



Techno-economic assessment of biomass-based natural gas substitutes against the background of the EU 2018 renewable energy directive

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Abstract

This paper investigates biomethane and BioSNG production processes against the background of the 2018 renewable fuel directive of the European Union (EU). The investigated biomethane processes use manure, clover grass, and grass silage as feedstock, are based on membrane separation gas upgrading processes, and generate 1.0 and 4.8 MW of biomethane. The investigated BioSNG processes use wood chips as feedstock, are based on the dual fluidized bed steam gasification technology and the VESTA SNG process from Amec Foster Wheeler, and generate 6.1, 12.2, and 49.1 MW BioSNG. The techno-economic assessment shows that the biomethane processes have, in general, a lower break-even price for the generated natural gas substitute. However, their scalability is limited and at larger scale (49.1 MW BioSNG capacity), the BioSNG processes become competitive. The 1.0 MW biomethane and all BioSNG plants meet the 2018 renewable fuel directive of the EU. In contrast, the 4.8 MW biomethane process does not meet the directive as the feedstock, which is mainly based on energy crops, causes significant CH₄ and CO₂ emissions.

Keywords BioSNG · Biomethane · Biomass gasification · Biogas · Techno-economic assessment · Renewable energy directive 2018

1 Introduction

A reduction of CO₂ emissions is necessary to meet the targets of the Paris agreement. Those targets should be mainly achieved by investing in wind and solar power, measures to increase the energy efficiency, reforestation, and reduction of deforestation [1]. Today, renewable energy sources like hydro-power and biofuels/charcoal mainly contribute to the production of electricity (about 18%) and heat (about 64%) [2]. Austria already has a significant share of renewables in the

electricity (about 76%) and district heat (about 44%) production [3]. In contrast, the industrial and the transportation sectors mainly use fossil fuels to cover their energy demand. Especially, the industrial sector could lower its CO₂ emissions by using biomass-based processes. Since a direct utilization of biomass is always challenging in terms of purity and solids handling, it is a promising option to convert biomass in a first step into an intermediate feedstock like already applied fossil fuels, e.g., bio-oil, biomethane (generated via biogas upgrading), or BioSNG (generated via biomass gasification and downstream methanation, SNG = synthetic natural gas). The downstream process then needs no significant adjustment and existing assets can be used. However, biomass-based feedstock come with a significant price increase as suitable technologies are not yet mature, capacities are small, and fossil energy, electricity, natural gas, and oil are available at low price levels today. These aspects lead to a difficult economic situation for the implementation and commercialization of biomass-based concepts.

Among the biomass-based energy carriers, renewable methane is a promising candidate since its production according to current specifications is relatively simple and existing

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infrastructure of natural gas can be used. Today, biomass-based methane is mainly produced from organic feedstock based on cellulose or starch via anaerobic digestion and biomethane purification. In this process, CO₂ and trace components (e.g., H₂S, organics, and ammonia) are removed from biogas, i.e., the raw gas from fermentation mainly consists of CH₄ and CO₂, typically 50–55 and 45–50%, respectively. The separation of CO₂ is carried out by unit operations like absorption (e.g., amine scrubbing or pressurized water scrubbing), adsorption (PSA), or gas permeation through polymeric membranes [4]. Although upgrading of biogas can be beneficial, the largest share of biogas plants are producing raw biogas for combined heat and power (CHP) operation [5, 6]. Today, among the total worldwide installed capacity for biogas (plants with capacities between 1.5 and 10,000 m³ h⁻¹ raw gas), 15% are for biomethane production [7]. The largest players are Germany, Sweden, and the UK with approximately 2 GW installed capacity of biomethane [7]. This distribution is mainly caused by local regulations. In Germany, as largest player in biogas production, since 2012, only plants with less than 75 kW electrical capacity (i.e., approximately 40 m³ h⁻¹ raw biogas) based on manure get high funding rates (the so-called *Güllebonus*). Therefore, in the last years, predominantly small plants have been built. In such small plants, the production of biomethane is not beneficial due to high investment and disadvantageous economy of scale.

Those plants that are favored for biomethane production have higher capacities (on average about 900 m³ h⁻¹ raw biogas, status 2016 [7]) and most of them (82% in 2016, energy-based number) are based on energy crops, of which 84% are represented by corn [5]. If an environmental-friendly and ethically correct production of biomethane on a significant industrial scale is targeted, alternative kinds of feedstock and technologies are required (for example, conversion of straw). The most promising option on the thermochemical conversion side is biomass gasification combined with a methanation to produce BioSNG.

Today, the generation of SNG via the thermochemical route by gasification is mainly carried out with coal as feedstock. The first commercial SNG production plant was the Great Plains Synfuels Plant in North Dakota, USA, employing lignite gasification [8]. Furthermore, several coal-based SNG projects are ongoing in China or planned for the upcoming years with a total expected SNG capacity of 5 GW in 2020 and 20 GW in 2030 [9]. However, these plants warrant a critical assessment regarding their CO₂ emissions and their general environmental impact [10]. In contrast to coal-based SNG, the GoBiGas plant in Gothenburg, Sweden, is a dual fluidized bed (DFB) biomass steam gasification-based BioSNG plant which can generate CO₂-neutral SNG from biomass [11]. However, due to hard market conditions, the plant was mothballed at the beginning of 2018 [12]. In addition, a BioSNG pilot plant employing fluidized bed methanation was extensively

investigated at the site of the commercial DFB CHP plant in Güssing, Austria [13, 14].

Biomethane from biogas and BioSNG production based on the thermochemical route are not to be considered as competitive technologies. Besides the different feedstock range for the processes, their different scalability make them both viable options for production of a renewable natural gas (NG) substitute. For both technologies, the injection regulations are defined in the standard EN 16723-1:2016.

In addition to an energetic utilization of biomethane/BioSNG, the large potential of biomethane and BioSNG in the chemical sector (e.g., H₂ production, methanol synthesis, and ammonia synthesis) can be pointed out. Hence, several sectors, transportation, heating, electricity generation, and chemical industry can benefit from a renewable production of methane as a key intermediate [15].

For the use of renewable methane in the transport sector, the entire production chain needs to fulfill the requirements of the EU Renewable Energy Directive [16] and its additions. The key parameters are the total greenhouse gas emissions, which need to be at least 60% lower than the reference case. This is valid since January 1, 2018, for plants that are commissioned after January 1, 2017 [16]. Since the emissions of all greenhouse gases have to be taken into account, a careful analysis of the overall process and product lifecycle is required. In this paper, a first evaluation of the expected GHG emissions will be made as an addition to the techno-economic assessment of the respective processes.

2 Materials and methods

This section describes the two investigated processes as well as the methodology of the techno-economic assessment. Furthermore, the approach for the CO₂ footprint calculation is introduced.

2.1 Biomethane

In this work, membrane separation is chosen for biogas upgrading as it is compact, requires mainly electricity for compression, and yields CH₄ at high purity and pressure ready for injection. The feedstock mixture is chosen according to its availability and in such a way that competition with food production is minimized. The following two biomethane production plants were investigated:

- Small unit, 80% manure, 20% clover grass, 1 MW biomethane capacity
- Medium unit, 20% manure, 50% clover grass, 30% roadside vegetation, 4.8 MW biomethane capacity

Figure 1 shows a simplified flowchart of the biomethane production processes.

In order to create the design basis for the biogas plants, the feedstock mixture was used as input for the KTBL biogas plant calculator [17], which also provides detailed feedstock information, to calculate the biogas capacity of the digester. The feedstock is converted in the anaerobic digester into biogas. A partial flow of the biogas as well as of the retentate of the first stage of the membrane separation unit is used as fuel in a boiler to heat the digester to maintain the temperature at a sufficient level between 30 and 55 °C. Subsequently, the raw biogas is cooled, where steam is condensed and then fed into the pretreatment unit where minor components like H₂S and NH₃ are separated using activated carbon filters. The cleaned biogas is compressed to an absolute pressure of 10 bars and subsequently fed into the two-stage membrane separation unit. The retentate of the first membrane unit is fed back into the boiler as fuel and the retentate of the second membrane unit is recycled back to the compressor to increase the partial pressure of the CH₄. Finally, the upgraded biomethane is sent to the injection station for drying, lower heating value (LHV) adjustment, and odorization and then injected into the natural gas grid. The injection station is not included in the techno-economic assessment.

2.2 BioSNG

The investigated thermochemical process for BioSNG production is based on DFB steam gasification of wood chips [18, 19] and the VESTA SNG process from Amec Foster Wheeler [20]. Information regarding gas-cleaning equipment was taken from [11]. The investigated BioSNG capacities are 6.1, 12.2, and 49.1 MW. Figure 2 shows a simplified flowchart of the BioSNG process. The upper part shows the DFB gasification process including the product gas compression and the lower part shows the VESTA SNG process.

Mass and energy balances are based on the base case of the BioSNG plant (10 MW gasifier power) in [21] without considering district heat. Wood chips are fed into a dryer where the water content is reduced from 40 to 20%. Subsequently, the wood chips are fed into the gasifier, where they are converted with steam into product gas. The product gas, which is composed of about 40% H₂, 25% CO, 20% CO₂, 10% CH₄,

and other components like higher hydrocarbons, sulfur components, and small amounts of N₂, is cooled, filtered, and fed into the RME (rapeseed methyl ester) scrubber where most of the tar, except BTEX (benzene, toluene, ethylbenzene, xylene), are removed and steam condensed. The condensate is reused for steam fluidization in the gasifier. After the RME scrubber, a partial flow of the product gas is extracted and used as fuel for the combustion reactor of the DFB system. The remaining product gas is led into regenerable fixed-bed adsorbers filled with activated carbon for removal of sulfur (especially H₂S) and BTEX. Then, the product gas is compressed to 10 bars and fed into the VESTA SNG process. In the first step, the product gas is led into the fixed-bed hydrogenation reactor where olefins are hydrogenated, and COS is converted into H₂S. The H₂S is subsequently removed by a ZnO adsorber bed. In the second step, the gas is fed with additional steam into a water gas shift (WGS) reactor where CO and H₂O react to H₂ and CO₂. Then the gas is cooled and led into the methanation section. Due to the highly exothermic methanation reaction, the section consists of several fixed-bed reactors in series. In each reactor, the CO and H₂ react to H₂O and CH₄. In addition, depending on operating conditions, CO and H₂O are formed from H₂ and CO₂ by the reverse WGS shift reaction. Subsequently, the gas enters an amine scrubber where CO₂ is removed. Finally, the gas enters the final methanation reactor where the remaining CO and H₂ are converted into H₂O and CH₄ at favorable operating conditions to reach the gas grid specifications before it is injected into the gas grid as BioSNG. Like the biomethane process, the injection station is not considered for the techno-economic assessment. The energy of the flue gas of the DFB system is recovered for steam generation which is needed for fluidization of the gasifier and for steam addition before the WGS reactor and combustion air preheating. The DFB gasification process operates at ambient pressure.

2.3 Techno-economic assessment

This section describes the methodology used for the techno-economic assessment of the investigated processes.

CAPEX were estimated based on a literature study as well as on budget quotes from different plant manufacturers. Investment costs from years other than 2016 were adjusted

Fig. 1 Simplified flowchart of the biomethane production process. Heat exchangers are not depicted [4]

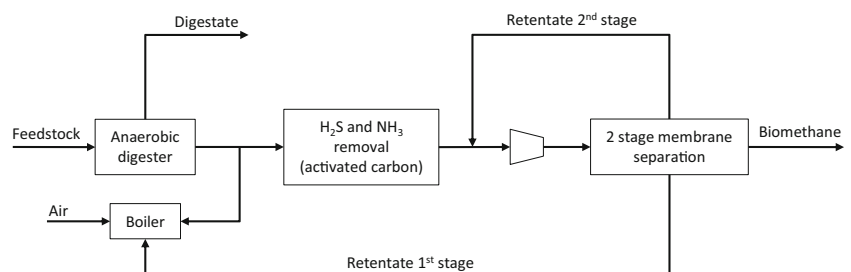
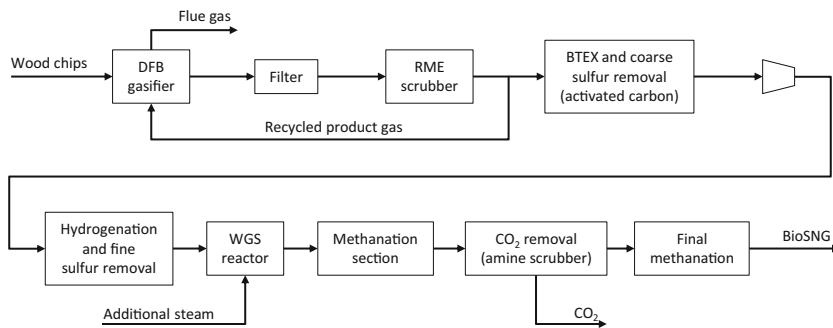


Fig. 2 Simplified flowchart of the BioSNG process. Heat exchangers are not depicted. Based on [11, 20, 21]



using the chemical engineering plant cost index (CEPCI; see Eq. 1). The assessment is carried out for the base year 2017 and it is assumed that 2016 CAPEX are equal to 2017 CAPEX.

$$\frac{\text{CAPEX } 1}{\text{CAPEX } 2} = \frac{\text{CEPCI } 1}{\text{CEPCI } 2} \tag{1}$$

First, the CAPEX of the smaller plant capacities were estimated. Subsequently, the CAPEX of the larger plant capacities were estimated using capacity rationing according to Eq. 2.

$$\frac{\text{CAPEX } 1}{\text{CAPEX } 2} = \left(\frac{\text{Capacity } 1}{\text{Capacity } 2} \right)^m \tag{2}$$

An exponent m of 0.67 was used as scaling factor for the BioSNG plants and biomethane plants as it is considered as good average [22]. The basis for the cost estimation was the inside battery limit (ISBL) costs, not taking the plant periphery, infrastructure, and site costs into account.

In addition, plant startup expenses (SUEX) were 10% of the calculated CAPEX. Therefore, the overall investment costs (INV) of a plant were calculated according to Eq. 3.

$$\text{INV} = \text{CAPEX} + \text{SUEX} \tag{3}$$

Tables 1 and 2 show the specific costs and prices of the different considered materials and energy streams as well as estimates for the calculation of the operating expenses (OPEX). These were taken from different sources after plausibility checks.

The annual depreciation was considered according to

$$\text{Depreciation} = \frac{\text{CAPEX}}{n} \tag{4}$$

Table 3 shows the assumptions for the techno-economic assessment covering the number of operators, their wage, the annual operating time, the overall plant lifetime, and the chosen return on investment (ROI).

It was assumed that the biomethane plants can be operated with one operator and the BioSNG plants need six operators to ensure a safe and reliable twenty-four-seven operation. In addition, a tax rate of 25% and a return on investment of 10% were chosen.

The following key figures were calculated to describe the techno-economics of the investigated processes.

The annual specific INV were calculated according to

$$\text{INV}_s = \frac{\text{INV}}{\dot{m}_{\text{Product}} \cdot \text{LHV} \cdot n \cdot t} \tag{5}$$

The annual specific OPEX were calculated according to

$$\text{OPEX}_s = \frac{\text{OPEX}}{\dot{m}_{\text{Product}} \cdot \text{LHV} \cdot t} \tag{6}$$

The annual specific TOTEX are the sum of CAPEX_s (INV_s) and OPEX_s.

$$\text{TOTEX}_s = \text{INV}_s + \text{OPEX}_s \tag{7}$$

Table 1 Specific costs and prices of the investigated material and energy streams

	Values	Units	Sources
Manure (wet)	0.000	EUR kg ⁻¹	KTBL Feedstock data base
Clover grass silage (wet)	0.027	EUR kg ⁻¹	KTBL Feedstock data base
Roadside vegetation (wet)	0.020	EUR kg ⁻¹	KTBL Feedstock data base
Wood chips (dry)	0.091	EUR kg ⁻¹	DFB plant Güssing
Electricity	0.080	EUR kWh ⁻¹	E-Control
RME	1.100	EUR kg ⁻¹	DFB plant Güssing
CaO	0.150	EUR kg ⁻¹	DFB plant Oberwart
Olivine	0.156	EUR kg ⁻¹	DFB plant Oberwart
Ash disposal	0.090	EUR kg ⁻¹	DFB plant Güssing

Table 2 Detailed and factored estimates for the calculation of the OPEX

	Detailed estimate	Factored estimate
Raw materials	Mass and energy balance	
Operating labor	Compare Table 3	
Utilities	Mass and energy balance	
Employee benefits		30% of operating labor
Supervision		10% of operating labor
Laboratory		10% of operating labor
Maintenance		6% of CAPEX
Insurances and taxes		3% of CAPEX
Operating supplies		3% of CAPEX
Plant overhead		1% of CAPEX
Depreciation	According to Eq. 4	

The before tax (BT) cash flow was calculated based on OPEX. It was calculated according to Eq. 8.

$$BT \text{ cash flow} = \text{Revenues} - \text{OPEX} \tag{8}$$

The after tax (AT) cash flow was calculated according to Eq. 9, which takes the BT cash flow, the tax rate, and depreciation into account.

$$AT \text{ cash flow} = BT \text{ cash flow} \cdot (1 - \text{Tax rate}) + \text{Depreciation} \tag{9}$$

The techno-economic assessment was based on the NPV, which was calculated with the AT cash flow, the discount rate (*i* or ROI), the plant lifetime, and the investment costs according to Eq. 3.

$$NPV = AT \text{ cash flow} \cdot \left[\frac{(1 + i)^n - 1}{i(1 + i)^n} \right] - INV \tag{10}$$

The natural gas substitute (BioSNG or biomethane) selling price at an NPV equal zero was calculated. In addition, sensitivity analyses with -25 to +25% of the annual operating time, the CAPEX, and the feedstock price were carried out.

The production efficiency of the investigated processes was calculated according to Eq. 11 considering the lower

heating value (LHV) of the feedstock and the produced renewable methane.

$$\eta = \frac{m_{\text{Renewable methane}} \cdot LHV_{\text{Renewable methane}}}{m_{\text{Biomass feed}} \cdot LHV_{\text{Biomass feed}}} \tag{11}$$

2.4 Calculation of the CO₂ footprint

The CO₂ equivalent emission calculation is based on summarizing the contributions of the major material and energy streams. The data are entirely based on available literature. To calculate the CO₂ equivalent emissions of the produced natural gas substitutes, the reference values in Table 4 were used.

Fehrenbach et al. [23] only take CO₂ emissions and a part of the CH₄ emissions into account. No losses from the digester are considered and only the CH₄ emissions from the digestate storage are considered (0.1% for closed storage and 2.7% for open storage, e.g., like in most small manure-based plants). Recent studies [24] showed that typical CH₄ emissions are higher and that the differences between single plants can be significant. Therefore, some of the GHG emissions in Table 4 might be too low. Other material and energy streams were neglected due to their low contribution. The fossil reference value is 83.8 g CO₂ equivalent per MJ natural gas substitute according to [16]. A 60% reduction according to the renewable energy directive 2018 leads to an allowed value of 33.5 g CO₂ equivalent per MJ natural gas substitute. With a higher value, the generated biomethane or BioSNG cannot be declared as biofuel.

3 Results and discussion

This section presents the results of the techno-economic assessment and the CO₂ footprint calculation.

3.1 Mass flows and energy efficiencies

Table 5 shows the mass flows of the investigated processes for biomethane and BioSNG production.

Table 3 Assumptions for the techno-economic assessment

	Biomethane 1.0 MW	Biomethane 4.8 MW	BioSNG 6.1 MW	BioSNG 12.2 MW	BioSNG 49.1 MW	Units
Operators	1	1	6	6	6	–
Wage per operator	50000	50000	50000	50000	50000	EUR a ⁻¹
Annual operating time (<i>t</i>)	8000	8000	8000	8000	8000	h a ⁻¹
Plant lifetime (<i>n</i>)	20	20	20	20	20	a
Tax rate	25%	25%	25%	25%	25%	–
Return on investment (ROI, <i>i</i>)	10%	10%	10%	10%	10%	–

Table 4 Reference values for the calculation of the GHG emissions (in CO₂ equivalent emissions) of the investigated processes, based on [23]

	Values	Units
Electricity, EU mix	155	g CO ₂ MJ ⁻¹
Biomethane from corn	44.1	g CO ₂ MJ ⁻¹
Biomethane from grass silage	44.3	g CO ₂ MJ ⁻¹
Biomethane from manure	24.2	g CO ₂ MJ ⁻¹
Biomethane from organic waste	26.7	g CO ₂ MJ ⁻¹
Wood chips	4.35	g CO ₂ MJ ⁻¹
RME	1988	g CO ₂ MJ ⁻¹

In general, the energetic efficiency (compare Eq. 11) of biomethane processes strongly depends on the employed feedstock. Based on the assumptions in this work, the biomethane processes reach energetic efficiencies of about 48 to 50% based on the ratio of the generated biomethane to the methane potential of the feedstock input [17]. The main sink of the energy is the digestate. Billig [25] gives conversion efficiencies based on the higher heating value between 39.8 and 73.8% depending on the used feedstock also employing membrane separation for the biogas upgrading.

The BioSNG processes reach a higher energetic efficiency (compare Eq. 11) of about 65% based on the ratio of the generated BioSNG to the wood chip input (wet). The energy losses are mainly thermal losses caused by the gasification process as well as of losses due to the heat of reaction in the water gas shift reactor and the methanation reactors. The results are in agreement with other published literature. Rehling et al. [13] simulated a DFB gasification-based SNG process using an isothermal SNG reactor and achieved a production efficiency of 66.0%. Furthermore, [26] simulated a combination of a DFB-based SNG process with addition of H₂ from a power to gas PEM electrolyzer where an overall efficiency of 64.2% was reached by considering the biomass input and the electricity input from the PEM electrolyzer. Moreover, at the

GoBiGas plant, which employs the DFB steam gasification process and the fixed-bed methanation TREMP process from Haldor Topsoe, a SNG production efficiency of 61.8% is reached [11]. The lower value can be explained by the lower water content of the fuel (8% compared to 40% in this work) and the corresponding increase of the lower heating value, and the additional recycle of syngas to the SNG stages as well as the difference in CO₂ removal (upstream of the methanation reactors). Bunten [27] reports an SNG production efficiency of 62% converting municipal solid waste into SNG by employing the VESTA SNG process. Moreover, [28] reports a SNG conversion efficiency of woody biomass between 60 and 67% by using the VESTA SNG process.

3.2 Cost estimations

Figure 3 shows the overall investment costs of the investigated plants including CAPEX and SUEX.

The absolute investment costs of the BioSNG plants are significantly higher than the investment costs of the biomethane plants. This can be dedicated to the more sophisticated process of the BioSNG plants with several reactors, heat exchangers, and the necessary gas-cleaning equipment. The estimation of the biomethane plants is based on [29, 30] and the estimation of the BioSNG plants is based on [21]. Both estimations include ISBL costs and the SNG compression to 10 bars. However, the grid injection station is not included.

Figure 4 shows the specific annual TOTEX of the investigated processes.

The specific TOTEX of the biomethane plants are lower than the specific TOTEX of the BioSNG plants. The specific investment costs and the CAPEX-related costs are always higher for the BioSNG plants. However, the highest specific raw material cost has the 4.8 MW biomethane process. In general, labor-related costs are insignificant

Table 5 Mass flows of the investigated biomethane and BioSNG processes

	Biomethane 1.0 MW	Biomethane 4.8 MW	BioSNG 6.1 MW	BioSNG 12.2 MW	BioSNG 49.1 MW	Units
Manure (wet)	1826	1534	–	–	–	kg h ⁻¹
Clover grass silage (wet)	465	3836	–	–	–	kg h ⁻¹
Roadside vegetation (wet)	–	2302	–	–	–	kg h ⁻¹
Wood chips (dry)	–	–	2050	4100	16400	kg h ⁻¹
Electricity	56	264	764	1528	6112	kW
RME	–	–	20	40	160	kg h ⁻¹
CaO	–	–	15	30	120	kg h ⁻¹
Olivine	–	–	20	40	160	kg h ⁻¹
Disposal	–	–	45	90	360	kg h ⁻¹
Biomethane or BioSNG	73	345	453	906	3623	kg h ⁻¹
Biomethane or BioSNG	1012	4796	6132	12264	49056	kW

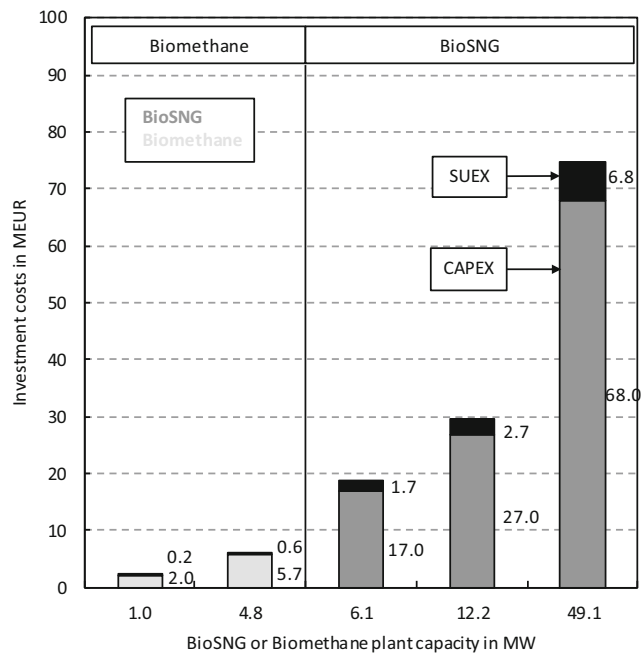


Fig. 3 Investment costs of the investigated biomethane and BioSNG plants

for all plants. The figure also shows that CAPEX-related OPEX have the highest share in case of the smaller plant capacities (compare Table 2).

Figure 5 shows the BioSNG and biomethane selling prices in dependence of the plant capacity considering a plant lifetime of 20 years and a ROI of 10%. The areas indicate the respective sensitivity analyses. The sensitivity of the CAPEX was calculated between -25 and +25% and the sensitivity of

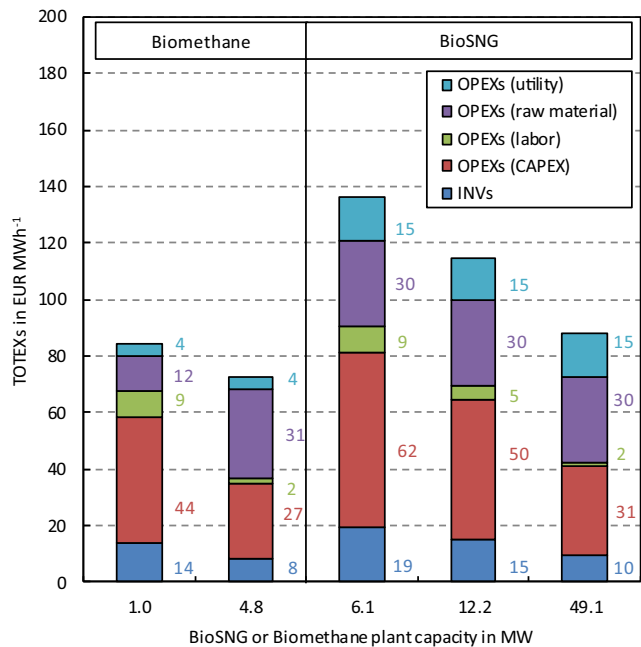


Fig. 4 Specific annual TOTEX of the BioSNG and biomethane processes

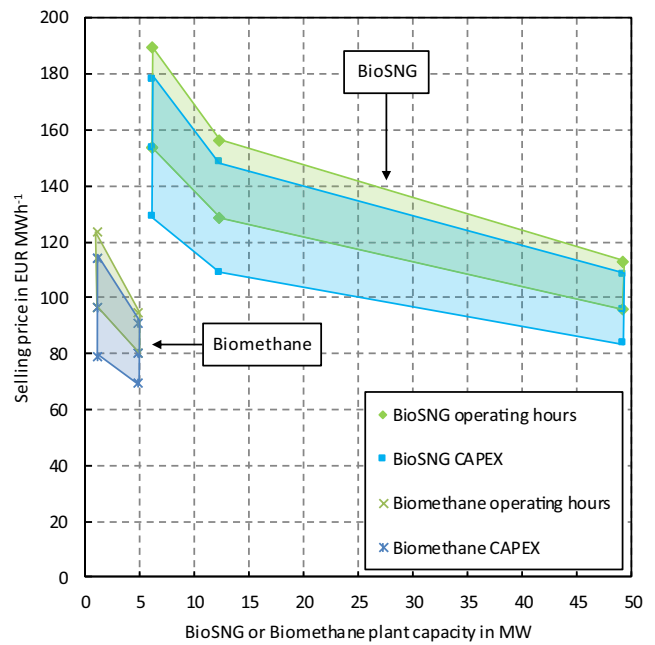


Fig. 5 BioSNG and biomethane selling prices including the sensitivity analysis for a plant lifetime of 20 years

the operating hours was calculated between the reference (8000 h a⁻¹) and -25% (6000 h a⁻¹).

The selling price of the BioSNG, especially for the smaller plant capacities, is significantly higher than the selling price of biomethane. This can be dedicated to the significantly higher CAPEX and CAPEX-related OPEX. In addition, the utility costs are also significantly higher (compare Fig. 4).

Gassner and Maréchal [31] report SNG production costs based on biomass gasification from 76 to 107 EUR MWh⁻¹ for a fuel power of 20 MW and 59 to 97 EUR MWh⁻¹ for a fuel power of 150 MW in 2009. However, they assumed higher production efficiencies between 69 and 76%. Moreover, [25] reports BioSNG production costs of biomass steam gasification plants between 68 and 182 EUR MWh⁻¹ depending on plant capacity and feedstock for the reference year 2012. Biomethane from biogas upgrading plants has production costs from 57 to 129 EUR MWh⁻¹ depending on the feedstock and the upgrading unit in the reference year 2012 [25]. In comparison, the actual price for natural gas in Austria (January 2018) according to [32, 33] is about 42 EUR MWh⁻¹ (incl. taxes and other charges).

The results of the biomethane plants are in agreement with [25] who gives production costs between 66 and 127 EUR MWh⁻¹ for 8.0 MW respectively 1.7 MW biomethane output for different feedstock.

3.3 GHG emissions and EU renewable energy directive

Figure 6 shows the results of the calculation of the GHG emissions.

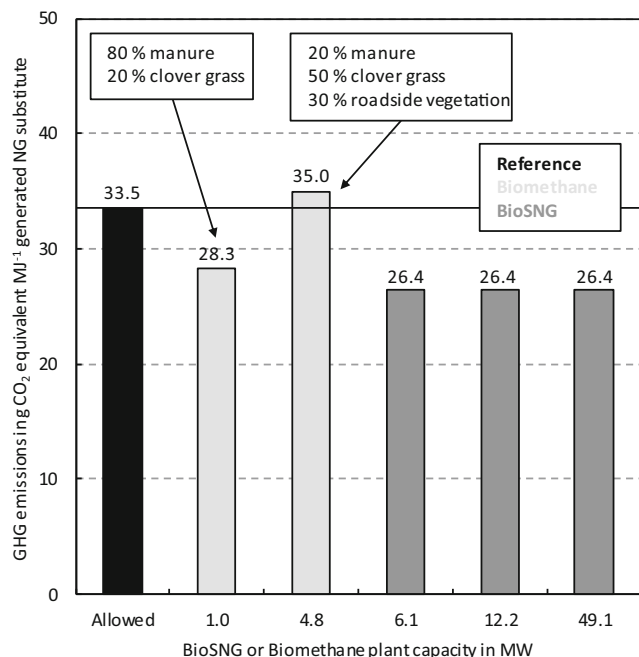


Fig. 6 GHG emissions of the investigated plants in comparison with the reference value which is allowed by the EU directive

The requirements of the 2018 renewable energy directive (RED) are met by the 1.0 MW biomethane plant and all BioSNG plant capacities. Electricity consumption (EU-mix) is the major contributor in all cases. Although most small manure-based plants have relatively high CH₄ emissions [24], typically a CH₄ credit is considered since less CH₄ emitted of the manure if it is used in a biogas plant instead of a simple storage. This leads to significantly lower GHG emissions than for grass as main feedstock. Therefore, the grass-based 4.8 MW biomethane plant does not meet the requirements of the directive. In general, the BioSNG plants show lower GHG emissions which can be dedicated to the higher production efficiency of the natural gas substitute and the used feedstock which causes significantly less CO₂ emissions (compare Table 4). In addition, in case of the BioSNG plants, it is feasible to omit CH₄ emissions, if state-of-the-art technologies like a central waste gas treatment and flares are applied. The installation of such technologies is legally mandatory and less cost intensive at larger plant capacities.

3.4 Case study: lowering operating expenses through co-feeding of residual materials

Co-feeding of residual materials with a negative price (for example, sewage sludge) would lower the feedstock costs of the investigated processes and hence increase the economic feasibility.

Figure 7 shows the sensitivity of the NG substitute selling price with respect to the feedstock price.

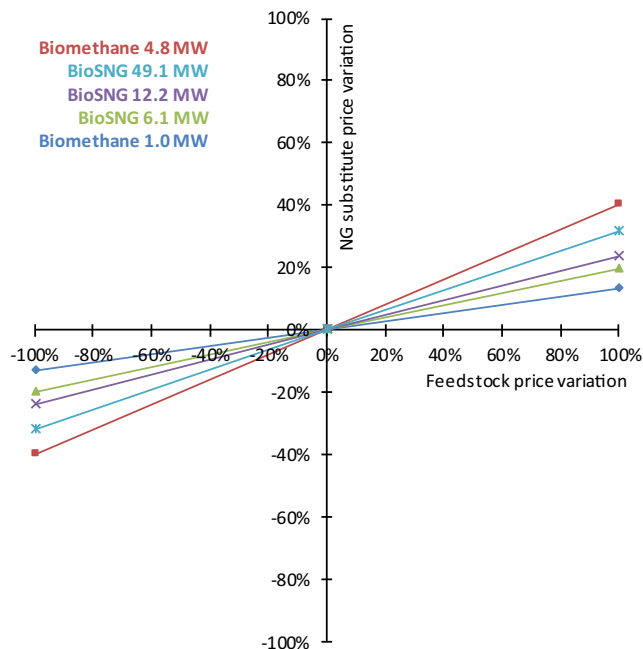


Fig. 7 Sensitivity analysis of the feedstock price of the investigated plants

The 4.8 MW biomethane process has the highest sensitivity regarding a feedstock price variation. A feedstock price decrease of 100% would lower the NG substitute selling price by about 40%. In contrast, the 1.0 MW biomethane process has the lowest sensitivity regarding a feedstock price variation. The BioSNG processes are in between, showing the highest sensitivity for the 49.1 MW process. This can be dedicated to

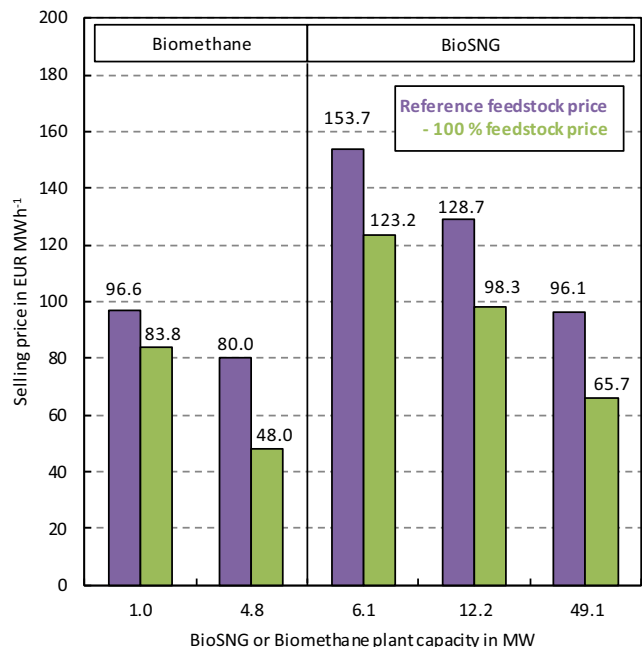


Fig. 8 Absolute NG substitute selling price at the reference feedstock price and at -100% feedstock price for the different investigated plant capacities

an increasing share of the variable costs with increasing plant capacity. These results are promising for utilization of cheap feedstock, e.g., biogenic waste materials or waste wood for the application in a thermochemical BioSNG production. The results in Fig. 7 also show the resistance of the process economics to feedstock price changes.

Figure 8 shows the influence of co-feeding of residual material respectively the influence of the feedstock price on the absolute NG substitute selling price.

If the feedstock costs could be reduced by 100%, the NG substitute selling price of the 49.1 MW BioSNG process would be lower than the reference price of the 4.8 MW biomethane plant. Nevertheless, as mentioned in Section 3.2, the natural gas price in Austria is 42 EUR MWh⁻¹ (incl. taxes and other charges), which is close to the selling price of the 4.8 MW biogas plant of 48 EUR MWh⁻¹ at 100% feedstock costs.

4 Conclusion and outlook

The results show that the natural gas substitute selling price of the BioSNG process is significantly lower at larger plant capacities of up to 50 MW natural gas substitute output. At 50 MW, the gasification-based route starts to get competitive with the biomethane processes. However, about 50 MW biomethane power is the output of the already largest biomethane production facility in Germany [34]. Therefore, at the moment, 50 MW biomethane output seems to mark the upper capacity for anaerobic digestion plants when feedstock availability is especially considered. Biomethane plants of this size usually do not produce according to the RED because of the used feedstock (maize silage). Consequently, from this scale upwards, the gasification-based BioSNG concepts with wood as feedstock are getting economically attractive due to their scalability and feedstock availability with a lower environmental impact. Smaller units may be attractive if cheaper feedstock can be used. In general, feedstock availability plays a vital role for both routes. Moreover, the feedstock is a major factor for the greenhouse gas emission for both technologies. However, both routes can employ different feedstock and can therefore coexist as both will be needed to replace fossil natural gas in the future. Nevertheless, biomethane plants are a commercially available and employed technology, whereas BioSNG plants are not in commercial operation so far.

To increase the economics, co-feeding of cheap low-quality feedstock is an option which needs to be extensively investigated. In addition, the sensitivity analysis showed that the annual operating time of the plants has significant influence on the economic feasibility. Therefore, measures should be implemented to achieve sufficient annual operating times as well as high process reliability.

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Abbreviations biomethane, natural gas substitute from biogas upgrading; BioSNG, natural gas substitute from biomass steam gasification; BTEX, benzene, toluene, ethylbenzene, and xylene; CHP, combined heat and power; DFB, dual fluidized bed; EU, European Union; GHG, greenhouse gas; ISBL, inside battery limit; NG, natural gas; RED, renewable energy directive according to the European Union; RME, rapeseed methyl ester; ROI, return of invest; SNG, synthetic/substitute natural gas

Symbols AT cash flow, after tax cash flow in EUR a⁻¹; BT cash flow, before tax cash flow in EUR a⁻¹; Capacity, NG substitute plant capacity in MW; CAPEX, capital expenditures in EUR; CEPCI, chemical engineering plant cost index in –; *i*, return of investment or discount rate in a⁻¹; INV, investment costs considering CAPEX and SUEX in EUR; INV_s, specific investment costs in EUR MWh⁻¹; LHV, lower heating value in MJ kg⁻¹; *m*, exponent for scale up in –; *ṁ*, mass flow in kg s⁻¹; *n*, plant lifetime in a; NPV, net present value in EUR; OPEX, operating expenditures in EUR a⁻¹; OPEX_s, specific OPEX in EUR MWh⁻¹; Revenues, revenues generated from the selling of natural gas substitute in EUR a⁻¹; SUEX, start-up expenses in EUR; *t*, annual operating time in h a⁻¹; Tax rate, tax rate on income taxes in –; TOTEX_s, specific total expenditures in EUR MWh⁻¹

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