Biogas and Bio-syngas Production

TECHNICAL HIGHLIGHTS

■ **PROCESS AND TECHNOLOGY STATUS –** Biogas and bio-synthetic gas (bio-SNG) uses are versatile: production of electricity and heat, or injection in the grid, and use as transportation fuel after upgrading to bio-methane. Production of biogas by anaerobic digestion of organic feedstock in digesters or landfills is commercially well established while production of bio-SNG by gasification is less mature. Feedstock for bio-chemically production of biogas includes organic wastes (municipal, industrial and agricultural wastes), sewage sludge, wastewater, human and animal manure, and crops (energy crops, crop residues, fresh or silage). Woody biomass is not suitable to anaerobic digestion because of its high content of lignin, but can be converted into bio-SNG by thermo-chemical gasification. From one country to another one, the biogas sources vary distinctively. In Europe, Germany and UK are the main producers of biogas, from farm digesters in Germany and landfills in UK. The use of manure and energy crops are considered as the main sources of future biogas production, but co-digestion of multiple types of feedstock offers the greatest potential mixing energy crops (maize being well established for biogas production), manure, sludge and food industry and household waste. In developing countries, family-scale bio-digesters contribute the supply of local energy for cooking, lighting and heating, and may contribute to rural electrification when associated with power generation. The digestate resulting from the production of biogas is a nutrient-rich fertilizer which can replace the mineral fertilizer.

■ **PERFORMANCE AND COSTS –** The total capital cost for an AD facility varies from USD 5000 to 7500 per Nm^3/h of biogas production capacity, depending on the size of the digester. The investment cost for biogas-to-bio-methane upgrading units ranges from USD 1950 to 2600 per Nm^3/h, for raw gas capacities larger than 800-1000 Nm3/h. Much higher costs are observed for smaller-scale facilities. Bio-SNG production costs are estimated in the range of 15 to 20 USD/GJ bio-SNG (feedstock excluded); these costs are expected to decrease 10-15% over the next 10 to 15 years. Gasification and gas cleaning and upgrade represent each 35% of total bio-SNG production costs. When associated with electricity production, the additional costs of the prime mover represent a small part of the total, from 5% to 15%. The typical investment costs of landfill gas collection and flaring system are around USD $6/m^3$.

■ **POTENTIAL AND BARRIERS –** The rapid development over the last decade was the result of incentive policies related to renewable energy and climate change (more particularly feed-in tariffs for electricity) but also waste management. While the sector rapidly grows, it hasn't received the same attention as for example liquid biofuels for transportation. Future development of the sector will continue be dependent on incentive policies. Moreover, the development of an integrated gas infrastructure including pipelines (including an easy access to it), upgrade units, heat network, filling stations is key to an increased production and use of biogas and bio-SNG. Advancements in upgrading and gas cleaning are expected to contribute to accelerate the commercial penetration of gasification, which would permit the use of woody resources, which cannot be digested.

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PROCESS AND TECHNOLOGY STATUS

Gas obtained from biomass feedstock is a gaseous mixture consisting mainly of methane and carbon dioxide (Table 1), with traces of other gases (amongst others, hydrogen, hydrogen sulphide, ammonia), which can be bio-chemically produced - by **anaerobic digestion** of organic feedstock (i.e. biological decomposition in digesters in the absence of oxigen) - or thermo-chemically produced -by **gasification** (in gasifiers) of organic feedstock. Biogas is the usual name of gas via the bio-chemical route. When resulting from gasification, it is usually called "bio synthetic gas, or (bio) syngas" (bio-SNG). The state of the thermo-chemical conversion route is slightly behind the bio-chemical option, but is expected to develop further.

The energy content of gas is bounded mainly to its methane content. Raw gas can be directly used for cooking, lighting, heating (e.g. residential use of biogas from small-scale domestic bio-digesters, especially in developing and emerging countries). Use for electricity and heat cogeneration is possible after a simple desulfurization process (e.g. farm-scale or larger scale desulfurization of biogas). Deeper cleaning from impurities and upgrading processes are required to convert raw gas into "biomethane" (methane content above 96%), which can then be injected in natural gas grids, or used in combustion-engine vehicles and in fuel cells. Final uses of raw gas and biomethane are beyond the scope of this Brief and are described in ETSAP E04, E05, and T03.

Feedstock for bio-chemically production of biogas includes organic wastes (municipal, industrial and agricultural wastes), sewage sludge, wastewater, human and animal manure, and crops (energy crops, crop residues, fresh or silage). Woody biomass is not suitable to anaerobic digestion because of its high content of lignin, but can be converted into bio-SNG by thermo-chemical gasification.

The **production chain** usually includes four stages: biomass feedstock gathering and pre-treatment (including sanitation, if needed); gas production (by digestion or gasification); gas post-treatment (desulfurization, upgrading), storage and utilization; and disposal or reuse of production waste i.e. digestate in the bio-chemical route.

■ **Anaerobic Digestion -** Anaerobic Digestion (AD) is a microbiological process of decomposition of organic matter, in the absence of oxygen in airproof reactor tanks (digesters). Decomposition results in two main end-products: biogas and digestate. The digestate is the decomposed substrate remaining after biogas production, which is rich in nutrients and usable as a fertilizer. The process includes three main stages:

a) *hydrolysis,* i.e. breaking of large compounds of fats, carbohydrates and proteins to form sugars, fatty acids and amino acids;
b) *acidogenesis and acetogenesis,* i.e. degradation of sugars, fatty acids and amino acids into carbon dioxide, hydrogen and acetates; and
c) *methanogenesis,* i.e. methane formation process.

Each stage is characterized by different microbial activities, which may occur simultaneously within the digester, and are strongly dependent upon each other.

Crucial determinants for optimal anaerobic digestion with impacts on energy consumption and costs, are:

• *Temperature Range*: The digester can be designed to operate within the *mesophilic* range of 30-45 ºC or within the *thermophilic* range of 50-60ºC; most commercial plants operate in the mesophilic range as the process tends to be more stable, easier to control and less expensive. However, the mesophilic process has a lower biogas production, requires larger digestion tanks, and sanitization, if needed, is to be done as a separate process stage;

• *Appropriate pH*: Optimal range 6.5 to 8.0;

• *Regular mixing:* To avoid stratification;

• Presence of *nutrients*: C/N ratio of 20 to 30;

• *Adequate load rate and retention time:* retention time is up to 20 days with thermophilic degradation, and more than 20 days with mesophilic process, depending on feedstocks and technologies; load can be done in either a batch (materials are loaded and maintained until the end of the retention time) or continuous mode (fresh feedstocks is continuously fed to the digester and digestate is continuously removed); quantities depend on the size of the digester;

• *Absence of toxic compounds*: detergents, antibiotics, disinfection agents are inhibitors of the process since by definition, they kill microorganisms. They can be found in both livestock slurry and human dejections (treatment, cleaning). Other substances such as heavy metals, salts and micronutrients are needed at low concentration but also inhibit the growth of bacteria at higher concentration. Examples of inhibiting concentrations are: ammonia (NH_4+NH_3) above 1000 mg N/l, sulphate (SO_4) above 500 mg/l, hydrogen sulphide (H_2S, produced by protein-rich waste and salty or stall rinse water) above 250 mg/l, chromium above 130 mg/l, sodium (Na) above 3500 mg/l, magnesium (Mg) above 3000 mg/l, zinc (Zn) above 350 mg/l (often present in pig manure, since zinc additive is used as an antibiotic), copper above 10 mg/l (Jørgensen, 2009).

Composition and properties of biogas obtained from anaerobic digestion depend on the input feedstock, the type of digester and operational factors (Table 2). Anaerobic digestion can work under *wet conditions* (5-15% dry matter) or under *dry conditions* (over 15% dry matter). Wet digestion usually requires less investment (capital) cost. Dry digestion is usually cheaper to run as there is less water to heat up, and offers more gas production per unit of feedstock. Digesters can work in *continuous flow or in batch flow.* Most digesters work in continuous flow given the lower operating costs, while some dry systems work with batch flow. Digestion can occur in *single- or multiple-step digesters*: multiple

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digesters enable higher efficiencies in each digestion step, but require higher investment costs.

The access to constant sources of feedstock, the clear definition of the supply scheme, as well as the quality of feedstock (in particular in the presence of several suppliers and diverse feedstock) are crucial elements for optimal operation and economy of the AD facilities. The feedstock needs to be checked accurately, and usually requires pre-treatments (either separation or mixing) to ensure the appropriate composition before entering the digester. Co-digestion of multiple types of feedstock is a common practice to achieve the best balance between biogas yield and process stability, especially in medium- to large-scale AD plants. For example, the fermentation of manure alone does not result in high biogas yield, but the high buffer capacity and the content of diverse elements have a positive impact on the stability of the AD process. Co-digestion offers in fact the highest potential for biogas production based on energy crops, manure and sludge, food industry and household waste. In Europe, maize (whole plant) is often used as the substrate in digestion facilities due to the high yield (t/ha) of maize.

The digestate**,** the decomposed substrate of digestion, has a high content of macro-nutrients (nitrogen, phosphorous, potassium) and micro-nutrients, as well as trace elements of boron, magnesium, manganese. Therefore, it is a valuable natural fertilizer and often represents the main motivation for the installation of domestic digesters in developing countries. It helps reduce the costs of fertilizer purchases and provides additional revenues. Stored digestate should be covered to prevent ammonia losses to the atmosphere, conserve nitrogen and optimize the monetary value of the nutrients. It should also be noted that the AD process is able to inactivate viruses, bacteria and parasites in the treated feedstock substrates. Pre-sanitation by pasteurization or by pressure sterilization may be required depending on feedstock (animal manure, for example).

■ **Biogas from Landfills** - Biogas can also be recovered from landfills, where a *passive (natural) anaerobic digestion* occurs. The recovery of biogas from landfill is limited, particularly in developing countries, but might increase with the implementation of emission mitigation strategies and mechanisms such as the Clean Development Mechanism (CDM) of the Kyoto Protocol. Biogas recovery techniques from landfills vary widely as a function of waste and landfill characteristics.

The level of CH4 emissions from landfills is estimated to be between 100 and 200 m^3 of CH4 per ton of municipal solid waste (Frøiland and Pipatti –IPCC, 2006). The average value for industrialized regions is 120 m^3/t municipal solid wastes (MSW) (Bahor et al., 2009). However, waste separation and recycling techniques tend to make available selected MSW components for more advanced treatments, including biogas production in AD plants. These techniques tend to reduce the potential for biogas production from landfills.

Guideline values for recovery efficiency are 35% for open cells (landfills) in operation, 65% for cells with temporary cover, 85% for a cells with final, clay cover, and 90% for a cell with a geo-membrane final cover (Bahor et al., 2009). The annual production of MSW is estimated at 1 ton/hab-yr in industrialized countries, and 0.5 ton/hab-yr in developing countries (Frøiland and Pipatti, 2006).

■ **Thermal Gasification** - Thermal gasification of biomass feedstock offers much higher production potential than AD because ligno-cellulosic biomass can be gasified. Technologies suitable for biomass gasification include *counter current (up-draft) fixed bed gasifiers* (steam, oxygen or air flows through a fixed bed of biomass in a counter clockwise direction), *co-current (down-draft) fixed bed gasifiers* (steam, oxygen or air flows downwards), *fluidised bed gasifiers* and *entrained flow gasifiers* (gasification reactions occur in a dense cloud of very small particles). These technologies follow the same principles as the ones used for coal gasification (see ETSAP P05 on coal gasification). The oxidation agent can be air, oxygen, steam, or a mixture of these gases. Air-blown gasifiers are cheaper than oxygen or steam-based gasifiers, but result in a lower energy content of the produced gas and with higher nitrogen content (from the air). Heat for the process can be provided from an external source, or directly from the reactor processes.The up-draft design is relatively simple and can handle biomass fuels with high ash and moisture content, and can be on a wide range of size. However, produced gas contains 10 to 20% volatile oils (tar) to be removed by filters and gas-scrubbers before future uses of the gas. Down-draft requires biomass with a low moisture content but produces a gas with a very low tar content. Fluidised-bed gasifiers require feedstock of less than 10 centimeters in length.

Fixed bed gasifiers are the preferred solution for small- to medium-scale applications with thermal requirements up to 1 MW_{th}. Updraft gasifiers can scale up to as much as 40 MWth. However, down-draft gasifiers do not scale well beyond 1 MW_{th} due to the characteristics of the processes. Entrained flow gasifiers cannot be used in small scale because the necessity for pretreatment of the fuels, making it very expensive (IRENA, 2012). It is however a promising technology for syngas utilization for high quality products (Bailón Allegue and Hinge, 2012). Of the 15 largest biomass gasifiers of the World, 5 have a capacity between 1 and 4 PJ/year (Finland, Germany, Netherlands, Belgium), while all others are smaller (Vakkilainen, 2013).

Pretreatment methods are possible to improve the conversion of lignocellulosic matter: physical methods include milling and grinding; physic-chemical methods cover steam explosion (rapid heating of biomass at high-pressure followed by anexplosive decompression); chemical methods treat biomass with acids, alkali, oxidizing agents, or organic solvents; and biological methods use microorganisms and fungi to treat biomass). Steam explosion pretreatment is the most commonly used method.

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Gas obtained from gasification of biomass can be upgraded into biomethane in the methanation process (conversion of H2 and CO produced by gasification into bio synthetic natural gas), and cleaned-up (removal of tars, particles, sulphur).

■ **Upgrading -** Biogas and bio-SNG upgrading to biomethane is needed for some applications such as the injection in natural gas networks or the use as a fuel for transportation vehicles or in fuel cells. . Many countries have implemented standards for the composition of biomethane for injection into natural gas pipelines and use as a transport fuel.

Upgrading techniques are developing quickly, and currently dominant technologies for biogas from AD and landfills are absorption technologies (water scrubbing, amine scrubbing, physical scrubbing with organic solvents) and pressure swing adsorption (PSA), which offer similar performance and involve similar investment costs. The simplicity and reliability of water scrubbing has made this the option of choice in many applications. Membrane separation and organic scrubbers still have a minor share of the biogas upgrading market. Cryogenic technology is a further option that is suited for combination with biomethane liquefaction. it is expected to break through within a short period of time.

As of mid-2013, more than 260 biogas upgrading units are in operation worldwide (IEA Bioenergy, 2013), most of them installed in Germany and Sweden (Table 3).

A range of technologies are also available to clean up gas streams produced from biomass gasification. The extent of the necessary gas treatment depends on the techniques used for gasification and gas utilisation (Bailón Allegue and Hinge, 2012; Held, 2012; IRENA, 2012; Zwart, 2009). Cyclones, can remove up to 90% of larger particles at reasonable cost, but removing smaller particles will require high temperature ceramic or sintered metal filters, or the use of electrostatic precipitators. Tar removal can be done by thermal (high temperature) or catalytic (lower temperature) cracking or wet scrubbing in conjunction with a Venturi scrubber. The OLGA tar removal process is based on multiple scrubbers with organic liquid and effectively recycles almost all of the tar to the gasifier to be eliminated. Whereas tar formation is mainly caused by the operating conditions of the gasifier and less by the composition of the biomass feedstock, sulphur and chlorine content of gas depends on the feedstock, which therefore determines the requirements for gas cleaning related to these components. Clean-up technologies for these aspects are of the same kinds as for biogas.

Table 1 - Typical Biogas Composition and Characteristics in Comparison with Natural Gas
(Al Seadi, 2008; IRENA, 2013; Persson *et al.*, 2006)

	Biogas	Landfill gas	Natural gas
Methane CH4 (in volume)	50-70%*	35-65%	80-90%
Carbon dioxide CO2 (in volume)	25-45%	15-50%	0.7-1
Water vapour (in volume)	1-5%	-	<1%
Oxygen O2 (in volume)	<2%	0-5%	0
Nitrogen (in volume)	<2%	5-40%	0-14
Hydrogen sulphide (ppm)	0-4000	0-100	<3
Ammonia (ppm)	100	5	0
Hydrogen (in volume)	<1%	<3%	0
Other hydrocarbons (in volume)	0	0	3-10
Lower heating value (kWh/Nm3)	6.5	4.4	9-11
Wobbe index - upper (kWh/Nm3)	6-10	5-7	12-15

*From carbohydrates: ~50%; from fat and proteins: ~70%; from manure: 60-65%; from energy crops: 50-60%; default value 60%

Table 2 - Main Digester Technologies					
Feedstock Type	Liquid Feedstock			Slurry Waste (<10% solids)	Semi-Solid Waste
Digester Type	Covered Lagoon	Upflow Sludge Blanket	Fixed Film	Complete Mix	Plug Flow
	Usually non-heated; Production varies with temperature fluctuations	Microorganisms agglomerated in granules in suspension, in the digester	Methane forming bacteria grow on a medium (e.g. plastic film) and liquids pass through the medium	Content regularly mixed, by motor-driven impeller or pumps	Constant feedstock additions force the material to move through the tank and be digested
Technology Level	Low	Medium	Medium	Medium	Low

Table 3 – Worldwide Installed Biogas Upgrading Capacity in 2013 (IEA Bioenergy, 2013)					
Country	Plant capacity (Nm3/h raw gas)	Number of plants	Country	Plant capacity (Nm3/h raw gas)	Number of plants
Germany	148186	117	Canada	1600	3
Sweden	28025	56	France	1400	3
The Netherlands	16720	21	Norway	1250	3
Switzerland	2225	15	United Kingdom	650	3
USA	79600	14	Finland	50	3
Austria	2210	10	Spain	4000	1
Japan	2400	6	Iceland	700	1
South Korea	1710	4	Denmark	300	1
Total	**291026**	**261**			

PERFORMANCE AND COSTS

■ **Anaerobic Digestion -** Typical AD-based biogas and/or methane yields for different types of feedstock are given in Table 10 (Summary Table). Anaerobic digesters based on wet biomass input typically convert into methane a 30% to 60% of the input. Most energy crops used as AD input are found to provide similar methane yields of around 300 m^3/t of organic matter (Banks, 2007). However, given the very different crop yields per hectare, the overall methane yield per hectare is highly variable by crops and regions, ranging from 1000 to 12,000 m^3 of methane per hectare (Murphy et al., 2011).

The energy consumption of the AD process is typically around 15% of the biogas produced (Murphy, 2011).

Typical AD-based biogas production and potential electric power generation from selected types of feedstock are provided in Table 4, while Table 5 provides key parameters for two typical AD production facilities.

If biogas is produced from energy crops, energy consumption and emissions associated with crops' growth are to be included in the energy and greenhouse gas balances in addition to energy use and emissions from AD and biogas upgrading (if any) processes (see Table 7).

The energy needed for crops' growth varies from 5 to 25 GJ/ha, depending on crop type and regions (Moller et al., 2008; Murphy *et al*., 2011). This may represent from 7% to up to more than 60% (for some crops) of the methane yield. On average, about 50% of the energy needed for crops growth is associated with fertilizers production; smaller amounts are required for machinery (22%), transport fuels (15%) and pesticides (13%) (Murphy et al., 2011).

The costs for anaerobic digestion include: a) costs of feedstock handling and storage (if any) - often handling and storage are available for other purposes, and are not accountable to the AD process; b) costs of the digester including heat and power generation; and c) costs of handling and storage of the digestate.

The total investment (capital) cost for an AD facility varies from USD 5000 to 7500 per Nm^3/h of biogas production capacity, depending on the size of the digester (Figure 1). The components of the AD system have an expected economic life of 15-20 years.

The annual fixed operation and maintenance (O&M) costs are estimated to range between 2% and 7% of the investment costs. Main O&M costs relate to the energy consumption (digester heating, pumping) and maintenance of equipment other than the digester. The digesters themselves require relatively little maintenance other than monitoring. Process energy requirements are typically around 15% of the biogas produced (Murphy, 2011).

While environmental and economic interest in biogas production is often associated with the potential management and re-cycling of municipal solid waste and agriculture or industrial organic waste, large-scale biogas production may require the purchase of crop feedstock to guarantee constant feedstock input flow and/or quality. The resulting biogas can be significantly more expensive as feedstock may account for up to more than 80% of the O&M costs, even after taking into account the economies of scale of high production capacity.

■ **Gasification -** Cost and technical data on gasification processes remain scarce since technologies are under development and providers are still reluctant in cost or engineering information sometimes still considered confidential. Capital costs of 60 to 70 million USD_{2011}, including tar removal and gas clean-up, are estimated to be needed for a gasification plant of 1000 dry metric tons/day of wood chips, producing 67200 cubic feet of clean gas per ton of dry feedstock), (Worley and Yale, 2012). It is considered that the capital costs for gasification and tar reformation equipment, between USD 2000 and 6000/kW equivalent, will decrease 10-15% over the next 10 to 15 years, in constant currency. Production costs (feedstock excluded) are estimated in the range of 15 to 20 USD/GJ bioSNG. Pretreatment represents around 5%, gasification 35%, methanation 10%, gas cleaning and upgrade 35%,and steam cycle 15% (Heyne, 2013). When associated with electricity production, the additional costs of the prime mover represent a small part of the total, from 5% to 15% (IRENA, 2012).Most commercial-scale gasification processes have a cold gas efficiency of at least 65% and some exceed 80% (Worley and Yale, 2012).

■ **Upgrading -** The investment cost for biogas-to-biomethane upgrading units ranges from USD 1950 to 2600 per Nm^3/h. This applies to upgrading units with raw gas capacities larger than 800-1000 Nm3/h (Table 6). Comparing the two main upgrading systems, i.e. amine and water scrubbers, costs are found to be very similar, especially for high capacity, with the key selection factor being the technical performance, which depends on raw gas input and biomethane quality requirements.

The specific investment cost of smaller units is significantly higher, i.e. up to USD 13000/Nm3/h. Because of these high specific investment costs, small-scale upgrading is not expected to become cost-effective. In contrast, economies of scale are expected from accelerated deployment and increased size of upgrading units (Bauer et al., 2013; IRENA, 2013). This could translate into a 10-20% cost reduction for upgrading units by 2020, which could only reduce the production cost of biomethane for vehicles by between 1% and 5% in 2020 (IRENA, 2013). On average, upgrading units account for 26% to 47% (depending on system size) of the total investment cost for biomethane production, including the digester (Figure 2).

The O&M costs of the upgrading units are dominated by the cost for electricity or heat (IRENA, 2013). The cost of potential biomethane compression and/or liquefaction are to be added, if any. While these costs (for pumping and cooling) are similar (Table 6) to those incurred for compression and liquefaction of natural gas, they are beyond the scope of this brief.

■ **Landfills -** The typical investment costs of landfill gas collection and flaring system are around USD $6/m^3$, while the annual O&M costs are around USD $1/m^3$ (US EPA, 2012). Typical costs for landfill-gas recovery and use (in 2003 USD/kW of installed capacity) are: 200-400 for gas collection; 200-300 for gas conditioning (blowers, compressors, dehydration, flaring); 850–1200 for internal combustion engines/generators; and 250–350 for planning and design (IPCC, 2007).

Table 4 - Typical AD-based Biogas Production and Electric Power Generation from Selected Types of Feedstock (Murphy et al., 2011; Bywater, 2011)

Feedstock obtained from ...	... is sufficient to produce ... (Nm^3 biogas/yr)
1 dairy cow (produces 20 m^3 liquid manure/yr)	500
1 pig (produces 1.5 to 6 m^3 liquid manure/yr)	42-168
1 cattle (beef) (produces 3 to 11 t solid manure/yr)	42-168
100 chicken (produce 1.8 m^3 dry litter/yr)	240-880
Maize silage obtained with 1 ha cultivated, assuming 40-60 t fresh matter/ha	7040-10560
Grass obtained with 1 ha cultivated, assuming 24 – 43 t fresh matter/ha	4118 - 6811
Feedstock obtained from ...	**... can feed a plant of...**
950 dairy cows or 5000 pigs or 45 ha of maize	100 kWe
8000-9000 ton MSW	1 MWe
100 dairy cows half the year + maize silage from 10 ha	20 kWe

Table 5 - Key Parameters for Two Typical AD Biogas Facilities (Murphy et al., 2011)

Grass-to-Gas Digestor

Grass silage yield (150 ha @ 11 tons DM/ha/yr @ 40% DM in silage)	4,125 tons sillage/yr, equivalent. 1,650 t DS/yr
Storage of sillage	4.4 months
Volatil solids (@ 92% VS in DS)	1,518 t VS/yr
Fermenter volume	4,000 m3
Loading rate	4,160 kg VS/day
Methane production @340 m3CH4/t VS	516,120 m3 CH4/yr, equivalent. 938,400 m3 biogas/yr

DM: dry matter VS: volatile solids

Digestor for 500 kWe CHP plant

Input of whole crop maize silage	5,700 ton/yr
Input of total plant cereal silage	2,760 ton/yr
Input of sunflower silage	1,490 ton/yr
Input of grass silage	720 ton/yr
Input of yard manure	830 ton/yr
Total feedstock	11,500 ton/yr
Potential biogas production	2.54 Nm3/yr
Electricity produced	4,140 MWh/hr
Thermal energy produced	4,340 MWh/yr
Own electricity consumption	350 MWh/yr (8.5%)
Own thermal consumption	275 MWh/yr (6.3%)

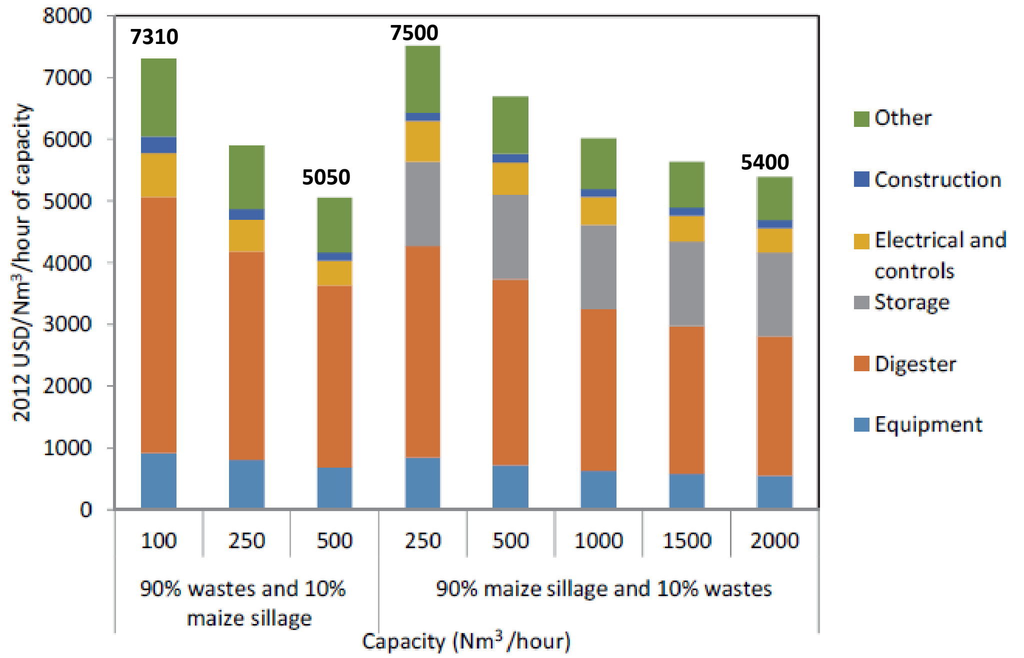

Figure 1 - Capital Cost of AD Systems (IRENA, 2013)

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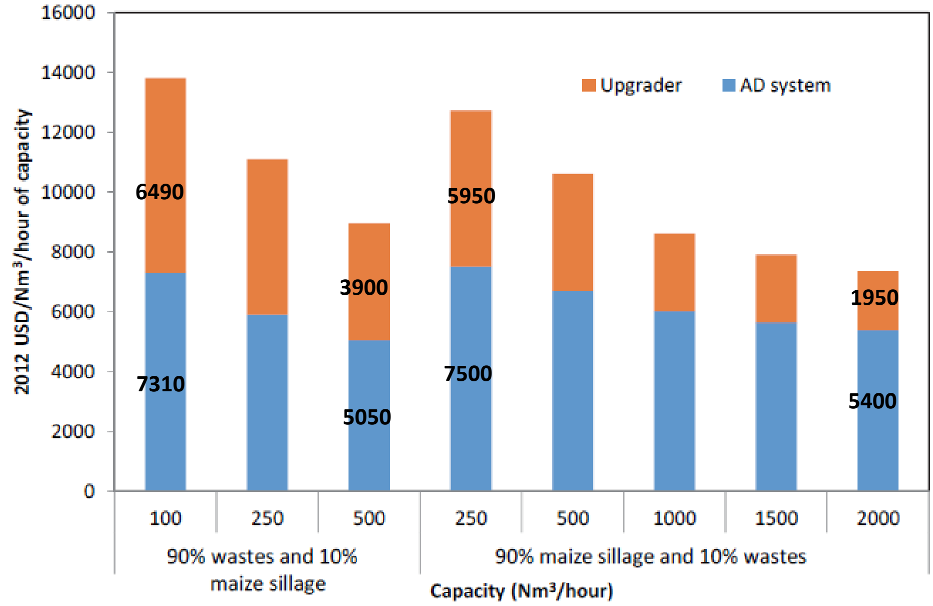

Figure 2 - Capital Cost of AD systems and biogas upgrading (IRENA, 2013)

Table 6 - Characteristics of Biogas Upgrading Systems (Bauer et al., 2013; WUT, 2012)

Technology	Investment cost (USD1000/m^3/h raw gas)		O&M costs (% invest/yr)	Availability	Energy use (kWh/m^3 raw gas)	CH_4 (%)	CH_4 slip (%)
	<500 m^3/h	500-2000 m^3/h*					
Water Scrubb.	2.6-13.0	2.0-2.6	2-3%	0.95-0.96	0.20-0.30	95-99%	2%
Amine Scrubb.	2.6-11.7	2.0-3.9	2-3%	0.96-0.98	0.12-0.14 + 0.55 heat**	close to 100%	0.04%
Pressure Swing Adsorp.	4.8-13.5	2.3-3.3	2%	0.95	0.20-0.30	98-99%	0.5%
Membrane Separ.	3.3-13.0	2.2-3.3	3-4%	>0.95	0.20-0.30	98%	0.5-20%
Organic Scrubb.	2.6-12.3	1.7-2.6	2-3%	0.96-0.98	0.20-0.25	95-99%	4%

* Lower bound corresponds to higher capacity; ** To regenerate the amine

Table 7 - Estimates of Net Energy Yield for Selected Crops (Murphy et al., 2011)

	Maize	Potatoes	Grass	Oilseed rape
Methane yield m^3/ha Methane yield GJ/ha	5748 217	9235 349	4303 163	1344 51
Process energy demand for digestion GJ/ha	33	52	24	8
Energy requirement in cropping GJ/ha	17	24	17	17
Total energy input GJ/ha	50	76	41	25
Net energy yield GJ/ha	167	273	122	26
Ratio Output (yield)/ Total energy input	4.3	4.6	4.0	2.0

Note: Default process energy demand for digestion is estimated to 15% of the energy produced

Potential and Barriers

■ **In industrialized countries**, almost 90% of bio-power is generated using solid biomass fuels, while landfill gas, biogas, synthesis gas and liquid biofuels make up the remaining 10%..

In 2012, almost 12,400 biogas digesters were in operation in Europe (8400 in Germany), with 2250 sewage sludge facilities(EBA, 2013).

Biogas is used primarily in CHP plants, and approximately 2% of the production plants upgrade biogas to biomethane for use as a fuel for vehicles or for injection into the gas grids; this market is however increasing and about 10% of the natural-gas vehicles in Germany use compressed biomethane rather than compressed natural gas (REN21, 2013).

It is estimated that in 2011 about 35.9 TWh of electricity were produced from biogas in Europe, i.e. 60% from power plants and 40% from CHP (see EBA, 2013 for data by country). This represents 26% of the electricity generation from biomass. In Europe, Germany produces more than half of the total biogas-based electricity, representing about 3% of its total domestic electricity production (EBA, 2013; REN21, 2013). The United Kingdom is the second producing country, with mostly landfill production. Landfill biogas is also the main biogas source in France, Italy and Spain (Eurobserv'er, 2011). This source might not be increased further in the mid to long term as the EU Directive on landfill waste envisages a gradual reduction of landfill disposal of biodegradable municipal waste, which could however become a feedstock for digestion plants. Incentives such as feed-in tariffs or quotas (Renewable Obligation Certificates) have been key drivers for the development of EU biogas markets.

The United States produced 9.1 GWh of electricity from biogas in 2012 (REN21, 2013). More than 500 facilities in the US use landfill gas and produce energy to power 433,000 homes).

■ **Amongst emerging and developing economies**, leading countries are China, India, and Nepal, where biogas is usually produced in small, domestic-scale digesters (volume < 10 m^3, investment cost < USD 650) to provide local heat for cooking, using animal manure as an input. The high interest in domestic bio-digesters is due to the need for ensuring access to energy in remote and poor areas, and to the use of nutrient-rich digestate as a fertilizer (reduced cost and/or additional revenue). More than 40 million small-scale domestic AD are already installed in China, while India leads the world in terms of capacity of small gasifiers for electricity generation, with a total capacity exceeding 155 MW (REN21, 2013). Plans to support domestic bio-digesters are being implemented in many different regions.

High upfront capital costs of large plants, O&M requirements, and the lack of familiarity remain major barriers to biogas uptake in poor, rural areas for both residential use and micro-grid or off-grid rural electrification.

■ **In the future**, based on a continued support for renewable energy projects, the global biogas-based electricity generation is expected to reach more than 130,000 GWh by 2030, with about 20,936 GWh in the US by 2025 (World of bioenergy, 2013).

In Europe, the current trend appears to fulfill the 2020 target of 60,000 GWh of biogas-based electricity and 4500 ktoe of biogas for heating services (Eurobserver, 2011) as a part of the EU renewable energy objective, i.e. 20% renewable energy share in energy supply by 2020. Germany has also defined its own biomethane production targets of 6 billion Nm^3 by 2020 and 10 billion Nm^3 by 2030 (REN21, 2013).

From a global perspective, biomethane production is expected to move from local-scale production based on wet-biomass to medium- and large-scale production, with extensive use of gasification of woody biomass.

In Europe, AEBIOM (2009) assumes a realistic biomethane potential from animal manure, energy crops and waste is estimated at about 1.7 EJ by 2020, with a total potential of 2.8 EJ (Table 8). It could represent one third of European natural gas production.

Although Europe and the US dominate the current biogas production, the trend is for emerging economies (e.g. China, India) to grow fast in production and use.

Advancements in biomass gasification and bio-SNG will highly contribute to enlarge the possibilities of biomass applications for gas production thanks to the use of woody and lignocellulosic biomass, still too expensive to be largely implemented. Combined with capture and sequestration, these technologies also offer high greenhouse gas mitigation potential.

■ The development of biogas production and use has been driven by **policy incentives** such as feed-in tariffs, tax exemption, green certificates, clean development mechanisms, etc. In the EU, biogas is included in three EU Directives on Renewable Energy, Landfills, and Waste Recycling and Recovery. While the first one aims to achieve a 20% renewable share in the energy mix by 2020, the second aims to reducing the amount of landfilled biodegradable municipal waste to 35% of 1995 level by 2016, and the third one aims to recycling up to 50% of municipal waste and 70% of construction waste by 2020. All these directives are expected to encourage more efficient biogas production than landfill gas recovery. The elaboration of criteria for "*biodegradable waste subject to biological treatment*" may also facilitate the development of biogas.

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■ From the environmental point of view, biogas production offers several advantages such as decontamination benefits (manure, wastewater); reduction of methane and ammonia emissions from manure; reduction of nitrate wash-out into groundwater; production of natural fertilizers and reduction of energy use and emissions for the production of mineral fertilizers; enhancement of soil properties; waste treatment; and reduced greenhouse gas emissions when replacing fossil fuels. The Annex V of the EU Directive on Renewable Energy defines default greenhouse gas savings for biogas, if produced with no net carbon emissions from land-use change (Table 9). The use of biogas for heat and power generation or in transport depends of the energy system available in each country and may be driven by different reasons (emission reduction, energy security). In terms of safety, the use of the digestate may pose potential health risks for animals and humans. Therefore, it is governed by national or regional regulations (requires e.g. pasteurization or sterilization). Methane leakages may also occur during the process, and the process energy is to be taken into account in the net balance of the process, as described in a previous section.

■ **Algae** can also be used as a renewable feedstock for biofuel production, especially liquid biofuels. Algae can be grown in areas that do not compete with food (e.g. saline conditions) and are more efficient than plants in CO_2 fixation. Biogas from microalgae can be obtained as a by-product from algae-based biodiesel production, with further digestion of algae residues, or by whole algae digestion, with biogas as the sole output. The second process provides higher energy yields (up to 0.8 m^3 CH_4/kgVS, or 27 MJ/kgVS). The current projects show yields closer to 0.2-0.5 m^3 CH_4/kgVS), and algae drying is not required (Torres et al., 2013; Lundquist, 2010). Moreover, algae can also be used to remove CO_2 from biogas in the upgrading stage. However, breakthroughs are still needed in the production chain, from algae growth to digestion process, in order to ensure a robust and cost-effective algal biofuel industry. In the shorter term, the production of microalgae in conjunction with wastewater treatment could allow for practical, near-term technology development in this field (Lundquist, 2010).

Table 8 - Biogas Potential (AEBIOM, 2009; WBA, 2013)

Feedstock	EU27Potential		*EU27Used 2020 (estimate)*	China Potential		Potential World	
	(bill m^3 CH_4)	PJ	(bill m^3 CH_4)*	(bill m^3 CH_4)	PJ	(bill m^3 CH_4)	PJ
Energy crops	27**	978	27 (100%)	50	1799		
Manure and other agriculture residues	32	1145	9 (28%)	104	3743		
Total agriculture	59	2123				630	23
Municipal waste, food processing, landfill gas	10	360	4 (40%)	72	2591		
Industrial waste	3	108	1.5 (50%)	32	1152		
Sewage sludge	6	216	4 (66%)	16	576		
Total other waste	19	684	9.5 (50%)	120	4319	370	13
TOTAL	78	2807***	46 (59%)	274	9861	1000	36
Primary energy 2010 (IEA statistics)	-		-	-	-	-	532

* Between brackets: percentage of total potential
** Assuming that 5 million ha of the 25 million ha agriculture land can be used for biogas crops
*** Estimate of potential of biogas of 3.6 PJ per 1 Million inhabitants, excluding energy crops, is frequently used

Table 9. Emissions Factors based on EU Directive Renewable Energy - Annex V (http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0028:en:NOT)

gCO_{2eq}/MJ	Processing	Transport & Distribution
Biogas from municipal organic waste	20	3
Biogas from wet manure	11	5
Biogas from dry manure	11	4

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Table 10 – Summary Table - Key Data and Figures for Biogas Production

Biogas and Methane Yields of Different Types of Feedstock (Al Seadi, 2008; Jørgensen, 2009; Murphy et al., 2011)						
Feedstock	A DM content (% fresh matter)	B Gas yield (m^3 biogas/tDM)	C CH_4 in biogas (%)	BxC Gas yield (m^3CH4/tDM)	D Organic VS (% DM)	BxC/D Gas yield (m^3 CH4/t VS)
Pig slurry	7-25	370	65 (70-80)	240	75 (70-80)	320
Cattle slurry	7-40	240	65 (55-75)	156	75-85	210
Chicken manure	10-30	400	65 (60-80)	260	75 (70-80)	350
Flotation sludge from sewage plants	5	410-860	70	287-602	80	360-750
Source-separated household waste	33	430	65	280	80	350
Leaves	80	380	65	247	90	410-450
Straw	78-90	350-450	55	195-250	90	240-320
Grass	35	570	55	371	90	350 (300-470)
Maize	30	610	55	397	90	370 (205-450)

DM = dry-matter weight of biomass (also called TS total solids or DS dry solids). Solid waste, energy crops: 20-35% ("dry digestion"). Manure, diluted substrate: 2-10% ("wet digestion"). Wastewater: <2%
VS = volatil solids = the organic matter which can be converted to gas; VS is the usual unit to assess biogas yields of feedstocks.

Examples of Methane Yields of Different Crops (AEBIOM, 2009; Murphy et al., 2011)					
Feedstock	A Crop yield (t DM/ha)	B Organic VS (% DM)	C Methane yield (Nm^3 CH_4/tVS)	AxBxC Methane (Nm^3/ha)	Equivalent energy (GJ/ha)
Maize	9-30	95	370 (205-450)	4660-12150	161-437
Winter catch crop	7.5	89	320	2136	77
Autumn catch crop	3.3	89	320	940	34
Green cuttings	8	88	300	2112	76
Grass	10-15	90	298-467	2682-6305	97-227
Reed Canary Grass	5-11	90	340-430	1530-4257	55-153
Miscanthus	8-25	90	179-218	1289-4905	43-177
Oilseed rape	2.5-7.8	90	240-340	540-2387	19-86
Sugar beet	9.2-18.4	90	236-381	1954-6309	70-227

Synthetic Gas Production Costs (IRENA, 2013; Van Foreest, 2012; Bywater, 2011; REN21, 2012)				
	Production Cost (USD/GJ)	Investment Cost (USD/kW)	Fixed O&M Cost (% invest cost)	Energy use (kWh/m^3 raw gas)
Biomethane from wastes	13.6-16.8	-	-	-
Biomethane from 10% purchased maize silage	19.8-22.7	-	-	-
Biomethane from mostly maize silage	22.2-28.2	-	-	-
Raw gas	13.4-21.7	-	-	-
Upgrading	5.1-8.3	-	-	-
Biomethane (raw gas+upgrading+ grid connection)	19.1-31.1	-	-	-
Collected landfill gas	6.9-1.8 1.4-4.9 cents/m^3	-	-	-
Capital cost of CHP added to a digester	-	+25% of digester capital cost	-	-
Anaerobic digester				
<500 m3/h raw gas	-	4875-7312	2-7%	Up to 15%
500-2000 m3/h raw gas	-	5265-5850	2-7%	Up to 15%
Upgrader				
<500 m3/h raw gas	-	2600-13000	2-4%	0.18-0.7 kWh/m^3 raw gas*
500-2000 m3/h raw gas	-	1700-3900	2-4%	
Electricity price (LCOE) incl.power gen.	cents/kWh			
Landfill around 5 MW	9.8	1950-2340	11-20%	-
AD around 1 MW	5.9-18.6	3600-6337	-	-

* High value only for amine scrubber; all other options are much cheaper.

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