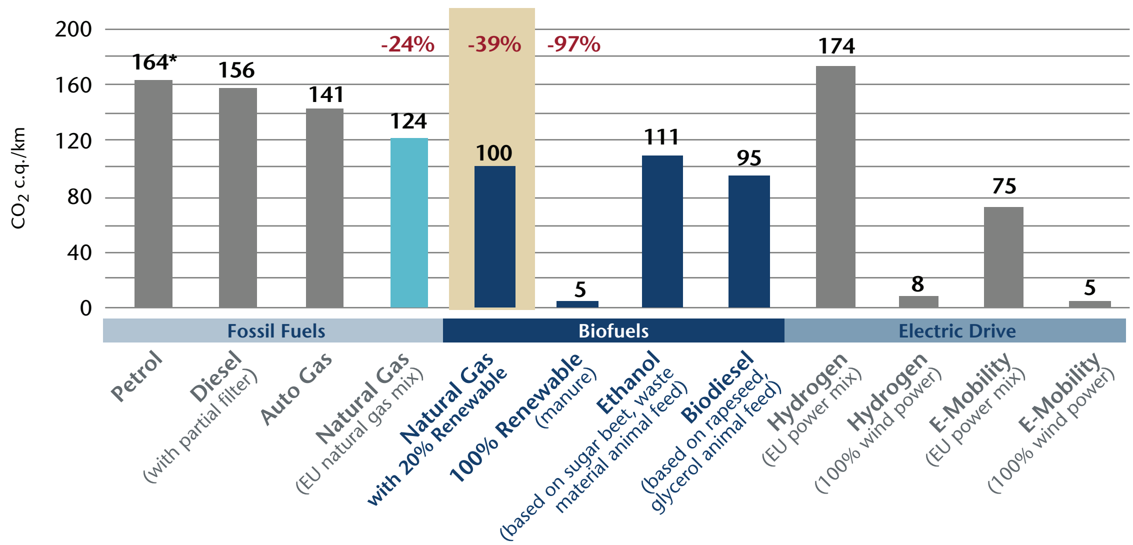
> The LCFS is the preferred approach for reducing transportation sector GHG emissions. A regulatory approach could achieve similar levels of emissions reductions but there are drawbacks….Traditional incentives are costly and yield only modest emission reductions that are not necessarily sustainable without continued funding…. Transportation pricing mechanisms would result in very high costs in the short-term as there are limited alternative options available. Moreover, carbon taxes are regressive and therefore politically difficult to implement. However, pricing mechanisms are very efficient and may be the favored approach once alternatives to petroleum are truly available. A LCFS over the next ten years could pull real alternatives into the marketplace so that in 2023, a pricing mechanism might be a viable alternative.

Greenhouse Gas Reductions

Biomethane use in transportation provides an enormous reduction in GHG pollution when compared to diesel fuel and compressed natural gas (CNG). Researchers in Europe have been studying the impacts of their choice to use biomethane for transportation vehicles. A study by German scientists reported by the German Energy Agency offered the comparative results shown in Figure 15.

Figure 15. Well-to-Wheel GHG Emissions

Source: DENA – German Energy Agency

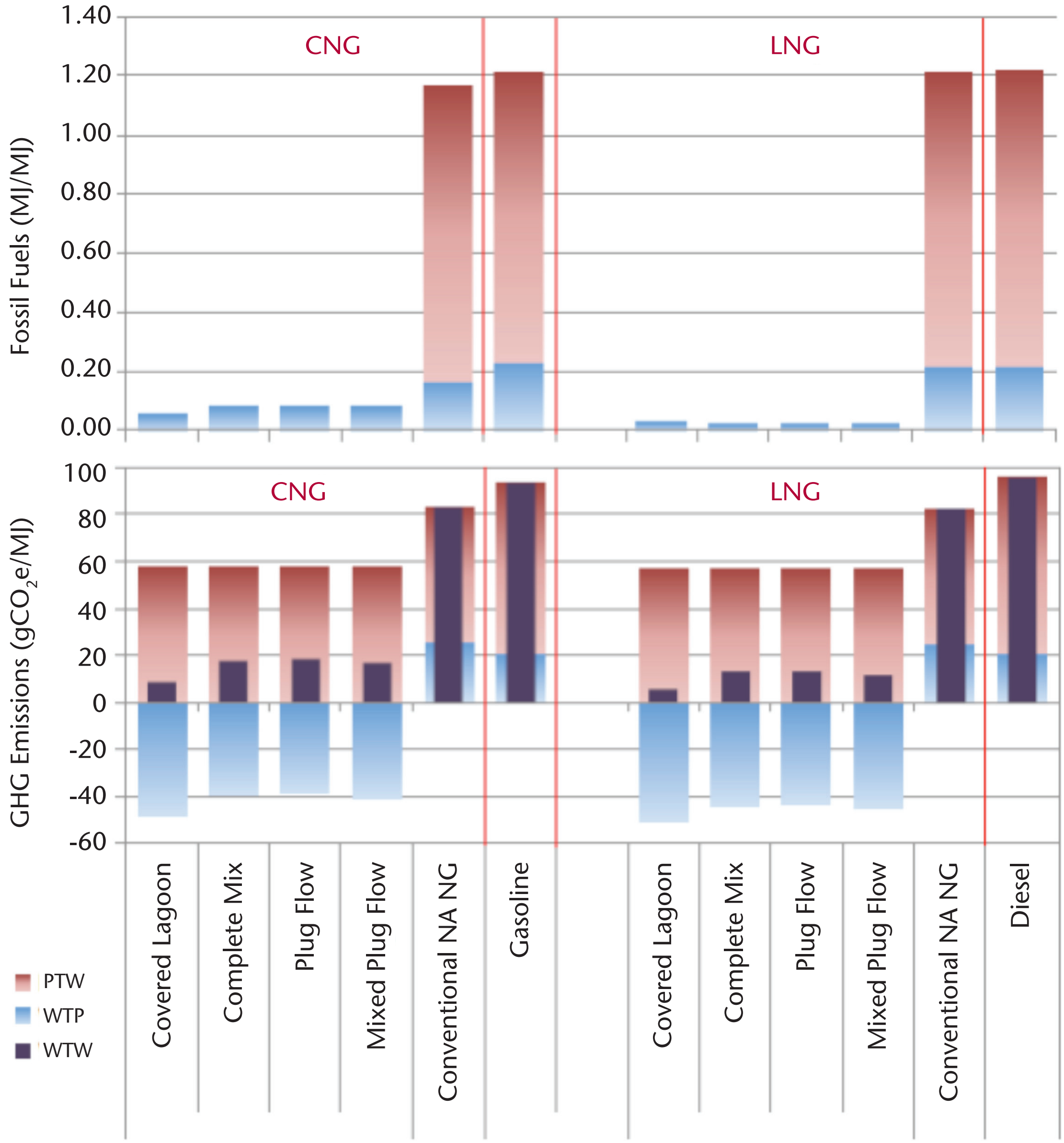


** Reference vehicle: gasoline engine (induction engine), consumption 71 per 100 km.*

In the United States, scientists at Argonne National Laboratory have been a chief source of data about the lifecycle GHG emissions of fossil and renewable transportation fuels. The lab manages the creation, use and modification of the models developed for EPA under the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Program. The GREET model estimates emissions of GHG and criteria pollutants. Researchers completed an assessment of landfill gas used for bio-CNG and recently completed a draft of the impacts of digester biogas from dairy manure. They continue to refine lifecycle estimates and explore pathways to GHG reductions for a range of alternative vehicle fuels.

The results of the modeling for landfill gas indicate that well-to-wheel (WTW) GHG emissions drop from approximately 93 grams per megajoule (g/MJ) for gasoline or diesel to about 74 g/MJ for fossil natural gas. By comparison, WTW GHG emissions for renewable CNG are 16-18 g/MJ and 21-22 g/MJ for renewable LNG using electricity from the grid. The GHG benefit achieved by using renewable natural gas (RNG) made from landfill gas is greater by far than that of any available alternative fuel – and is about equal to the benefit of renewable hydrogen (which is not yet commercially available).

Figure 16: GREET Estimates of the PTW, WTP and WTW Fuel Use and Emissions by Technology



The results of modeling for conventional and biomethane forms of CNG and LNG produced from biogas originating from different types of animal waste digesters is summarized in Figure 16. Fossil fuel use per MJ is lowest for bio-CNG produced from biogas from a covered lagoon digester, mainly because covered lagoons typically operate at ambient temperatures with long hydraulic retention times and thus have smaller energy inputs. Fossil fuel use per MJ is lowest for bio-LNG because the LNG is assumed to power the liquefaction and distribution by truck.

Emissions of GHGs by digester technology follow similar patterns, indicating that the various technologies mitigate methane loss to the atmosphere efficiently. The differences among the digester technologies are very small compared to the differences between all biomethane sources and conventional natural gas.

The GREET model is available to the public to use for modeling purposes. See the website at: *http://www.transportation.anl.gov/modeling_simulation/GREET*. Worldwide, there are more than 15,000 registered users.

This GHG emission reduction benefit can be measured in many ways. Though there is no federal reduction mandate or market for carbon credits, many corporations are being proactive about setting and meeting targets for reducing GHG impacts. For many manufacturers or wholesale suppliers of goods and services, this has become a retail sustainability mandate. In recent years, some large retailers have imposed a series of carbon accounting procedures on all of their suppliers and vendors. This has forced these companies to become more aware of GHGs and their role in company operations which, in turn, has forced these companies to calculate the costs and benefits of GHGs in relation to being permitted to do business with retail buyers that have carbon accounting procedures.

In addition, two state-level markets for GHG emissions are taking hold. In the Northeast, the Regional Greenhouse Gas Initiative (RGGI) has been in operation since 2008.

In California, the assembly passed AB 32 – the Global Warming Solutions Act of 2006 – which establishes a target for overall reduction in carbon emissions of 83 percent by 2050. Caps set on industries throughout the state will impose added costs on the use of high-GHG fuels such as diesel and gasoline.

Further, California is moving forward with creation of a cap-and-trade marketplace for GHG emissions, through which regulated entities (large GHG polluters) will be required to obtain GHG allowances or GHG offsets to comply with annual reduction targets. GHG offsets, also referred to as carbon credits, allow regulated entities to pay and get credit for GHG reductions undertaken by entities that are not required to make reductions. These voluntary reductions of GHGs throughout the market may be more cost effective than actions available to individual regulated entities. This mechanism provides for overall GHG reductions to occur, for the major polluters to pay, but for the market to find the lowest-cost methods to achieve reductions.

The Climate Action Reserve (CAR), established initially as the California Climate Action Registry, has created systems and standards for creating and validating offsets for compliance in the California market. Under current rules, California will initially recognize four types of offsets – methane capture from dairy digesters, forestry, urban forestry, and reduction of ozone-depleting substances – from projects in the United States. The California GHG market is scheduled to take effect in 2013. Current prices for carbon allowances or credits under the RGGI and CAR programs range from $1.45 to $1.93 per unit, measured as 1 metric ton of CO_2 equivalent. However, this has not stopped industry watchers from predicting impressive values for carbon credits in the future. For example, the floor price for carbon allowances to be auctioned by California in the future is set at $10.00/ton. Also, recent trades at Intercontinental Exchange for CAR carbon futures (2013) have netted an average of $19.00/ton *(Raphael, 2011)*.

These kinds of values would have a major impact on markets in Washington. Currently, Washington's rules for renewable power generated in compliance with I937 tie up all the environmental attributes together. This is contrary to the practice in other areas, where the renewable energy credit (REC) includes the reduction of CO_2 from reduced fossil fuel power generation, but not necessarily the reduction of methane from changes in manure management practices (i.e., the addition of anaerobic digestion) prior to power generation. This rule in Washington could have the effect of driving development toward biomethane use for transportation or injection into the pipeline, allowing for the monetization of carbon credits from methane reductions in addition to alternative fuel attributes.

Chapter 6. Policies and Incentives

A variety of policies and incentives have been and are being used to support biomethane as a transportation fuel. This review includes recent and current policies to show the range of actions used and available to government officials.

Federal Policies

Energy Tax Policy Act of 2005

This legislation provided a number of incentives that supported natural gas vehicles, fuel, and infrastructure. It included a motor vehicle income tax credit for qualified alternative fuel vehicles (AFV). It applied to the purchase of a new, dedicated, repowered, or converted AFV. The available credit ranged from $2,500 to $32,000, depending on the size of the vehicle. This credit expired at the end of 2010; however, Congress provided a bonus depreciation provision, allowing businesses to depreciate vehicles like new capital equipment.

For natural gas or biomethane fuel, the act provided an excise tax credit of $0.50 per gasoline gallon equivalent of compressed natural gas (CNG) or liquid gallon of liquefied natural gas (LNG) for use as a motor vehicle fuel. This credit was introduced in 2006 and had its original sunset at the end of 2009. It was extended for two years, but it is scheduled to expire at the end of 2011. Advocates hope to get the credit extended, separately or as part of the proposed Natural Gas Act.

For fueling infrastructure, the act provided an income tax credit equal to 30 percent of the cost of natural gas fueling equipment, up to $30,000 for large stations and $1,000 for home sites. This provision expires at the end of 2011; however, Congress extended the accelerated depreciation rules for capital equipment to the type of fueling equipment – worth 50 percent of the cost of property placed in service.

American Recovery & Reinvestment Act

This act increased the credit value for purchasing and installing equipment to store and dispense qualified alternative fuels when put into service during 2009-2010.

Natural Gas Act

The New Alternative Transportation to Give Americans Solutions (NAT GAS) Act of 2011, also referred to as the Natural Gas Act, is being promoted by the natural gas industry. It provides the following provisions:

- Vehicle purchase income tax credit – extension for 5 years
- Refueling property income tax credit – extension for 5 years
- Motor fuels excise tax credit ($0.50/GGE) –extension for 5 years
- Transferability/improved ability of tax exempt organizations to monetize vehicle and station credits. Taxable entities will be able to apply credits toward the alternative minimum tax.

Washington State Policies

Washington State government has an ambitious goal for deploying alternative fueled vehicles. Government fleets at state and local levels are looking ahead at mandated targets for switching to alternative fuels in the near future. Legislators in 2007 mandated that state and local governments meet 100 percent of their fuel needs using electricity or biofuels by June 2015 to the extent “practicable,” as determined by the Washington Department of Commerce, with an interim mandate for state agencies of 40 percent by June 2013. In 2011, the local government mandate was pushed out three years by the legislature. Nevertheless, governments will be looking for ways to incorporate biofuels, so local biomethane projects may find strong support.

Additional incentives include the sales and use tax exemptions for alternative fuel vehicles, including natural gas vehicles, through June 2015. The exemptions extend to vehicles that were converted to use the alternative fuel.

Though not specific to transportation, the State of Washington has two incentives designed to support development of digesters at Washington dairies. First, the State provides a property tax exemption for six years for digester proejcts. This provision is set to continue through 2012. Second, the State offers retail sales tax exemptions for the equipment, components, materials and services for digester construction, No expiration has been set for this incentive.

Chapter 7: Conclusions and Recommendations

Source Expansion

- Encourage development of digester capacity through financing and loan support to encourage production of electricity or biofuel.
- Encourage diversion mandates and programs to separate organic materials from MSW.
- Conduct education and outreach especially for wastewater and solid waste industry officials, and provide technical assistance to potential sources.
- Partner with potential sources to conduct feasibility studies for projects that expand digester capacity, incorporate new feedstocks, or evaluate gas cleanup and distribution infrastructure developments.
- Partner with other agencies and advocates to expand digester capacity in the state's dairy industry.
- Support improvements in biodigester efficiency and yields.
- Support research, market development, and investment in waste-to-energy efforts

End Use Market Development

- Conduct education and outreach to fleets and provide technical assistance to address issues related to vehicles, fuel access, and capital for infrastructure.
- Work with public agencies to leverage government contracts or other purchasing requirements in support of alternative fuels and vehicles. For example, consider if school districts could mandate or encourage adoption of alternative fuels for delivery vehicles.
- Support alternative fuel infrastructure development.
- Enhance vehicle subsidies.

Biomethane Policies and Incentives

- Encourage federal fuel subsidies.
- Maintain support for the federal Renewable Fuel Standard (RFS) and make certain it treats biomethane fairly with other alternative fuels.
- Support life cycle assessments of biomethane.
- Partner with other agencies and advocates to move Washington State to adopt a low-carbon fuel standard and/or a carbon tax with equalization components as discussed in the State Energy Strategy update.
- Support markets for Renewable Identification Numbers generated through renewable fuel standard or low-carbon fuel standard regulations.
- Support valuation of the emission and greenhouse gas benefits of biomethane, such as carbon reduction mandates or carbon taxes.

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