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PREFACE

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

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

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

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

ABSTRACT

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

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

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

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Executive Summary

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

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

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

Based upon the results of this study, recommendations are:

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

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

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

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

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

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

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

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

CHAPTER 1: Introduction

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

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

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

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

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

Report Structure

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

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

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

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

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

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

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

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

Biogas Resources, Production, and Utilization

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

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

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

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

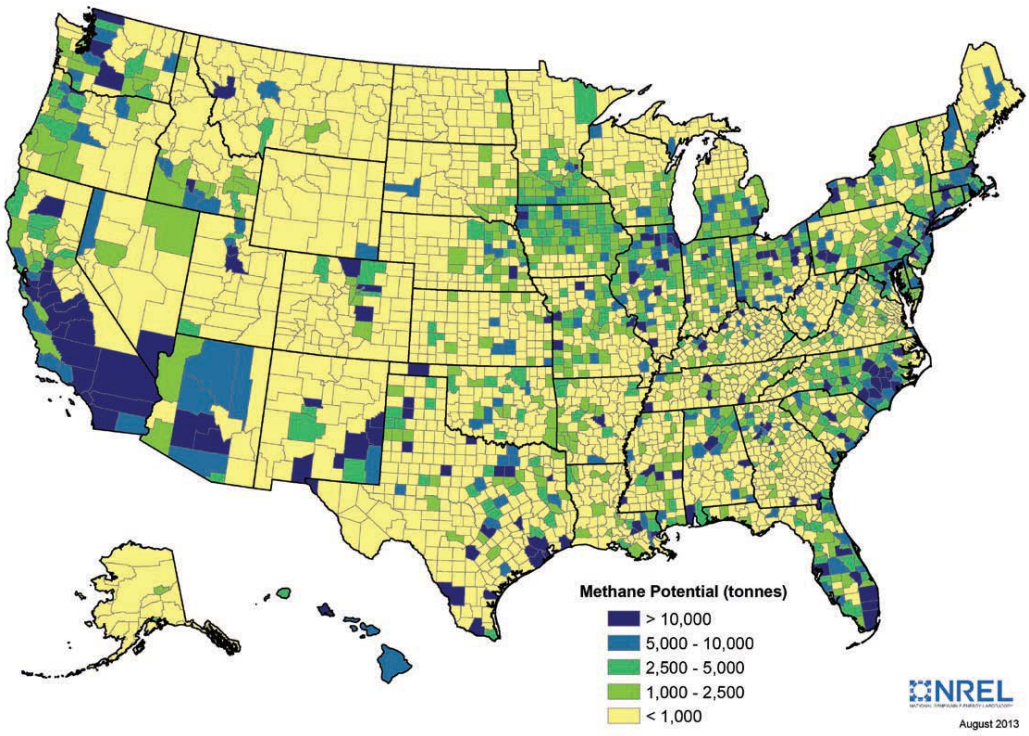


Illustration Credit: NREL (2013)

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

potential to increase biogas energy production from California's WWTPs by almost 50% (Kester 2014). California biopower facilities and capacity are shown in Table 1.

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

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

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

Source: California Biomass Collaborative facilities database (2013)

The California Renewable Portfolio Standard (RPS) eligibility for biogas delivered by pipeline was suspended on March 28, 2012 due to lack of confidence in biomethane delivery reporting methods. The concerns were addressed by AB 2196 (Chesbro) and SB 1122 (Rubio)—both enacted on September 7, 2012. AB 2196 (Chesbro) allowed electrical generating facilities using landfill or digester gas to qualify for RPS and set limitations on the ability of out-of-state biomethane for RPS. On April 30, 2013, the new RPS eligibility requirements for biomethane were implemented in the Seventh Edition of the Renewables Portfolio Standard Eligibility Guidebook. SB 1122 (Rubio) directs the investor owned electrical corporations to procure at least l 250 MW of new biopower capacity (maximum 3 MW per project) through eligible bioenergy feed-in tariff power purchase agreements. The 250 MW was allocated among the following categories: 1) 110 MW: Biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion; 2) 90 MW: Dairy and other agricultural bioenergy; and 3) 50 MW: Bioenergy using byproducts of sustainable forest management.

As the US biogas industry continues to mature, other avenues of biogas utilization are beginning to open, including the injection of biogas into natural gas pipelines. Doing so will diversify the energy supply and may foster in-state production of biogas and biomethane. As shown in Figure 2, only 9.4% – 14.8% of natural gas used in California comes from in-state sources (California Energy Commission 2011). Utility companies deliver about 80% of natural gas consumed in California while the rest is delivered directly by the Kern River Gas Transmission Company and other California gas producers.

Figure 2: California Daily Natural Gas Consumption by Source

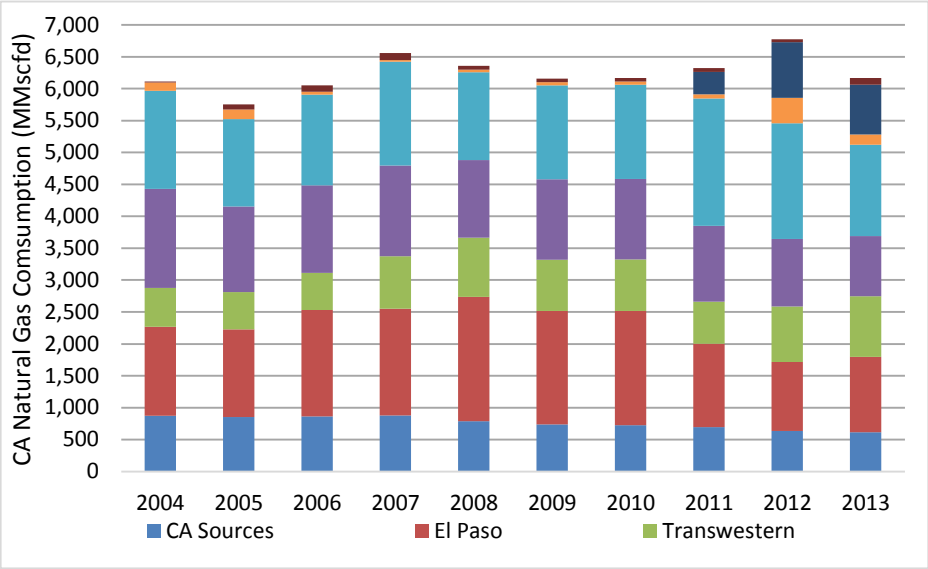


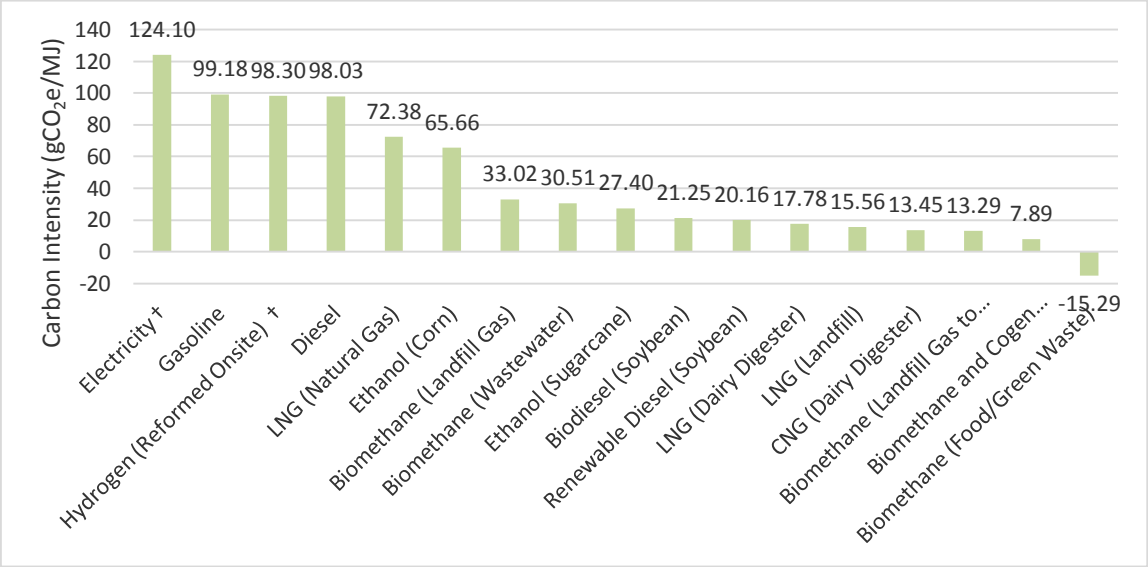
Chart Credit: Author; Data Credit: Southern California Gas Company et al. (2009); Southern California Gas Company et al. (2014)

Biogas pipeline injection is an attractive alternative to distributed power generation for biogas producers in nonattainment air districts, where restrictive air quality standards limit small-scale onsite burning and utilization of biogas. It also provides the potential for all of the biogas to be utilized, and converted at higher efficiency if used for power generation, compared to use if smaller, less efficient distributed facilities. However, high capital investment cost constrain pipeline injection to large-scale projects that can afford them, such as landfills and large capacity digesters near existing pipelines. Pipeline injection of biogas also requires removing contaminants (cleaning), upgrading to biomethane (remove carbon dioxide to achieve pipeline standards. As of 2012, Germany and Sweden, followed by Switzerland and the Netherlands, lead the way in implementing biogas cleaning and upgrading technologies. As of 2010, Germany the leading producer of biomethane, generated from energy crops, manure and MSW residues, with the gas being injected into the natural gas distribution system (Canadian Gas Association 2012). Germany alone had 83 biogas upgrading plants by the end of 2011 out of 200 in Europe (The Biogas Handbook: Science, Production and Applications). Sweden implemented the use of biogas in 2002 with upgrading of biogas to biomethane for natural gas grid injection, primarily for vehicle fuel use. By 2008, biomethane was being used to operate 130,000 vehicles (Canadian Gas Association 2012).

Overall, biogas utilization can assist in the development of sustainable waste management practices and reduce greenhouse gas emissions by avoiding uncontrolled natural release of methane through decomposition and by displacing fossil carbon-intense fuels. One way to

indicate net process (or energy pathway) greenhouse gas emissions is by calculating its carbon intensity (CI with units of grams of carbon dioxide emission equivalents per unit of energy). The California Air Resources Board (ARB) has developed CIs for a number of transportation fuel pathways based upon Argonne National Laboratory's GREET model for use in the California Low Carbon Fuel Standard (LCFS). Biofuels from residue materials produced and used in-state have the lowest carbon intensities compared to most other gas and liquid fuel systems (Figure 33). For example, the proposed pathway for biomethane produced from high-solids anaerobic digestion of food and green waste has a carbon intensity of -15.29 g CO_2e/MJ, while biomethane produced from anaerobic digestion of wastewater sludge at low/medium and medium/large wastewater treatment plants have proposed carbon intensities of 30.51 and 7.89 g CO_2e/MJ, respectively (California Air Resources Board 2014b; California Air Resources Board 2014c).

Figure 3: ARB Pathways and Fuel Carbon Intensities



† Values will be significantly lower if generated using renewables (e.g., 33% renewable onsite hydrogen has a carbon intensity of 76.10 CO_2e/MJ)

Note: The carbon intensity values listed above are subject to change in February 2015 when the ARB is expected to readopt the LCFS and transition from using the CA-GREET 1.8b model to the CA-GREET 2.0 model to determine new values for all past and future pathways, until a time in which the model is updated again.

Chart Credit: Author; Data Credit: California Air Resources Board (2014b); California Air Resources Board (2012)

CHAPTER 2:
Biogas Quality and Composition

Biogas is a product of anaerobic (biological) decomposition (it occurs naturally in wetlands, rice fields, and landfills, in ruminant livestock, or in engineered anaerobic digestion systems). It is composed primarily of methane and carbon dioxide, with minor amounts of trace contaminants, e.g., hydrogen sulfide, ammonia, siloxanes, volatile organic carbons, and halogenated compounds. Because raw biogas is created in a moist or water-based medium, it is usually saturated with water vapor. Nitrogen and oxygen may also be present depending upon how well the anaerobic digestion process is sealed from the atmosphere. Biomass derived methane can also be synthetically created using thermochemical processes, i.e., gasification.

Anaerobic Digestion Process

Anaerobic digestion is the biological process by which communities of microorganisms consisting of bacteria and archaea metabolically break down complex organic molecules in the absence of oxygen to produce biogas—. The metabolic process of anaerobic digestion can be viewed as four consecutive steps: hydrolysis, acidogenesis, acetogenesis, and methanogenesis (

Figure 4). In hydrolysis, large organic particulates and macromolecules are broken apart into soluble macromolecular compounds. Acidogenesis then breaks the soluble organics down further into volatile fatty acids (VFAs), i.e., butyric acid, propionic acid, and acetic acid. Through acetogenesis, all of the VFAs are converted into acetic acid and other single-carbon compounds. Finally, by methanogenesis, aceticlastic methanogens convert acetic acid into methane and carbon dioxide while other methanogens convert hydrogen gas and carbon dioxide into methane.

Figure 4: Anaerobic Digestion Pathways

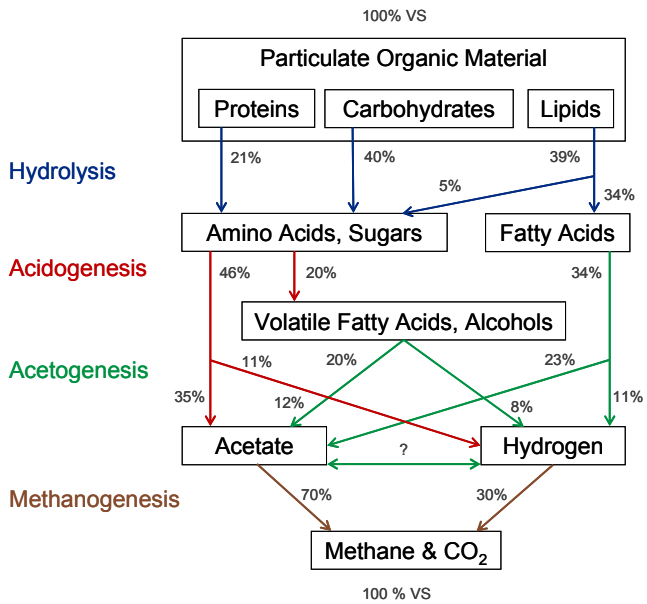
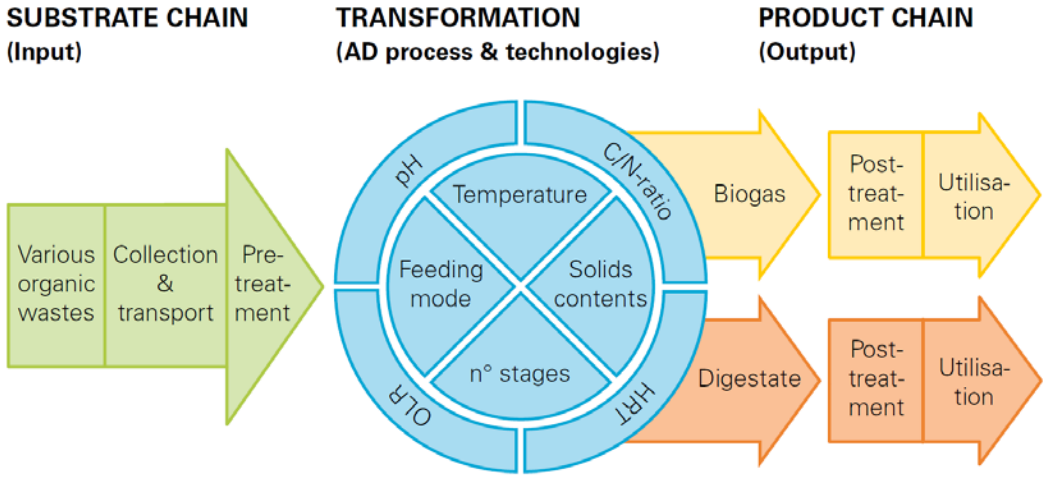


Illustration Credit: Adapted from Gujer and Zehnder (1983)

Trace amounts of hydrogen sulfide, ammonia, siloxane, non-methane volatile organic carbons, and halocarbons are also typically generated by other species of microbes present in the complex community. The concentrations and production rates of these compounds, as well as of methane and carbon dioxide, will vary depending upon the source/feedstock material, process design, and environmental factors (Figure 5). The following sections summarize typical quality and composition of biogas from landfills, wastewater treatment plants, agricultural waste and manure digesters, and municipal solid waste digesters.

Figure 5: Anaerobic Digestion Process Chain



HRT: Hydraulic Retention Time, OLR: Organic Loading Rate

Illustration Credit: Vögeli et al. (2014)

Thermal Gasification

Renewable methane, or renewable synthetic natural gas (RSNG), can be created via thermal gasification with follow-on gas cleaning and processing. Thermal gasification is the process whereby solid or liquid carbonaceous matter is converted into fuel gases and other by-products. The fuel gases can be used directly for energy production (heat and/or power), or, with sufficient gas cleaning and processing, can be used to produce chemicals such as methanol and liquid and gaseous vehicle fuels. Common feedstocks for gasification include coal and woody biomass. The raw product gas is called producer gas and consists of carbon monoxide, hydrogen, carbon dioxide, methane and light hydrocarbons, water vapor, tar, particulate matter, trace compounds, and, depending on the gasifier design, up to 50% nitrogen and small amounts of oxygen. Synthesis gas (or syngas) is made from cleaning and processing the producer gas. Syngas nominally consists of carbon monoxide and hydrogen. Some definitions of syngas allow for methane, and other hydrocarbons, carbon dioxide and nitrogen in addition to the carbon monoxide and hydrogen. The relative concentration of each gas depends upon the composition of the material feedstock used and process operating conditions, e.g., temperature, pressure, autothermal or allothermal gasifier, steam, air, or oxygen fed, etc.

Methane can be produced from syngas by reacting carbon monoxide and carbon dioxide with hydrogen gas using a metal catalyst, such as nickel and ruthenium. The metal catalysts and reaction conditions induce methanation, Sabatier, and water-gas shift reactions which contribute to the formation of methane from syngas (Table 2). Methanation catalysts strongly bond with sulfur, thereby deactivating and poisoning the catalyst. Thus, sulfur compounds should be removed from the syngas prior to methanation. Fortunately, sulfur concentrations in syngas are minimal compared to those found in biogas. Nevertheless, the catalysts require eventual replacement. With proper gas pretreatment, Ni/Al_2O_3 catalysts used for industrial methanation have a lifetime of 5 – 10 years while conventional tubular nickel steam reforming catalysts have a typical lifetime of 3 – 5 years (Hagen 2006; Wagner, Osborne, and Wagner 2003).

Table 2: Methane from Syngas Reactions

Methanation	$CO + 3H_2 \rightarrow CH_4 + H_2O$
Water-gas shift	$CO + H_2O \rightarrow CO_2 + H_2$
Sabatier reaction	$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$

An emerging thermal process is hydrothermal catalytic gasification (HCG). HCG is a thermochemical process by which organic matter reacts with a catalyst (e.g., methanation catalysts, alkaline hydroxides) under moderate temperature and high pressure (typically 300 – 450 °C and 1246 psi). High pressures keep water and most other liquids in the liquid phase, thereby saving energy that would have been expended on evaporation making it more feasible to thermally process high moisture feedstocks. The product gas consists primarily of methane, hydrogen, and carbon dioxide. Without an HCG catalyst, the process would be pressurized pyrolysis producing a bio-oil—an aqueous mixture resembling crude oil (Yu 2012). HCG

processes can achieve high gasification efficiencies greater than 90% at relatively low reaction times—within minutes to hours—using assorted biomass feedstocks, including lignocellulosic materials (Azadi et al. 2012; Elliott 2008). However, research is still being conducted to develop HCG catalysts and catalyst mixtures with longer lifetimes and greater resistance to fouling and poisons to make the process cost-effective.

Biogas Sources

The four largest potential waste-derived biogas sources (excluding thermal conversion methods) for which gas collection systems can be feasibly implemented are landfills, wastewater, animal manure, and organic municipal solid waste. As shown in Figure 6, landfills are California's current greatest potential biogas resource.

Figure 6: California Biogas Production Potential by Source

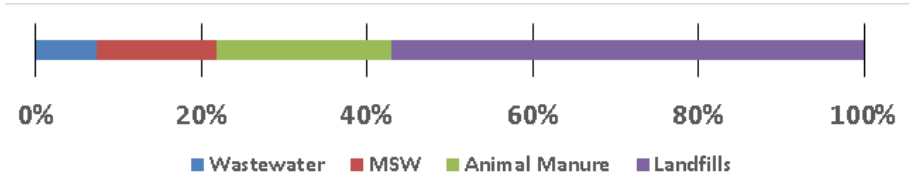


Chart Credit: California Biomass Collaborative

The following subsections outline the method, nature, and status of gas production from these five bio-derived fuel gas sources, as well as summarize the gas quality expected from each.

Landfills

More than 1.2 billion tons of solid waste have been amassed in California's 370 landfills, with approximately 30 million tons added each year (California Air Resources Board 2013). Landfilled municipal solid waste becomes buried beneath layers of soil and fresh waste while aerobic microorganisms quickly consume oxygen trapped in the lower layers, creating an anaerobic environment that allows for the organic fraction to decompose and be converted into biogas. Material can continue to produce gas for more than 50 years after being placed into the landfill. Generally, landfills must put systems in place to recover and then dispose of landfill gas (LFG)to minimize emission of methane and odorous gas, however there is still significant fugitive emission of—approximately 6.72 MMT CO_2e in 2010 (California Air Resources Board 2013). The most prevalent emissions control technology is flaring. Landfill gas is also collected to avoid incidents that can occur from the accidental formation of explosive gas mixtures, since methane is explosive at a 5 – 15% concentration in air. However, gas collection may not be practical for all landfill systems. In general, biogas collection is only practical for landfills larger than 35 acres, at least 35 ft deep, and with more than 1 million tons of waste (Agency for Toxic Substances and Disease Registry 2014).

Compared to the other biogas sources, landfills have the largest biogas production potential and existing generating capacity, benefit from existing waste collection and disposal infrastructure, and are therefore easier to feasibly implement. Existing systems that flare their gas would already have the collection systems in place and commonly only require the addition of gas

cleaning and/or upgrading and utilization equipment. However, landfill gas systems are also less well-sealed from the atmosphere, leading to lower raw gas quality and higher concentrations of O_2 and N_2 which are difficult to remove. This may limit gas utilization options at certain landfills or simply increase the cost of gas upgrading.

As of January 6, 2014, the US has 636 landfill gas energy projects and the potential for 450 more. In California alone, there are 79 landfill energy projects—more than twice of any other State—with the potential to feasibly add another 32. (US EPA 2014a, California Biomass Collaborative).

Wastewater Treatment Plants

Of the more than 16,000 WWTPs in the US, roughly 1,200 – 1,500 use anaerobic digestion, and about 860 beneficially use the produced biogas (Sinicropi 2012). In addition to number of currently existing WWTP digesters that can add biogas utilization systems, there is the potential for 4,000 more WWTPs to implement anaerobic digestion technology (Traylen 2014). In California, there are approximately 140 WWTPs that utilize anaerobic digesters and 56 that generate electricity (US EPA 2013, California Biomass Collaborative). For a typical WWTP that processes 100 gallons/day/person, about 1 cf/day/person of biogas is produced. When used for CHP, this comes out to roughly 100 kW electricity per 4.5 MGD processed (Eastern Research Group, Inc. and Resource Dynamics Corporation 2011).

Although anaerobic digestion at waste water treatment facilities is far from widespread, it has become an accepted option for wastewater treatment operations seeking to reduce the amount of solid waste (sludge) produced in the treatment process. This works by pumping settled solids from the primary and secondary clarifiers into an anaerobic digester to convert a fraction of the organic solids into gas. Anaerobic digestion provides some energy savings by reducing the load on biological aerobic organics destruction and can potentially turn wastewater treatment plants (WWTPs) into net energy producers (McCarty, Bae, and Kim 2011). Anaerobic digestion has also been shown to aid in disinfection, especially under thermophillic conditions, removing pathogenic bacteria by up to 99% (Smith et al. 2005). There are several engineering consulting firms that support the design and development of anaerobic digesters for wastewater treatment plants in California (e.g., Kennedy/Jenks Consultants, West Yost Associates).

Agricultural Waste and Manure Digesters

For the agricultural industry, anaerobic digestion represents a potential alternative waste disposal option. Dairy manure solids reductions of 29 – 62% within the digester tank and 52 – 76% for the entire processing system are common. Meanwhile, fugitive methane emissions from manure can be reduced by 60 – 70% (Summers 2013). Nitrogen compounds are also converted into ammonia, and effluents can be used as a liquid fertilizer.

Digesters can be designed as standard complete-mix tanks, plug-flow basins, or covered lagoons. The different designs will affect the hydraulic retention time, digestion efficiency, cost, and physical footprint of the system. Design selection is typically based upon limiting factors such as available land area and total volume requirements, but can sometimes depend on preferences and judgments of project developers.

Although farm-based digesters have been encouraged in Europe, they are still relatively rare in the US. In the US, there are around 8,200 dairy and swine operations that can support biogas recovery systems, but only 239 farms actually have anaerobic digesters (US EPA 2011; US EPA 2014a). This is due to economics (i.e., higher energy prices in Europe) and stricter US regulations that limit digester implementation. California has approximately 11 operational manure digester projects and 10 that had been shut down, primarily due to economic reasons (California Biomass Collaborative).

Figure 7: Complete-Mix Tank (Top Left), Plug Flow (Top Right), and Complete-Mix Lagoon (Bottom) Anaerobic Digesters

Photo Credit: US EPA (2014d)

Municipal Solid Waste Digesters

In 2012, 65.3% of the municipal solid waste (MSW) generated in the United States comprised of readily digestible organic materials—44.6% after recycling and composting (US EPA 2014c). California's landfill disposal stream consists of 59%- 64.% biomass derived material, dominated by paper & cardboard and food waste—17.3% and 15.5%, respectively (Figure 8) (Cascadia Consulting Group 2009). Municipal solid waste digesters operate similarly to agricultural waste and manure digesters, and may even be combined with them. MSW digesters may be more prone to performance variations and upsets than other systems due to constant, large, unpredictable changes in the incoming waste stream (especially with mixed post-consumer

food wastes). There are many operating AD systems in Europe utilizing MSW or source-separated MSW components. Total installed capacity is more than 6 million tons per year (De Baere & McDonald, 2012). There are approximately twelve systems operating in California (Franco, 2014).

Figure 8: California's Overall Landfill Waste Stream, 2008

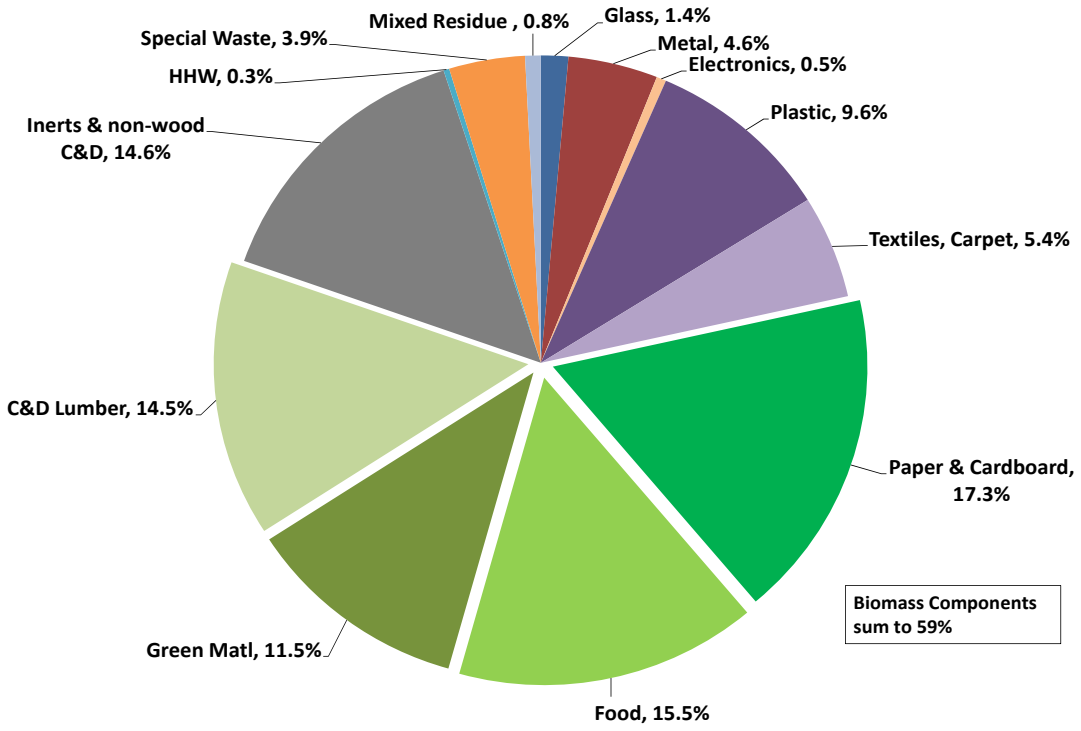
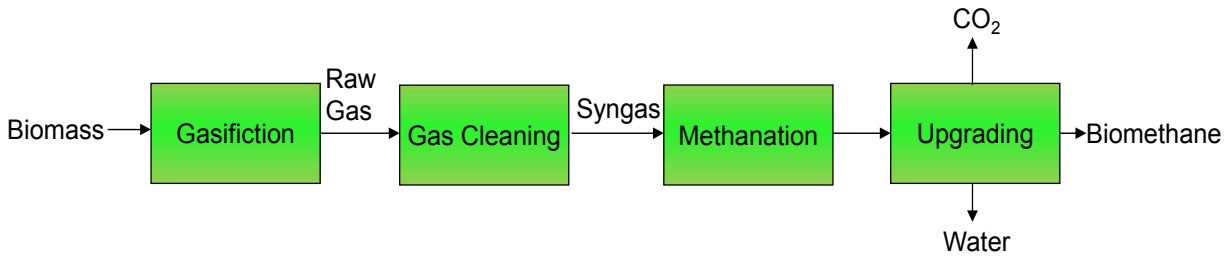


Chart Credit: Cascadia Consulting Group (2009)

Biomethane via Thermal Conversion Pathways (Gasification)

Biomethane can also be produced via thermal gasification with appropriate raw gas cleaning and reforming to a synthesis gas followed by methanation and upgrading to biomethane (Figure 9). Methane synthesized via this thermal gasification / methanation route is sometimes called synthetic natural gas (SNG) and renewable SNG (RSNG) if derived from biomass. Overall efficiency for RSNG would be ~ 65% for commercial scale facilities (Aranda et al., 2014; Kopyscinski et al., 2010; Mensinger et al. 2011). Overall thermal efficiency of biomass to RSNG to electricity would be ~30-33% if burned in a combined cycle natural gas power plant (assumes 50% efficient combined cycle power plant).

Figure 9. RSNG Schematic



Gasification also allows for effective utilization of woody and herbaceous biomass, feedstocks with fairly low methane potential through biological decomposition. Woody and herbaceous biomass have high contents of lignin and hemicellulose, which are extremely difficult for anaerobic digestion microbes to decompose. A majority of lignin and some hemicellulose material is usually left undigested by digester systems.

Biomass-Derived Gas Quality by Source

In addition to methane, biogas can contain these other compounds:

- Carbon dioxide: CO_2 constitutes the largest gaseous byproduct of anaerobic digestion. Any carbon dioxide present will decrease the biogas's energy content.
- Sulfur Compounds: Sulfur is present in all biological materials, especially those containing high protein concentrations. Small sulfur compounds (e.g., H_2S, mercaptans, COS, dimethyl sulfide) are produced by the biological degradation of these materials. Sulfur compounds are odorous and can be detrimental in many ways. Hydrogen sulfide in particular is highly toxic and poses health risks. Hydrogen sulfide in the presence of moisture can be corrosive, and when combusted, hydrogen sulfide is converted to sulfuric acid. Sulfur also poisons many of the metal catalysts that used for a number of different purposes (e.g., fuel cell electrodes, methane reforming).
- Moisture: Biogas will almost always be saturated with water vapor. Water vapor not only lowers the gas's energy content, but any hydrogen sulfide or carbon dioxide present will partially dissolve into the condensed water and form corrosive acids.
- Silicon compounds: Siloxanes, used in many industrial processes and consumer products ranging from tubing and paints to fabric softeners and toiletries, are present in nearly all biogases. When combusted, siloxanes are converted to microcrystalline silicon dioxide (SiO_2), also known as silica, with physical and chemical properties similar to glass. SiO_2 will deposit onto equipment, damaging boilers, engines, heat exchangers, and catalytic exhaust gas treatment systems, as well as fouling surfaces (e.g., sensors, catalysts) and plugging pipes.
- Nitrogen: Nitrogen will be present from any air introduced into the system. Nitrogen will dilute the gas, lowering its energy content.
- Oxygen: Oxygen will also be introduced with any air. Oxygen promotes microbial growth and can create an explosion hazard at certain CH_4-to-O_2 ratios (Figure 10).

Figure 10: Methane Flammability Chart

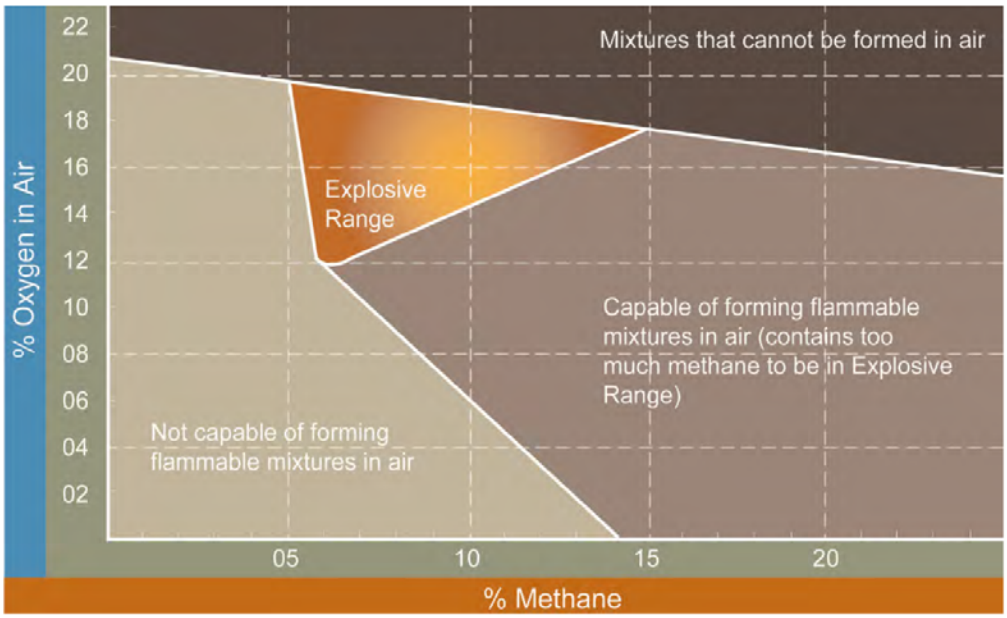


Chart Credit: Environment Canada (2011)

- Volatile organic compounds: VOCs include such compounds as aromatics, oxygenates, alkanes, and halocarbons. In addition to being air pollutants in and of themselves, VOCs can form highly toxic compounds when combusted. VOCs also include non-methane hydrocarbons, which can add to the overall gas's higher heating value.
- Halogen compounds: (e.g., halocarbons) can be found in biogas from the volatilization of compounds in plastics, foams, solvents, and refrigerants. Halogens form corrosive gases when they are run through combustion or reforming processes.
- Particulate Matter: Biogas can contain dust from gas collection systems or oil particles from compressors. Inorganic particulates will abrasively erode equipment and plug/damage the pores of membranes and adsorbents. Fibrous fragments can plug certain points in the gas collection system.

Due to the biological nature of anaerobic digestion, different microbial communities will respond differently to the same feedstocks, and vice versa. Furthermore, differences in feedstock material, microbial communities, reactor conditions (e.g., temperature, pH), and operating parameters (e.g., hydraulic retention time) will produce minor variations in gas quality and composition. However, biogas composition is mostly dependent upon its source. Table 3 shows the properties and ranges of assorted gases that are found in the four major biogas sources (referenced to earlier in this Chapter).

Dr. Michael Kleeman at UC Davis is Principal Investigator of project investigating biogas composition by source. The project is funded by the California Energy Commission and the Air Resources Board.

Table 3: Composition of Biomass-Derived Gas from Different Sources

Compound	Landfill	Wastewater Treatment Plants	Agricultural Digester	MSW Digester
Energy Content (Btu/scf, HHV)	208 – 644	550 – 650	550 – 646	550 – 650
Temperature (°C)	10 – 30	30 – 40	40 – 60	N.D.
Methane	20 – 70%	55 – 77%	30 – 75%	50 – 60%
Carbon Dioxide	15 – 60%	19 – 45%	15 – 50%	34 – 38%
Hydrogen Sulfide	0 – 20,000 ppm	1 – 8,000 ppm	10 – 15,800 ppm	70 – 650 ppm
Total Sulfur	0 – 200 mg/m³	N.D.	N.D.	N.D.
Nitrogen	0 – 50%	< 8.1%	0 – 5%	0 – 5%
Oxygen	0 – 10%	0 – 2.1%	0 – 1%	0 – 1%
Hydrogen	0 – 5%	0%	0%	
Ammonia	0 – 1%	0 – 7 ppm	0 – 150 ppm	
Carbon Monoxide	0 – 3%	0 – 0.01%	N.D.	N.D.
Non-methane Hydrocarbons	0.01 – 0.25%	N.D.	N.D.	N.D.
Aromatics	30 – 1,900 mg/m³	N.D.	N.D.	0 – 200 mg/m³
Halogenated Compounds	0.3 – 2,900 mg/m³	0 – 2 mg/m³	0 – 0.01 mg/m³	100 – 800 mg/m³
Total Chlorine	0 – 800 mg/m³	N.D.	0 – 100 mg/m³	N.D.
Total Fluorine	0 – 800 mg/m³	N.D.	0 – 100 mg/m³	N.D.
Siloxanes	0 – 50 mg/m³	0 – 400 mg/m³	0 – 0.2 mg/m³	N.D.
Moisture	1 – 10%	N.D.	N.D.	5 – 6%
Methyl Mercaptan	0 – 3.91 ppm	N.D.	N.D.	N.D.
Dichlorobenzene	0 – 5.48 ppm	N.D.	N.D.	N.D.
Ethylbenzene	0.576 – 40.2 ppm	< 1 ppm	< 0.34 ppm	N.D.
Vinyl Chloride	0.006 – 15.6 ppm	N.D.	N.D.	N.D.
Copper	< 30 µg/m³	< 30 µg/m³	< 20 µg/m³	N.D.
Methacrolein	< 0.11 ppm	< 0.0001 ppm	N.D.	N.D.
Alkyl Thiols	6.1 – 6.8 ppm	1.04 – 1.15 ppm	< 7.3 ppm	N.D.
Toluene	1.7 – 340 mg/m³	2.8 – 117 mg/m³	0.2 – 0.7 mg/m³	N.D.

N.D.: Not Determined or not found. Listed where contaminant is expected to be present, but concentration data was not found in the literature.

Chart Credit: Author; Data Credit: Allegue and Hinge (2012a); Asadullah (2014); California Air Resources Board and California Office of Health Hazard Assessment (2013); Eastern Research Group, Inc. (2008); Kaparaju and Rintala (2013); Petersson (2013); Ratcliff and Bain (2001); Rasi (2009); Robertson and Dunbar (2005); Wheeldon, Caners, and Karan

CHAPTER 3:
Available and Emerging Biogas Utilization Technologies

The methane in biogas has chemical energy that can be used for heat, power, vehicle fuel or as a feedstock for production of other chemicals or fuels (i.e., hydrogen, methanol, etc.). If no economic use is available at the biogas source, then simply burning or flaring the gas to oxidize the methane to CO_2 and H_2O is recommended or required to minimize fugitive methane emissions

Flaring

Flares or thermal oxidizers are used to oxidize combustible waste gas to reduce VOC and methane emissions to the atmosphere. It is the simplest method of safely disposing biogas when it cannot be processed or stored. However, hydrogen sulfide is converted to SO_2, another toxic substance which contributes to acid rain. The EPA's 40 CFR 60.104 Standards for Sulfur Oxides forbids combusting gas with hydrogen sulfide concentrations above 10 grain per 100 scf (~ 0.23 g m^{-3}).

Despite the environmental benefits and low cost, no energy is recovered by flaring. The majority of biogas producers in California currently flare their biogas and/or used a flare prior to installing a biogas utilization system. The following sections discuss ways in which to positively utilize biogas's energy potential.

Distributed Generation

The simplest approach to beneficially use biogas is to use it for heat and power generation by combusting or electrochemically converting the biogas onsite (using reciprocating engines, gas turbines, fuel cells, steam boilers, etc.).

Boilers

Boilers consist of a pressure vessel containing water that is heated and evaporated by burning a fuel (Figure 11). Steam can be used to provide heat or work when expanded through a steam engine or turbine (a generator operated by the steam engine will produce electricity) for another process. When operating on biogas, boilers that are made to run on natural gas should be adjusted by altering the fuel-to-air ratio (i.e., changing the carburetor) and enlarging the fuel orifice or burner jets to handle the higher flowrate of biogas needed to ensure proper combustion. The biogas should also be tested prior to use to determine if gas pre-treatment is necessary to remove hydrogen sulfide, siloxanes, and particles that may damage the boiler. Hydrogen sulfide will form sulfuric acid with water in the condensers, causing corrosion, although the metal surfaces should be coated to help prevent that. The exhaust should also be maintained above 150 °C to minimize condensation. Siloxanes will convert to SiO_2 when burned and deposit in the boiler along with any particles in the feed gas, which can eventually clog the boiler's flame tubes if not managed. High H_2S concentrations can also cause the flame tubes to clog.

Figure 11: Steam Boiler Structure

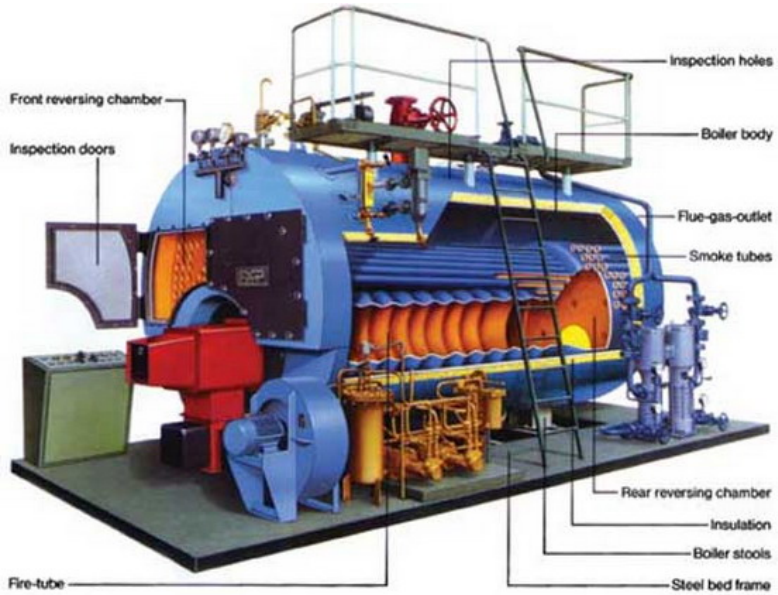


Illustration Credit: Fann Azmayan Pooyandeh Company (2002)

Boilers are relatively simple, have minimal cost and maintenance requirements. Their thermal efficiency is generally between 75 – 85%.

Reciprocating Engines

Reciprocating engines, also known as piston engines, include steam engines, Stirling engines, and gas and liquid fueled spark and compression ignition engines (often called internal combustions engines). Spark ignition gas (reciprocating) engines are the most popular application for biogas use. Depending on size, reciprocating engine-generators electrical efficiency ranges 18 – 43%. Engines are available that range from a few kW to several (10) MW. They are simple to operate and maintain and have relatively low to medium investment costs. They have higher pollutant emissions thane gas turbines or fuel cells which is an issue in some air basins in California.

Internal combustion engines can be divided into two types: rich burn and lean burn. Rich burn engines operate near the stoichiometric air-to-fuel ratio (and have low-to-zero oxygen in the exhaust), whereas lean burn engines run at higher A:F ratios (> 4% O_2 in the exhaust). Rich burn engines have higher uncontrolled NOx emissions. Lean burn engines have excess O_2 present during combustion, ensuring complete fuel combustion and lowering exhaust temperatures to inhibit the formation of NOx. Lean-burn engines are often used with for natural gas and especially for biogas applications since biogas contaminants can poison the three-way catalyst used with rich-burn engines.

Biogas should be cleaned to remove H_2S, which can lead to sulfuric acid formation, resulting in bearing failures and damage to the piston heads and cylinder sleeves. To minimize acid fume

condensation, it is recommended that the engine coolant temperatures be above 87 °C. Siloxanes and particulates will cause the same problems found in boilers, and should be removed as well.

The exhaust from an internal combustion engine can be as hot as 650 °C. Waste heat can be recovered using a water jacket or exhaust gas heat exchanger. Recovered heat can be used to warm digesters or for certain biogas upgrading systems.

Microturbines

Microturbines are small gas turbines and operate on the Brayton Cycle (Figure 12). They have lower emissions compared to reciprocating engines, generally, and may have lower maintenance Microturbines have higher capital costs than reciprocating engines, but may have lower overall costs when air pollution control equipment is considered. Microturbines achieve 15 – 30% electrical efficiencies. Due to tight California air quality restrictions, commercial units for use in California are generally rated to produce less than 4 – 5 ppmvd NOx (at 15% O_2), while non-California versions generate 9 ppmvd NOx.

Microturbines generally have a capital cost of $700 – $1,100/kWh and a maintenance cost of $0.005 – $0.016/kWh (Capehart 2010).

Figure 12: Microturbine Structure

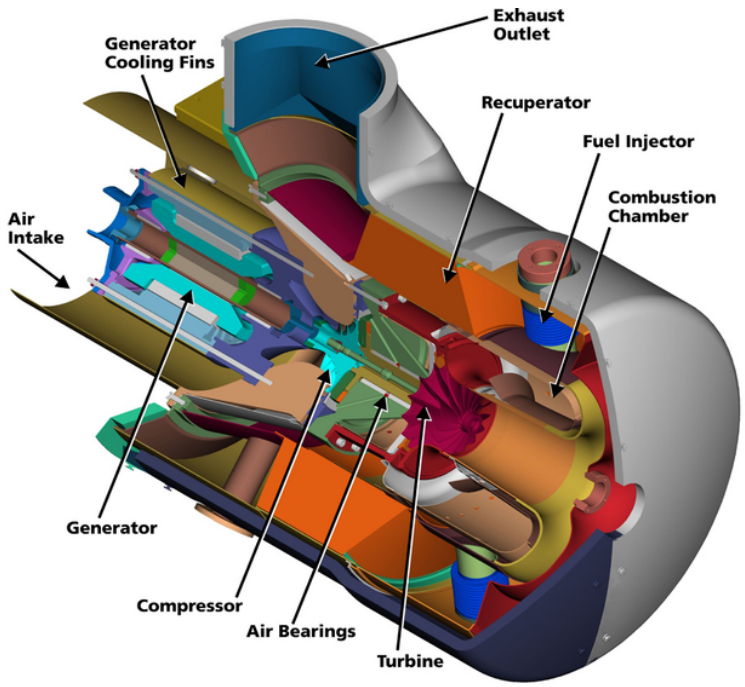


Illustration Credit: Capstone Turbine Corporation (2010)

Typically, microturbines can tolerate up to 1,000 ppm H_2S, and encounter the same problems with burning siloxane and particles. Also, since the biogas must be compressed in order to be injected into the pressurized combustion chamber, the biogas needs to be dry to avoid condensation.

Fuel Cells

Fuel cells have for several decades been the technology of space exploration, but have in recent years garnered significant attention for distributed power, transportation, and small mobile applications. They have high electrical efficiency (30 – 70%), and very low air pollutant emissions.

Fuel cells basically consist of an anode and a cathode separated by an electrolyte. Hydrogen gas catalytically splits on the anode, causing electrons to pass from anode to cathode through a circuit (electricity generation), and ions to pass from anode to cathode through the electrolyte. The hydrogen ions react withoxygen at the cathode producing water., The operation and performance of a fuel cell depend upon the anode and cathode material, electrolyte substance, and design configuration.

Methane in biogas can be used for fuel cells if it is first reformed to hydrogen and CO_2. The gas produced from reforming pure methane contains roughly 40 – 70% H_2, 15 – 25% CO_2, and 1 – 2% CO. Methane can be externally steam reformed using a catalyst (usually nickel) at high temperatures and pressures (700 – 1000 C°), or internally reformed at high-temperature fuel cell operations using the anode material as a catalyst. Hot fuel cells above 800°C can also cause CO_2 to act as an electron carrier instead of inhibiting the electrochemical process. High temperature fuel cells are more fuel flexible and more tolerant to fuel impurities. Waste heat from external reforming can be used to heat low – mid temperature fuel cells. The reformer-shift reactor sequence generally has a net efficiency of ~ 75% for large-scale installations and ~ 60% for smaller ones (< 1,000,000 scf methane/day).

There are currently five major types of fuels cells that are being researched and industrially applied: Polymer electrolyte membrane or proton exchange membrane (PEMFC), alkaline, phosphoric acid (PAFC), molten carbonate (MCFC), and solid oxide (SOFC). Each of these designs differ from one another in the materials and chemicals used in their construction, which changes their operating conditions and the reactions that occur to produce electricity (

Figure 13). MCFCs and SOFCs operate at high temperature and are internal reforming. PEMFCs and PAFCs types do not employ internal reforming so biogas or natural gas must be reformed to hydrogen before being used in the fuel cell. While biogas has been demonstrated on or experimented with internal and external reforming fuel cell types (Scholz, 2011), MCFC systems appear to be the type most often used for biogas applications systems (FuelCellToday, 2012)

Figure 13: Fuel Cell Reactions

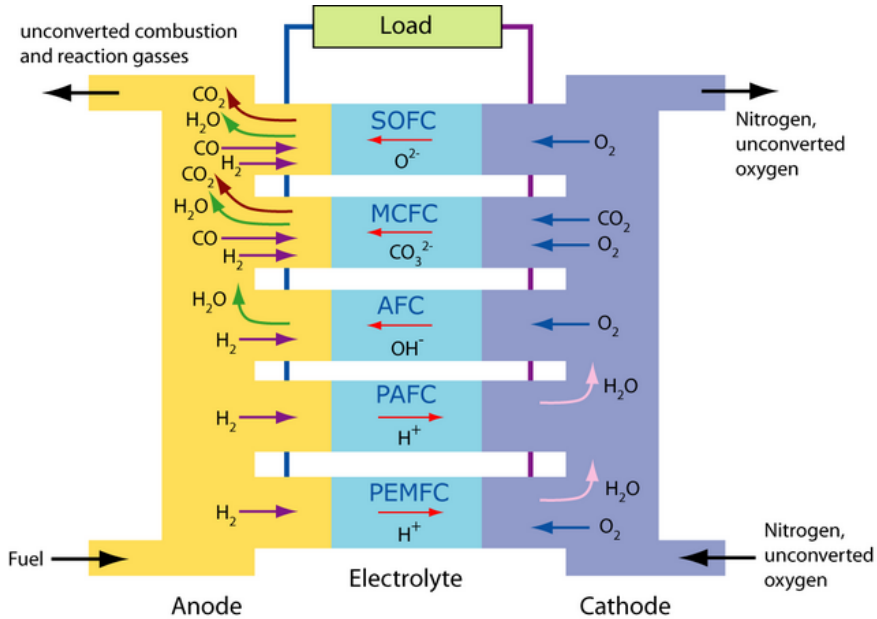


Illustration Credit: Adapted from Fray, Varga, and Mounsey (2006)

Depending upon the expected incoming gas quality, desired application, and power size, an appropriate fuel cell type can be chosen.

Table 4 provides a technical comparison of the five fuel cell types, with a breakdown of their contaminant limits. Overall, fuel cells are more electrically efficient than other gas-powered electricity generation technologies. However, they are mostly still in the research and development phase, although there are several pilot and early commercial systems available. The downside of fuel cells is their high capital costs, which are at least ten times more expensive than other electricity generating options. They are also less intolerant to contaminants, and so require superior gas cleaning.

Table 4: Fuel Cell Technology Comparison

	Polymer Electrolyte Membrane	Alkaline	Phosphoric Acid	Molten Carbonate	Solid Oxide
Application	Space; Vehicles; Mobile	Military; Space	Stationary power, Vehicles	Stationary power	Stationary power; Vehicles
Fuel gas	H_2, Methanol, Reformed gas [CH_4]	H_2, Hydrazine	H_2, Reformed gas [CH_4, Natural gas, Coal gas, Biogas]	H_2, CH_4, Natural gas, Coal gas, Biogas	H_2, CH_4, Natural gas, Coal gas, Biogas
Charge Carrier	H^+	OH^-	H^+	CO_3^{2-}	O^{2-}
Temperature	50 – 120 °C	60 – 120 °C	130 – 220 °C	600 – 700 °C	650 – 1000 °C
Stack Power Size	1 W – 500 kW	0.5 – 100 kW	10 kW – 1 MW	0.1 – 3 MW	1 kW – 2 MW
Electrical Efficiency	CH_4: 35 – 40% H_2: 60%	50 – 70%	35 – 50%	40 – 60%	45 – 60%
CO_2		100 – 500 ppm			
H_2S	< 1 ppm		< 2 – 4 ppm	0.1 – 10 ppm	≤ 1 ppm
Total Sulfur	0.1 ppm		< 4 – 50 ppm	0.01 – 10 ppm	0.1 – 10 ppm
CO	5 – 50 ppm	0.001 – 0.2%	0.5 – 1.5%		
Oxygen			< 4%	0.1%	
NH_3	10 – 200 ppm		< 0.5 – 4%	0.05 – 3%	0.5%
Halogens			< 4 ppm	0.1 – 1 ppm	< 1 – 5 ppm
Total Silicon	N.A.	N.A.	N.A.	10 – 100 ppm	< 0.01 ppm
Mercury	N.A.	N.A.	N.A.	30 – 35 mg/m^3	N.A.
Olefins	N.A.	N.A.	0.5%	0.2%	N.A.
Status	Research, Commercial	Governmental	Commercial	Research	Research

Chart Credit: Author; Data Credit: Allegue and Hinge (2012a); Deublein and Steinhauser (2011); Kaparaju and Rintala (2013); Papadias, Ahmed, and Kumar (2011)

Vehicle Fueling

Biogas can be upgraded to biomethane and used for vehicle fuel applications (as renewable compressed natural gas (CNG) or liquid natural gas (LNG). Biogas use for vehicles can be an attractive alternative to distributed power generation because air emissions are transferred to the vehicle (and local air permitting is simplified) and possibly economics.

Light-duty and heavy-duty vehicles can be fueled by natural gas (or renewable natural gas). Light-duty natural gas vehicles are often designed to run on both gasoline and CNG (with two separate tanks). Heavy-duty vehicles are normally designed to run on a single fuel type (CNG or diesel). When natural gas displaces diesel as vehicle fuel, emissions reductions of 60 – 85% for NOx, 10 – 70% for CO, and 60 – 80% for particulates can be achieved. Non-methane VOC emissions and the ozone forming potential decrease by 50%.

To produce vehicle-grade R-CNG and R-LNG, raw biogas must be cleaned and upgraded to biomethane. Moisture, siloxanes, hydrogen sulfide (and possibly other contaminants) are cleaned from the biogas which is then upgraded to biomethane (typically to >88% methane). Oxygen content will also have to be closely monitored and adjusted to avoid gas mixtures that permit explosions to occur. Unlike other systems, there is little concern about biological contamination since microbial growth does not occur under such high pressures.

Large-scale liquefaction of pipeline natural gas is commonplace around the world, but small-scale operations (5,000 – 50,000 gpd) have presented technological and economic challenges. As of October 2014, the US has 752 public CNG fueling stations and 669 private ones, and 64 public LNG fueling stations and 41 private ones. California has 156 public CNG fueling stations and 129 private ones, and 14 public LNG fueling stations and 31 private ones (US DOE 2014).

Natural Gas Pipeline Injection

Another emerging option for biogas utilization is to upgrade and inject into natural gas pipelines. This choice is ideal in situations where the biogas producer's energy and fuel demands are either not significant enough, or those demands are already met by a fraction of the total available biogas. Biogas pipeline injection takes advantage of the pre-existing network infrastructure and ideally allows 100% of the biogas to be utilized. Pipeline injection also allows for more efficient use of the biogas, since larger natural gas to electricity facilities are much more efficient than small-scale, on-site, distributed power generation systems.

High investment and operating costs, as well as complicated regulatory hurdles (e.g., gas quality standards, gas testing and monitoring requirements, permits) imposed by government agencies and utility companies , have generally constrained pipeline injection to large biogas generators with high biomass throughput (i.e., landfills, WWTPs, centralized digester plants) that have the resources to pursue such an endeavor. However, as air quality standards are recently becoming stricter in California, especially in nonattainment air districts (e.g., San Joaquin Valley and South Coast), existing and new small-scale biogas-fueled distributed generation systems such as those found on dairy farms will begin having a harder time meeting these standards. Small-scale pipeline injection provides a possible alternative. To make pipeline injection for farms more economically feasible, several nearby farms can form a co-op to send their raw biogas to a central cleaning and upgrading facility. Thus, the expensive investment costs are divided among multiple parties and it becomes less expensive on an individual basis. In addition, the equipment needed is more cost-effective (lower levelized cost of energy) at

larger scales. Under this scenario, some minor contaminant removal will still be required at each source to avoid transmitting chemicals that will corrode the collection pipeline.

Another issue is that the local pipeline capacity may not be sufficient, especially in more rural locations. Even if there is a pipeline, not all sites can feasibly participate since some may not be close enough to gas transmission lines. And even if there is a pipeline close enough, it may not be able to handle the necessary throughput capacity for biogas injection.

The first biogas upgrading and pipeline injection facilities in the US were installed in the 1980s using gas from landfills and WWTPs. Currently, there are around 60 projects in the US that inject biomethane into natural gas pipelines: at least 33 landfill projects, 25 WWTP projects, and one farm-based project (California Air Resources Board and California Office of Health Hazard Assessment 2013). There is currently at least one operating biomethane pipeline injection project operating in California at the Point Loma Wastewater Treatment Plant in San Diego. A detailed description of this project can be found in Appendix B of this report.

CHAPTER 4:
Regulatory and Technical Standards for Biogas Usage

Raw biogas from any source contains trace amounts of contaminants, some of which have the potential to compromise human health and safety, equipment integrity, and environmental wellbeing if at high enough concentrations. Thus, biogas needs to be cleaned and upgraded to appropriate standards. For injection to natural gas pipelines, the biogas should be upgraded to biomethane by removing the majority of carbon dioxide, producing a gas consisting of more than 95% methane.

Aside from technical requirements, there are numerous regulations that must be met. Regulations and regulatory agencies exist for nearly all facets of a biogas project, e.g., air emissions, water usage, wastewater discharge, solid waste disposal, environmental impact, construction, etc. For example, if the biogas cleaning process uses or disposes of hazardous waste chemicals, the operator must obtain a permit from the California Department of Toxic Substances Control. A permit from the State Water Resources Control Board is required for wastewater discharge and storm water runoff or construction—a new permit is needed for digester installation. Along with constructing any biogas cleaning/upgrading or digester system, there are city and county planning ordinances and zoning requirements that must be followed. The new installations need to meet building code requirements and building permits for the digesters are required. The project may additionally necessitate a California Environmental Quality Act (CEQA) or National Environmental Policy Act (NEPA) Environmental Impact Report to be completed prior to construction if an Initial Study finds that the project will have a significant impact on the environment. Because these systems have potential for air emissions, authority to construct and permits to operate must be obtained from the local air district.

One of the primary uncertainties regarding the California biogas industry is the fact that regulations have been subject to change at unpredictable times. Some changes excluded preexisting systems, while others afforded some time to achieve compliance. This means that after project completion, their remains an ongoing requirement for operators need to keep themselves informed about any future enactments that will affect their system.

Relevant regulations and technical requirements differ depending upon where and how the biogas is collected, cleaned/upgraded, and utilized. The following subsections outline the regulatory and technical standards that processed biogas generally must meet for distributed power or injection into California natural gas pipelines.

Distributed Power Generation Gas Standards

As with any energy technology, there are numerous government and corporate regulations and policies that apply to distributed power generation. However, only in recent years have rules for waste gas (i.e., biogas) been amended into existing electricity generation regulations, the

most pressing being those related to air emissions. Other policies have been enacted to promote electricity generation from bioenergy resources. Technical limitations on biogas also exist because of compounds found in biogas that can damage the power generation systems. The following sections discuss the regulations, policies, and technical constraints of the distributed power generation technologies referenced in Chapter 3.

Regulations and Policies

Developing a centralized digestion processing facility requires amending waste, water, and air permits for each source facility in addition to permits for the processing facility. Co-digestion adds another level of permitting, reporting, and oversight. Permitting is often a lengthy process that can delay or even terminate projects. For example, it can take over two years to get State Water Resources Control Board permits concerning expected nitrate and salt concentration effects on groundwater. Updates to regulations can also be detrimental to biogas projects. At least one California farm digester shut down due to changes in local air district requirements for power generation equipment, i.e., San Joaquin Valley Air Pollution Controld District Rule 4702 (Sousa 2010). Keep in mind that there are only about a dozen farm digesters operating in California. Out of all the permits involved in implementing distributed generation technologies, air quality-related standards are one some of the most pertinent.

There are 35 regional air districts in California which regulate stationary air pollution sources in the state (Figure 14). Air districts that exceed the national ambient air quality standards for a pollutant are labeled as 'nonattainment' areas for that pollutant and must take action to bring the district into compliance (i.e., reduce emissions). For example, both the South Coast Air Quality Management District (SCAQMD) and the San Joaquin Valley APCD are in nonattainment for ground-level ozone, which is formed by reaction of oxides of nitrogen (NOx) and volatile organic compounds (VOCs) in the presence of sunlight (photochemical smog). As a result, SCAQMD has revised Rule 1110.2: Emissions from Gaseous- and Liquid-Fueled Engines that sets stationary and portable internal combustion engine emission standards to reduce NOx to < 11 ppmvd, CO to < 250 ppmvd, and VOCs to < 30 ppmvd for landfill and digester gas-fired engines. The San Joaquin Valley Air Pollution Control District enacted Rule 4702: Internal Combustion Engines which set more stringent air pollution emission standards for spark-ignition internal combustion engines. Specifically, for any stationary internal combustion engine rated above 50 bhp running off of biogas, emission must be limited to < 50 ppmvd NOx, < 2,000 ppmvd CO, and < 250 ppmvd VOCs. Alternatively, an engine can be compliant if it achieves an aggregate NOx emission level less than 90% of the NOx emissions achieved over a seven month period given 2,000 ppmvd NOx. This rule alone forced the closure of at least one dairy digester operation that could not meet the new specification and hinders the reinstatement of at least two other digesters that had previously been forced offline by other regulations (Sousa, 2010). Thus, when developing a biogas project in California, it is more prudent to ensure that systems be designed that are technically flexible enough within economic reason to adjust to any new regulatory changes that may occur. Over-specifying a system may cost more money initially, but can avoid future frustrations, problems, and downtime.

Figure 14: Map of California Air Districts

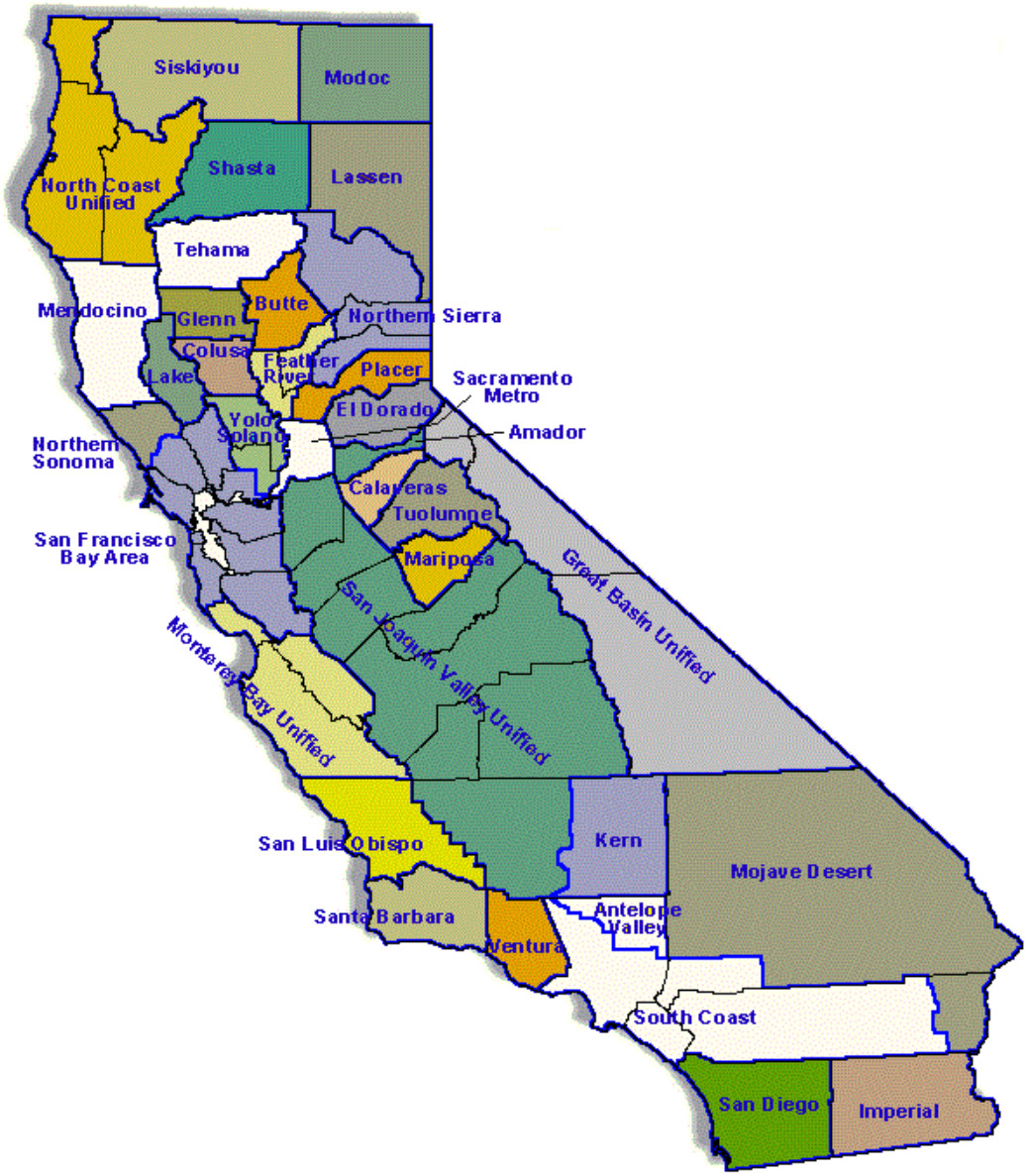


Illustration Credit: California Air Resources Board (2014)

Table 5 summarizes the rules pertinent to biogas utilization for the aforementioned air districts. To meet these standards, H_2S and ammonia are removed from the biogas to reduce NOx and SOx emissions. Concentration of halogens in the feed gas, which can lead to hazardous air emissions, are usually not high enough to regulate (but would be if present in sufficient concentration). Halocarbons would fall under the category of VOCs.

Table 5: List of Distributed Power Emission Requirements for Several California Air Districts

Air District	Rule	Applicability	SOx / SO_2	NOx / NO_2	CO	H_2S	NH_3	Combustion Contaminants	Particulates	Compliance Date
Butte	202	All							0.3 grain/scf	8/22/2002
	261	All				0.03 ppm				8/22/2002
	262	All	0.2% (2,000 ppm)							8/22/2002
	250	Boilers, Steam generators, Process heaters		70 ppmv (0.084 lb/MMBtu)	400 ppmv		20 ppm (at 3% O_2)			3/25/2004
	252	Stationary IC engines (lean burn, 50 - 300 bhp)		740 ppmv	4,500 ppmv					1/1/2006
		Stationary IC engines (lean burn, > 300 bhp)		150 ppmv	4,500 ppmv					
Eastern Kern	404.1	All							0.1 grain/scf	1/24/2007
	407	All	0.20%							4/18/1972
	409	Boilers, Engines, Turbines						0.1 grain/scf (at 12% CO_2)		5/7/1998
	425.2	Boilers, Steam generators, Process heaters (> 5 MMBtu/hr)		70 ppmv (0.09 lb/MMBtu) (at 3% O_2)	400 ppmv (at 3% O_2)					11/30/1997
	427	Stationary IC engines (lean burn, > 250 bhp)		125 ppm (2 g/bhp-hr) (at 15% O_2)	2,000 ppmv (at 15% O_2)					11/1/2001
	425	Cogeneration Gas Turbine Engines (> 10 MW)		RACT: 10 ppmv; BACT (20*EFF/25) ppmv						1/1/1997

Air Quality Management District	Rule	Applicability	SOx / SO_2	NOx / NO_2	CO	H_2S	Compliance Date
San Francisco Bay Area	9-1	All	300 ppm				5/20/1992
	9-2	All				0.06 ppm (3 min avg)	10/6/1999
	9-3	Heat transfer Systems		125 ppm (new); 175 (existing)			4/19/1975
	9-6	Boilers, Water heaters (0.075 - 0.4 MMBtu/hr)		14 ng/J			1/1/2013
		Boilers, Water heaters (0.4 - 2 MMBtu/hr)		20 ppm (at 3% O_2)			1/1/2013
	9-7	Boilers, Steam generators, Process heaters (> 10 MMBtu/hr)		30 ppmv (at 3% O_2)	400 ppmv (at 3% O_2)		1/1/1996
	9-8	Stationary internal combustion engines (lean burn, > 50 bhp)		70 ppmv (at 15% O_2)	2,000 ppmv (at 15% O_2)		5/31/2012
	9-9	Stationary gas turbines (0.3 - 10 MW)		42 ppmv (at 15% O_2)			1/1/1996
		Stationary gas turbines (> 10 MW w/o selective catalytic reduction)		15 ppmv (at 15% O_2)			1/1/2000
		Stationary gas turbines (> 10 MW w/ selective catalytic reduction)		9 ppmv (at 15% O_2)			1/1/2000

Air Quality Management District	Rule	Applicability	SOx / SO_2	NOx / NO_2	CO	VOCs	Combustion Contaminants	Particulates	Compliance Date
San Joaquin Valley Unified	4201	All						0.1 grain/scf	12/17/1992
	4301	All	200 lb/hr	140 lb/hr			0.1 grain/scf (at 12% CO_2)		12/17/1992
	4308	Boilers, Steam generators, Process heaters (0.075 - 0.4 MMBtu/hr)		77 ppmv (at 3% O_2)					1/1/2015
		Boilers, Steam generators, Process heaters (0.4 - 2.0 MMbtu/hr)		30 ppmv (at 3% O_2)					
	4702	Stationary IC engines (non-agricultural, lean burn, > 50 bhp)		65 ppmv (at 15% O_2)	2,000 ppmv (at 15% O_2)	750 ppmv (at 15% O_2)			1/1/14; 1/1/16; 1/1/17
		Stationary IC engines (agricultural, lean burn, > 50 bhp)		150 ppmv (at 15% O_2)	2,000 ppmv (at 15% O_2)	750 ppmv (at 15% O_2)			1/1/2010; 1/1/2015
	4701	Stationary IC engines (waste derived gaseous fuel, > 50 bhp)		125 ppmv (at 15% O_2)	2,000 ppmv (at 15% O_2)	750 ppmv (at 15% O_2)			5/31/2001
	4703	Stationary gas turbines (< 3 MW)		9 ppmvd (at 15% O_2)	200 ppmv (at 15% O_2)				1/1/2012
		Stationary gas turbines (3 - 10 MW)		8 - 12 / 9 / 5 ppmvd (at 15% O_2)	200 ppmv (at 15% O_2)				
		Stationary gas turbines (> 10 MW)		5 / 25 ppmvd (at 15% O_2)	200 ppmv (at 15% O_2)				

Air Quality Management District	Rule	Applicability	SOx / SO_2	NOx / NO_2	CO	VOCs	Combustion Contaminants	Particulates	Compliance Date
South Coast	432.1	Stationary equipment (Landfill gas)	150 ppmvd						6/12/1998; 11/17/1995
		Stationary equipment (Sewage digester gas)	40 ppmvd						
	409	IC engines					0.1 g/scf (at 12% CO_2)		7/7/1981
	407	All	500 ppmv		2,000 ppmv				7/1/1982
	404	All						≤ 450 mg/m3	2/7/1986
	474	All		125 ppm (at 3% O_2)					12/4/1981
	476	Boilers, Steam generators, Process heaters		125 ppm (at 3% O_2)			0.1 g/scf (at 3% CO_2)		5/7/1976
	475	Stationary gas turbines (New: > 10 MW, Existing: > 5 MW)					0.1 g/scf (at 3% CO_2)		8/7/1978
	1146.2	Boilers, Steam generators, Process heaters		20 ppm (at 3% O_2)					1/1/2012
	1110.2	Stationary IC engines (agricultural, lean burn, > 50 bhp)		11 ppmvd	250 ppmvd	30 ppmvd			7/1/2012
	1134	Stationary gas turbines (0.3 - 2.9 MW)		25 ppm (at 15% O_2)					8/8/1989
		Stationary gas turbines (digester, 2.9 - 10 MW)		25 ppm (at 15% O_2)					

Air Quality Management District	Rule	Applicability	SOx / SO_2	NOx / NO_2	CO	VOCs	Combustion Contaminants	Particulates	Compliance Date
South Coast (cont.)	1134	Stationary gas turbines (2.9 - 10 MW w/o selective catalytic reduction)		15 ppm (at 15% O_2)					8/8/1989
		Stationary gas turbines (> 10 MW)		9 ppm (at 15% O_2)					
		Stationary gas turbines (> 10 MW w/o selective catalytic reduction)		12 ppm (at 15% O_2)					
	1135	All		0.1 lb/MWh					7/19/1991
Yolo-Solano	2.16	Heat/Power generators	200 lb/hr	140 lb/hr				40 lb/hr	
	2.37	Boilers (400k - 1M Btu/hr)		20 ppm (at 3% O_2)					1/1/2014
	2.32	Stationary IC engines (lean burn, > 50 bhp)		150 ppmv (at 15% O_2)	2,000 ppmv (at 15% O_2)				5/31/1997
	2.34	Stationary gas turbines (0.3 - 2.9 MW)		42 ppm (at 15% O_2)					7/13/1998

Chart Credit: Author; Data Credit: California Air Resources Board

Other regulations affecting distributed power generation technologies include Best Available Control Technology, District Rule 2201: New and Modified Stationary Source Review Rule, and the ARB distributed generation certification program.

Producers that generate excess electricity or do not want to use it themselves can opt to sell electricity to their local electricity utility company. The three largest electricity investor-owned utility companies in California are: Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (Figure 15). The energy price and rules for selling electricity into the grid are dictated by the utility company's electricity feed-in tariff.

Figure 15: Map of California Electricity Utility Service Areas

Illustration Credit: California Energy Commission (2014)

Relevant policies to promote renewable energy generation include the California RPS and the recently enacted Senate Bill 1122 (Rubio): Bioenergy Feed-in Tariff, which requires investor-owned electrical utilities to procure a cumulative 250 MW of new, small scale (< 3 MWe) biopower generating capacity allocated among the following categories: 110 MW to biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion; 90 MW to dairy and other agricultural bioenergy; 50 MW to bioenergy using byproducts of sustainable forest management. At the same time, Assembly Bill 2196 (Chesbro): Renewable Energy Resources, declares biomethane delivered to a generation facility via common carrier pipeline to be eligible for RPS credits if it meets certain requirements including limited applicability of out-of-state biomethane.

Technical Constraints

Distributed power generation technologies can accept a range of fuel energy content characteristic of raw biogas. Reciprocating engines and fuel cell stacks are available in large power sizes in the MW range while microturbines are limited to smaller power sizes in the hundreds of kW (Table 6).

Table 6: Features and Technical Requirements of Distributed Power Generation Technologies and CNG Vehicles

	Boilers	Reciprocating Engines	Microturbines	Fuel Cells	CNG Vehicles
Energy Content - minimum or range (BTU/scf HHV)	N.A.	400 – 1,200	350 – 1,200	450 – 1,000	900
Power Size	N.A.	5 kW – 10 MW	25 kW – 500 kW	1 kW – 3 MW	N.A.
Electrical efficiency	0%	18 – 45%	15 – 33%	30 – 70%	0%
Thermal efficiency from CHP	75 – 85%	30 – 50%	20 – 35%	30 – 40%	N.A.

Chart Credit: Author; Data Credit: Allegue and Hinge (2012a); Australian Meat Processor Corporation (2014); Krich et al. (2005); Zicari (2003)

Gas fueled power generation technologies have certain technical limitations regarding contaminants and trace compounds allowable in the fuel gas. The most prevalent contaminants and their effects on distributed power generation systems include the following:

- Sulfur compounds are corrosive when dissolved in water. When hydrogen sulfide is also combusted it is converted to sulfur dioxide which is a criteria pollutant and forms corrosive sulfuric acid when dissolved in water. Sulfur compounds can accumulate in engine oil and accelerates bearing wear, but can be somewhat mitigated with frequent

oil changes. Sulfur poisons many of the metal catalysts (e.g., nickel, platinum) that used for fuel cell electrodes, methane reforming, and catalytic air pollution control devices.

- Entrained water and compressor oil droplets can damage combustion systems by injector wear, filter plugging, power loss and corrosion of engine fuel system parts. They also lead to the majority of natural gas vehicle problems, causing reduced drive performance and erratic operation. Water vapor may condense or form ice during large pressure changes.
- Siloxane converts to silicon dioxide (SiO_2) when combusted. SiO_2 can form hard deposits on the inner walls of pipes and valves, cylinder heads, pistons, turbine blades, and heat exchanger surfaces. They can also abrasively erode engine blades or block openings and seals and degrade sensors.
- Ammonia in the fuel gas contributes to NOx production when burned and should be managed or minimized if NOx is a concern.
- Halogenated compounds are corrosive in the presence of water. Combusting halogenated compounds under certain temperature and time conditions can create dioxins and furans, which are highly toxic.
- Particulate matter can wear down equipment and can plug the gas system.

Hydrogen sulfide and siloxanes are the two most significant contaminants due to the extent of damage they can cause. However, different contaminants have different effects, and even the same contaminant can affect each type of distributed generation technology differently. Thus, the feed gas contaminant restrictions will vary depending upon the generation equipment used.

Table 7 summarizes these requirements.

Table 7: Fuel Gas Requirements for Distributed Power Generation Technologies and CNG Vehicles

	Boilers	Reciprocating Engines	Microturbines	Fuel Cells	CNG Vehicles
CH_4	> 50%	> 60%	> 35%	N.D.	> 88%
Hydrocarbon Dew Point					> 10 °F
Hydrocarbons					C_2H_6: <6% C_3+: <3% C_6+: <0.2%
H_2S (ppm)	< 1,000	< 50 – 500	<1,000 – 70,000	< 0.1 – 10	N.D.
Total S (ppm)	N.D.	<542 – 1,742	N.D.	< 0.01 – 50	< 16
Total Inerts					<1.5 – 4.5%
CO_2 (ppm)				< 100 – 500	
CO (ppm)				< 0.001 – 50	< 1,000
Oxygen (%)		< 3%		< 4%	< 1%
Hydrogen (%)					< 0.1%
NH_3 (ppm)	N.D.	< 25	< 200	< 0.05 – 200	
Chlorine (ppm)	N.D.	< 40 – 491	< 200 – 250	< 0.1 – 5	< 1,000
Fluorine (ppm)	N.D.	< 40	1,500	< 0.1 – 5	
Siloxanes (ppm)	N.D.	< 2 (0.03 – 28 mg/m^3)	< 0.005	< 0.01 – 100	< 1
Mercury (mg/m^3)	N.D.	N.D.	N.D.	< 30 – 35	N.D.
Olefins	N.D.	N.D.	N.D.	< 0.2 – 0.5%	N.D.
Dust	N.D.	< 5 mg/kWh	< 20 ppm	N.D.	N.D.
Particle size	N.D.	< 3 μm	< 10 μm	< 10 μm	N.D.

N.D.: Not Determined or not found listed where values are expected to be non-negligible, but data were not found.

Chart Credit: Author; Data Credit: Allegue and Hinge (2012a); Australian Meat Processor Corporation (2014); Krich et al. (2005); Zicari (2003)

LNG is created by cooling natural gas (or biomethane) to about -160 C. Because contaminants will freeze, the gas should contain less than 0.5 ppm H_2O, 3.3 – 3.5 ppm H_2S, 50 – 125 ppm CO_2,

10% C_2 to C_4 hydrocarbons, 1 ppm C_5+ hydrocarbons, and 10% O_2 and N2, as well as have a moisture dew point less than -70 °C.

Gas Pipeline Injection Standards

Natural gas is transported and distributed in California primarily by four investor-owned natural gas utility companies that supply separate regions. In order of descending geographic size, these are: Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDGE), and Southwest Gas Corporation (SWGas).

PG&E services 4.3 million gas customers in 70,000 square mile throughout northern and central California. SoCalGas's 20,000 square miles throughout Central and Southern California, from Visalia to the Mexican border, supplies natural gas to 5.8 million customers. SDGE provides natural gas to 860,000 customers in 4,100 square miles spanning San Diego and southern Orange County. Finally, SWGas's services 187 thousand customers in 2,347 square miles covering roughly one-eighth of San Bernadino County and the area surrounding Lake Tahoe (

Figure 166). In addition to these four, there are numerous other public and private natural gas providers throughout California, but whose sum total coverage area is less than PG&E's and SoCalGas's. Gas companies operating within California are regulated by the California Public Utilities Commission (CPUC).

Figure 16: Map of California Natural Gas Utility Service Areas

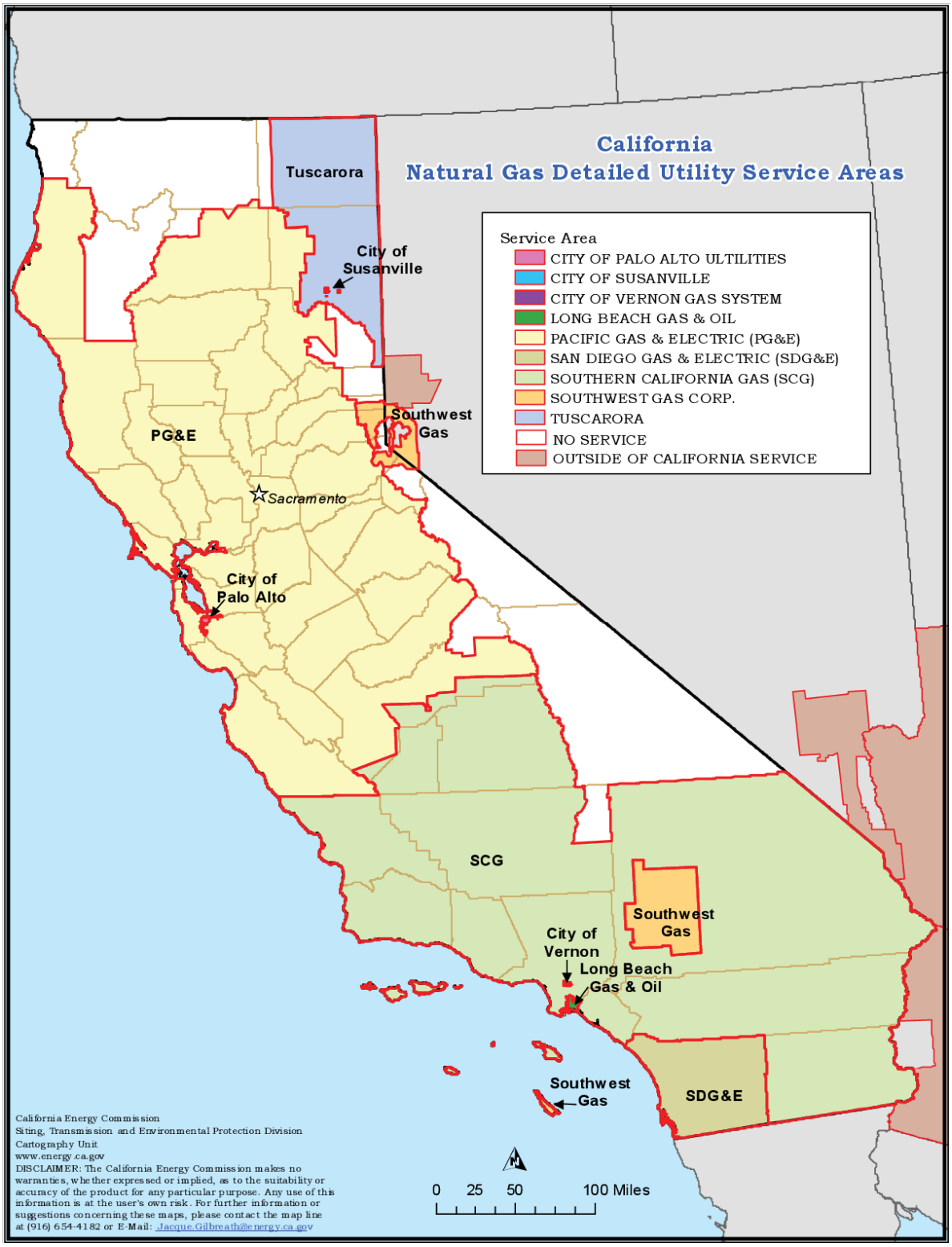


Illustration Credit: California Energy Commission (2012)

Vinyl Chloride in LFG and the Hayden Bill

In the mid-1970s, vinyl chloride was identified as a potent gaseous carcinogen that gave rise to angiosarcoma, a rare form of cancer that develops tumors in vessel walls and the liver. With the development of the plastic PVC industry, which heavily used the chemical, vinyl chloride exposure became an increasing concern throughout the U.S. during the 1980s. Studies investigating sources of vinyl chloride emissions found landfills to be a potential major source in California, emitting low concentrations of vinyl chloride into the air from anaerobic microbial action on organic chlorinated compounds (Molton, Hallen, and Pyne 1987).

As a result of these concerns, Assembly Bill 4037 (Hayden) was passed in 1988 to protect the public from potentially harmful exposure to vinyl chloride present within collected landfill gas that may be transported through natural gas pipelines. This bill specifically dictated that the maximum amount of vinyl chloride that may be found in landfill gas to be 1170 ppbv at the point of pipeline injection, mandated twice monthly sampling of landfill gas for vinyl chloride, and set a $2,500 fine to both the gas producer and pipeline owner if the vinyl chloride limit was exceeded. To avoid the risk of fines and especially forced shutoffs, all of the large gas companies in California refused to accept landfill gas into their pipelines. CPUC General Order No. 58: Standards for Gas Service in the State of California, enacted December 16, 1992, expanded upon the Hayden Amendment by adding concentration limits to hydrogen sulfide and total sulfur.

New Biomethane Standard for Pipeline Injection (Assembly Bill 1900)

Assembly Bill 1900 (Gatto)[3] amended the California Health and Safety Code Section 25420-25422, which defines health and safety limitations of biogas/biomethane use. The goals of AB 1900 were to remove existing barriers to biomethane pipeline injection and facilitate its implementation, including lifting the bans on landfill gas pipeline injection. The Bill required OEHHA, in consultation with other state agencies, to develop standards for biogas focusing on constituents of concern in order to protect human health as well as ensure pipeline integrity and safety. OEHHA and ARB identified 12 potential biogas constituents of concern: Antimony, Arsenic, Copper, p-Dichlorobenzene, Ethylbenzene, Hydrogen sulfide, Lead, Methacrolein, n-Nitroso-di-n-propylamine, Mercaptans (alkyl thiols), Toluene, and Vinyl chloride. A risk management strategy was then developed based upon Trigger, Lower Action, and Upper Action concentration levels in treated biogas (at the point of pipeline injection) for these 12 constituents (Table 8).

At concentrations above the trigger level, the constituent must be routinely monitored (quarterly or annually). The constituents required to be measured depend on the biogas source (i.e., landfill, dairy, POTW), while the frequency of monitoring is set by an initial pre-injection screening evaluation. Typically, testing is conducted annually when below the trigger level, and quarterly when above. A compound's testing interval can be extended from quarterly to annually after consecutive tests show concentrations below the trigger level, but is reset once the trigger level is exceeded. If the lower action level is exceeded three times in a 12 month period or at any time the levels exceed the upper action level, the facility must be shut-off (stop injecting into the pipeline) and repaired. To the author's knowledge, no other state or country has regulations equal or

[3] Chaptered 27 September, 2012 – Chapter 602

similar to those regarding constituents of concern and human health impacts for biomethane injected into natural gas pipeline systems. Aside from hydrogen sulfide and mercaptans, only antimony has been found to be mentioned elsewhere (see the UK Environmental Agency's Quality Protocol: Biomethane from waste).[4]

Table 8: Risk Management Levels for Constituents of Concern in Treated Biogas for Pipeline Injection

Constituent of Concern	Risk Management Levels (Health Based Standards) mg/m^3 (ppmv)			Source-Specific Constituents of Concern		
	Trigger Level	Lower Action Level	Upper Action Level	Landfills	POTW	Dairy
Carcinogenic Constituents of Concern						
Arsenic	0.019 (0.006)	0.19 (0.06)	0.48 (0.15)	✔		
p-Dichlorobenzene	5.7 (0.95)	57 (9.5)	140 (24)	✔	✔	
Ethylbenzene	26 (6.0)	260 (60)	650 (150)	✔	✔	✔
n-Nitroso-di-n-propylamine	0.033 (0.006)	0.33 (0.06)	0.81 (0.15)	✔		✔
Vinyl Chloride	0.84 (0.33)	8.4 (3.3)	21 (8.3)	✔	✔	
Non-carcinogenic Constituents of Concern						
Antimony	0.60 (0.12)	6.0 (1.2)	30 (6.1)	✔		
Copper	0.060 (0.02)	0.60 (0.23)	3.0 (1.2)	✔		
Hydrogen Sulfide	30 (22)	300 (216)	1,500 (1,080)	✔	✔	✔
Lead	0.075 (0.009)	0.75 (0.09)	3.8 (0.44)	✔		
Methacrolein	0.075 (0.009)	11 (3.7)	53 (18)	✔		
Alkyl Thiols (Mercaptans)	N.A. (12)	N.A. (120)	N.A. (610)	✔	✔	✔
Toluene	904 (240)	9,000 (2,400)	45,000 (12,000)	✔	✔	✔

Chart Credit: California Air Resources Board and California Office of Health Hazard Assessment (2013)

The CPUC issued Decision (D.) 14-01-034 on January 22, 2014, which required PG&E, SDGE, SoCalGas, and SWGas to change their respective gas tariffs to allow biomethane from all organic sources other than hazardous waste landfills to be injected into the utility's gas pipeline, and develop corresponding concentration standards and monitoring, testing, reporting, and recordkeeping requirements. Subsequently, on February 18, 2014, all four gas companies submitted currently pending advice letters to the CPUC to update their gas tariffs to include the

[4] https://www.gov.uk/government/publications/quality-protocol-biomethane-from-waste

12 constituents of concern and accept non-hazardous waste landfill gas. CPUC Decision (D.) 14-01-034 still prohibits the purchase of biomethane from hazardous waste landfills. The OEHHA/ARB standards will be added to pre-existing gas quality standards set by each company, with the exception of SWGas, which is writing a new tariff document explicitly for biomethane, but will also include other gas quality standards in addition to the constituents of concern.

Prior to the establishment of the 12 constituents of concern for biomethane, the investor-owned utilities (IOUs) published individual natural gas tariffs that specified gas quality requirements. The tariffs normally addressed sulfur species (e.g., hydrogen sulfide, mercaptans) and moisture which can lead to pipeline corrosion, oxygen which promotes microbial growth and can cause explosions, and nitrogen and carbon dioxide that dilute the gas reducing energy content. Biomethane for pipeline injection must meet the specifications for the 12 constituents of concern, as well as the other (natural) gas quality requirements set by the IOUs (

Table 9).[5]

[5] Gas tariffs: PG&E Gas Rule 21; San Diego Gas & Electric Company Rule 30; Southern California Gas Company Rule 30; and Southwest Gas Corporation Rule 22

Table 9: California IOU Gas Quality Standards

Attribute or Compound	PG&E	SoCalGas	SDGE	SWGas
Energy Content (Btu/scf, HHV)	750 – 1150† (990 - 1050)‡	990 – 1150	990 -1150	950 - 1150
Temperature (°F)	60 – 100	50 – 105	50 – 105	40 - 120
Wobbe Index (Btu/scf)	N/A	1279 – 1385	1279 – 1385	≥ 1280
Water Vapor (lb/MMscf)	7	7	7	7
Hydrocarbon Dew Point	45°F at 400 psig if P < 800 psig (or 20°F at 400 psig if P > 800 psig)	45°F at 400 psig if P < 800 psig (or 20°F at 400 psig if P > 800 psig)	20°F at P > 800 psig	20°F
Hydrogen Sulfide (grain/100 scf)	0.25	0.25	0.25	
Mercaptans (grain/100 scf)	0.5	0.3	0.3	
Total Sulfur (grain/100 scf)	1	0.75	0.75	20
Total Inerts (C_1 to C_6+, CO_2, N_2, O_2, CO, H_2)	4%	4%	4%	4%
Carbon Dioxide	1%	3%	3%	2%
Nitrogen				3%
Oxygen	0.1%	0.2%	0.2%	0.2%
Hydrogen	0.1%	0.1%	0.1%	0.1%
Ammonia	0.001%	0.001%	0.001%	0.001%
Biologicals	40,000/scf, Free of < 0.2 µm filter	40,000/scf, Free of < 0.2 µm filter	40,000/scf, Free of < 0.2 µm filter	40,000/scf, Free of < 0.2 µm filter
Siloxane (mg/m³)	0.1: Lower Action 0.01: Trigger	0.1: Lower Action 0.01: Trigger	0.1: Lower Action 0.01: Trigger	0.1: Lower Action 0.01: Trigger
Mercury (mg/m³)	0.08	0.08	0.08	0.08

† Normal PG&E range of higher heating values. PG&E dictates that the interconnecting gas shall have a heating value that is consistent with the standards established by PG&E for each Receipt Point.

‡ Typical higher heating value for a PG&E receipt point.

Chart Credit: PG&E (2014); SoCalGas (2014); SDGE (2014); SWGas (2014)

The gas tariffs referenced in

Table 9 also address dust, sand, dirt, gums, oils, liquids, and other substances that would cause gas to be unmarketable or are injurious to utility facilities, employees, customers, or the general public—e.g., bacteria, pathogens, and hazardous substances including but not limited to toxic and/or carcinogenic substances and/or reproductive toxins.

Note that the OEHHA/ARB biomethane trigger levels are maximums that the IOUs must follow. The IOUs can set lower contaminant maximum concentrations. For instance, the OEHHA/ARB trigger level for hydrogen sulfide is 22 ppm, while three of the four IOUs specify hydrogen sulfide concentrations less than 4 ppm.

In addition to the various contaminants that must be tested, a significant concern among the biogas industry regards the relatively high energy content (or higher heating value [HHV]) of upgraded biomethane required by the pipeline tariffs. Unlike natural gas, biogas does not naturally contain larger hydrocarbon compounds (i.e., ethane, propane, butane, etc.) that would help increase the HHV. Unless enriched with higher energy hydrocarbon gases, biogas generally relies solely upon methane for its HHV. The gross energy content of pure methane is approximately 1012 Btu/scf, meaning that biogas would need to be upgraded to at least 97.8% methane to meet the 990 Btu/scf requirement of the three largest IOUs (Southwest Gas appears to accept 950 Btu/scf (HHV) gas (Table 9). Although technologies exist to upgrade biogas up to 98 – 99% methane, they are expensive and complex. Simple, low-cost upgrading techniques that are cost-effective for small-scale applications can only upgrade biogas to around 95 – 97% methane (e.g., 960-980 Btu/scf (HHV)). While it is allowable to add a small amount of higher energy hydrocarbon to upgraded biomethane in order to boost energy content (e.g., propane which has gross energy of 2557 Btu/scf, or mixing w/ a larger amount of natural gas before injection), biomethane advocates would like the HHV requirement be reduced from 990 Btu/scf to around 960 Btu/scf—similar to the values used in other states and countries.

A number of natural gas pipeline companies in other states and countries accept gas lower than 990 Btu/scf (HHV) (Tables 10, 11). (Foss 2004). Table 10 lists pipeline injection gas quality requirements for US gas companies that accept biomethane. Energy content requirements for other US gas companies are all lower than 990 Btu/scf with some as low as 950 Btu/scf (corresponds to methane concentration of about 94%). The standards for common gas contaminants (i.e., hydrogen sulfide, mercaptans, total sulfur, total inerts, carbon dioxide, nitrogen, oxygen, hydrogen, and moisture) are comparable.

e 10: United States Natural Gas Pipeline Companies' Gas Quality Standards for Pipeline Injection

North Pacific US	New Mexico	Texas	Southern US	Kansas	Michigan	Midwest US	New England
Williams Northwest Pipeline	New Mexico Gas Company	Atmos Energy	Gulf South Pipeline Company	Kansas Gas Service	Westcoast Energy Inc.	Northern Natural Gas	Algonquin Gas Transmission
La Plata A / La Plata B		Core Area / West Area			Raw / Processed		
≥ 985	950 – 1100	950 – 1100	950 – 1175	950 – 1100	≥ 966	≥ 950	967 – 1110
40 – 120 °F / ≤ 120 °F	40 – 120 °F	40 – 120 °F	40 – 120 °F	25 - 120 °F	≤ 49 – 54 °C / ≤ 54 °C	≤ 120 °F	
							1314 – 1400
7		7		7	4	6	7
15 °F at 100 – 1000 psia	15 °F at 100 – 1000 psia	40 °F		25 °F			15 °F
	0.20 gal / 1000 scf		0.20 gal / 1000 scf				C_2+: 12% C_4+: 1.5%
0.25	0.25	0.25	1	0.25	6.6 – 131 / 0.26	0.25	0.5
	0.3	1					
0.75 / 5	0.75	5	20	0.5	N.A. / 1	20	5
					0.7%		
3%	5%	4% / 3%					4%
2%	2%	2%	3%	2%	2%	2%	2%
			3%				
0.1% / 0.2%	0.2%	0.05%	0.2%	0.01%	N.A. / 0.4%	0.2%	0.2%
			0.04%				
			Tech. free†				
Tech. free			Tech. free				

free

Table 11: Non-U.S. Gas Quality Standards for Pipeline Injection, Part I

Country	Austria	Austria	Austria		Belgium		BC, Canada	Germany	
Organization			Gas Connect Austria		Fluxys		FortisBC	DVGW	
Year	2006	2010	2014		2014		2014	2010	
Level	Biogas		Entry-Exit	Point-to-Point	Low	High	Biomethane	Low	High
Methane content	≥ 96%		≥ 85.0%	≥ 85.0 - 89.7%					
Higher heating value (Btu/scf)		1034 – 1,237	1,034 – 1,237	956 – 1,498	920 – 1,038	1,043 – 1,234	≥ 966	811 – 1,266	811 – 1,266
Temperature (°C)			≤ 50	≤ 42 - 50	2 - 38	2 - 38	≤ 54		
Wobbe Index (Btu/scf)		1,285 – 1,517	1,304 – 1,498	1,304 – 1,498	1,179 – 1,258	1,335 – 1,495		1,016 – 1,256	1,237 – 1,517
Water vapor	≤ -8 °C at 40 bar	≤ -8 °C at 4 Mpa	≤ -8 °C at 64 bar	≤ -7 °C at 39 - 40.2 bar; ≤ -8 °C at 40 - 64 bar	≤ -8 °C up to 69 barg	≤ -8 °C up to 69 barg	≤ 65 mg/m³		
Hydrocarbon Dew Point		≤ 0 °C at max op. pressure	≤ 0 °C at 1 - 70 bar	≤ -5 °C at 39 - 69 bar; ≤ 0 °C at 1 - 70 bar	≤ -2 °C up to 69 barg	≤ -2 °C up to 69 barg			
Ethane			≤ 7.0%	≤ 6.0 - 7.0%					
Propane			≤ 3.0%	≤ 3.0%					
Hydrocarbons (C3+)				≤ 2.1%					
Butane			≤ 2.0%	≤ 2.0%					
Hydrocarbons (C5+)			≤ 1.0%	≤ 1.0%					
Hydrogen Sulfide (mg/m³)	≤ 5	< 5	≤ 6.8	≤ 5.4 - 6.8	≤ 5	≤ 5	≤ 6	≤ 5	≤ 5
Mercaptans (mg/m³)	≤ 6	< 6	≤ 16.9	≤ 15.75 - 16.9	≤ 6	≤ 6		≤ 6	≤ 6
COS (mg/m³)		< 5			≤ 30	≤ 30			
Total Sulfur (mg/m³)		< 10	≤ 120.0	≤ 105.0 - 120.0			≤ 23	≤ 30	≤ 30
Carbon Dioxide	≤ 3%	< 2%	≤ 2.0%	≤ 1.575 - 2.0%	≤ 2.5%	≤ 2.5%	≤ 2%	≤ 6%	≤ 6%
Nitrogen		< 5%	≤ 5.0%	≤ 2.1 - 5.0%					
Oxygen	≤ 0.5%	< 0.5%	≤ 0.02%	ND - 0.02%	≤ 0.1%	≤ 0.1%	≤ 0.4%	≤ 3%	≤ 3%
Ammonia	ND	ND							
Hydrogen	≤ 4%	< 4%						≤ 5 %	≤ 5 %
Halocarbons (mg/nm³)	0	ND							
Siloxanes (mg/nm³)	≤ 10						≤ 1		

Chart Credit: Author

Table 12: Non-U.S. Gas Quality Standards for Pipeline Injection, Part II

Country	Hungary		Ireland	Netherlands		Sweden	Sweden	UK	UK
Organization			Gaslink				Swedegas		Scotia Gas Networks
Year	2010		2013	2012		2011	2014	2014/1996	2014
Level	2S	2H		G-gas [Lower]	H-gas [Higher]	Biogas Fuel			
Methane content						≥ 97%			78 - 100%
Higher heating value (Btu/scf)	832 – 1,215	832 – 1,215	990 – 1,135				980 – 1,278		671 – 1,181
Temperature (°C)			1 - 38				0 – 50		0 - 20
Wobbe Index (Btu/scf)	974 – 1,116	1,225 – 1,470	1,267 – 1,380	1,166 – 1,264	1,261 – 1,543		1,315 – 1,527	1,267 – 1,380	1,208 – 1,449
Water vapor			≤ 50 mg/m³			≤ -9 °C at 200 bar	≤ -8 °C at 70 bar		-100 - 20 °C
Hydrocarbon Dew Point	≤ 4 °C at 4 Mpa	≤ 4 °C at max op. pressure	≤ -2 °C up to 85 barg						-100 - 20 °C
Ethane			< 12%						
Propane									≤ 7%
Hydrogen Sulfide (mg/m³)	≤ 20	≤ 20	≤ 5	≤ 5	≤ 5	≤ 10	≤ 5	≤ 5	≤ 10
Mercaptans (mg/m³)				≤ 10	≤ 16				
Total Sulfur (mg/m³)	≤ 100	≤ 100	≤ 50	≤ 45	≤ 45	≤ 23	≤ 10	≤ 50	
Carbon Dioxide			≤ 2.5%			≤ 3%	≤ 2.5%		≤ 7%
Nitrogen			≤ 5%						
Oxygen	≤ 0.2%		≤ 0.2%	≤ 0.5%	≤ 0.5%	≤ 1%	≤ 0.1%	≤ 0.2%	≤ 2.5%
Ammonia (mg/nm³)						≤ 20			
Hydrogen			< 0.1%			≤ 0.5%		≤ 0.1%	
Organo Halides (mg/nm³)			< 1.5						
Radioactivity (Becquerels/g)			< 5						

Chart Credit: Author

The California IOUs' 990 Btu/scf specification is a historical number for their natural gas supply. Taking into account the potential impacts on the pipeline system and end-users, the IOUs assert that although other states may have lower HHV requirements, their own HHV requirements should depend upon the historical quality of gas delivered since lowering the heating value or allowing noncompliant biomethane access to the system may have detrimental effects on end-use customer equipment and may not be compatible with many systems already in place (Inside EPA 2013). Specifically, some legacy gas equipment may not have burner geometry or controls that can be adjusted for small changes in gas purity. Consequently, this could potentially lead to equipment instabilities, flashbacks, or flameout conditions.

In practice, however, injected biomethane will constitute a small proportion of the overall gas supply under most circumstances, and would have negligible impact to bulk gas quality, assuming complete mixing. However, in some circumstances, complete mixing may not always occur. A modeling study by the National Energy Technology Lab in 2007 found that when injecting gas of different composition, steady injections would mix within a short distance of typically 100 pipe diameters, while for certain transient injections, the two gases could flow well-defined for large distances (> 100 km) before mixing. In addition, depending upon pipeline size and route at the point of injection, the biomethane may comprise the majority of gas.

For the cases where the biomethane producer purchases natural gas for blending with biomethane prior to injection in order to meet the HHV requirement, it should be noted that the gas quality standards set by AB 1900 (the 12 constituents of concern (COCs)) do not apply to natural gas. The 12 COCs were not evaluated for natural gas and it is possible that mixing natural gas with biomethane prior to injection in order to meet the energy content or other tariff requirements can introduce one or more of the COCs such that the mixture does not meet the injection quality requirements. For example the ARB report detailing the constituent of concern noted that concentrations of benzene and alkyl thiols are higher in natural gas than in biogas from all sources. To remedy this issue, the COC standards should apply before biomethane is mixed with natural gas for energy content enhancement rather than for the mixture at the point of injection.

It is also important to be aware that having a pipeline nearby does not necessarily mean that it can be used for biomethane injection. The specific pipeline's capacity must be taken into account. Not all pipelines, especially low pressure pipelines and those with low seasonal usage, can handle gas receipt.

To ensure unhindered project development, an IOU should be contacted as early as possible when exploring the option of pipeline injection. SoCalGas recommends working with them 18 – 24 months in advance of the desired in-service date. The IOUs may also have other requirements or preferences that may affect how the project is developed. For example, SoCalGas prefers that they provide the design and interconnector builds. A utility interconnection fee is considered to be one of the most expensive capital costs of pipeline biomethane implementation. However, the cost of implementing biogas cleaning and upgrading can be even more expensive. To assist with the high capital costs, SoCalGas provides an optional Biogas Conditioning and Upgrading Services Tariff (G-BCUS) in which SoCalGas

will plan, design, procure, construct, own, operate and maintain the biogas conditioning and upgrading equipment on the customer's premises. The customer will be the sole owner of the treated gas before, during, and after the process until it is formally sold to SoCalGas. The customer is also responsible for ensuring that the treated biomethane meets Rule 30 standards for pipeline injection. Currently, for the second phase of AB 1900 implementation, the CPUC is addressing cost issues related to biogas pipeline injection, including those for interconnection. The economic feasibility of biomethane pipeline injection is discussed in Chapter 7 of this report.

Assembly Bill 2196

In addition to AB 1900, there are state regulations that dictate prerequisites for eligible biomethane pipeline injection. Assembly Bill 2196 (Chesbro): Renewable Energy Resources, specified requirements for RPS-eligible biomethane that is delivered to a generating facility via common carrier pipeline (Chesbro 2012). It requires:

(1) The biomethane to be injected into a common carrier pipeline that physically flows within California or toward the eligible generating facility that contracted for the biomethane;

(2) Sufficient renewable and environmental attributes of biomethane production and capture to be transferred to the retail seller or local publicly owned utility that uses that biomethane to ensure that any electric generation using the biomethane is carbon neutral, and that those attributes be retired, and not sold, as specified; and

(3) The source of biomethane to demonstrate that the reduction in emissions through capture and injection of biomethane causes a direct reduction of air or water pollution in California or alleviates a local nuisance within the state that is associated with the emission of odors (Chesbro, 2012).

In developing future policies to promote biomethane pipeline injection, the U.S. and California can look to the experience of other countries for guidance. A prime example is the German Renewable Energy Act, which established priority for the connection, purchase, and transmission of electricity produced from renewable resources while setting a fixed fee for electricity paid by grid operators for a 20-year period. Related to specifically biogas, it also established feed-in tariffs based upon power output and input materials, as well as bonuses for biogas upgrading and the use of renewable primary products or cultivated biomass. Further endorsement of biogas came with changes to Germany's Gas Network Access Ordinance (Gasnetzzugangsverordnung – GasNZV) in 2008 whereby a biomethane pipeline injection target of 6% of natural gas consumption (60 TWh) by 2020 and 10% (100 TWh) by 2030 was formed. GasNZV also gave preferred pipeline entry and access to biomethane and stated that it cannot be denied by the grid operator under the premise of an existing capacity shortage. With regards to grid access costs, the interconnection (up to 10 km), gas pressure metering plant, compressor, and calibrated measurement plant are split between the grid operator (75%) and the biomethane supplier (25%, up to €250k). The grid operator also covers the operation and maintenance costs.

Another interesting concept to consider is that Germany, Belgium, France, Hungary, the Netherlands, and Switzerland have two gas standards since gas of different qualities is supplied to different regions: one for low quality natural gas (e.g., 89% flammable gas) and another for high quality natural gas (e.g., 97% flammable gas). This would invariably require significant infrastructure changes and developments that are likely impractical for California. However, these may be possible to implement at a small scale by having dedicated biogas pipelines that send the gas to a committed end user.

CHAPTER 5:
Biogas Cleaning Technologies

Raw biogas needs to be cleaned to remove toxic and harmful constituents (e.g., hydrogen sulfide, ammonia, VOCs, halides, moisture, siloxanes, particulates, AB 1900 COCs, etc.) to meet regulatory and technical standards. The principle cleaning techniques used currently include adsorption, biofiltration, water scrubbing (an absorption process), and refrigeration. Most contaminants can be removed by adsorption onto a porous material or by scrubbing the gas with water. Hydrogen sulfide can also be removed biologically by biofiltration. Moisture is typically removed by cooling the gas to condense the water which can be drained from the system.

This chapter focuses on post-production gas treatment processes, which can be applied to all biogas sources. In-situ technologies, such as sulfide precipitation, which can only be applied to digester systems, are not discussed in detail. Gas upgrading to biomethane (removal of CO_2) techniques are discussed in Chapter six.

Adsorption

Adsorption is the adhesion of compounds onto a solid surface. When biogas is flushed through an adsorbent bed, contaminant molecules will bind to the adsorbent's surface, removing the contaminants from the gas stream. Some adsorption systems induce reactions between the contaminant and adsorbent (or involve a catalyst) that creates a stable or non-harmful compound that can be removed from the adsorbent. Effective adsorbents are generally highly porous with high surface area which greatly increases their removal capacity. The pores can additionally act as physical traps for certain compounds.

Activated Carbon

The most commonly used adsorbent is activated carbon (AC), owing to its low costs, widespread availability, high surface area, and adsorptive affinity for most compounds present in biogas: hydrogen sulfide, carbon dioxide, moisture, VOCs, halides, siloxanes, etc., with the exception of ammonia. AC is a highly porous powdered or granulated carbon material created by heating carbonaceous matter—biomass or charcoal—under high temperatures of 600 – 1200 °C. With surface areas of 500 – 2500 m^3/g (usually around 1500 m^3/g), contaminants become trapped within the many micropores. Typically, 20 – 25% loading by weight of H_2S can be achieved. AC can then be thermally regenerated using the same process in which it was made. However, it is more economically favorable to simply purchase new AC material from a supplier than onsite regeneration using this method. To increase AC's adsorption capacity and affinity for certain compounds, AC can be impregnated with alkaline or oxide solids. Sodium hydroxide, sodium carbonate, potassium hydroxide, potassium iodide, and metal oxides are the most common coatings employed. However, there is greater difficulty in handling and disposing of caustic-impregnated carbon. To further assist in the adsorption of H_2S, air can be added to the biogas, causing some H_2S to convert to elementary sulfur and water.

Zeolites
Another common adsorbent are zeolites—naturally occurring or synthetic silicates with extremely uniform pore sizes and dimensions. Generally, polar compounds (e.g., water, H_2S, SO_2, NH_3, carbonyl sulfide, mercaptans) are very strongly adsorbed by zeolites. A typical zeolite's adsorption preference, from high to low, is: H_2O, mercaptans, H_2S, and CO_2. But, depending upon their chemical composition and pore size, different zeolites have greater affinities for different compounds. For example, clinoptilolite has a strong affinity for ammonia. Zeolite 13X is commonly used for the desiccation, desulphurization and purification of natural gas. With a pore size of 8 Å, it is capable of co-adsorbing H_2O, H_2S, and CO_2.

Molecular Sieves
Carbon molecular sieves are also commonly employed as an alternative to activated carbon and zeolites. As opposed to activated carbon and zeolites which are primarily equilibrium adsorbents that rely upon the capacity to adsorb more contaminants than methane, carbon molecular sieves are kinetic adsorbents that have micropores allowing contaminant molecules to penetrate faster than methane. However, note that activated carbon and zeolites can also act as molecular sieves.

Alkaline Solids
Alkaline solids can also be used for acid gas removal, relying upon chemical adsorption versus physical adsorption used by activated carbon and zeolites. Alkaline solids react with acid gases like H_2S, SO_2, CO_2, carbonyl sulfides and mercaptans in neutralization reactions, removing about 112.5 g CO_2/kg of media and 10 g H_2S/kg media. Synergistic mixtures of hydroxides can be used to improve the contaminant loading. When alkaline solids are dissolved in solution, they can be used for biogas upgrading. This is more deeply discussed in a later section about biogas upgrading on page 69.

Iron Sponge
Iron and zinc oxide/hydroxide particles can also be used to remove sulfurous compounds (iron or zinc sponge). Hydrogen sulfide endothermically reacts with these compounds to form metal sulfides and water. The optimal temperature range for this reaction is between 25 – 60 °C for iron oxides and 230 – 430 °C for zinc oxides. The metal oxide/hydroxide particles are often embedded onto wood chips. Due to the heat produced by the reaction, the material can become pyrophoric—spontaneously combust in air if allowed to dry out. Fortunately, the reaction requires water, so the biogas does not need to be dried prior to this stage. However, condensation in the sponge bed should be avoided since water can coat or "bind" metal oxide material, somewhat reducing the reactive surface area. It is therefore important to maintain proper humidity in the sponge bed.

A loading of roughly 20 kg H_2S/100 kg sorbent can be achieved with iron sponges. Iron sponges can be regenerated by aeration, by which atmospheric oxygen reattaches to the iron, and releasing the sulfur as elemental sulfur. Typically, dual or multiple reaction beds are installed, with one bed undergoing regeneration while the other is operating to remove H_2S from the biogas. Iron sponge beds can regenerated roughly 15 times before their removal efficiency drops to a level that requires replacement. Iron sponges can sometimes fuse together, requiring

a high-pressure water jet for removal. Zinc oxides are more selective than iron oxides and have maximum sulfur loadings typically in the range of 30 – 40 kg sulfur/100 kg sorbent. However, they are also more expensive than iron oxides and the reaction is irreversible, meaning that zinc oxides must be replaced after each cycle. Thus, iron oxides are usually favored for their lower maintenance requirements and costs. Although metal oxides are effective at removing hydrogen sulfide, they are not very reactive with organic sulfur compounds (e.g., mercaptans). Catalytic hydrodesulfurization can be implemented to convert organic sulfur compounds into hydrogen sulfide for removal.

Iron compounds can also be used for in-situ sulfide precipitation within digester systems. Iron salts added to a digester react with H_2S and induce the precipitation of insoluble iron sulfide salt particles. This process is relatively inexpensive and will also remove ammonia, but is less effective in maintaining low and stable H_2S levels.

Silica Gel

Silica gel or aluminum oxide can remove siloxanes and moisture by trapping them within their crystalline structure. They are easily regenerated by drying at high temperatures and pressures.

General Adsorption Attributes

The adsorbent must be replaced once it is filled or can be regenerated a limited number of times. This is contributes to operational cost.

In general absorption systems are simple to operate, require minimal maintenance, have a small space requirement, and are inexpensive. Basic construction consists of the adsorbent housed inside a vessel or drum with a gas inlet and outlet. The majority of adsorbents can remove most of the contaminants found in biogas to a high degree or at least partially, though they are typically sensitive to moisture and particulates. Adsorption systems are commonly applied as a biogas pretreatment step before biogas upgrading to avoid poisoning the upgrading chemical and to lower the upgrading material's regeneration requirements.

Water Scrubbing

Water scrubbing relies upon the principle that gases will dissolve (or absorb) into a liquid to maintain a pressure-dependent equilibria (Henry's Law). Water is commonly used as the working liquid since it is readily available, inexpensive, nontoxic, and is free of the contaminants that are desired to be removed (ensuring that the contaminant gases will dissolve into it). In addition, methane has a lower water solubility than the majority of contaminants, making the process highly effective in retaining methane in the gas phase.

Water scrubbers are commonly designed to have biogas finely bubbled up through a tall vertical column of downward-flowing water. Mist eliminators at the gas outlet location minimizes water droplets from escaping the system. A variant of the common water scrubber is the atomized mist scrubbers, in which atomized water droplets are sprayed into the gas stream. These systems however have a slow response to rapid variations in gas contaminant concentrations.

Water scrubbers are cost-effective for high flow rates, and have a small space requirement. They are especially effective at removing H_2S, NH_3, VOCs, and siloxanes. However, for low pressure

water scrubbing, absorbed contaminants are not easily purged so it is not effective to recycle the used water. In addition, the product gas will always be moisture-saturated. Any added water will increase drying costs, although the biogas will likely already be saturated with moisture. The primary drawback of water scrubbing is the fact that any O_2 and N_2 dissolved in the water from the atmosphere can be released into the biogas. Consequently, water scrubbing may not be optimal in applications where high HHVs are required such as R-CNG/R-LNG production or pipeline injection. Above ambient pressures, water scrubbers can also be used to effectively remove CO_2. This aspect of water scrubbing is discussed at greater lengths in a later section about biogas upgrading on Page 71.

Biofiltration

Biofiltration relies upon the natural biological metabolism of sulfur-oxidizing bacteria species to convert hydrogen sulfide into elemental sulfur or sulfate. These microbial species include *Beggiatoa* and *Paracoccus*, with the most common and utilized being *Thiobacillus*. Biofiltration systems are designed to ensure a high-density microbial community and maximize contact between the microorganisms and the feed gas.

Biofiltration systems can be set up in three different configurations: bioscrubber, biofilter, and biotrickling filter (Figure 17). In a bioscrubber, pollutants are absorbed into liquid flowing counter-currently through an absorption column, similar to a water scrubber. The liquid is then sent to a bioreactor for microbes to degrade the contaminants. A biofilter consists of a packed bed of organic material that stimulates biofilm growth through which humidified biogas is pumped. Contaminants in the biogas contact absorb and adsorb into the biofilm and interact with the microbes. Although biofilters are the most commonly used (compared to bioscrubbers and biotrickling filters), H_2S-induced acidification due to the static medium can occur, which hinders microbial activity and can render biofilters ineffective for long-term H_2S removal for gas streams with high H_2S inlet concentrations. Biotrickling filters overcome this problem by combining biofilters with bioscubbers. Biotrickling filters contain a packed bed of chemically inert materials that provide large surface area for gas contact biofilm accumulation. Biogas is injected up through the column while liquid counter-currently flows down, providing contaminant absorption, delivering nutrients to the microbes, and controlling the pH. Biogas is mixed with 4 – 6% air before entry into the filter bed to supply sulfur-oxidizing microorganisms with O_2 needed for the conversion of H_2S to S_2 and H_2S_4O.

In lieu of biofiltration, the air or oxygen can be injected directly into the digester head space, allowing sulfate-oxidizing microorganisms to naturally grow on the head space surfaces without requiring inoculation. Head space microbial H2S removal is less effective than biofiltration.

Figure 17: Biofiltration Process Schematic—A) Bioscrubber, B) Biofilter, C) Biotrickling Filter

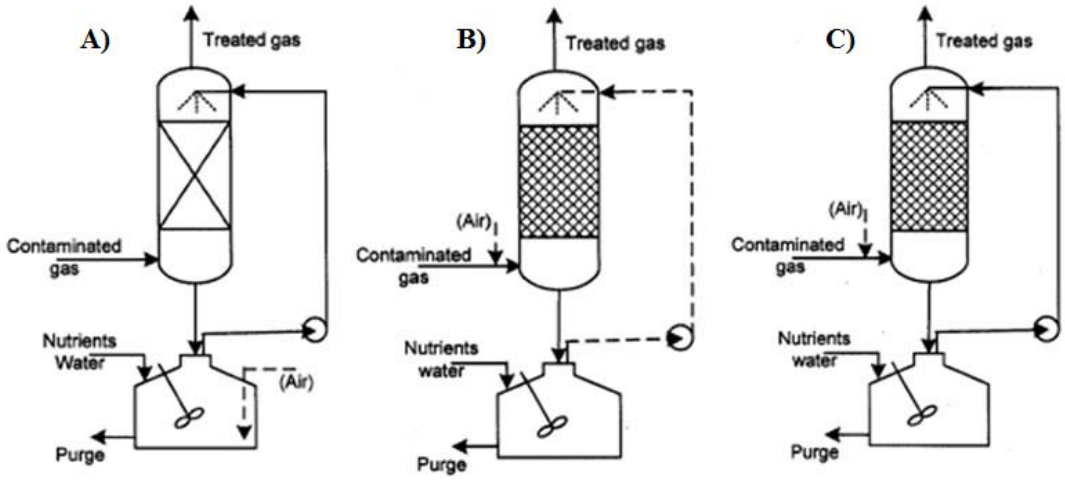


Illustration Credit: American Biogas Council (2014)

Biofiltration systems are effective at treating low and high concentrations of H_2S, from 50 – 100 ppm to 2,000 – 4,000 ppm, achieving 89 – 99.9% H_2S removal at a rate of 20 – 125 g $H_2S/m^3/h$. They can also achieve > 90 – 99% VOC removal, in addition to ~ 92% ammonia removal at low H_2S concentrations of around 200 ppm and ~ 30% ammonia removal at higher H_2S concentrations. Yet, due to being a biological process, biofiltration system performance is subject to variations depending upon environmental conditions such as temperature, pH, moisture, nutrient concentrations, and microbial community. The majority of microbes grow and function optimally near 35 °C and neutral pH. Wide deviations from these levels will negatively impact the efficiency of the biofiltration unit (Rattanapan and Ounsaneha 2012). The optimal moisture content for biofilters varies from 20 to 60 wt%.

Biofiltration units have relatively low capital costs due to its simple design with minimal control and system connections needed, requiring only a basic vessel, pumps, and inexpensive media. Biofiltration systems also benefit from low operating costs since no chemicals are needed, there are no large inorganic waste flow requiring disposal, almost no utilities are necessary, and they have high energy efficiencies.

However the characteristics of biological processes inlcude several drawbacks. Biofiltration units require a 1 – 3 month start-up time before achieving high and consistent performance, are susceptible to unforeseen performance drops by loading shocks, and can experience clogging from excessive microbial growth. The addition of air for the microbes introduces N_2 and O_2 to the gas, which are difficult to remove and this generally rules out biofiltration systems for the production of pipeline-quality or vehicle fuel gas. They also require a large space and the media must be replaced or washed (every 2 – 4 years for organic media, 10 years for inorganic media), since the pressure drop through media increases with media age. Nevertheless, biofiltration systems work synergistically with anaerobic digesters and can be applied on farms and wastewater treatment plants that plan for distributed power generation.

Refrigeration/Chilling

Refrigeration, or gas cooling, provides a simple means for removing moisture from biogas. When the gas is cooled (typically to between -18 – 2 °C), water vapor condenses on the cooling coils and can be captured in a trap. Some ammonia will also be removed given the high solubility of ammonia in water. Insignificant trace amounts of other compounds may also be absorbed into the water. At lower temperatures of < -73 °C, VOCs will condense and can be removed too. At -70 °C, 99% removal of siloxane can be achieved as well, but it is costly to operate at such low temperatures.

H_2S should be removed prior to refrigeration to significantly lengthen the life of the refrigeration unit. The power needed for refrigeration is minimal—generally less than 2% of the biogas energy content (Krich et al. 2005).

When only limited moisture removal is necessary, a rudimentary alternative to refrigeration is to bury the gas line underground over a long distance with a condensate trap attached. The cool underground temperatures will induce some moisture to condensate, but will not reach the high moisture removal achieved by refrigeration.

Biogas Cleaning Technology Comparison

Raw biogas contains a variety of compounds aside from methane. These include hydrogen sulfide (H_2S), oxygen (O_2), nitrogen (N_2), volatile organic compounds (VOCs), siloxanes, and moisture (H_2O). To remove these contaminants, adsorption, water scrubbing, biofiltration, and/or refrigeration processes are employed. Each of these technologies is able to treat different contaminants to various degrees (Table 13).

Table 13: Contaminant Treatability for Biogas Cleaning Technologies

Biogas Cleaning Process	H_2S	O_2	N_2	VOCs	NH_3	Siloxanes	H_2O
Adsorption	**	/	-	**	*	**	**
Water Scrubbing	**	--	--	**	**	**	--
Biofiltration	**	--	--	**	/	/	--
Refrigeration	/	-	-	/	**	*	**

Legend: ****** High removal (intended) ***** High removal (pre-removal by other cleaning technology preferred) **/** Partial removal
- Does not remove **--** Contaminant added **R** Must be pretreated

Two symbols may be in the same box if one or the other can be applicable

Chart Credit: Severn Wye Energy Agency (2013); Starr et al. (2012)

To operate effectively, each biogas cleaning technology also requires different operating conditions and specific consumables that must be replaced at regular intervals. The features of these cleaning technologies are summarized in Table 14.

Table 14: Features of Biogas Cleaning Technologies

Process	Pressure (psig)	Temperature (°C)	Sulfur Pre-Treatment	Consumables
Adsorption	0 – 100	25 – 70	Not needed	Adsorbent
Water Scrubbing	0	20 – 40	Not needed	Water; Anti-fouling agent; Drying agent
Biofiltration	0	35	Not needed	Water; Drying agent
Refrigeration	0 – 58	-29 – 5	Preferred / Required	Refrigerant

Chart Credit: Severn Wye Energy Agency (2013); Starr et al. (2012)

The primary contaminant in raw biogas, with the exception of inert compounds, is hydrogen sulfide. Hydrogen sulfide can be removed via physical adsorption by activated carbon, biofiltration, and chemical adsorption by iron and zinc oxides and hydroxides. Table 15 compares the requirements and efficiencies of these technologies.

Table 15: Comparison of Biogas H_2S Removal Technologies

	Method	Relativity to Digester	Outlet H_2S Concentration	O_2 Required	Desulphurization
Adsorption	Activated Carbon	External	50 – 250 ppm	No	Primary
	Impregnated activated carbon	External	< 1 ppm	Yes	Precision
	Iron salts	Internal	100 – 150 ppm	No	Primary
	Iron hydroxide	Internal	100 – 150 ppm	No	Primary
	Iron oxide/hydroxide	External	< 1 ppm	Yes	Precision
	Zinc oxide	External	< 1 ppm	No	Precision
Biofiltration	Biofiltration	Internal / External	50 – 200 ppm	Yes	Primary
	Biofiltration + Lye scrubber	External	20 – 100 ppm	Yes	Primary

Chart Credit: Beil and Hoffstede (2010)

All of these technologies can be applied for boilers and microturbines, which have the highest sulfur tolerances of any biogas utilization equipment. Reciprocating engines can potentially use every technology, but the removal system would need to operate near the lower end of the

possible H_2S outlet range. Fuel cells require precision desulfurization techniques since the highest H_2S concentration that any fuel cell can handle is 50 ppm, while most require less than 10 ppm. As a standalone process, precision desulfurization would also be necessary for pipeline injection in California since the IOUs require 4 ppm H_2S (0.25 grain/100 scf). Zinc oxide would be recommended since it does not require O_2 addition (N_2 will also not be added since air is commonly used to add O_2), as O_2 and N_2 are difficult to remove. However, it is common to instead use a primary desulfurization system as H_2S pretreatment, and then rely upon the biogas upgrading system for precision-level H_2S removal.

Note that there can be several exceptions to the H_2S outlet concentrations listed in Table 15, as the actual performance depends upon the inlet concentration and varies from one manufacturer to another. For example, DARCO® H_2S (Cabot Norit) is an activated carbon product that is advertised to treat gas streams as low as < 10 – 20 ppm of H_2S down to undetectable levels. Thiopaq® (Paques) is a biotrickling filter with alkaline solution gas pre-treatment that can reduce H_2S concentrations to below 4 ppmv, although typical outlet concentrations range from 5 – 100 ppm.

CHAPTER 6:
Biogas Upgrading Technologies

The primary function of biogas upgrading involves removing CO_2 to improve gas quality by increasing the volumetric energy content. Upgrading is usually necessary for natural gas pipeline injection or vehicle fuel applications. The most widely commercialized and used upgrading technologies are those that have been long employed by the natural gas industry—pressure swing adsorption (PSA), chemical solvent scrubbing (using amines), and pressurized water scrubbing. Newer technologies that have recently broken into the market by improving efficiencies, lowering costs, or decreasing the footprint include physical solvent scrubbing (using glycols), membrane separation, and cryogenic distillation. There are also a number emerging gas upgrading technologies in the research and pilot phase that claim lower operating costs as well as simpler and more compact process designs (e.g., rotary water scrubbing, supersonic separation, industrial lung).

Although the main purpose of biogas upgrading technologies is to remove CO_2 from the gas stream, other contaminants may also be removed. However, specific contaminant pre-treatment (especially for hydrogen sulfide) is usually recommended to improve the adsorbent's or absorbent's lifetime, lower regeneration costs, and reduce maintenance intervals. The following sections describe upgrading technologies, provide details into different operating options, and assess their advantages and disadvantages.

Pressure Swing Adsorption

Pressure swing adsorption (PSA) is a method for the separation of carbon dioxide from methane by adsorption/desorption of carbon dioxide on zeolites or activated carbon at alternating pressure levels. This technology is most prevalently applied in in the gas treatment industry as because it is also effectively removes volatile organic compounds, nitrogen and oxygen from industrial gas streams. PSA requires a pressure between 1 – 10 bar, but often 4 – 7 bar, and a temperature of 5 – 35 °C. Upon pressurization, CO_2 (and some other contaminants) preferentially adsorb onto the media. The remaining unadsorbed gas, rich in methane, is transferred out of the vessel. When pressure is reduced in the vessel, the captured gases desorb and can be vented or sent elsewhere. Typically, multiple vessels are used in parallel to smooth gas production rate and improve energy efficiency.

Figure 18 shows a four-vessel pressure swing adsorption system using carbon molecular sieves, cycling between absorption and regeneration.

Figure 18: Pressure Swing Adsorption Process Diagram

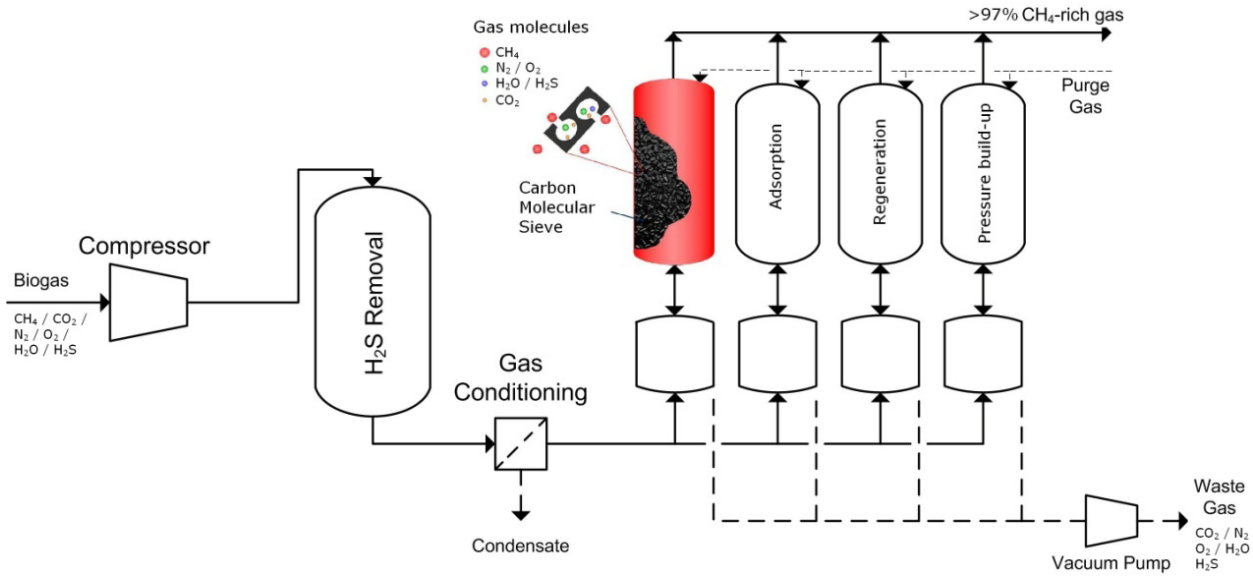


Illustration Credit: Zhao et al. (2010)

PSA systems can produce upgraded gas with methane concentrations as high as 95-98%. Methane recovery rates can range from 60 to 80%. The balance of methane leaves the system in the tail gas with the desorbed CO_2 (which would be 10-20% methane by volume). The tail gas is combusted to destroy the bypass methane with the possibility for heat recovery. Alternatively, the waste gas can be sent through another PSA cycle for additional methane recovery. By mixing the blowdown gas with the raw biogas, methane recovery can be increased by up to 5%. Carbon beds have an operating life of 4,000 to 8,000 hours, but are longer at low H_2S levels. Thus, hydrogen sulfide pretreatment may be preferred. However, moisture should always be removed prior to PSA since water would block the absorbent's micropores, reducing system performance.

Simple PSA systems can be cost-effective at small scale applications as low as 10 Nm^3/h of raw biogas. Thus, PSA systems have also been used as a follow-up polishing step for other upgrading processes, using long (several hour) cycles to remove small fractions of CO_2.

A variant of PSA is rapid cycle PSA, which operates at 5 – 20 times the cycle speed by using multi-port selector rotary valves and a multitude of smaller adsorption chambers. Rapid cycle PSA systems boast smaller sizes, lower capital costs, simple control interfaces (despite their engineering complexity), lower pressure drops, and higher throughputs. However, their high speed comes at the cost of lower methane recovery. Their complexity also makes it difficult to personally perform maintenance, and valve wearing becomes more of an issue. Nevertheless, rapid cycle PSA systems have proven their efficacy with many successful full-scale operating projects. One of the largest suppliers of rapid cycle PSA technology is Xebec Inc. (merged with QuestAir Technologies), which sells turnkey systems that can handle 150 to 5,000 Nm^3/h of raw biogas. A cost summary for the installation of a Xebec M-3100 system (300 – 3,000 Nm^3/h) at a crude oil platform is shown in Table 16. Please note that some of the costs, such as demolition, may not apply for a biogas project.

Table 16: 2010 Project Costs of Xebec M-3100 Fast-Cycle PSA System for Venoco, Inc.'s Platform Gail

Engineering	$180,000
PSA Skid	$770,000
Compressor Skid	$600,000
Demolition	$130,000
Structural Modification	$300,000
Installation	$750,000
Materials (pipes, electrical, etc.)	$100,000

Chart Credit: Toreja et al. (2014)

Chemical Solvent Scrubbing

CO_2 can also be removed from a gas stream by chemically binding it to certain dissolved compounds or liquid chemicals, i.e., alkaline salt solutions and amine solutions. After absorption, the methane rich product gas is ready for application. The solvent with CO2 (and some other contaminants) can be regenerated for reuse. The CO2 is desorbed to gaseous state.

Alkaline Salt Solution Absorption

Adding alkaline salts to water increases the physical absorption capacity of the water. Thus, the process uses less water and lower pumping demands than water scrubbing. H_2S in the biogas reacts with the dissolved alkaline salts, e.g., NaOH or KOH, to irreversibly form an insoluble alkaline sulfide salt. The alkaline salts will also react with CO_2 to form an alkaline carbonate. Because H_2S is adsorbed more rapidly than CO_2 by alkaline solutions, some partial selectivity can be achieved when both gases are present by providing fast contact times at low temperatures. The alkaline carbonates could theoretically be partially regenerated by air stripping, but in practice, the process is ineffectual and prohibitively expensive. Consequently, spent caustic solution is regularly removed from the scrubber to prevent salt precipitation. The waste is highly toxic and is difficult to handle. Overall, the complexity of these processes makes them unattractive for H_2S removal from small biogas streams.

Amine Absorption

Some of the most widely used chemical solvents for acid gas treatment are organic amines, with the most common being Diethanolamine (DEA), Monoethanolamine (MEA), and Methyl diethanolamine (MDEA). In amine absorption processes, biogas is bubbled up through a column of down-flowing organic amine solution at near atmospheric or only slightly elevated pressures—typically less than 150 psi (Figure 19). The amines exothermically react with CO_2, pulling it into the aqueous phase and bonding to it. Amines will also drive H_2S and NH_3 into solution. The amine solution is regenerated in a steam stripper column by heating (106 – 160 °C) and pressure reduction (if the biogas was pressurized) to drive off the CO_2 and H_2S.

Figure 19: Amine Absorption Process Flow Diagram

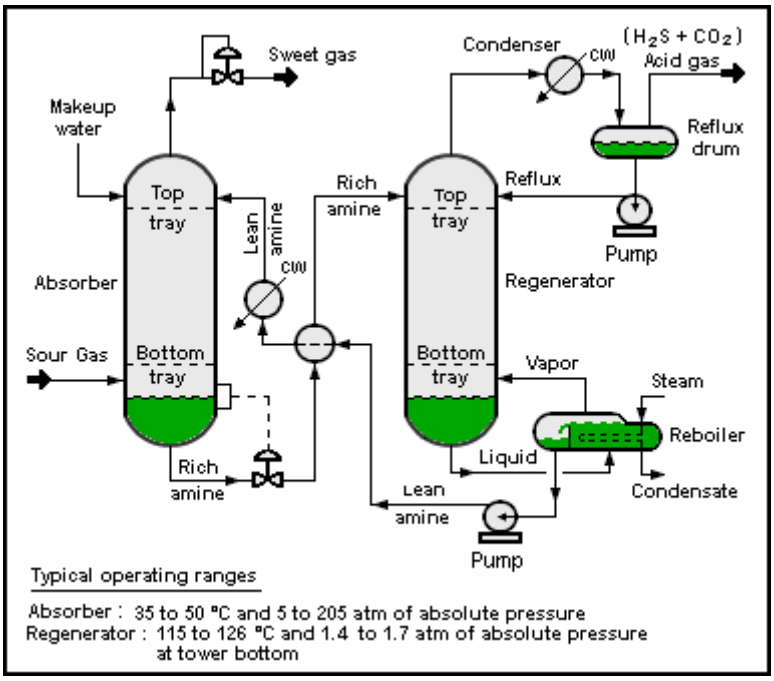


Illustration Credit: Beychok (2006)

Amines have a high selectivity and loading for CO_2 (Figure 20)—one to two orders of magnitude more CO_2 can be dissolved per unit volume in amines than in water. Low CH_4 absorption also affords a low methane slip of 0.04 – 0.1%, which is an order of magnitude less than other absorption and scrubbing technologies. To avoid equilibrium limitations, amine solution is fed at 4 – 7 times the amount of biogas CO_2 on a molecular basis. After amine absorption, the product gas is saturated with moisture and must be dried.

Figure 20: CO_2 Equilibrium Solubility in Amine Solutions

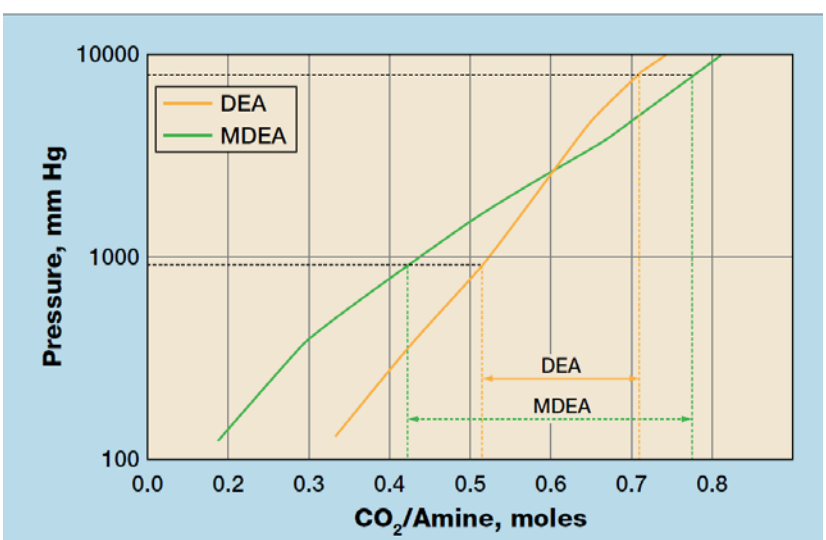


Chart Credit: Lallemand et al. (2012)

Although H_2S can be removed by amine absorption, hydrogen sulfide pretreatment is preferred to reduce regeneration energy demands. Furthermore, if H_2S is removed prior to amine absorption, CO_2 can then be recovered as an essentially pure by-product. Amine scrubbing is widely used for food-grade CO_2 production and large-scale recovery of CO_2 from natural gas wells. Oxygen must be removed prior since it reacts irreversibly with amines. Fortunately, there is little to no risk of bacterial growth because of the high pH of amines.

The most common problems that amine absorption systems experience are corrosion, amine breakdown, contaminant buildup, and foaming. In addition, some amine solution is lost when it side-reacts with other contaminants, thermally degrades above 175 °C, or evaporates. Consequently, amine solution must slowly be added and/or replaced. The overall complexity of amine systems make them difficult to apply to small-scale systems like farms, but can be effectively applied at landfills and large centralized plants. Maintenance costs are estimated to be roughly 3% of the investment cost.

Pressurized Water Scrubbing

Compounds can be physically absorbed (or dissolved) into a liquid solution. Water is commonly used due to low cost, low toxicity, and high availability.

CO_2 and H_2S preferentially dissolve into water compared to CH_4. Carbon dioxide and hydrogen sulfide are 26 and 75 times, respectively, more soluble than methane in water.[6] H_2S can also be selectively removed by water scrubbing because it is more soluble in water than CO_2. However, the H_2S desorbed after contacting can result in fugitive emissions and odor problems. Pre-removal of H_2S is considered to be a more practical and environmentally friendly approach, but is not required. Like pressure swing adsorption, water scrubbing is a popular process for gas treatment because of its ability to simultaneously remove many other contaminants: ammonia, sulfur dioxide, chlorine, hydrogen chloride, hydrogen fluoride, aldehydes, organic acids, alcohol, silicon tetrachloride, silicon tetrafluoride, and siloxanes.

Following Henry's Law, a gaseous compound's absorption into water is greater at higher pressures. When water scrubbing is used for CO_2 removal, the biogas is pressurized typically to 100 to 300 psig with a two-stage compressor, before entering the bottom of the column. The column typically contains a packed bed consisting of a high surface-area plastic media, allowing for efficient contact between the water and gas phases. The bed height and packing type determine the removal efficiency, while the bed diameter determines the gas throughput capacity. The CO_2-saturated water is continuously withdrawn from the bottom of the column and the cleaned gas exits from the top. The product gas is around 93 – 98% methane, but the process loses about 1 – 2% methane into the tail gas—more than most other systems. In an ideal system with 100% CO_2 absorption, at least 4% of the methane will also be dissolved into the water. The waste CO_2- and H_2S-laden water can be regenerated in a flash tank where the pressure is reduced, releasing the dissolved gases. Again owing to CH_4's low water solubility,

[6] Solubilities in waster: Carbon dioxide- 8.21E-4 mole fraction at 15°C, hydrogen sulfide- 2.335E-3 mole fraction at 15°C, methane- 3.122E-5 mole fraction at 15°C.

CH_4 is released first and can be recirculated to the scrubbing column, effectively increasing the biogas CH_4 concentration. Air stripping the waste water may also be done to remove H_2S since H_2S may clog pipes in the regenerative system. However, air stripping introduces oxygen into the water which will desorb into the biogas, so this may not be suitable for applications where high methane concentrations are required. The treated waste water is then recycled into the scrubber unit. The exhaust gas can be treated by regenerative thermal oxidation or flameless oxidation to avoid SO_2 emissions. Figure 21 shows the design and fluid flow through a biogas regenerative water scrubber system.

Figure 21: Biogas Water Scrubber System Design, Greenlane Biogas

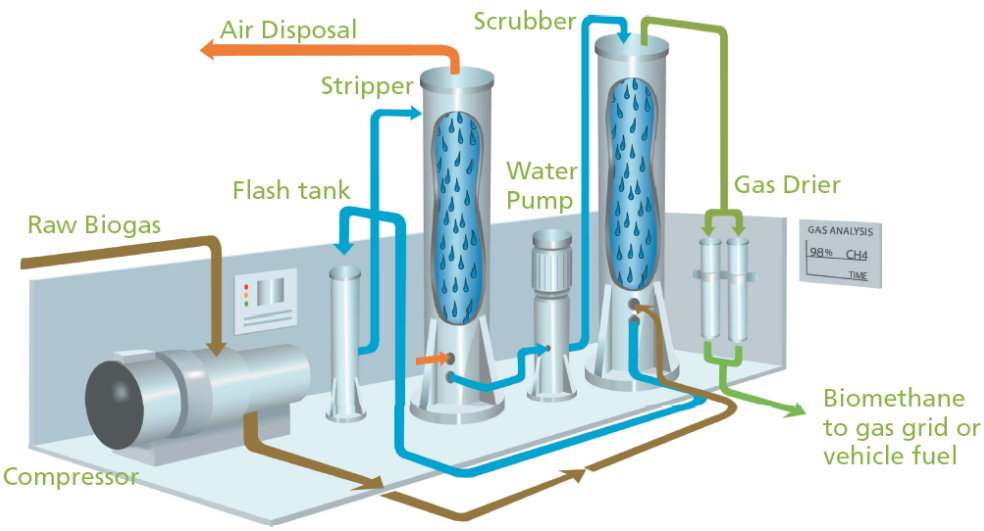


Illustration Credit: Hudde (2010)

Flashing and air stripping are incapable of completely regenerating the working water, so the water must be gradually replaced over time. Furthermore, as more CO_2 is absorbed in the scrubbing column, its partial pressure decreases, making it harder to absorb more CO_2. Thus, high water flows are needed to reach low CO_2 concentrations. Therefore, even with regeneration, water scrubbing requires a large amount of water—0.9 – 40 L discharged scrubbing water per Nm^3 of raw biogas processed (or 10% of the process water per hour) for regenerative scrubbing, and 100 – 233 L/Nm^3 for non-regenerative scrubbing (Persson 2003). Water scrubbers are more efficient and cost-effective without regeneration, when a constant supply and discharge of water is possible, such as at a wastewater treatment facility. In fact, the first time a water scrubber was used to clean biogas in the US was at a WWTP in Modestoin the 1970s. Additional cost and energy savings can be had by using secondary or tertiary treated wastewater as the scrubbing water, but this may also add microbial-related problems. The fact that there are microorganisms present in the wastewater creates the risk of introducing pathogens into the gas stream, which can contaminate the gas transmission system and pose health hazards. However, a study by Vinnerås, Schönning, and Nordin (2006) found that natural gas contained low concentrations of spore-forming bacteria such as *Bacillus* spp., and that the densities of microorganisms found did not differ much from what was found in biogas

upgraded by wastewater scrubbing. At such low biological concentrations, gas intoxication and explosions were said to likely occur before ingesting a dose of pathogens high enough to cause an infection. With regards to the possible issue of plugging by biological growth, the water scrubber should be internally cleaned with detergent or externally cleaned several times a year.

Water scrubbing processes are the most prevalent upgrading technology, as they are simple, robust, flexible, proven, and have relatively low investment and operational costs. They are best implemented in medium and large applications, with competitive pricing for larger projects, and especially for higher concentration H_2S streams. Practical gas throughput capacity limits are around 2,200 Nm^3/hr. Water scrubbing can be slightly less energy efficient than most other systems, typically requiring close to 0.3 kWh/Nm^3 of cleaned gas. There are also limitations in H_2S removal. When removing large quantities of H_2S or CO_2, the tank and pipework should be made of stainless steel to avoid corrosion. In addition, not only does water scrubbing not remove inerts (e.g., O_2, N_2), but it may in fact add O_2 by desorbing O_2 that was dissolved in the incoming water. Water scrubbers can be sensitive to environmental conditions such as temperature. Maintenance costs are typically 2 – 3% of the investment cost.

A variant of conventional water scrubbers is the high pressure batch-wise water scrubber that uses pressures above 2,100 psi. It operates by first filling the scrubbing columns with compressed biogas. Pressurized water is then pumped into the columns and displaces the gas. The water is afterwards purged and regenerated by a flash tank and a desorption column. A high pressure batch-wise water scrubber system is produced and sold by Metener Ltd under the name BKP Biogas Upgrading Unit. Tailored towards raw gas flows of 30 – 100 m^3/h, the system produces a 92 – 95% methane gas with 1 – 3% methane slip. Compared to conventional systems, it uses significantly less water (0.05 – 0.1 m^3/kg of product gas, or 33.4 – 66.8 L/Nm^3 of product gas), but consumes more energy (0.4 – 0.5 kWh/Nm^3 raw biogas). It is also smaller size, but must be built to withstand much higher pressures. Metener lists the maintenance costs to be around €0.04 – 0.08/kg of upgraded pressurized gas. There are presently at least three built BKP Biogas Upgrading Units (two in Finland and one in northern China).

Another variation upon conventional water scrubbers is the rotary coil water scrubber, in which water and gas flow through a rotating coiled tubing. Water is first fed into the outermost coil turn at 29 psi (2 bar). As the coils rotates, water columns are forced inward and compress the gas in between, effectively increasing the pressure to 145 psi (10 bar) (Figure 22). This results in efficient carbon dioxide absorption, producing a gas with 94% methane with about 1% methane slip. To increase the methane content further to 97%, the rotary coil can be equipped with a post-process conventional water column. The rotary coil water scrubber technology is marketed by Arctic Nova as the Biosling and is directed at small-scale applications such as farms with 200 – 1,000 cow facilities with raw gas capacities of 14.6 – 73.1 Nm^3/h. The Biosling is claimed to be more energy efficient than conventional water scrubbers, consuming only 0.15 – 0.25 kWh/Nm^3 of raw biogas (0.26 – 0.44 kWh/Nm^3 of product gas). Although the BioSling is commercially available, there are no full-scale commercial installations at this time (Arctic Nova 2014; Bauer et al. 2013).

Figure 22: Rotary Coil Water Scrubber Design Cross-Section and Arctic Nova Biosling

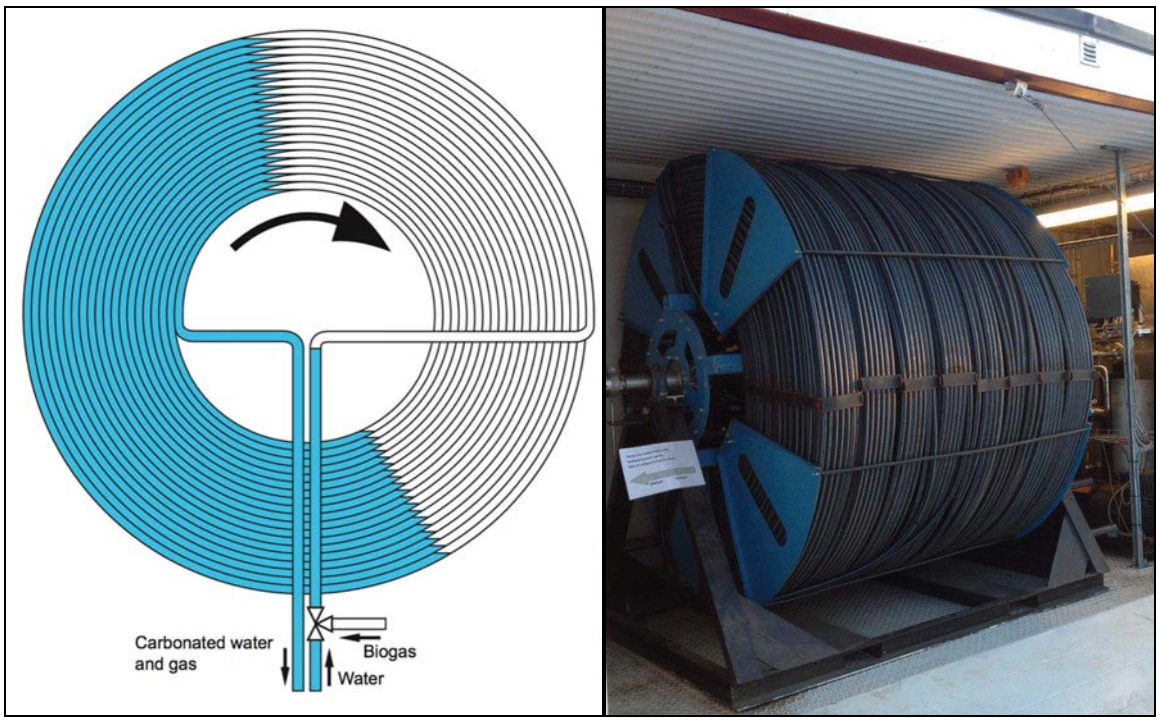


Illustration Credit: Biosling AB (2012)

Physical Solvent Scrubbing

Carbon dioxide and hydrogen sulfide can also be absorbed using liquid solvents other than water. The most industrially applied of these are organic glycols (e.g., polyethylene glycol). In return for higher cost and complexity than water scrubbing, these physical organic solvents allow for greater H_2S and CO_2 solubility than in water, allowing for lower solvent demand and reduced pumping. Glycols for scrubbing biogas can be commercially found with such names as Genosorb® 1753, SELEXOL, Purisol, Rectisol, Ifpexol, and Sepasolv.

To improve absorption, gas is compressed to 4 – 8 bar (around 60 – 115 psi) and the temperature is cooled to 10 – 20 °C. Physical solvent scrubbers operate in a similar manner to water scrubbers, using counter-current flows and a packed media bed. To regenerate the saturated solvent, it passes through a flash column, heated to 40 – 80 °C, and then run through a packed air stripper/desorption column. The product gas is normally made to consist of 95 – 98% methane with 1.5 – 4% methane slip. The physical solvent solution is afterwards regenerated by depressurization in a flash column, heating (40 – 80 °C), and steam or air stripping. Although the solvent can be regenerated, it would need eventual replacement, producing some hazardous liquid waste. However, only a minor addition of solvent roughly once a year is usually

required. The stripper exhaust gas must be treated by regenerative thermal oxidation (at 800 °C) since its methane concentration is too low for flameless oxidation.

Figure 23: Physical Solvent Scrubber Process Diagram

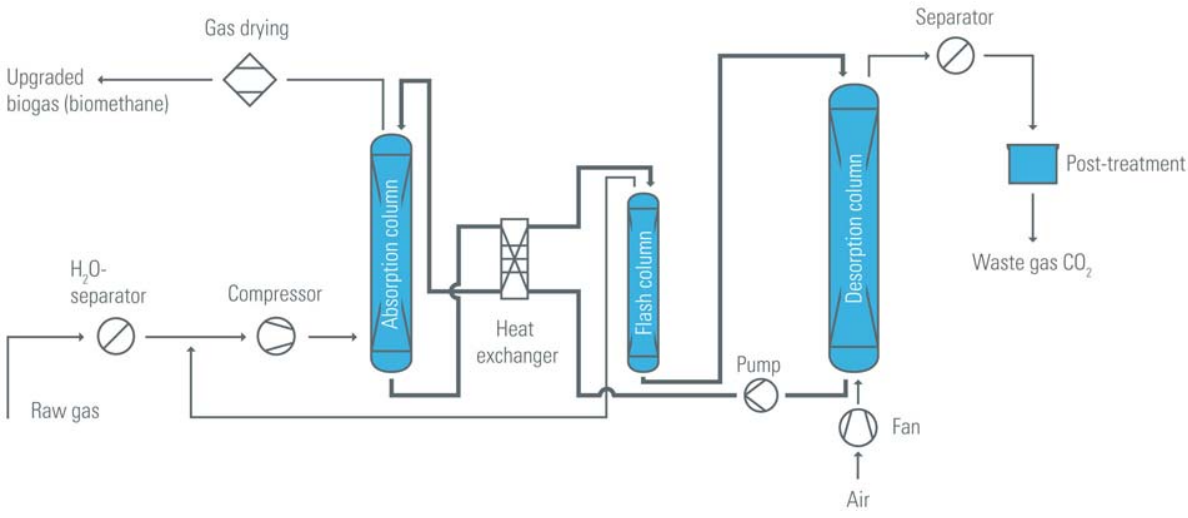


Illustration Credit: ÖKOBIT GmbH (2014)

Generally no precision desulphurization is required for glycol scrubbing. Another advantage over water scrubbing is that glycols are hygroscopic, meaning that they will absorb water by forming crystalline structures. This provides co-adsorption of H_2S, and CO_2, and H_2O. Nevertheless, moisture pretreatment by refrigeration is preferred in order to minimize the burden on glycol regeneration. Glycols will also scrub halogenated hydrocarbons and ammonia, but they will react with ammonia to form unwanted reaction products. N_2 or O_2 may only slightly be removed, but it is likely to be insignificant.

Scrubbing with organic solvents has several other advantages over using water. First of all, greater contaminant solubilization into glycols permits glycol systems to have smaller designs and lower circulation rates. Organic solvents are also anticorrosive, so pipework does not need to be made of stainless steel. Furthermore, their low freezing point allows low temperature operation, which is better for absorption. In places with water shortages, they may additional gain support from the fact that no water or antifoaming agent is consumed.

In exchange for these many benefits, physical solvents are more expensive for small-scale applications than pressurized water scrubbing or pressure swing adsorption. They also require a larger total energy demand, although this largely consists of the heat needed for solvent regeneration. The electricity requirement actually tends to be lower than most other upgrading technologies. Physical solvent scrubbing can be energy-competitive if waste heat from another process is utilized. Akin to pressurized water scrubbing, maintenance costs are close to 2 – 3% of the investment cost. Maintenance includes occasional turnovers of the organic solvent, compressor lubricant, and any adsorbent used for preliminary H_2S removal.

Membrane Separation

Membrane separation utilizes high gas pressures to create a large pressure differential across a nano-porous material (membrane) causing gas separation by several different mechanisms: molecular sieving (size exclusion), Knudsen diffusion (mean path difference), solution-diffusion (solubility difference), surface diffusion (polarity difference), and capillary condensation (adsorption). The primary transport mechanisms are dependent upon the membrane pore size, which affects the permeation rate of each type of gas (Figure 24).

Figure 24: Gas Separation Membrane Permeation Rates

Relative Permeation Rates														
Fast	H_2O	He	H_2	NH_3	**CO_2**	H_2S	O_2	Ar	CO	N_2	**CH_4**	C_2H_4	C_3H_6	Slow

Illustration Credit: Dirkse Milieutechniek (2014)

Contaminant or target molecules are forced through the membrane by pressurizing the feed gas side to somewhere between 100 – 600 psi (7 – 10 bar), depending upon the biomethane quality requirements as well as the design and manufacturer. The feed gas is passed across the membrane at an optimal velocity to allow for optimal contaminant gas permeation and minimal methane permeation. After membrane treatment, the majority of carbon dioxide, water, hydrogen, and ammonia will pass through the membrane and be removed. The feed gas will retain most of the methane, with some hydrogen sulfide, nitrogen, and oxygen. Figure 25 shows typical gas permeability through a membrane.

Figure 25: Gas Separation Membrane Permeability

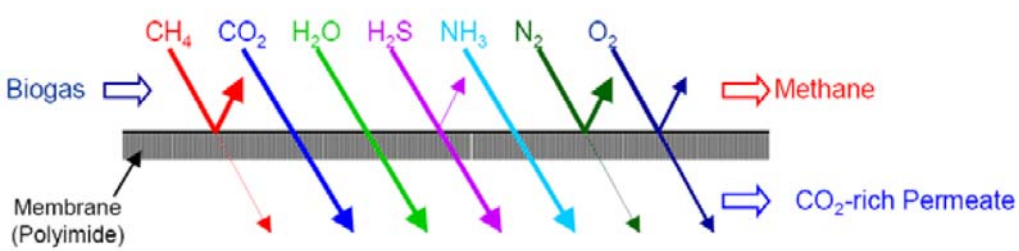


Illustration Credit: Harasek (2006)

Biogas generally requires pre-treatment to remove aggressive substances that can destroy the membrane material, in addition to the fact that the membranes do not remove H_2S or inerts (e.g., O_2, N_2) very well. Substances that can harm the membrane include water, hydrogen sulfide, ammonia, VOCs, siloxanes, particulates, and oil vapor. Water is removed to prevent condensation during compression, and hydrogen sulfide is removed since it is not sufficiently removed by membranes. Oils that are naturally present or picked up from the compressor should be removed to prevent membrane fouling. Ammonia can cause membrane swelling, while siloxanes and particles can physically damage the compressor and membrane structure.

Despite the use of gas pretreatment systems, the membranes can still suffer from plasticization, compaction, aging, competitive sorption, and fouling. Eventually, the membranes must be replaced. Typical membrane replacement intervals span > 2 years, between 5 – 10 years.

Gas separation membranes are mostly constructed from bundled polymeric (e.g., polysulfone, polyimide, polydimethylsiloxane) hollow-fiber membrane or carbon membrane, as opposed to natural organic or sheet, for superior structural integrity and higher surface-area-to-volume ratios. The hollow-fibers are bundled within small self-contained vessels, allowing for easy membrane unit replacement (Figure 26).

Figure 26: Hollow-Fiber High-Pressure Gas Separation Membrane Design and Process Configuration

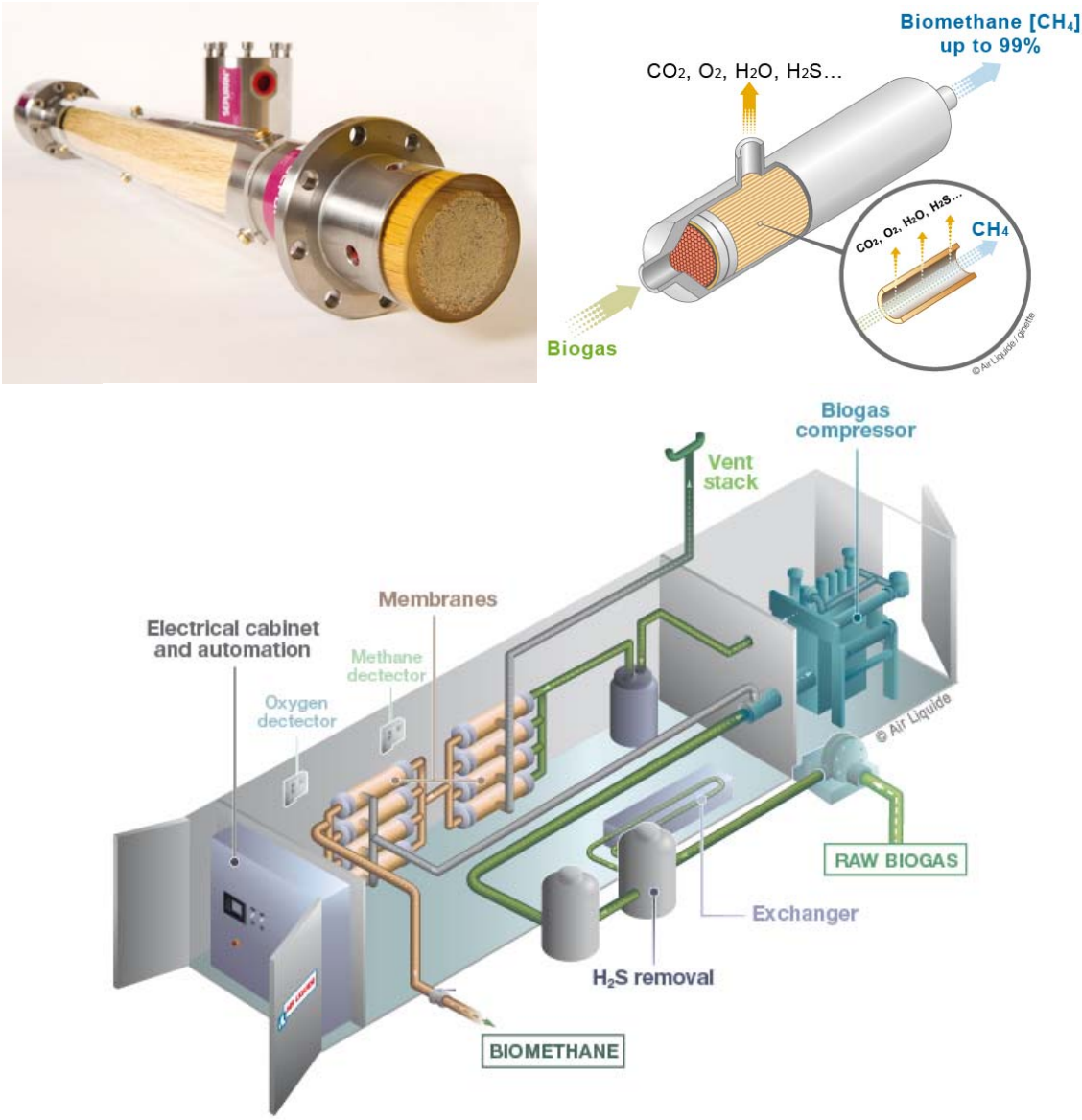


Illustration Credit: Air Liquide (2014); Fairbanks (2014)

High-pressure gas separation systems are highly reliable, easy to operate, have a simple and compact plant design, and can also be used for gas dehydration. Although these systems have relatively low capital costs, they are most competitive at the low capacity range of applications. However, to minimize the time give for methane to permeate the membrane, gas membrane separation is only reasonable at flow rates of more than 500 m^3/h. Nevertheless, this process often has more methane slip (0.5 – 15%) than other upgrading technologies, which increases with higher product gas methane requirements. The off-gas is therefore commonly either reprocessed by another membrane column or used for distributed power or heat generation.

In order to achieve higher methane content in the product, several stages may be used. For instance, biogas can be upgraded to around 92% methane content with a single membrane, or 96% with two or three membranes in series. However, the use of more membranes leads to higher methane loses and greater energy consumption. Membrane separation processes can have low or high energy consumption (0.18 – 0.77 kWh/Nm^3), with the potential for low power consumption (< 0.22 kWh/Nm^3) with highly selective membranes.

A potential enhancement to high-pressure membrane separation is gas-liquid adsorption, in which the gases are first separated by membrane permeability and then absorbed into a solution (e.g., alkaline, amine) (Figure 27). The concurrent use of absorbents significantly lowers the pressure requirements (close to atmospheric pressure) and therefore reduces power consumption. This can allow wet separation to be more economical than dry separation. Furthermore, as opposed to conventional gas-liquid contact absorption, the use of a membrane between the gas-liquid interface prevents typical problems like foaming and channeling. Gas-liquid separation can also allow highly selective separation of gases (e.g., caustic soda solution to remove H_2S, amine solution to remove CO_2), and high purity CO_2 can be sold as a product. Nevertheless, this requires not only the eventual replacement of membranes, but fluids as well.

Figure 27: Membrane Separation Techniques

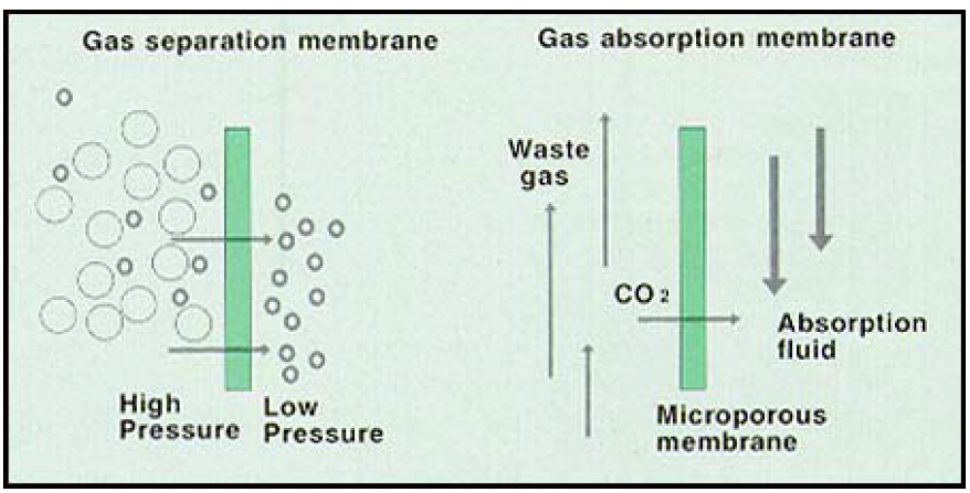


Illustration Credit: Persson and Svenskt Gastekniskt Center (2003)

Cryogenic Distillation

Cryogenic distillation takes advantage of the fact that carbon dioxide will condense and freeze before methane condenses allowing the CO2 to be removed from the gas stream as a liquid or solid.

In cryogenic distillation, biogas is compressed anywhere between 260 – 435 psi (18 – 30 bar) and cooled by heat exchangers down to -45 to -59 °C until certain gases become liquefied. High system pressures are used to ensure that carbon dioxide remains in the liquid phase and does not freeze, which would clog the pipe and heat exchanger system. The liquefied carbon dioxide is then easily separated from the remaining gas, producing highly pure biomethane. Hydrogen sulfide, which has a boiling point of -60 °C at 1 bar, can also be removed with carbon dioxide. Nitrogen and oxygen are not directly removed from the biogas since their boiling points (-196 °C and -183 °C, respectively, at 1 bar) are lower than methane's. Yet, methane can be liquefied and separated from the gaseous nitrogen and oxygen after carbon dioxide and other gas contaminants are removed. Other impurities in the gas (i.e., VOCs, halocarbons, and siloxanes) can be removed by adsorption onto molecular sieves, membranes, or by using the extracted CO_2 as a solvent scrubber. However, removing the other contaminants beforehand is preferred in order to avoid freezing over the heat exchangers and other issues. The high-pressure methane product gas can then be depressurized for pipeline injection or distributed power generation (e.g., fuel cells). Alternatively, the resulting biomethane can be cooled down further to be liquefied. Thus, cryogenic distillation can serve as an efficient method of producing compressed and liquefied natural gas, which can be used for vehicle applications.

Cryogenic distillation is able to produce a 96 – 97% methane product with 0.5 – 3% methane slip. Their primary advantage is that the gas does not contact any chemicals or moisture, meaning that there are no large recurring chemical purchase costs and no post-treatment is necessary. However, the coolant (e.g., glycol) does require infrequent replacement, so the process will still create a hazardous waste over time.

Despite savings on maintenance, cryogenic distillation systems have high capital and operating costs (i.e. high power consumption). Consequently, the process is only cost-effective at large scales. They also have complex plant designs and require higher safety standards due their operation at very low temperatures and high pressures. Operational problems may also be encountered from solid CO_2 formation on the heat exchangers. Work is ongoing at the pilot and commercial scale to overcome these issues and increase the overall system's efficiency.

A cryogenic distillation system designed by Acrion Technologies called CO_2 Wash (Figure 28) increases its performance by being combined with several other upgrading technologies. It ingeniously uses some of its waste liquid CO_2 to scrub the biogas contaminants and has MEDAL™ membranes to further reduce the product gas's CO_2 concentration. Because the scrubbing solution is made in situ, no regeneration and no solvent purchase or disposal is required. In addition to producing high-purity methane, more than 80% of the carbon dioxide is recovered as food-grade CO_2.

Figure 28: Cryogenic Distillation Process Diagram, Acrion Technologies CO_2 Wash

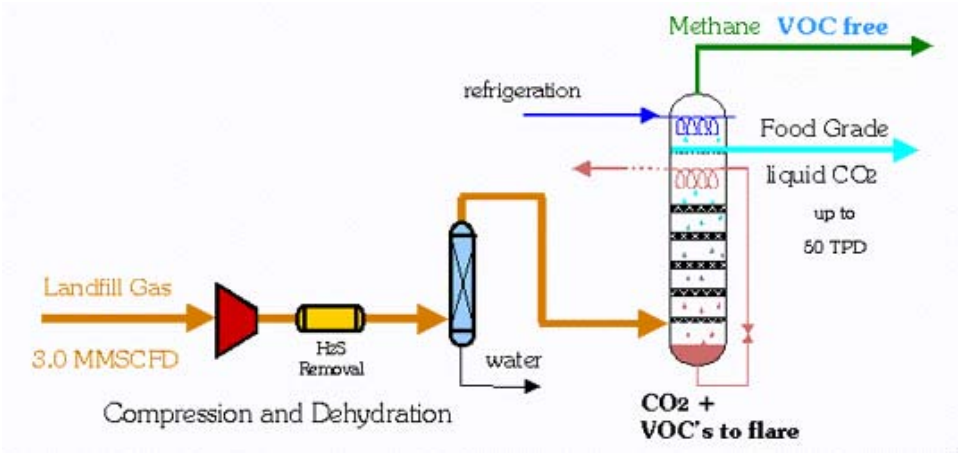


Illustration Credit: Adapted from Acrion Technologies, Inc. (2014)

Supersonic Separation

A recent, novel approach to gas clean-up is supersonic separation, consisting of a compact tubular device that effectively combines expansion, cyclonic gas/liquid separation, and re-compression. A Laval nozzle is used to expand the saturated feed gas to supersonic velocity, which results in a low temperature and pressure (Figure 29). This causes the formation water and hydrocarbon condensation droplet mist. A high vorticity swirl centrifuges the droplets to the wall, and the liquids are split from the gas using a cyclonic separator. This gas conditioning technology has been used to simultaneously condense and separate water and hydrocarbons from natural gas. Further developments allowing for the bulk removal of CO_2 and H_2S are currently underway.

Figure 29: Supersonic Separator Cross-Section

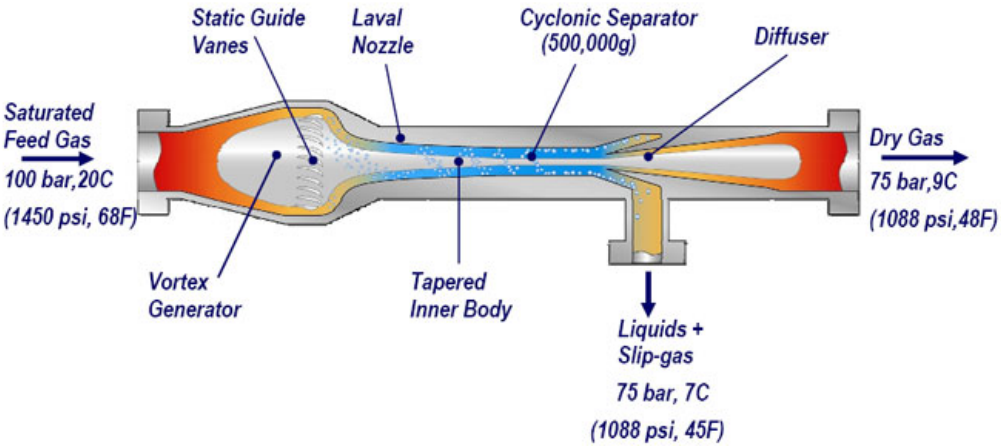


Illustration Credit: Twister BV (2014)

Similar to membrane technology, supersonic separation is simple, reliable, not susceptible to fouling or poisoning, and can offer significantly lower life cycle costs compared to conventional adsorption-based systems. Unlike all other systems, there are no downtime constraints due to utility equipment failures (e.g., glycol pumps, regeneration systems, membrane replacement, etc.), thereby providing full process automation in control systems ensuring safer and more efficient operation.

Industrial Lung

An industrial lung, also known as an ecological lung, is a bioengineered process which utilizes carbonic anhydrase—the enzyme present in our blood that catalyzes the dissolution of carbon dioxide formed from cell metabolism. Carbonic anhydrase pulls CO_2 into the aqueous phase in an absorber column where it can be picked up by an absorbent (Figure 30). The CO_2-rich absorbent is then regenerated by heat in a stripper column releasing a pure stream of > 90% CO_2.

Figure 30: Industrial Lung Process Diagram

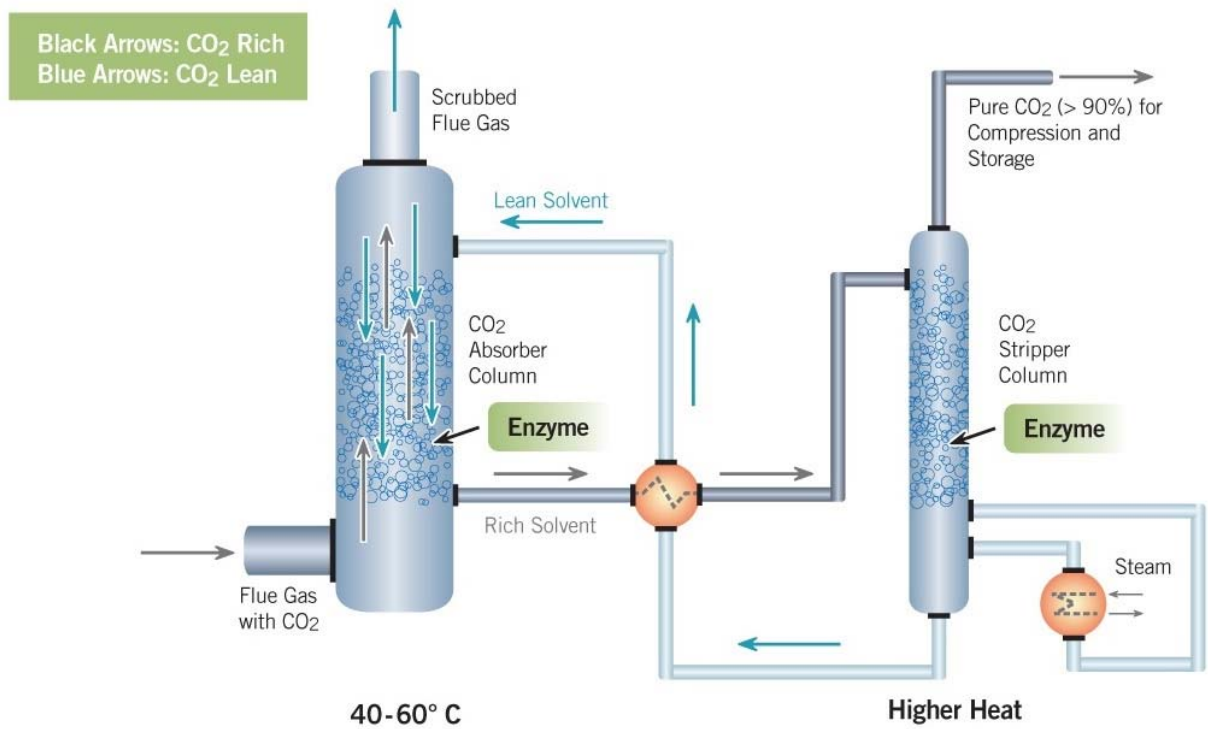


Illustration Credit: Adapted from CO_2 Solutions (2011)

This technology is patented and marketed by CO_2 Solutions, Inc. based in Quebec. CO_2 Solutions bioengineers a form of carbonic anhydrase that is 10 million times more stable than the form found in nature, and is able to withstand higher temperatures (at least 85 °C) and pH. Using just carbonic anhydrase in water, the industrial lung process is constrained by limited enzyme lifetime and high enzyme production costs. However, the special thermal and pH

resistance of bioengineered carbonic anhydrase allows it to be synergistically combined with specialized absorption processes to improve removal rates. In this situation, only minute concentrations of carbonic anhydrase are required (typically 1E-5 mol/L). One of their studies showed that the addition of carbonic anhydrase increased MDEA CO_2 absorption rates by 50 times, and reduced solvent regeneration and process energy consumption by 30%. As a result, the absorption column height can be smaller by approximately 11 times (Carley 2014; Carley 2013). Laboratory experiments with biogas showed that they can purify it to 95 – 99% methane content with a CO_2 content less than 1%. CO_2 Solutions is currently operating a large bench-scale unit processing 0.5 tonne-CO_2/day, and is planning a 15 tonne-CO_2/day pilot unit in partnership with Husky Energy to start running in 2015 (Dutil and Villeneuve 2004).

Biogas Upgrading Technology Comparison

For certain applications (i.e. fuel cells, vehicle fuel, pipeline injection), biogas must be upgraded to remove CO_2 and effectively increase its methane content (volumetric energy content). The upgrading technologies discussed above have a range of operating conditions (temperature and pressure), product methane purity, methane losses (methane slip), and consumed material types. Some require pretreatment for removal of sulfur or other gas contaminants. Table 17 summarizes the operating conditions, requirements, performance and consumables required for various upgrade techniques. The industrial lung is not listed since its characteristics are dependent upon what absorbent is used in alongside the carbonic anhydrase.

Table 17: Features of Biogas Upgrading Technologies

Biogas Upgrading Process	Pressure (psig)	Temp (°C)	Product CH_4 Content	Methane Slip	Methane Recovery	Sulfur Pre-Treatment	Consumables
Pressure Swing Adsorption	14 – 145	5 – 30	95 – 98%	1 – 3.5%	60 – 98.5%	Required	Adsorbent
Alkaline Salt Solution Absorption	0	2 – 50	78 – 90%	0.78%	97 – 99%	Required / Preferred	Water; Alkaline
Amine Absorption	0 (< 150)	35 – 50	99%	0.04 – 0.1%	99.9%	Preferred / Required	Amine solution; Anti-fouling agent; Drying agent
Pressurized Water Scrubbing	100 – 300	20 – 40	93 – 98%	1 – 3%	82.0 – 99.5	Not needed / Preferred	Water; Anti-fouling agent; Drying agent
Physical Solvent Scrubbing	58 – 116	10 – 20	95 – 98%	1.5 – 4%	87 – 99%	Not needed / Preferred	Physical solvent
Membrane Separation	100 – 600	25 – 60	85 – 99%	0.5 – 20%	75 – 99.5%	Preferred	Membranes
Cryogenic Distillation	260 – 435	-59 – -45	96 – 98%	0.5 – 3%	98 – 99.9%	Preferred / Required	Glycol refrigerant
Supersonic Separation	1,088 – 1,450	45 – 68	95%	5%	95%	Not needed	

Chart Credit: Author; Data Credit: Beil and Beyrich (2013); Severn Wye Energy Agency (2013); Starr et al. (2012); Twister BV (2014)

Amine absorption produces the purest biomethane with the lowest methane slip due to how well amines select for CO_2. Conversely, alkaline salt solution absorption and pressurized water scrubbing produce the lowest methane purity as a result of non-specific CO_2 selection. Membrane separation can yield either low or high methane purity, contingent upon number of sequential membrane stages used. More stages bear higher methane quality, but incur additional methane slip loses. As a result, membrane separation can incur the highest methane slip.

Each upgrading technology is also able to remove and array of different contaminants, while some require the pre-removal of specific contaminant. Table 18 describes general ability to treat common biogas contaminants for the main upgrade techniques. Again, the industrial lung is not included because its contaminant treatability is dependent upon the absorbent used.

Table 18: Contaminant Treatability for Biogas Upgrading Technologies

Biogas Upgrading Process	CO_2	H_2S	O_2	N_2	VOCs	NH_3	Siloxanes	H_2O
Pressure Swing Adsorption	**	* **R**	/	/	*	*	*	* **R**
Alkaline Salt Solution Absorption	**	*	-	-	/ -	-	*	--
Amine Absorption	**	*	**R**	-	/ -	*	/ -	--
Pressurized Water Scrubbing	**	*	--	--	*	*	*	--
Physical Solvent Scrubbing	**	**	/	/	*	*	*	*
Membrane Separation	**	* /	* /	/	* -	*	*	*
Cryogenic Distillation	**	*	**	**	*	*	*	*
Supersonic Separation	**	**	-	-	**	*	*	**

Legend: ** Complete removal (intended) * Complete removal (pre-removal by cleaning preferred)
/ Partial removal - Does not remove -- Contaminant added **R** Must be pretreated
Two symbols may be in the same box if one or the other can be applicable

Chart Credit: Author; Data Credit: Severn Wye Energy Agency (2013); Starr et al. (2012); Twister BV (2014)

When implementing a biogas upgrading system, it is likely that one or more upstream cleaning technologies will be used for t removal of various contaminants. Thus, the upgrading system does not necessarily have to remove every contaminant. Alternatively, the cleaning steps may not need to achieve precision-level contaminant removal since that may be accomplished by the upgrading system. Upgrading systems and cleaning systems should be designed together to take into account the other's abilities and requirements with the desired product gas quality as the primary objective. Figure 31 illustrates this concept with several possible cleaning and upgrading combinations that produce high quality biomethane.

Figure 31: Combining Biogas Cleaning and Upgrading Technologies

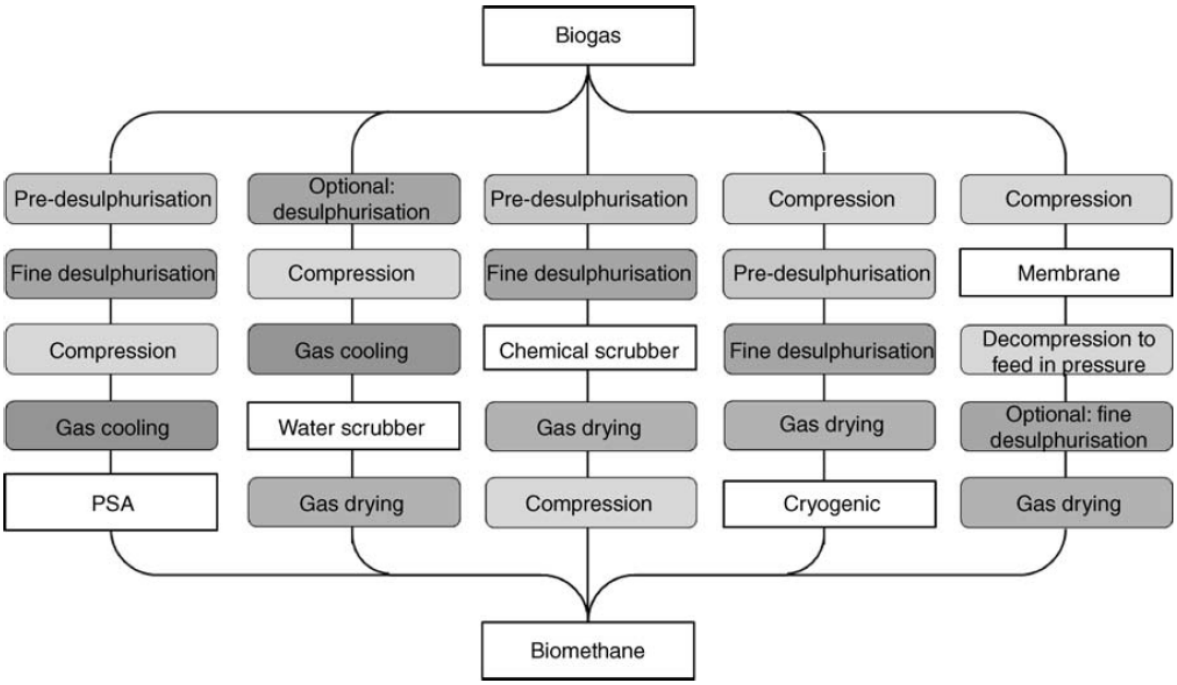


Illustration Credit: Petersson (2013)

Each upgrading technology relies upon different physical and chemical principals, and thus have different advantages and disadvantages over one another. In addition to some having higher product methane content, lower methane slip, or higher contaminant tolerance or removal, others may have lower energy requirements, smaller footprints, lower capital or maintenance costs, or greater proof of concept. These distinctions are summarized in

Table 19.

Either due to low investment price, high reliability, high removal efficiencies, or a diverse range of contaminants removal, the most commonly applied upgrading technologies are water scrubbing, PSA, and chemical scrubbing. Overall, upgrading technology selection should minimally consider the application and product gas quality requirements. However, upgrading technologies are generally expensive to purchase and can be costly to operate and maintain. As a result, the deciding factor when selecting an upgrading technology may lie with the cost (capital and O&M). Chapter 7 reviews the costs involved in employing various biogas cleaning, upgrading, and utilization technologies.

Table 19: Advantages and Disadvantages of Biogas Upgrading Technologies

	Advantages	Disadvantages
Pressure Swing Adsorption	- Low energy use - No heat demand - No chemicals - Relatively inexpensive - Compact - Applicable for small capacities - Many reference facilities	- Medium methane content - High/medium methane losses - H_2S and water pretreatment needed - Extensive process control - CH_4 loss when valves malfunction
Alkaline Salt Solution Absorption	- Removes other contaminants	- Low methane content
Amine Absorption	- Highest methane content - Low electricity demand - No gas pressurization - High CO_2 removal - Very low CH_4 losses - No moving components (except blower)	- Expensive investment costs - High heat demand for regeneration - Corrosion - Amines decompose and poison by O_2 - Salt precipitation - Foaming possible - H_2S pretreatment normally needed
Pressurized Water Scrubbing	- Simple and easy to operate - Inexpensive - Most reference facilities - Co-removal of ammonia and H_2S (H_2S > 300 – 500 ppmv) - Capacity adjustable by changing pressure or temperature	- Uses a lot of water, even w/ regeneration - H_2S damages equipment (if > 300 ppmv) - Medium methane contents - High/moderate methane losses - Clogging from bacterial growth - Foaming possible - Low flexibility for input gas variation - Biomethane drying necessary
Physical Solvent Scrubbing	- High methane content - Higher CO_2 solubility than water - Relatively low CH4 losses - Co-removal of NH_3, H_2S and other impurities, but rough pretreatment recommended.	- Expensive investment and operation - Difficult to operate - Heating required for complete regeneration
Membrane Separation	- Simple construction (lightweight and small footprint) - Simple operation (no moving components except blower) - Low maintenance - Modular configuration - No chemical or heat demand - High reliability - Small gas flows treated without proportional increase of costs	- Low membrane selectivity - Multiple steps needed for high purity - Moderate methane content - Medium to high CH_4 losses - Membrane replacement 1 – 5 years - Generally not suitable for biogas with many undefined contaminates, like landfill or WWTP biogas - Membranes can be expensive - Few reference facilities
Cryogenic Distillation	- High methane content - Low methane losses - Pure CO_2 as by product - No chemicals - Low extra energy to make LNG	- Expensive capital and O&M costs - Contaminant pretreatment needed - Technically very demanding - Full scale implantation very recent - Energy efficiency and tech not well proven
Supersonic Separation	- Simple construction and operation - No chemicals	- Expensive investment - No reference facilities - Experimental; Not well proven

Chart Credit: Allegue and Hinge (2012a)

CHAPTER 7:
Economics of Biogas Technologies

Project costs include direct capital and operation and maintenance costs for each piece of biogas-related equipment, indirect costs associated with design, engineering, construction, developing supporting infrastructure, permitting, and access fees. Some of these costs for biogas technologies are discussed below.

Equipment Cost Comparison of Biogas Cleaning, Upgrading, and Utilization Technologies

Biogas Cleaning Equipment Cost

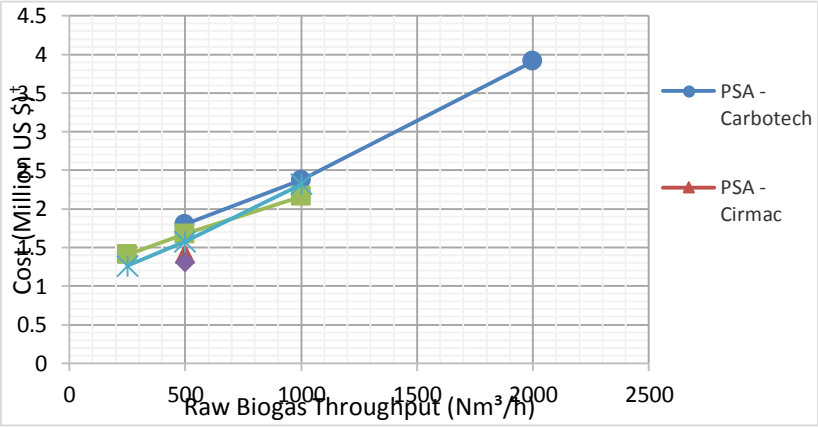
Biogas cleaning, whether by adsorption, water scrubbing, or biofiltration, requires the purchase of a reactor vessel. Water and bio scrubbers require large sized reactors and liquid pumps whereas dry absorption chambers do not. However, adsorption systems require the eventual change-out or regeneration of media. Thus, adsorption systems will have lower upfront and operating costs, but can have higher maintenance costs. Hydrogen sulfide is usually the largest contaminant in biogas, and thus a primary target for cleaning. Consequently, the cost of biogas cleaning is often listed in terms of dollars per amount of sulfur or hydrogen sulfide removed. For gas streams with 500 – 2,500 ppm H_2S, it generally costs $1.50 – $5.00 per pound of sulfur removed (McDonald and Mezei 2007). To remove moisture, a refrigeration or gas condensation system is often applied.

Biogas Upgrading Equipment Cost

Biogas upgrading technologies, on the other hand, are more complex and more costly. New and emerging technologies that consolidate biogas cleaning and upgrading, such as cryogenic distillation and supersonic separation, will generally be more expensive than already established technologies. Membrane separation may be an exception, providing cost savings so long as membrane replacement rates remain low. However, among the three most common upgrading technologies—pressure swing adsorption, pressurized water scrubbing, and amine absorption—there is no clear winner in terms of initial cost. As seen in

Figure 32, the lowest cost is highly dependent upon the manufacturer.

Figure 32: Biogas Upgrading Equipment Costs by Technology and Manufacturer



† Conversion using 2007 average Euro exchange rate of 1.37 USD per 1 Euro, and inflated to 2014 dollars using consumer price index; Source data was collected 2007 - 2008

Chart Credit: Urban, W. (2009)

Upgrading technologies are also affected by economies of scale. , the cost of treating biogas drops sharply with higher raw biogas throughputs up to 1,000 Nm^3/hr (

Figure 32). Small-scale biogas upgrading (0 – 100 Nm^3/h raw biogas) is usually very expensive due to high upgrading equipment investment costs. For small farms and other low volume biogas producers, biomethane production is likely not economical. In these situations, it may be more economical to transport raw biomass or biogas to a large central processing facility. However, this introduces the technical challenges associated with piping or transporting raw biogas, which is corrosive. Two solutions would be to use pipes that can withstand corrosion or to remove H_2S at each source prior to shipping.

Maintenance costs include those for periodic solid/liquid regenerative/non-regenerative media/solution changeout and membrane replacement, while operating costs include labor and energy requirements. Energy required to operate is a significant fraction of the O&M cost.

Figure 33 is a box plot showing the ranges and median electricity and heat requirements for the six most prevalent commercially available biogas upgrading technologies. For chemical and physical solvent scrubbing, a large proportion of the required energy is heat for thermal regeneration of the solvent.

Figure 33: Energy Requirements for Biogas Upgrading Technologies

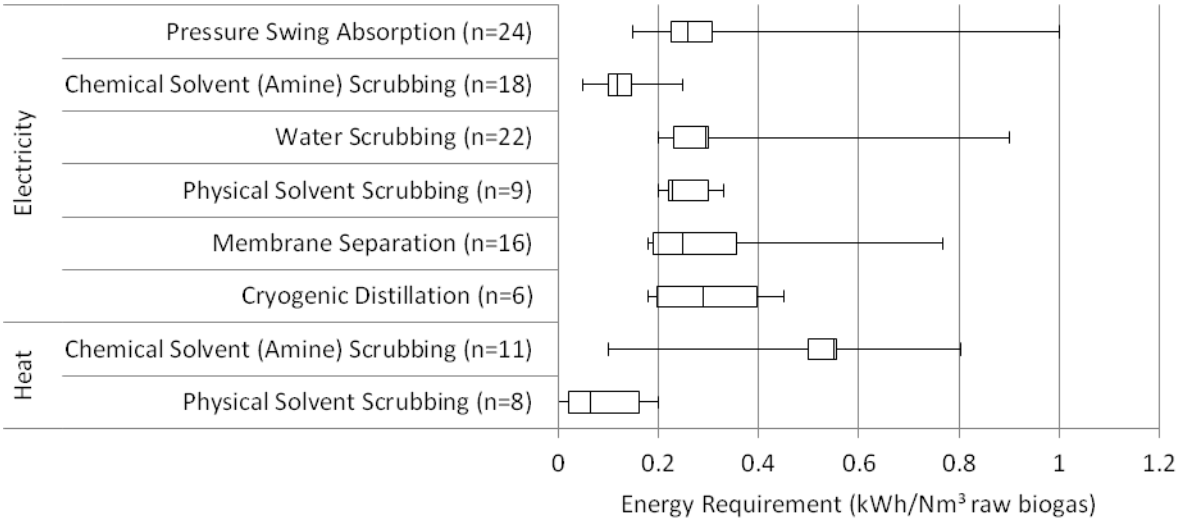


Chart Credit: Author; Data Credit: Agency for Renewable Resources (2014); Allegue and Hinge (2012b); Bauer et al. (2013); Beil and Beyrich (2013); Günther (2006); Johansson (2008); Kharrasov (2013); Niesner, Jecha, and Stehlík (2013); Patterson et al. (2011); Purac Puregas (2011); Vijay (2013)

When adding up the capital and O&M costs, there can be significant price differences between the three most common upgrading technologies at low biomethane product output rates ≤ 500 Nm^3/h (Table 20). But at higher output rates, economies of scale begin to equalize differences in capital and O&M costs such that the choice of equipment supplier again has a larger effect on the overall levelized cost of energy (

Figure 34). However, the cost of cryogenic distillation will almost always be higher than other options, but purified CO_2 and other gas streams that are produced can possibly be sold to offset some costs.

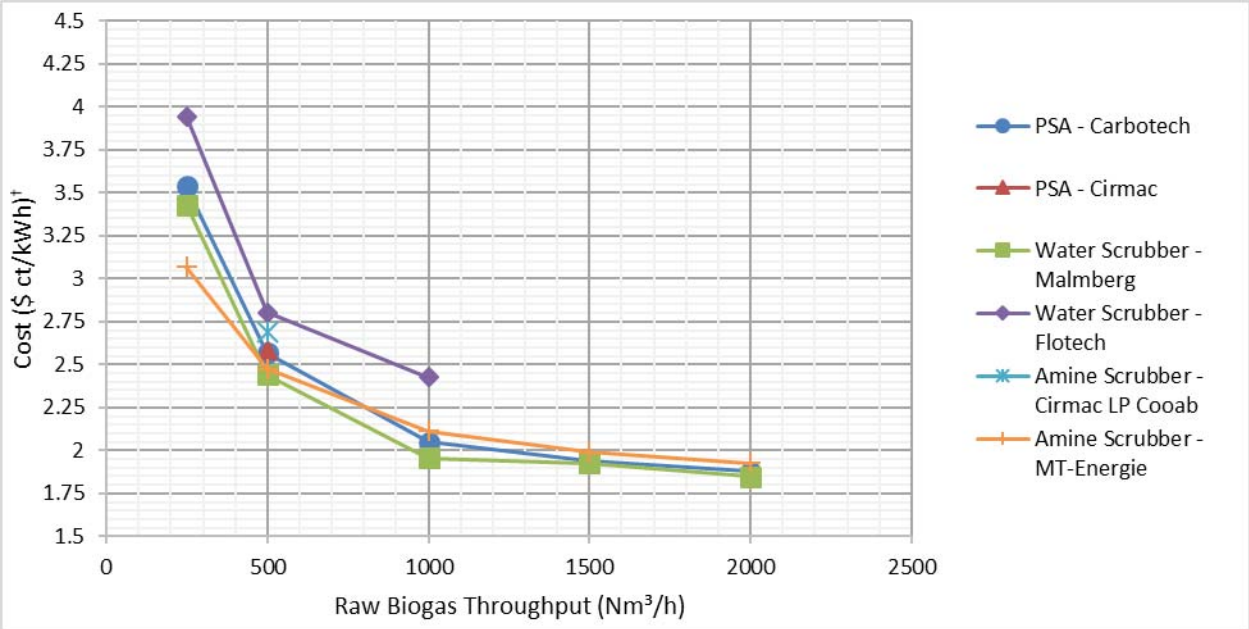
Table 20: Total Investment and Running Cost to Upgrade Biogas

Technology	US$/1000 scf biogas†
Pressure swing adsorption	9.21
Chemical absorption	6.32
Water scrubbing	4.74
Membrane separation	4.47
Cryogenic distillation	16.32

† Data for 130 – 161 Nm^3/h product gas output rate

Chart Credit: (Jensen 2013; de Hullu et al. 2008)

Figure 34: Levelized Cost of Biogas Upgrading by Technology and Manufacturer (Normalized by Biomethane Product's Energy)



† Conversion using 2007 average Euro exchange rate of 1.37 USD per 1 Euro, and inflated to 2014 dollars using consumer price index; Source data was collected 2007 - 2008

Chart Credit: Urban, W. (2009)

From reviewing several dozen biogas cleaning and upgrading companies, it is apparent that to reduce installation and construction costs and time, the industry is shifting towards turnkey solutions in which the entire upgrading system is pre-fabricated and skid-mounted onto one or more bulk units that only require piping and wiring connections when brought to the project site. It is also perceptible that the industry is focusing more on lowering energy consumption and improving contaminant removal and resistance than increasing methane product purities.

Distributed Power Generation Equipment Cost

Table 21 compares the characteristics and typical cost range for different distributed power generation and transportation applications. As with all technologies, the actual price will vary by manufacturer. However, the general relation holds that fuel cells will be more expensive than microturbines, which will be more expensive than reciprocating engines, which will be more expensive than boilers. The only exception is that microturbines can cost less to operate and maintain than reciprocating engines.

Table 21: Comparison of Distributed Power Generation and Vehicle Applications

	Boilers	Reciprocating Engines	Microturbines	Fuel Cells	CNG/LNG Vehicles
Minimum HHV (BTU/scf)	N.D.	N.D.	350	N.D.	900
Capital Cost ($/kW)	N.D.	300 – 900	300 – 1,200	3,000 – 12,000	N.D.
O&M Cost ($/kWh)	N.D.	0.008 – 0.025	0.008 – 0.022	$0.01 – $0.04	N.D.
Capacity	N.D.	5 kW – 10 MW	25 – 500 kW	1 kW – 3 MW	N.D.
Electrical efficiency	0%	18 – 45%	15 – 33%	30 – 70%	0%
Thermal efficiency with CHP	75 – 85%	30 – 50%	20 – 35%	30 – 40%	
Biogas treatment requirement	Low	Medium	Medium	High	High
HHV Requirement	Medium	Medium	Low	Any	High
NOx emissions	High	High	Low	Very low	Very low
Capital cost	Low	Medium	Medium	High	High
O&M cost	Low	Medium	Low – Medium	Low	Low

N.D.: Not Determined or not found. Listed where value should exist, but data were not found.

Chart Credit: Author; Data Credit Deublein and Steinhauser (2011); Eastern Research Group, Inc. and Resource Dynamics Corporation (2011); Environmental Science Associates (ESA) (2011); Kaparaju and Rintala (2013); US EPA (2007)

Overall Cost Discussion

Overall Cost of Injection into Natural Gas Pipelines

Due to the simplicity of biogas cleaning (conditioning) systems, they are significantly less expensive than upgrading technologies. But in terms of overall system costs (excluding biogas production and collection system costs), biogas cleaning and upgrading together represent a large part, if not the majority, of the capital and operations and maintenance costs for implementing either vehicle fueling or pipeline injection.

For example, the City of Janesville, Wisconsin's 18 – 20 MGD WWTPrecently installed a biogas upgrading and fueling station. The system currently processes 0.1 MMscfd of biogas, or about half of its total processing capacity. Prior to developing an R-CNG station, the plant had two 200 kW Waukesha reciprocating engines generating 719,600 kWh annually of electricity. Their biogas cleaning/upgrading system consists of an iron sponge chamber for H_2S removal (175

ppmv to 10 ppmv), glycol scrubbing for CO_2 removal, polymer microbeads for siloxane removal, and activated carbon to remove other contaminants. The biogas is upgraded from 60% to 90% methane in this process. The capital cost of the gas conditioning system alone was $288,320 (Table 22). R-CNG gas compressions, storage and dispensing equipment cost about $186,700 (total equipment cost $475,000). This gas conditioning system accounts for almost 61% of the total project's investment cost. Nevertheless, the final cost of R-CNG was about $0.88 per gallon gasoline equivalent.

Table 22: Gas Conditioning Skid Costs for the Janesville Wastewater Treatment Plant, WI

Capital Cost (excl. installation)	$288,320
Operations and Maintenance Costs	
Oil and Filters	$5,000/year
Microbead media	$4500/batch
Labor and Spent media disposal	$1,200
CNG compressor oil and filter change (once per year)	$1,000/year

Chart Credit: Zakovec (2014)

However, out of all currently available biogas utilization options, pipeline injection has the highest total capital and operation and maintenance (O&M) costs. Unison Solutions Inc., a supplier of biogas conditioning equipment, estimates a $3.5 million capital cost for biogas upgrading at a 350,000 scf CH_4 per day facility (Ahuja 2014). To reiterate a point made earlier, biogas cleaning and upgrading together represent a large fraction of a costs, both capital and O&M, of a pipeline injection project (more than 50% of total project cost (

Figure **35**). The City of Hamilton (Canada) WWTP spent $4 million to upgrade biogas to biomethane, while the Union Gas interconnection cost was only $300,000 (Gorrie 2012). In the 2012 SoCalGas General Rate Case Proposal, SoCalGas sought to install four biogas conditioning systems ($5.6M each) at small to midsize WWTPs (200 – 600 scfm) to produce biomethane for their facility and fleet vehicles (Goodman 2011).

Figure 35: Biomethane Pipeline Injection 15-Year Cost Breakdown

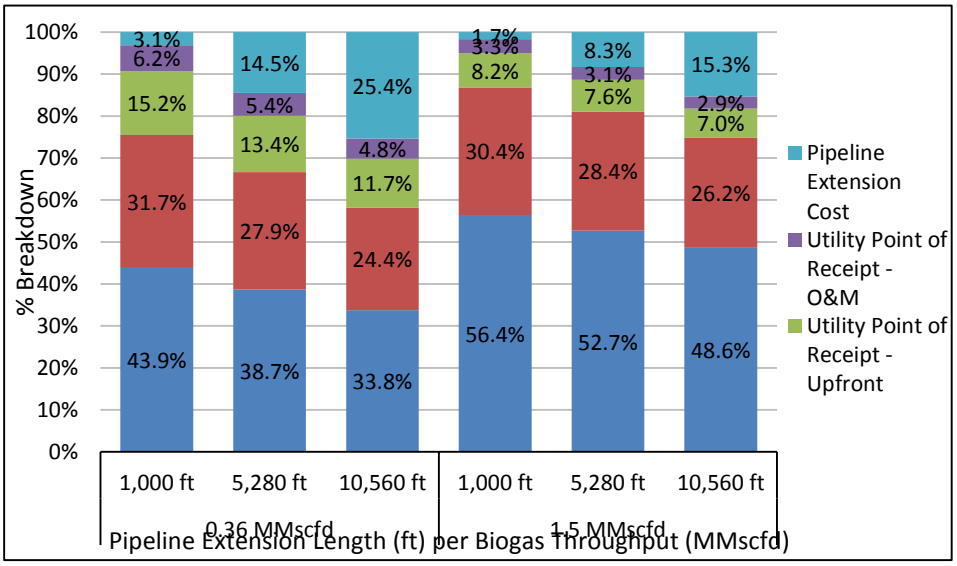


Chart Credit: Adapted from Lucas (2013b)

Pipeline interconnection costs can also be high. For the George DeRuyter and Sons Dairy in Outlook, WA, $3.4M was spent on a 3.7 mile pipeline extension to the Williams Northwest Pipeline, interconnection, and metering station. Half of the cost was funded by a Yakima County grant (Evans 2014). In California, the utilities have quoted total interconnection costs to be somewhere between $1,500,000 and $3,000,000 (Escudero 2013). SoCalGas in particular estimated the total interconnection cost in 2014 to be $2.7M. This value includes pipeline extension, point of receipt, and taxes (Lucas 2013b). Total SoCalGas interconnection capital costs have also been cited to be $1.3M – $1.9M for 1 – 10 MMscfd facilities, along with $200 – $300/ft for pipeline extension and $14,000 for pre-injection testing per Decision (D.) 14-01-034. Operating costs were estimated to be $3.5k/month for Point of Receipt facility O&M and $6k-24k/yr for periodic testing per D. 14-01-034. For the Point Loma WWTP in San Diego, CA, the cost of interconnecting with an SDGE pipeline interconnect was $1.99M (Mazanec 2013). Interconnecting also includes compressing the gas up to pipeline pressures, which adds additional cost (

Table 23). Furthermore, gas quality must be monitored, which can cost $50,000 – $100,000 for a simple monitoring system (excl. compressors), or $100k – $400k for complex systems that use chromatographs (Electrigaz Technologies Inc 2008).

Overall, interconnection costs in California are much greater than in other states. Comparatively, three projects developed outside California paid interconnections costs of $82,546, $70,816, and $272,170 as of 2013.

Table 23: Gas Compressor Costs

Model	Feed Flow Rate (scfh)	Feed Flow Pressure (psi)	Output Flow Rate (scfh)	Output Flow Pressure (psi)	Unit Cost ($/unit)	O&M Cost ($/yr)
Regression	6,000	100	5,695	800	$132,500	$9,465
GE Gemini	21,000	100	19,920	800	$200,000	$16,400
GE Gemini	42,000	100	39,780	800	$225,000	$45,500
GE Gemini	72,000	100	68,220	800	$325,000	$119,900
GE Gemini	120,000	100	113,700	800	$450,000	$193,800
GE Gemini	300,000	100	284,220	800	$600,000	$474,000

Chart Credit: Cooley et al. (2013)

To drive down total interconnection costs, proximity to a pipeline is key. When long distances are required, the cost of pipeline extension can rise to be nearly as high as the costs of the biogas upgrading equipment. From PG&E's experience, biogas injection projects more than 4 – 5 miles from a transmission pipeline are economically viable (Environmental Science Associates (ESA) 2011) Table 24 gives estimated pipeline costs. However, when land acquisition, right-of-way purchases, and difficult terrain are factored in, the total pipeline extension cost is commonly between $100,000 – $280,000 per mile, or but can be up to twice as high (Environmental Science Associates (ESA) 2011; R. Goldstein 2009; Jensen 2013). This is comparable to the cost in other countries. For example, a biomethane plant in Borås, Sweden paid $213,000 per mile for four miles of pipeline extension, while the Swedish cost of horizontally trenched pipeline is roughly $100,000 per mile (Krich et al. 2005).

Table 24: Estimated Pipeline Cost by Size and Distance

Pipe Size Diameter (in)	Flow (MMscfd)	Cost ($1000/mi)
0.5	0.007	55.643
1	0.044	58.057
2	0.268	63.334
3	0.768	68.511
4	1.585	73.890

Chart Credit: Adapted from Prasodjo et al. (2013)

Associated with the total cost of the interconnection facility and pipeline extension, there may be costs for utility facility enhancement, land acquisition, site development and construction, right-of-way, metering, gas quality, permitting, regulatory, environmental, unusual construction, and operating and maintenance of other components. Pipeline flow schedules may vary, so gas storage may also need to be purchased and installed.

When working with PG&E, they will build, own, and operate the interconnection station However, the gas supplier must obtain all rights-of-way, permits, and easements needed for a lateral pipeline, interconnection station, and access road. The supplier is also responsible for all

actual capital costs and formula-based O&M costs. In 2007, PG&E's total charge for an interconnection fee, interconnection facilities, monitoring equipment, metering controls, and engineering was $265,000. If the throughput was > 0.5 MMscfd, PG&E subsidized $85,000 for interconnection, metering controls, and engineering (Anders 2007) At the same time, SoCalGas had an estimated interconnect fee of $800,000 for 1 MMscfd and $1,000,000 for 10 MMscfd (Anders 2007). In 2011, the PG&E interconnect fee was cited as being $400,000 – $600,000 (Environmental Science Associates (ESA) 2011).

For SoCalGas, there are natural gas pipeline pre-installation interconnection costs (i.e., Interconnection Capacity Study fee, Preliminary Engineering Study fee, Detailed Engineering Study fee) and post-installation interconnection costs (i.e., odorant costs of approximately $0.0003/Dth). The gas supplier pays 100% of the costs or is charged an incremental reservation rate on a going forward basis (SoCalGas 2013). To assist with the high investment cost of biomethane pipeline injection, SoCalGas developed an optional Biogas Upgrading/Conditioning Tariff Service designed for facilities that produce ≥1000 scfm raw biogas. Under this service, SoCalGas would design, install, own, operate, and maintain biogas conditioning and upgrading equipment. SoCalGas would then charge the customer a fully allocated cost under a long-term service agreement. However, the biogas producers would still own the biogas entering and exiting the biogas system, and is still responsible for ensuring that the biomethane product meets SoCalGas's Rule 30 quality standards. The biogas producer would also still need to pay for the interconnection facility. Nevertheless, using this service would largely lower a project's capital cost, but would add a running cost. Compared to using third-party subcontractors, this option is expected to expedite SoCalGas's approval process for allowing pipeline injection. Prior to the Biogas Upgrading/Conditioning Tariff Service, SoCalGas proposed a Biogas Conditioning Services and Bioenergy Production Facilities Services program, but it was rejected by the CPUC. Under this option, SoCalGas would also construct a biogas facility if one did not already exist onsite. SoCalGas would likewise own, operate, and maintain the biogas equipment. Another proposed SoCalGas program was the Sustainable SoCal Program, tailored for four small to medium wastewater treatment plants with 200 – 600 scfm raw biogas production rates, where SoCalGas would provide the same services as those mentioned above and also pay for the interconnection facility, but would own the raw and upgraded biogas (Lucas 2013a).

There are also state and federal taxes, which include sales taxes, energy taxes, property taxes, the Contributions in Aid of Construction (CIAC) tax, and the Income Tax Component of Contributions and Advances (ITCCA). The CIAC tax applies to all property, including money, received by a utility from an eligible customer to provide for the installation, improvement, replacement, or expansion of utility facilities (such as an interconnection facility). The ITCCA is a federal and state tax that the utility pays on income received as a CIAC. Effective January 1, 2014, the ITCCA rate is 35%. This thus adds 35% to the interconnect construction and supply costs. Tax exemptions may be available to certain components, such as real and personal property, and should be investigated to provide substantial cost savings. However, the largest savings are likely to come from federal, state, or local incentive programs and grants. These

include competitively solicited contracts and grants from the California Energy Commission[7] and the California Air Resources Board[8]

Overall Cost of Distributed Power Generation

Small biogas power costs were estimated by Black and Veatch in support of CPUC proceedings to implement SB1122. Energy production cost (LCOE) for energy from waste water and dairy digester biogas is shown in Table 25 (does not include cost of producing the biogas).

Table 25: Levelized Cost of Energy (LCOE) for Biogas Distributed Power Generation (does not include gas production/digester cost)

Feedstock / Facility Type	Estimate	Project Size (MW)	Capital Cost ($/kW)	Operating Cost ($/kW-yr)	Tipping Fee ($/ton)	Feedstock Cost ($/dry ton)	LCOE ($/MWh)
Wastewater	Low	3	2,145	144			**51**
	Med	3	2,681	180			**63**
	High	3	3,217	216			**76**
Dairy Manure	Low	1	8,720	760			**211**
	Med	1	10,900	950			**278**
	High	1	13,080	1,140			**334**

Chart Credit: Black & Veatch (2013)

Compared to pipeline injection, the cost of distributed power generation will be less due to lower costs associated with interconnection (Table 26). Nevertheless, there are still a variety of interconnection-related fees that must be paid.

In order to interconnect with the PG&E electricity grid, there are also pre-installation costs (i.e., interconnection request fees, study/review fees/deposits, interconnection facility and system modification and ongoing maintenance costs) and post-installation costs (i.e., standby charges, non-bypassable charges) (PG&E 2014a). However, exemptions and incentives are available. For example, clean customer electricity generation, including net-metered systems, under 1 MW are eligible for CPUC's self-generation incentive program or similar CEC programs and are thereby automatically exempt from paying the PG&E's cost responsibility surcharge.

[7] http://www.energy.ca.gov/contracts/

[8] http://www.arb.ca.gov/ba/fininfo.htm

Table 26: Cornerstone Environmental Group, LLC Cost Estimates for 165 scfm (0.24 MMscfd) Biogas Utilization Systems

Distributed Power Generation		Pipeline Injection	
Capital Cost		Capital Cost	
Engineering / Permitting	$75,000	Engineering / Permitting	$75,000
Gas conditioning system	$265,000	Gas conditioning system	$265,000
Genset turbines	$500,000	Biogas upgrading	$450,000
Grid interconnection	$50,000	Pipeline extension and Interconnection	$250,000
Construction	$100,000	Construction	$100,000
Operations and Maintenance Cost	$80,000/year	Operations and Maintenance Cost	$80,000/year

Chart Credit: Torresani (2009)

Ultra-clean and low emission customers over 1 MW and other types of customer generation subject to the statewide megawatt cap may also qualify for certain exemptions. Exemptions provided for in Decision 03-04-030 are discussed in greater detail in PG&E's Advice Letter 2375-E-B[9] and Electric Rate Schedule E-DCG[10] CPUC's Self-Generation Incentive Program, funded through December 31, 2014, provides incentives for biogas-operated fuel cells ($3.45/W), internal combustion engines ($2.08/W), microturbines ($2.08/W), gas turbines ($2.08/W), and waste heat to power technologies ($1.13/W). The incentive payout rate depends upon the energy production capacity: 100% for 0 – 1 MW, 50% for 1 – 2 MW, and 25% for 2 – 3 MW (PG&E 2014b).

With respect to Southern California Edison (SCE), projects that propose to interconnect to their distribution system must follow their Wholesale Distribution Access Tariff under the jurisdiction of the Federal Energy Regulatory Commission, as well as their Rule 21: Generating Facility Interconnections under the jurisdiction of the California Public Utilities Commission. Projects that interconnect to their transmission system must follow their CAISO tariff and are governed by and fall under the jurisdiction of the Federal Energy Regulatory Commission. SCE has several payback options available for electricity suppliers—Energy Procurement options, Renewable Energy Self-Generation Bill Credit Transfer, or Net Energy Metering. Application and interconnection study fees are charged to applicants of these programs[11]. Network Upgrades costs are also paid by the customer, but is typically refunded on a straight-line basis, including interest, over the five-year period commencing after the Project achieves commercial operation (Southern California Edison 2014).

[9] http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_2375-E-C.pdf

[10] http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-DCG.pdf

[11] https://www.sce.com/wps/portal/home/residential/generating-your-own-power/

CHAPTER 8: Conclusions

Regulatory and Technical Standards

Distributed Power Generation

Distributed power generation is the simplest (with regards to design, permitting, and regulation) and lowest cost option for biogas utilization at existing biogas production facilities, aside from heat generation with boilers. Many facilities that are already collecting biogas and flaring it that decide to utilize their biogas opt to generate electricity. The primary biogas-powered electricity generation technologies are reciprocating engines, microturbines, and fuel cells. When biogas is used as the intake, the type of reciprocating engine typically used is a lean burn internal combustion engine. Reciprocating engines are well-established technologies and require only moderate gas pretreatment. Microturbines require less maintenance, but come in smaller power sizes and may be less efficient. Fuel cells come in five major varieties—polymer electrolyte membrane, alkaline, phosphoric acid, molten carbonate, and solid oxide. The types most commonly applied to stationary power generation are polymer electrolyte membrane, molten carbonate, and solid oxide. Fuel cells are more electrically efficient than other systems, but require greater gas contaminant pretreatment. In general, fuel cells are more expensive than microturbines, which are more expensive than reciprocating engines, which are more expensive than boilers. The only exception is that microturbines can cost less to operate and maintain than reciprocating engines.

Biomethane Pipeline Injection

An emerging application for biogas utilization is injection into natural gas pipelines. In California, the four largest natural gas transmission and distribution pipeline investor-owned utilities (IOUs) are Pacific Gas and Electric (PG&E), Southern California Gas (SoCalGas), San Diego Gas and Electric (SDGE), and Southwest Gas (SWGas). Each IOU has their own gas quality standards listed among their tariffs, but they are all fairly similar. As evident in **Error! Reference source not found.**, raw biogas from any source must undergo significant treatment to meet the IOU standards.

IOU standards for common gas contaminants are comparable to that of other states and countries. Meeting these standards is of little concern, as most cleaning and upgrading technologies are more than capable of achieving them. However, the regulations regarding the 12 constituents of concern are unique to California. It is unprecedented that California biogas pipeline injection facilities must measure up to 12 contaminants on a quarterly to annual basis per CARB's Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biomethane into the Common Carrier Pipeline in response to AB 1900 mandates.

Table 27: Partial List of Biogas Source Concentrations and IOU Standards For Biomethane Pipeline Injection

	HHV (Btu/scf)	CO_2 (%)	H_2S (ppm)	Siloxane (mg/m^3)
Landfill	208 – 644	15 – 60	0 – 20,000	0 – 50
Wastewater Treatment Plant	550 – 650	19 – 45	1 – 8,000	0 – 400
Agricultural Digester	550 – 646	15 – 50	10 – 15,800	0 – 0.2
MSW Digester	N.A.	34 – 38	70 – 650	N.A.
Gasifier	94 – 456	10 – 30	80 – 800	N.A.
PG&E	750 – 1150† (990 - 1050)‡	1	4	0.1
SoCalGas	990 – 1150	3	4	0.1
SDGE	990 -1150	3	4	0.1
SWGas	950 – 1150	2		0.1

† Normal PG&E range of higher heating values. PG&E dictates that the interconnecting gas shall have a heating value that is consistent with the standards established by PG&E for each Receipt Point.

‡ Typical higher heating value for a PG&E receipt point.

Chart Credit: Author

It is also of particular importance to note that all of the IOUs in California with the exception of SWGas require the injected gas to have a higher heating value ≥ 990 Btu/scf. This value is greater than those found in all other states and most other countries. **Error! Reference source not found.** shows that a majority of upgrading technologies are barely able to achieve the specified gas quality using a single one stage process. The only technology that is reliably capable of doing so is amine absorption. Unfortunately, amine absorption is expensive, complicated, and requires difficult/costly O_2 pre-removal. Other technologies require more than one stage (additional upgrading system in series) and/or high-end designs to reach a 990 Btu/scf product. Because single upgrading systems are already expensive, it is most likely to be economically infeasible to produce pipeline-quality biomethane at small farms and other low biogas producers.

Table 28: Partial List of Biogas Upgrading Specifications

	Product CH_4 (%)	Product HHV (Btu/scf)	Product H_2S (ppm)	Methane Slip (%)	Methane Recovery (%)	Sulfur Pre-Treatment
Pressure Swing Adsorption	95 – 98	960 – 990	< 4	1 – 3.5	60 – 98.5	Required
Amine Absorption	99	1000	< 0.2 – 8	0.04 – 0.1	99.9	Preferred / Required
Pressurized Water Scrubbing	93 – 98	940 – 990	< 1 – 2	1 – 3	92 – 99.5	Not needed / Preferred
Physical Solvent Scrubbing	95 – 98	960 – 990	< 0.1 – 20	1.5 – 4	97 – 99	Not needed / Preferred
Membrane Separation	85 – 99†	860 – 1000†	< 1 – 4	0.5 – 20	75 – 99.5	Preferred
Cryogenic Distillation	96 – 98	970 – 990	< 0.02	0.5 – 3	98 – 99.9	Preferred / Required
Supersonic Separation	95	960	N.A.	5	5	Not needed

† Multiple stages required for high CH_4 purity, but results in higher methane slip

Data Credit: Allegue and Hinge (2012a); Beil and Beyrich (2013); Persson (2003); Severn Wye Energy Agency (2013); Starr et al. (2012); Twister BV (2014)

Biogas Cleaning and Upgrading

Biogas is primarily composed of methane and carbon dioxide but can contain a large number of other compounds (in smaller amounts) some of which are detrimental to biogas appliances or contribute to unwanted air emissions.[12] Hydrogen sulfide is typically the largest concentration contaminant in biogas and is detrimental to biogas appliances, and thus a primary target for cleaning. A majority of contaminant compounds can be removed (cleaned / conditioned) by adsorption, biofiltration, or water scrubbing processes. Moisture is commonly removed by refrigeration or some other condensation process, although adsorbents can also be effective.

For certain applications, biogas must be upgraded to biomethane by removing the CO2. The most commercially deployed and available upgrading technologies are pressure swing adsorption, amine adsorption, and water scrubbing. They are highly reliable, predictable, and

[12] Hydrogen sulfide and other sulfur compounds (e.g., alkyl thiols / mercaptans), ammonia, inert compounds (e.g., nitrogen, oxygen, carbon monoxide), hydrogen, non-methane hydrocarbons, aromatics (e.g., p-Dichlorobenzene, ethylbenzene, toluene), halogenated compounds (e.g., chlorine and fluorine compunds, vinyl chloride), n-Nitroso-di-n-propylamine, methacrolein, siloxanes, arsenic, antimony, copper, lead, and moisture.

vetted technologies, having long been used in many gas industries including natural gas. Several newer technologies are starting to Including physical solvent scrubbing (using glycols), membrane separation, and cryogenic distillation. Although many biogas upgrading technologies can simultaneously clean out contaminants, specific contaminant pretreatment is typically recommended to maximize the adsorbent's or absorbent's lifetime, reduce regeneration costs, and extend maintenance intervals. Biogas upgrading technologies are more expensive to purchase, operate, and maintain than cleaning technologies due to higher complexity.

There can be significant differences between the levelized cost of energy for the three most common upgrading technologies at low biomethane product output rates of less than 500 Nm^3/h, but at higher rates, economies of scale begin to equalize differences in capital and O&M costs such that the choice of equipment supplier has a larger effect on the overall levelized cost of energy.

Recommendations

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

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

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

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

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

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

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

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

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APPENDIX A:
Acronyms, Definitions, and Units of Measurement

Acronyms

AB	California Assembly Bill
AC	Activated carbon
AD	Anaerobic digestion
AFC	Alkaline fuel cell
ARB	California Air Resources Board
CHP	Combined heat and power
CNG	Compressed natural gas
CPUC	California Public Utilities Commission
GHG	Greenhouse gas
HCG	Hydrothermal catalytic gasification
IOU	Investor-owned utility
LNG	Liquefied natural gas
O&M	Operations and maintenance
OEHHA	California Office of Environmental Health Hazard Assessment
LACSD	Los Angeles County Sanitation District
MCFC	Molten carbonate fuel cell
MSW	Municipal solid waste
PAFC	Phosphoric acid fuel cell
PEMFC	Polymer electrolyte membrane fuel cell
PG&E	Pacific Gas and Electric Company
POTW	Publicly Owned Treatment Works
PSA	Pressure Swing Adsorption
R-CNG	Renewable compressed natural gas
R-LNG	Renewable liquid natural gas
RPS	California Renewables Portfolio Standard
RSNG	Renewable Synthetic Natural Gas
SB	California Senate Bill
SCE	Southern California Edison
SDGE	San Diego Gas and Electric Company
SoCalGas	Southern California Gas Company
SOFC	Solid oxide fuel cell
SWGas	Southwest Gas Corporation
VOC	Volatile organic carbon
WWTP	Wastewater treatment plant

Definitions

Biogas	Gas produced by the anaerobic decomposition of organic material that is composed primarily of methane and carbon dioxide
Biomethane	Cleaned and upgraded biogas, typically > 95% methane
Cleaning	The removal of contaminants or impurities from a gas mixture
Slip	Leaked emissions from a process
Syngas	Gas produced by the thermochemical process of gasification that is composed primarily of hydrogen, carbon monoxide, and carbon dioxide
Upgrading	The removal of carbon dioxide from biogas to create biomethane

Units of Measurement

bhp	Brake horsepower
Btu	British thermal unit
cf	Cubic foot
DGE	Diesel gallon equivalent
ft	Foot
in	Inch
gal	Gallon
gr.	Grain
MGD	Million gallons per day
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
lb	Pound
mi	Mile
Nm^3	Normal cubic meter, at 0 °C and 1.01325 bar (atmospheric)
ppb	Parts per billion
ppbv	Parts per billion, by volume
ppm	Parts per million
ppmv	Parts per million, by volume
ppmvd	Parts per million, by dry volume
psi	Pounds per square inch
psig	Pounds per square inch, gauge
scf	Standard cubic foot

Unit Conversions

1 gr. sulfur compound/100 scf	=	17 ppm sulfur compound
1 mg H_2S/m^3	=	0.717 ppm H_2S
1 mg mercaptans/m^3	=	0.717 ppm mercaptans

APPENDIX B: Descriptions of Several Biogas Projects

Landfill gas is typically collected by gas blowers which pull the gas from a network of vertical extraction wells, consisting of permeable (perforated or slotted) pipes, and through covered horizontal tranches. Landfill gas can also be collected passively (without gas blowers) by taking advantage of the pressure generated by the evolving gases, but requires well-sealed gas containment. Passive systems have lower capital and O&M costs, but have higher inefficiencies and minimal collection capacity. The design and performance of US landfills is regulated by federal requirements under Subtitle D of Resource Conservation and Recovery Act for Landfill Gas Mitigation Control.

Landfill Gas Projects

The Veolia ES Greentree Landfill in Kersey, PA produces 6,000 – 6,500 scfm of 53% CH_4 landfill gas. A multi-stage Air Liquide MEDAL membrane system removes nitrogen, 98% of the carbon dioxide, and half of the oxygen present. The gas is then transported through a pipeline to a utility where it is used to generate power in combined-cycle equipment. The total cost of the system was $35 million. (Torresani 2009).

The Rodefeld Landfill in Dane County, WI, produces R-CNG to fuel 25 – 30 CNG vehicles. The system was expanded from a daily production capacity of 100 gasoline gallon equivalents per day to 250. Biogas is conditioned and upgraded through a $400,000 Bio-CNG 50 system. The station cost roughly $500,000, $150,000 of which was funded by a State of Wisconsin Office of Energy grant. The last five CNG vehicles were also funded by a $28,800 State of Wisconsin Office of Energy grant. The price of the R-CNG gas produced, as of September 2013, was $1.25 per gallon (NGV Global 2013).

The Altamont City landfill in Livermore, CA collects, cleans, upgrades, and liquefies its biogas to produce renewable liquid natural gas (R-LNG) vehicle fuel. A Guild Associate Inc.'s Molecular Gate pressure swing adsorption system is applied to clean and upgrade the landfill gas by removing sulfur compounds, water, siloxanes, halogens, non-methane hydrocarbons, N_2, and CO_2 (1 – 2% in product gas). The 96.6 – 97% CH_4 gas is then liquefied to -260 °F by a Linde mixed hydrocarbon refrigerant liquefier system. Their system produces roughly 13,500 gallons of R-LNG fuel daily for use on their fleet of 300 – 400 refuse trucks. Roughly $16M in initial capital investment was spent to build their facility. $14M was privately funded by Linde and Waste Management while the remaining $2M were provided by various grant-giving agencies— California Air Resources Board ($610,000), CalRecycle ($740,000), Southern California Air Quality Management District ($250,000) and California Energy Commission ($990,000). Subsidies and tax credits also help to offset costs (Underwood 2012).

The Los Angeles County Sanitation District (LACSD) also uses 1% of its landfill gas at the Puente Hills Materials Recovery Facility in City of Industry, CA to produce R-LNG vehicle fuel. The gas is upgraded using a multi-stage high-pressure membrane separation process, which required frequent membrane replacement—the membranes suffered from 30% losses in

permeability after 1.5 years. With a capacity of 90 scfm, it produced about 1,000 gallons of gasoline equivalent daily. The greater part of Puente Hills' landfill gas is sent to a separate gas-to energy facility—a 50 MW Rankine cycle stream power plant that uses boilers to produce superheated steam which drives stream turbines/generators. The excess 46 MW of electricity is sold to Southern California Edison. In 2006, an 8 MW gas-fired internal combustion engine facility was added, consisting of three 3 MW Caterpillar 3616 engines. This facility nets 6 MW and powers the San Jose Creek Water Reclamation Plant (LACSD 2014a; LACSD 2014b).

Wastewater Treatment Plant Biogas Projects

In 2001, The Chiquita Water Reclamation Plant in Santa Margarita, CA began operating two 30 kW Capstone C30 microturbines that feed electricity to the San Diego Gas and Electric Company (SDGE). The system had cost $83,666 for construction, $1,400 for SDGE interconnection, $1,611 for South Coast Air Quality Management District permits for two turbines, and $9,520 for emissions source testing from a representative turbine. The total installation cost, excluding the equipment cost, was $114,020. This system provided $4,000 – $5,000 per month in energy savings. In March 2003, the plant added two more microturbines and a Microgen hot water generator for an installation cost of $160,582. Turbine emissions averaged 1.25 ppmv NOx and 138.5 ppmv CO. With a $77,400 grant from the South Coast Air Quality Management District, a $92,369 grant from the San Diego Regional Energy Office, and as much as $8,000 in monthly energy savings, the $372,937 invested in the project was paid back in only 2.5 years. (US DOE 2011b).

The Inland Empire Utilities Agency in Ontario, CA operates a 44 million gallons per day wastewater treatment plant that collects and purifies its biogas through an ESC CompHeet® System that removes H_2S, siloxane, and moisture. The biogas is then utilized in a 600 scfm fuel cell system that was installed in 2012 and generates 2.8 MW of electricity (Environmental Systems & Composites, Inc. 2014).

The Columbia Boulevard Wastewater Treatment Plant in Portland, OR treats 80 – 90 million gallons/day and uses its biogas on a 200 kW ONSI PC25C fuel cell and four 30 kW Capstone microturbines. Fuel cell installation cost $1,300,000, while the microturbine installation cost $340,000. The maintenance costs are around $0.02/kWh for the fuel cell and $0.015/kWh for the microturbines. The system provides more than $60,000 in energy savings and profits from selling excess energy. (US DOE).

The King County South Treatment Plant in Renton, WA scrubs the majority of its gas using high-pressure Binax scrubbers to remove hydrogen sulfide and carbon dioxide, and sells it to Puget Sound Energy as pipeline quality biomethane. For a two-year demonstration project from 2004 to 2006, a portion of the raw digester gas was diverted to a SulfaTreat and two activated carbon absorbers to reduce H_2S concentration to 0.1 ppmv before being sent to a 1 MW molten carbonate fuel cell (the world's largest). A waste heat recovery unit for the fuel cell's exhaust was sized for 1.7 MMBtu/hour and brought the fuel cell system's efficiency up from 45% to 67.5%. Fuel cell emissions of ≤ 0.2 ppm NOx, ≤ 13 ppm CO, and no detectable NMHC, were far under the region's air quality standards (Bloomquist 2006). Methane breakthrough was only

about 290 ppm and the electrical efficiency was around 45%. However, numerous components required frequent maintenance, further burdened by high replacement costs. The fuel cell was also highly sensitive to gas quality, leading to shutdowns, the majority of which were caused by spikes in methane content. The fuel cell stack was estimated to have a lifetime of < 3 years, while the gas catalysts should last 5 years. SulfaTreat was replaced every 7 – 8 months and the activated carbon absorbers every 3 – 4 months. Fuel cell start time was approximately 10 hours. The King County WWTP currently operates an 8 MW plant running dual-gas turbines.

Point Loma Wastewater Treatment Facility in San Diego, CA is the only project currently operating in CA that injects biomethane into a common-carrier natural gas pipeline. BioFuels Energy, LLC holds a long-term rights agreement to Point Loma's biogas. 900 – 1,100 scfm of 59% methane biogas coming out of the digesters has hydrogen sulfide removed by a Sulfatreat unit and then is upgraded by a two-stage Air Liquide membrane system. The gas is afterwards polished by passing through activated carbon to produce a 98% methane product gas with approximately 0.5% CO_2, 0.1% O_2, and 1.3% N_2. Part of the biomethane is diverted to an onsite 300 kW DFC fuel cell that powers the biogas purification system. In total, the plant consumes 2 MW. The remaining biomethane is transported by San Diego Gas and Electric pipelines to the University of California, San Diego which operates a 1.4 MW DFC1500 fuel cell, and the City of San Diego South Bay Water Reclamation Plant which feeds a 2.8 MW DFC3000 fuel cell. A 300 kW DFC fuel cell powers the biogas purification system. In total, 5.5 – 5.8 MW of electricity is generated from the biogas. Of the total $45M investment cost, $1.99M went to interconnection. The project used $14.4M in Self-Generation Incentive Program incentives along with federal Investment Tax Credits (30% of net project cost) and New Market Tax Credits (39% of the qualified equity investment, after applying the Self-Generation Incentive Program, over a seven year period). The California Pollution Control Financing Authority provided $12M in tax-exempt bonds. Revenue is earned by selling fuel cell electricity and renewable energy credits. BioFuels Energy shares the credits with the City of San Diego and the University of California, San Diego, except for the last five years in which University of California, San Diego owns their portion (Greer 2011; Mazanec 2013).

Agricultural Waste and Manure Digester Biogas Projects

Joseph Gallo Farms' 5,000 cow Cottonwood site in Atwater, CA generates 300,000 cf/day of biogas from a lagoon digester system. The biogas is fed into a 300 kW Caterpillar 3412 and a 400 kW Caterpillar G399 reciprocating engine, which together output 5.9 GWh/year of electricity. The engines require oil changes every 500 hours, tune-ups every 1,000 hours, and major overhauls every 16,000 hours. The entire digester system costs $150,000/year to maintain. The total investment cost including interconnection, but excluding the 400 kW engine, was $2.7 million. Partial project funding was received from California state grants for alternative energy programs administered by Western United Resource Development and Pacific Gas and Electric Company (US DOE 2010).

With the assistance of Sacramento Municipal Utility District (SMUD), New Hope Dairy's 1,200 cow dairy in Galt, CA uses a covered lagoon digester to produce biogas that is used to generate 450 kW or power. SMUD also provided assistance in the construction of another digester

system in Galt, CA at the Van Warmerdam Dairy. Both of these digesters were helped funded by $5.5 million in grants from the U.S. Department of Energy and the California Energy Commission (Sacramento Municipal Utility District 2013).

In 2008, Tollenaar Holsteins Dairy in Elk Grove, CA began generating 113,000 ft^3/day of biogas in a complete-mix lagoon digester designed by RCM International. Biogas is fed into a 250 kW genset that cycles for three days on and one day off. The total turnkey cost of the digester was around $1.7 million. $500,000 were covered by a conventional bank loan at 5.3% interest, while the rest was supplied by $1.2 million in grants: $500,000 from the United States Department of Agriculture's (USDA) Rural Energy for America Program (REAP), $250,000 from a cost-share agreement with the USDA's Natural Resources Conservation Service's (NRCS) Environmental Quality Incentives Program (EQIP), $250,000 from the Sacramento Municipal Utility District (SMUD), and $200,000 from the California Energy Commission (US EPA 2012a).

Starting in late 2006, the Sierra Nevada Brewing Company in Chico, CA began running four 250 kW FuelCell Energy DFC300A molten carbonate fuel cells on 25 – 40% biogas from brewery's wastewater anaerobic digester. Residual thermal energy is used for facility heating and to produce steam for their brewing process (US DOE 2011a).

In 2005, the 6,000 – 10,000 milking cow Hilarides Dairy in Lindsay, CA began collecting biogas from two covered lagoon digesters that were producing 300 – 500 cf/min of biogas. Biogas was cleaned using Sulfatreat and then used to run four 125 kW Caterpillar G324 reciprocating engines for electricity production. Two more engines were later added in 2008, but there was still excess biogas available. Around that time, more stringent restrictions on stationary power emissions were enacted, which made the owner, Rob Hilarides, reconsider the idea of just adding more biogas engines. Hilarides considered upgrading his gas for biomethane pipeline injection, but decided against it due to the complexities of the process in California. He determined that he would rather continue offsetting his retail costs and be able to apply his own gas quality standards, and so chose to install a system to produce compressed biomethane that would be used as fuel for his milk trucks and farm equipment. This was an especially attractive option because diesel prices at the time were around $4.50/gallon and the estimated cost of biogas CNG was $2/DGE. The system, which began operation in 2009, first pressurizes the biogas to 175 psi (12 bar) before sending it to a Xebec M-3200 pressure swing adsorption system to produce 970 BTU/cf biomethane. The 200 BTU/cf off-gas is mixed with biogas and sent to the generators. Vilter compressors then further pressurize the biomethane into CNG at 3,600 psi. At least two semi-trucks, a pickup truck, and four hot water heaters have been converted on the farm to run on the biomethane. (Greer 2009; Western United Resource Development, Inc. 2006).

Vintage Dairy in Riverdale, CA, was established by David Albers, who also founded BioEnergy Solutions LLC, a company that designed, built and maintained biogas systems on farms and processing facilities. On the farm, biogas produced from the manure of 3,000 – 5,000 dairy cows in a 38,140,000 gallon lagoon digester was scrubbed in a Natco bioreactor to remove H_2S (to < 4 ppm) and then processed in a pressure swing adsorption system to remove CO_2 (to < 1%) and

moisture. The 99% pure biomethane product was injected into Pacific Gas and Electric Company's common-carrier pipelines (at 650 psi) from October 2008 to December 2009, providing 2.39 GWh/year. Plans were in order to develop a central biogas upgrading facility and collection network that would take biogas from nine surrounding farms. However, BioEnergy Solutions declared bankruptcy in December 2011. This may in part be due to the high investment cost of the facility—$3.7 million. Further economic hardship came with the suspension on biomethane RPS eligibility that lasted from March 2012 to April 2013. To recoup costs, Vintage Dairy was listed for sale at $21.5 million (Harvey 2012; PG&E 2008; D. W. Williams 2009).

Scenic View Dairy in Fenville, Michigan was the first commercial facility in the US to produce both pipeline quality methane and electricity from animal waste. With 3,450 head of cattle, the dairy produces 324,000 cf/day of biogas from three 870,000 gallon complete mix digesters. In 2006, the dairy began generating 4.5 GWh/year using two 400 kW Caterpillar G3412 Co-Generator reciprocating engines. Excess electricity is sold to Consumers Electric Company. The generators cost $35,000 while the electric panel was $25,000. Including an oil change every 600 hours, the engine system's O&M cost is $1,000/month. In 2007, the dairy began upgrading its gas in a $200,000 Xebec M-3200 PSA system to be sent to 2,000 Michigan Gas Utilities customers. Total system costs were around $2.75 million, including $1.2 million for the digesters, $400,000 for the biogas upgrading system, $1 million for the engines and interconnection to the utility grid, and $150,000 on other costs related to solids separation and new buildings (N. Goldstein 2007; US EPA 2012b).

The Huckabay Ridge Anaerobic Digestion Project, owned by Elements Markets in Stephenville, TX, is the largest anaerobic digestion facility in North America. Its 6,800,000 gallons of working volume is used to convert manure collected from dairy farms within a 20 mile radius and grease-trap wastes from Dallas–Fort Worth restaurants. The facility generates 2,700,000 cf/day of raw biogas and upgrades it to pipeline quality biomethane, contractually sending up to 8,000 MMBtu/day to PG&E pipelines until 2018. The facility was purchased from Environmental Power Corporation in 2010, and had recently been put up for auction on Nov. 21, 2013. Huckabay Ridge's aggregate design considerably saves on construction costs, but may not be as simple to implement in CA where dairies already have individual permits for their wastes and if the wastes are comingled, then the product would fall under a different permitting classification (US EPA 2012c).

Municipal Solid Waste Digester Biogas Projects

Zero Waste Energy LLC, based in Lafayette, CA, is a global project developer utilizing patented SMARTFERM anaerobic digestion technology. To date, Zero Waste Energy has designed and developed three dry anaerobic digestion facilities in California that digest food and green waste in Marina (Monterey Regional Waste Management District), San Jose (ZWEDC), and South San Francisco (SSF Scavenger). Each of these systems produce 3,000 – 3,200 ft^3 of biogas per ton of waste. The Marina facility began operation in February 2013 and treats up to 5,000 tons of waste per year, generating 100 kW of CHP electricity. The ZWEDC plant, the largest commercial dry anaerobic digestion facility in the US, treats 90,000 tons of waste per year and generates 1.6 MW

of CHP electricity. The SSF Scavenger site treats 11,200 tons of waste per year and generates > 100,000 DGE/year of compressed natural gas.

CleanWorld, based in Gold River, CA, markets high-solids anaerobic digestion technology. On December 14, 2012, CLeanWorld unveiled a high-solids BioDigester at the South Area Transfer Station in Sacramento, CA. It is the largest commercial high-solid anaerobic digester, currently processing nearly 40,000 tons/year of food waste. The biogas that is collected runs through a 190 kW 2G Cenergy gas conditioner and engine to generate 3.17 million kWh/year, enough power for 400 California homes. The facility also produces 700,000 DGE/year using a BioCNG 100 gas conditioning and upgrading system for removal of hydrogen sulfide, VOCs, siloxanes, moisture, and carbon dioxide. The CNG is used by Atlas Disposal to fuel its trucks. CleanWorld has a partnership with EcoScraps to produce liquid fertilizer from the digester effluent. The liquid and solid residues are processed to make 10 million gallons/year of fertilizer and soil amendments.

On April 22, 2014, CleanWorld opened the UC Davis Renewable Energy Anaerobic Digester which converts 20,000 tons of the university's food waste per year. Gas from the thermophilic three-stage digester system is mixed with gas from a nearby landfill at a 2:1 ratio, and then treated by a Unison Solutions biogas cleaning system to remove hydrogen sulfide, siloxanes, and moisture. A Capstone C800 800 kW microturbine package and a 125 kW organic Rankine cycle generator together create 5.6 million kWh/year. To overall investment costs to build the UC Davis system was $8.5 million.

To save costs on infrastructure development, municipal solid waste can be digested using the excess capacity already available at existing WWTPs. The EPA estimates CA's excess capacity to be 15 – 30% (US EPA 2013). By adding wastes from outside sources, WWTPs will benefit from greater biogas production and can earn revenue from tipping fees. The downsides to this consist of the potential for process upsets, additional new permits must be obtained, and infrastructure (e.g., storage, pretreatment to remove debris and other indigestible material) must be added to handle the incoming waste.

The East Bay Municipal Utility District in Oakland, CA was the first wastewater treatment plant in the US to anaerobically digest post-consumer food scraps. Investment costs included $125,000 for system design, $1.1 million for ten 60 kW Capstone C60 microturbines, $410,00 for turbine installation, $360,000 for a 633 kW York absorption chiller, $130,000 for gas and electrical connections, $100,000 for a service contract, $30,000 for air permits, and $255,000 for other costs (US DOE 2011c). After installing a new 4.6 MW turbine in 2012, it became the first WWTP to be a net energy producer in North America, producing 130% of plant demand in 2013. The residual biosolids are used for land application at non-food crop sites in Merced and for alternative daily cover at nearby landfills (East Bay Municipal Utility District 2014).

Wood-to-RSNG Demonstration Projects

There is a wood-to-RSNG demonstration project in California partially funded by the Energy Commission. This project is headed by G4 Insights of Canada partnering with Placer County. The demonstration project plans to use forest biomass as feedstock and will employ a hydro-

pyrolysis technology (hydrogen enriched gasification/pyrolysis) to create a methane rich product gas. Standard gas upgrading equipment is used to clean the product gas. Some of the product methane is recycled to a steam-methane reformer (SMR) to produce the hydrogen needed for the hydropyrolyzer (though the demonstration test unit planned for the project will omit the SMR and use bottled hydrogen instead). This will be a small facility with capacity for about 50 lbs of biomass per batch run with two to four runs per week (with 2 – 3 gasoline gallon equivalents of RSNG production per run) (Ng 2010).

The Paul Scherrer Institute (PSI) has developed a fluidized bed methanation reactor (based on the Comflux technology) for use on a portion of the product gas at the Güssing, Austria allothermal gasification CHP plant. Initial demonstration with a 10 kW_{SNG} reactor took place between 2003 and 2008 which included a run of more than 1,000 continuous hours. The 10 kW_{SNG} demonstration led to development of a 1 MW_{SNG} process development unit (PDU), complete with gas upgrading, at the Güssing site. In 2009, a 250-hour run of the 1 MW_{SNG} PDU was completed producing about 100 m^3/h of SNG (Kopyscinski 2010).

In the Netherlands, ECN (a research lab) and the utility HVC are building a $10MW_{th}$ wood fueled gasification CHP facility that will include demonstration of RSNG production (Bush 2012). There are plans for a follow-on 50 -100 MWSNG commercial scale demo (Aranda, 2014).

The GAYA Project in France would build and demonstrate a 20-60 MWSNG commercial scale demonstraton facility possibly as early as 2017 (Aranda, 2014). GAYA is a research consortium composed of technology providers and academic institutions.

Announced Commercial Wood-to-RSNG Projects

The GoBiGas project in Sweden, has built and is commissioning a 20 MWSNG wood-to-RSNG facility with an 80 -100 MW SNG Phase II facility planned (~ 2017 start?). Allothermal gasification technology by Repotec (that is used at the Güssing facility mentioned above) was selected for the GoBiGas project (Göteborg Energi 2012).

The European utility company E.ON is siting a 200 MW SNG wood-to-RSNG facility in Sweden. Named "Bio2G" (second-generation biogas) E.ON, in partnership with the Gas Technology Institute (GTI) and others has tested methanation reactors and are developing designs for up to 600 MWSNG capacity (Bush 2012; Ståhl 2011).

APPENDIX C: Fuel Cell Descriptions

Polymer electrolyte membrane fuel cells (PEMFCs), also known as a proton exchange membrane fuel cells, have a membrane serving as the electrolyte which allow protons to permeate while keeping hydrogen on the anode side and oxygen on the cathode side. The membrane electrolyte must be water saturated to avoid membrane dehydration and provide suitable ion conductivity. The electrodes are made of porous, platinum-impregnated carbon paper. Compared to other fuel cell technologies, PEMFCs operate at lower temperatures, are lighter and more compact, can fast-start due to high operating current densities, and use no corrosive liquid. Researchers envision PEMFC use in small mobile applications and electric vehicles since they have a higher energy density and recharge faster than batteries. With respects to larger applications such as biogas utilization, PEMFCs are sensitive to impurities, have low power sizes, and their operating temperatures (50 – 120 °C) are too low for cogeneration.

Alkaline fuel cells (AFCs) use an aqueous alkaline solution, such as KOH, as the electrolyte. The electrodes can be made from a number of different inexpensive materials (e.g., graphite, carbon blacks, carbon paper, PTFE). Consequently, AFCs are the cheapest to manufacture while still having high performance. However, carbon dioxide easily poisons the electrolyte because the alkaline chemicals are highly reactive with CO_2. Consequently, pure hydrogen or CO_2-scrubbed gas must be used. For this reason, AFCs are not the best candidate to use in conjunction with biogas technologies, which yield up 50% CO_2. There is also the hazard of using a caustic medium.

Phosphoric acid fuel cells (PAFCs) use highly concentrated or pure phosphoric acid saturated in a silicon carbide matrix as the electrolyte. Like PEMFCs, PAFC electrodes are also made of porous, platinum-impregnated carbon paper. However, the higher operating temperatures of PAFCs slows down CO poisoning of the platinum catalyst so that higher CO concentrations can be withstood. PAFCs are not as sensitive as PEMFCs to most fuel impurities and can also tolerate CO_2 unlike PEMs. Their operating temperature (130 – 220 °C) is also high enough for the expelled water to be converted to steam and used for CHP applications. The primary drawbacks to PAFCs are that they use a very corrosive electrolyte and have a low power density.

In a molten carbonate fuel cell (MCFC), the high operating temperature causes carbonate salts to melt in a ceramic matrix of $LiAlO_2$ and conduct carbonate ions to serve as the electrolyte. MCFCs use a nickel anode and a nickel oxide cathode. The high MCFC operating temperatures of above 600 °C provide an environment for several synergistic chemical reactions to occur, producing additional H_2. Firstly, CO reacts with water following the water gas shift reaction pathway to produce H_2 and CO_2. Secondly, CH_4 may be internally reformed to H_2 at high temperature using the anode as a catalyst. Although MCFCs also use a very corrosive electrolyte and are sensitive to even more impurities, their ability to directly use methane, CO_2 and siloxane tolerance, and potential for large power sizes make MCFCs a prime candidate for use with biogas.

Solid oxide fuel cells (SOFCs) use an electrolyte consisting of a solid, nonporous metal oxide (e.g., Y_2O_2-stabilized ZrO_2). High temperatures of 650 – 1000 °C permit the conduction of oxygen ions from cathode to anode through the electrolyte. The anode is made of $CoZrO_2$ or $NiZrO_2$ cermet while the cathode is made of Sr-doped $LaMnO_3$. Even though SOFCs do not require precious metal catalysts, the materials can still be expensive, but the use of a solid electrolyte avoids the corrosion problems that most other fuel cells have. Like MCFCs, high operating temperatures allow for internal methane reformation, but in addition to the water gas shift and internal reforming reactions, methane can undergo the steam reforming reaction ($CH_4 + H_2O \rightarrow CO + 3H_2$) and be converted into hydrogen without a catalyst. SOFCs are generally designed for small applications of a few kW. However, tubular, flat plate, and monolithic cell stacking configurations can be used to increase voltage and power.

APPENDIX D: Supplementary Figures and Tables

Table 29: Natural Gas Pipeline Quality Standards for Other Gas Pipeline Operators in California

Company	City of Long Beach, Gas & Oil Department	City of Vernon Natural Gas Department	El Paso Natural Gas Company / Kinder Morgan	Kern River Gas Transmission Company	Mojave Pipeline Company / Kinder Morgan	North Baja Pipeline LLC / TransCanada	Tuscarora Gas Transmission Company / TransCanada
Higher Heating Value (Btu/cf)	990 – 1,150	990 – 1,150	≥ 967	≥ 970	≥ 970	990 – 1,150	≥ 975
Temperature (°F)	50 – 105	50 – 105	50 – 120	40 – 120	50 – 105	50 – 105	100
Wobbe Index	1,279 – 1,385	1,279 – 1,385				1,279 – 1,385	
Water Vapor (lb/MMscf)	7	7		7	7	7	4
Hydrocarbon Dew Point		45°F at 400 psi if P<400 psi (or 20°F at 400 psi if P>800 psi)	20°F at normal pipeline psig	15°F at < 800 psig	20°F at < 600 psig	20°F at < 600 psig	
Hydrogen Sulfide (grain/100 scf)	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Mercaptans (grain/100 scf)	0.3	0.3	0.75	0.3	0.3	0.3	
Total Sulfur (grain/100 scf)	0.75	0.75	5	0.75	0.75	0.75	10
Total Inerts	4%	4%	3%	4%	4%	3%	
Carbon Dioxide			2%	3%	3%	2%	2%
Oxygen	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.4%
California ARB Constituents of Concern	Yes	No	No	No	No	No	No

Chart Credit: Author

Table 30: List of Nonattainment Air District in California

	Ozone	PM2.5	PM10	H_2S
Amador	✔		✔	
Antelope Valley	✔		✔	
Butte	✔	✔	✔	
Calaveras	✔		✔	
Colusa			✔	
Eastern Kern	✔		✔	
El Dorado	✔		✔	
Feather River	**T**		✔	
Glenn			✔	
Great Basin Unified	✔		✔	
Imperial	✔		✔	
Lake				
Lassen			✔	
Mariposa	✔		**P**	
Mendocino	✔		✔	
Modoc			✔	
Mojave Desert	✔	**P**	✔	**P**
Monterey Bay Unified	✔		✔	
North Coast United			**P**	
Northern Sierra	**P**	**P**	✔	
Northern Sonoma				
Placer	✔		✔	
Sacramento	✔		✔	
San Diego	✔	✔	✔	
San Francisco Bay Area	✔	✔	✔	
San Joaquin Valley Unified	✔	✔	✔	
San Luis Obispo	✔		✔	
Santa Barbara	✔		✔	
Shasta	✔		✔	
Siskiyou				
South Coast	✔	**P**	✔	
Tehama	✔		✔	
Tuolumne	✔			
Ventura	✔		✔	
Yolo-Solano	✔		✔	

P: Region is partially nonattainment T: Region is transitioning to nonattainment

† All California air districts are either classified as attainment or unclassified for carbon monoxide, nitrogen dioxide, sulfur dioxide, sulfates, lead, and visibility reducing particles

Chart Credit: Author; Data Credit: California Air Resources Board (2014a)

Table 31: Operating Conditions, Features, and Requirements of Biogas Cleaning and Upgrading Technologies

Biogas Cleaning / Upgrading Process		Pressure (psig)	Temperature (°C)	Product CH_4 Content	Methane Slip/Loss	Sulfur Pre-Treatment	Consumables
Cleaning†	Adsorption	0 – 100	25 – 70			Not needed	Adsorbent
	Water Scrubbing	0	20 – 40			Not needed	Water; Anti-fouling agent; Drying agent
	Biofiltration	0	35			Not needed	Water; Drying agent
	Refrigeration	0 – 58	-29 – 5			Preferred / Required	Refrigerant
Upgrading†	Pressure Swing Adsorption	14 – 145	5 – 30	95 – 97.5%	1 – 3.5%	Required	Adsorbent
	Alkaline Salt Solution Absorption	0	2 – 50	78 – 90%	0.78%	Required / Preferred	Water; Alkaline
	Amine Absorption	0 (< 150)	35 – 50	99%	0.04 – 0.1%	Preferred / Required	Amine solution; Anti-fouling agent; Drying agent
	Pressurized Water Scrubbing	100 – 300	20 – 40	93 – 98%	1 – 3%	Not needed / Preferred	Water; Anti-fouling agent; Drying agent
	Physical Solvent Scrubbing	58 – 116	10 – 20	95 – 98%	1.5 – 4%	Not needed / Preferred	Physical solvent
	Membrane Separation	100 – 600	25 – 60	85 – 99%	0.5 – 20%	Preferred	Membranes
	Cryogenic Distillation	260 – 435	-59 – -45	96 – 98%	0.5 – 3%	Preferred / Required	Glycol refrigerant
	Supersonic Separation	1,088 – 1,450	45 – 68	95%	5%	Not needed	

† Cleaning refers to the removal of miscellaneous contaminants, while upgrading specifically focuses on the removal of carbon dioxide

Chart Credit: Author; Data Credit: (Beil and Beyrich 2013; Severn Wye Energy Agency 2013; Starr et al. 2012; Twister BV 2014)

Table 32: Contaminant Treatability for Biogas Cleaning and Upgrading Technologies

Biogas Cleaning / Upgrading Process		CO_2	H_2S	O_2	N_2	VOCs	NH_3	Siloxanes	H_2O
Cleaning†	Adsorption	/	**	/	– –	**	*	**	**
	Water Scrubbing	/	**	– –	– –	**	**	**	– –
	Biofiltration	/	**	– –	– –	**	/	/	– –
	Refrigeration	–	/	–	–	/	**	*	**
Upgrading†	Pressure Swing Adsorption	**	* **R**	/	/	*	*	*	* **R**
	Alkaline Salt Solution Absorption	**	*	–	–	/ –	–	*	– –
	Amine Absorption	**	*	**R**	–	/ –	*	/ –	– –
	Pressurized Water Scrubbing	**	*	– –	– –	*	*	*	– –
	Physical Solvent Scrubbing	**	**	/	/	*	*	*	*
	Membrane Separation	**	* /	* /	/	* –	*	*	*
	Cryogenic Distillation	**	*	**	**	*	*	*	*
	Supersonic Separation	**	**	–	–	**	*	*	**

Legend: ** Complete removal (intended) * Complete removal (pretreatment preferred) / Partial removal
– Does not remove – – Contaminant added **R** Must be pretreated

Two symbols may be in the same box if one or the other can be applicable

† Cleaning refers to the removal of miscellaneous contaminants, while upgrading specifically focuses on the removal of carbon dioxide

Chart Credit: Author; Data Credit: (Severn Wye Energy Agency 2013; Starr et al. 2012; Twister BV 2014)

Figure 36: Total Energy Requirements for Biogas Upgrading Technologies

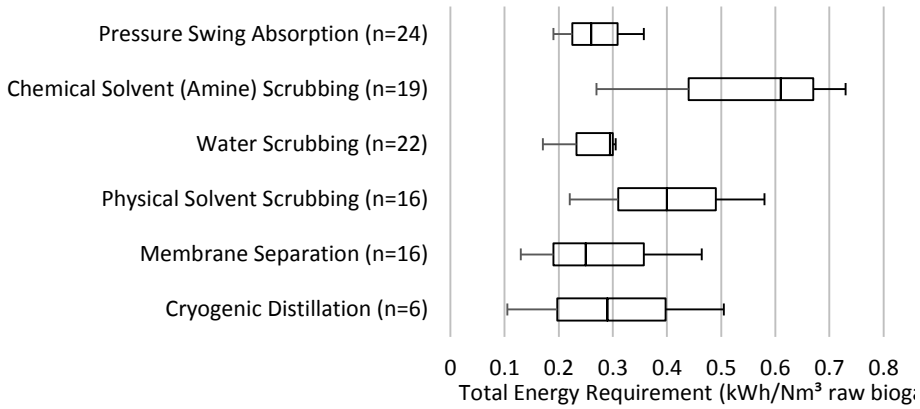

Chart Credit: Author; Data Credit: (Agency for Renewable Resources 2014; Allegue and Hinge 2012b; Bauer et al. 2013; Beil and Beyrich 2013; Günther 2006; Johansson 2008; Kharrasov 2013; Niesner, Jecha, and Stehlík 2013; Patterson et al. 2011; Purac Puregas 2011; Vijay 2013)

Figure 37: Electricity Requirements for Biogas Upgrading Technologies

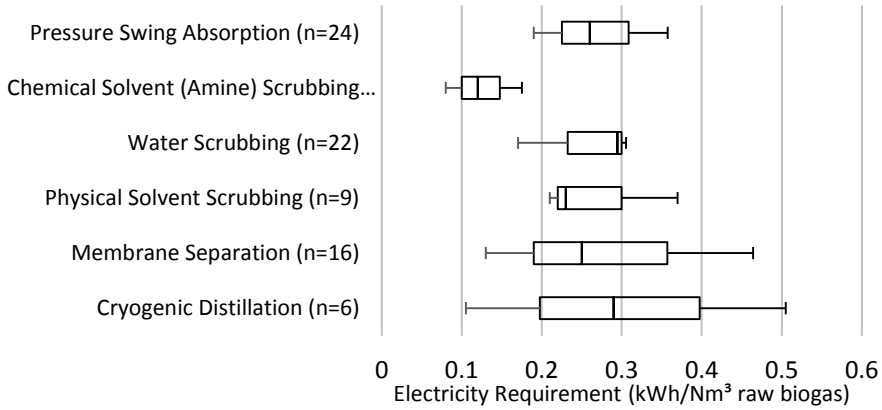

Chart Credit: Author; Data Credit (Agency for Renewable Resources 2014; Allegue and Hinge 2012b; Bauer et al. 2013; Beil and Beyrich 2013; Günther 2006; Johansson 2008; Kharrasov 2013; Niesner, Jecha, and Stehlík 2013; Patterson et al. 2011; Purac Puregas 2011; Vijay 2013)

Table 33: Review of Commercially Available Products

ess	Brand Name	Capacity	Regen	Specific to Biogas	US Biogas Plants	Turn Key	Company	Location
arbon				Y		N	Bosch KWK Systeme	Lollar, Germany
arbon	DARCO® BG/BGH, NORIT® RB 30M/RB 40M, SORBONORIT® B 4			N		N	Cabot Norit	Marshall, TX
arbon	DARCO® H2S			N		N	Cabot Norit	Marshall, TX
arbon	DARCO® VOC			N		N	Cabot Norit	Marshall, TX
arbon ed with	NORIT® ROZ 3			N		N	Cabot Norit	Marshall, TX
arbon ed)	Type FCA®			N		N	Calgon Carbon Corporation	Stockton, CA
arbon ed with 3% KI)	Chemsorb® 1202			N		N	Molecular Products Ltd.	Boulder, CO
arbon ed)	Sofnocarb KC®			N		N	Molecular Products Ltd.	Boulder, CO
arbon ed)	Westates Carbon		N	N		N	Evoqua Water Technologies	Vernon, CA
arbon ed)	OdorClean™					Y	Enduro Composites	Houston, TX
d	Sofnolime® RG Grade			N		N	Molecular Products	Boulder, CO
ide	Media G2®		Y, 15x	Y		N	ADI Systems Inc.	Denver, CO
	Iron Sponge		Y, 3x	Y		N	Connelly-GPM Inc	Chicago, IL

Adsorption	Iron Oxide (Iron-oxide-impregnated wood chips)	OdorFilter™ / BAM™	< 10,000 cfm		Y	Y	Y	MV Technologies	Golden, CO
	Iron Oxide (Iron-oxide-impregnated wood chips)	H2SPlus™ / BAM™	150 - 15,000 cfm		Y	Y	Y	MV Technologies	Golden, CO
	Iron Oxide (Iron-impregnated wood chips)	SulfrPack CIS			Y		Y	Robinson Group LLC	Bothell, WA
	Iron Oxide (Iron-impregnated clay pellets)	SulfrPack ST			Y		Y	Robinson Group LLC	Bothell, WA
	Iron Oxide	SulfaTreat® (Standard, HP, 410HP, XLP)		N	N	Y	N	M-I SWACO / Schlumberger	Bakersfield, CA (Global)
	Iron Oxide (Fe_2O_3)	SOXSIA®			Y		N	Gastreatment Services	Bergambacht, Netherlands
	Iron Oxide	Sulfur-Rite®		N	N		N	Merichem Company	Houston, TX
	Iron Oxide (Fe_2O_3)	GTP Filter	10 – 2,500 Nm^3/h		Y		Y	Gastreatment Services	Bergambacht, Netherlands
	Mixed Metal Oxide	Select HP®			N		N	M-I SWACO / Schlumberger	Bakersfield, CA (Global)
	Mixed media	GES 350/400/600/900/1500	300 – 2,500 scfm		Y		Y	Parker Hannifin Corporation	Haverhill, MA
	Mixed media (Activated alumina, activated carbon, molecular sieves, silica gels)	Gas Conditioning System Skid	1,000 scfm	Y	Y		Y	Venture Engineering and Construction	Las Vegas, NV
	Multi-layer graded & pleated nanofiber filtration media	GES S4 Biogas Filter			Y		Y	Parker Hannifin Corporation	Haverhill, MA

Adsorption	Polymer Media	SRT System		Y	Y		Y	DCL International Inc.	Oak Ridge North, TX
	Polymeric Media	BGAK Siloxane Reduction System		Y	Y	Y	Y	Willexa Energy, LLC / PpTek Limited	Charlotte, NC
	Segmented activated gradient media and HOX silica gel-based media	SAGPack			Y		Y	Robinson Group LLC (acquired Applied Filter Technology, Inc.)	Bothell, WA
	Zeolite (13X)	Z10-03		Y	N		N	Zeochem	Louisville, KY
	Zeolite (13X)	Sofnosiv™			N		N	Molecular Products Ltd.	Boulder, CO
	Zinc Oxide	Puraspec®		N	N		N	Johnson Matthey Process Technologies	Pasadena, TX
	?	CJC Filtersorb AC64, CJC VOC Deep Bed Series	100 – 1,500 m^3/h		N		Y	C.C.JENSEN A/S	Newnan, GA
	?	CJC Filtersorb AC64, CJC VOC Annular Bed Series	500 – 6,000 m^3/h		N		Y	C.C.JENSEN A/S	Newnan, GA
	?	CJC™ Biogas Filter Medium	100 - 6,000 m^3/h		Y		Y	C.C.JENSEN A/S	Newnan, GA
	?	CompHeet®		Y	Y	Y	Y	ESC Energy Systems	Redmond, WA
	?	SRS Siloxane Reduction System		Y	Y	Y	N	Willexa Energy, LLC	Charlotte, NC

Biofiltration	Biofilter	BioSulfurex®	12 – 2,000	Y	Y		Y	DMT Environmental Technology	Joure, Netherlands
	?	OdorClean™ Biofilter Systems		Y	Y		Y/N	Enduro Composites	Houston, TX
	Biotrickling filter with activated carbon	OdorClean™ 250/500	425 – 850 m^3/hr	Y	Y		Y	Enduro Composites	Houston, TX
	Biotrickling filter	BioStrip	150 - 3,000 scfm	Y	Y		Y	Robinson Group LLC	Bothell, WA
	Biotrickling filter with alkaline solution gas pre-treatment	Biopuric™		Y	Y		N	Veolia Water Technologies	Pennsauken, NJ
	Biotrickling filter with alkaline solution gas pre-treatment	Sulfothane™		Y	Y		N	Veolia Water Technologies	Pennsauken, NJ
	Biotrickling filter with alkaline solution gas pre-treatment	Thiopaq®	10 – 50,000 Nm^3/h	Y	Y		N	Paques	Wilmington, DE
Chemical Solvent Scrubbing	Alkaline Salt Solution	LRS 10		Y	N		N	British Gas Company	Rotherham, England
	Alkaline Salt Solution	Sulfurex®	200 – 1,320 Nm^3/h		Y	N	N	DMT Environmental Technology	Joure, Netherlands
	Alkaline Salt Solution	MECS® DynaWave®			N		N	MECS, Inc.	Chesterfield, MO (Global)
	Alkaline Salt Solution	DGE-BCM 2	100 – 5,000 Nm^3/h		Y		Y	DGE GmbH	Lutherstadt Wittenberg, Germany

Chemical Solvent Scrubbing	Amine absorption	AdvAmine™	0.0125 – 1.05 Nm^3/h		N		N	PROSERNAT	Puteaux, France
	Amine absorption	HySWEET®			N		N	PROSERNAT	Puteaux, France
	Amine absorption	Sulfa-Bind G100		Y	N		N	NuGreen	Mansfield, TX
	Amine absorption	Sulfa-Bind G200		Y	N		N	NuGreen	Mansfield, TX
	Amine absorption	Sulfa-Bind G201		Y	N		N	NuGreen	Mansfield, TX
	Amine absorption (Methyl diethanolamine, Tetrahydrothiophene dioxide)	Sulfinol®			N		N	Shell	Houston, TX
	Amine absorption	ADIP-X			N		N	Shell	Houston, TX
	Amine absorption	Sulfa-Scrub® (Hexahydrotriazine)			N		N	Quaker Chemical	Conshohocken, PA
	Amine absorption	The Eliminator			N		N	Gas Technology Products	Schaumburg, IL
	Amine absorption	LP Cooab®	50 – 5,000 Nm^3/h		Y		N	Cirmac	Apeldoorn, Netherlands
	Amine absorption	LP Cooab®	450 – 3,400 Nm^3/h		Y		N	Purac (Läckeby Water Group)	Lund, Sweeden
	Amine absorption	LI'LTEX™ / BIGTEX™ / MIGHTYTEX™ / MIGHTYTEX™		Y	N		Y	SouthTex Treaters, Inc.	Odessa, Texas
	Amine absorption	AminSelect			Y		Y	Dreyer & Bosse	Gorleben, Germany
	Amine absorption	MT-Amine Scrubbing	150 – 2,000 Nm^3/h		Y		Y	MT-BioMethan GmbH	Zeven, Germany

Chemical Solvent Scrubbing	Amine absorption	PuraTreat™ / PuraTreat® R+	< 1,500		Y		N	Bilfinger Berger Industrial Services GmbH	Cloppenburg, Germany
	Amine absorption	Sulf-X			Y	Y	N	ChemE Solutions	Lake Stevens, WA
	Amine absorption	Sulfa-Clear®			N		N	Weatherford International	Addison, Texas (Global)
	Iron Solution (Chelated-Iron)	LO-CAT		Y	N		N	Merichem Company	Houston, TX
	Iron Solution (Chelated-Iron)	MINI-CAT		Y	N		N	Merichem Company	Houston, TX
	Iron Solution (Chelated-Iron)	SulFerox		Y	N		N	Le Gaz Integral	Nanterre, France
	Iron Solution (Chelated-Iron)	SulfInt			N		N	Le Gaz Integral	Nanterre, France
	Iron Solution	SweetSulf™			N		N	PROSERNAT	Puteaux, France
	Sodium Nitrite Solution	Sulfa-Check®			N		N	NALCO	Burlingame, CA (Global)
	Styrene-divinyl benzene-based ion-exchange resin	BioGas AutoKleen (600, 1200, 2000, 2400, 3000, 4000, 5000)	350 – 5,000 m^3/h	Y	Y		Y	PpTek Limited	West Sussex, United Kingdom
	Styrene-divinyl benzene-based ion-exchange resin	BioGas ManualKleen (50, 150, 300)	50 – 350 m^3/h	Y	Y		Y	PpTek Limited	West Sussex, United Kingdom
	Hydrocarbon (Heavy) Liquid	CrystaSulf®			N		N	URS Corporation	Sacramento, CA (Global)
	Unknown	MECS® SULFOX™ NK/HK/MET/SAR			N		N	DuPont	Chesterfield, MO (Global)
	Unknown + Adsorption	IBCS 300	100 – 1,600 scfm		Y	Y	Y	Quadrogen Power Systems	Vancouver, British Columbia, Canada

Cryogenic Distillation		CO_2 Wash®		N	Y	Y	N	Acrion Technologies	Cleveland, OH
		Sprex® / Sprex® CO_2			N		N	PROSERNAT	Puteaux, France
		GPP® / GPP®plus			Y	N	Y/N	Gastreatment Services BV	Bergambacht, Netherlands
Industrial Lung					Y	N	N	CO_2 Solutions Inc.	Québec, Canada
Membrane Separation	High-pressure gas separation	PRISM® PB6050-P3	60 – 120 Nm^3/h	N	Y	Y	N	Air Products	Allentown, PA
	High-pressure gas separation	Sepuran® Green membranes	10 – 1,000 Nm^3/h	N	Y	Y	N	Evonik	Portland, OR
	High-pressure gas separation	Carborex® MS	50 – 750 Nm^3/h	N	Y	N	Y	DMT Environmental Technology	Joure, Netherlands
	High-pressure gas separation	Cynara®			N	N	Y/N	Cameron	Antioch,CA (Global)
	High-pressure gas separation	Separex™			N	N	Y	UOP LLC (Honeywell)	Anaheim, CA
	High-pressure gas separation	Medal™	100 – 11,200 Nm^3/h		Y	Y	N	Air Liquide	Houston, TX
	High-pressure gas separation	MT-Membrane Technology (Uses Evonik SEPURAN®Green membrane modules)	250 – 700 Nm^3/h		Y	N	Y	MT-BioMethan GmbH	Zeven, Germany
	High-pressure gas separation	EnviThan (Uses Evonik SEPURAN®Green membrane modules)			Y	N	Y	EnviTec Biogas	Saerbeck, Germany
	High-pressure gas separation	AE-Membrane (Uses Air Products PRISM® Membranes)	100 – 1,000 Nm^3/h		Y	N	Y	Arol Energy	Le Bourget-du-Lac, France

Membrane Separation	High-pressure gas separation	MemfoACT AS Keyless Biogas Upgrading Solution	50 – 2,500 Nm^3/h		Y	N	Y	MemfoACT AS	Heimdal, Norway
	High-pressure gas separation		> 80 – 500 Nm^3/h		Y	N	N	Axiom (Axiom Angewandte Prozesstechnik Ges.m.b.H.)	Ebreichsdorf, Austria
	High-pressure gas separation/Cryogenic		250 – 700 Nm^3/h		Y	Y	N	Pentair Haffmans	Delavan, WI (Global)
	High-pressure gas separation/Cryogenic	BioCNG™ 50/100/200	50 – 200 scfm		Y	Y	Y	BioCNG	Dublin, CA
	Gas-liquid adsorption		10 – 1,000 scfm		Y	N	Y	Nrgtek Inc.	Orange, CA
Physical Liquid Scrubbing	Propylene Carbonate	Fluor Solvent™			N		N	Fluor Corporation	Dublin, CA
	N-Methyl-2-Pyrrolidone	Purisol			N		N	Air Liquide	Houston, TX
	Selexol (dialkyl ethers of polyethylene glycol, mixed tetraethylene glycol dimethyl ethers)	Genosorb® 1753	250 – 2,000 Nm^3/h (up to 600,000)	Y	Y		N	Clariant GmbH	Sulzbach (Taunus), Germany
	Selexol (dimethyl ethers of polyethylene glycol)	SELEXOL™		Y	N		N	UOP LLC (Honeywell)	Anaheim, CA
	Methanol	Rectisol®			N		Y/N	Air Liquide	Houston, TX
	Methanol	Ifpexol	< 353,961 Nm^3/h		N		N	PROSERNAT	Puteaux, France
	Methyl isopropyl ether	Sepasolv®			N		N	BASF Global	Orange, CA
	Polyethylene glycol	BGAA	200 – 700 Nm^3/h		Y		Y	Schwelm Anlagentechnik GmbH	Schwelm, Germany

Physical Liquid Scrubbing	Polyglycol	Biogas-Upgrader	310 – 2,000 Nm^3/h		Y		Y	BMF HAASE Energietechnik GmbH	Neumünster, Germany
	Triethylene glycol	TEG Regenerator Unit			N		Y	SouthTex Treaters, Inc.	Odessa, Texas
	Water	Kanuka / Rimu / Matal / Torara / Torara+	50 – 2,500 Nm^3/h	Y	Y		Y	Greenlane Biogas	Burnaby, British Columbia, Canada
	Water	COMPACT®	100 – 3,000 Nm^3/h		Y		Y	Malmberg Water	Yngsjö, Sweden
	Water	Carborex® PWS		Y	Y	N	Y	DMT Environmental Technology	Joure, Netherlands
	Water	OdorClean™ Wet Scrubbers		Y	Y	Y	Y/N	Enduro Composites	Houston, TX
	Water	(Uses Greenlane Biogas System)	850 Nm^3/h	Y	Y		Y	Anaergia	Carlsbad, CA
	Water	CO_2Strip			Y		Y	Robinson Group LLC	Bothell, WA
	Water (Rotary Coil)	BioSling			Y	N	Y	Arctic Nova	Vittangi, Sweden
Pressure Swing Adsorption		Molecular Gate®			Y	Y	Y/N	Guild Associates	Dublin, OH
		FirmGreen			Y	Y	Y	FirmGreen	Newport Beach, CA
		M-3200	100 – 300 Nm^3/h		Y	Y	Y	Xebec Adsorption Inc.	Houston,TX
		M-3100	300 – 3,000 Nm^3/h		Y	Y	Y	Xebec Adsorption Inc.	Houston,TX

Pressure Swing Adsorption		M-3200*	3,000 – 10,000 Nm^3/h		Y	Y	Y	Xebec Adsorption Inc.	Houston,TX
		DGE-BCM 4	100 – 5,000 Nm^3/h		Y	N	Y	DGE GmbH (Dr.-Ing. Günther Engineering GmbH)	Lutherstadt Wittenberg, Germany
		ZETECH$_4$© (BGAA250 - BGAA1400)	250 – 1,400 Nm^3/h		Y	N	Y	Schmack Carbotech GmbH	Essen, Germany
		BIOSWING	500 – 5,000 Nm^3/h		Y		Y	Mahler AGS GmbH	Stuttgart, Germany
		Methane purification plant	800 scfm		Y	Y	Y	ARC Technologies	Yukon, PA
Refrigeration		DriPack			Y		Y	Robinson Group LLC	Bothell, WA
		Air Cooled Dehydration Module			Y		Y	Willexa Energy, LLC	Charlotte, NC
	Glycol chiller	TCR system			Y		Y/N	Gastreatment Services	Bergambacht, Netherlands
	Glycol chiller	E Series	100 – 2,500 scfm		Y		Y	Pioneer Air Systems Inc.	Monroeville, PA
	Glycol chiller	TCR Series	100 – 3,600 scfm		Y		Y	Pioneer Air Systems Inc.	Monroeville, PA
Supersonic Separation		Twister® Supersonic Separator	60,000 Nm^3/h		N	N	Y/N	Twister BV	Rijswijk, Netherlands

Temperature Swing Adsorption		ADAPT (Advanced Adsorption Process Technology)		Y	N	N	N	GL Noble Denton / DNV GL	Houston, TX

Notes: Robinson Group LLC acquired Applied Filter Technology, Inc.

Xebec Adsorption Inc. merged with QuestAir Technologies

Gas Technology Products is a division of Merichem Chemicals & Refinery Services LLC

Greenlane Biogas was formerly known as Flotech

Air Liquide acquired Lurgi AG

Please contact the author for more details on these technologies, including advertised and actual removal efficiencies for various contaminants and pricing

Chart Credit: Author