POLYGENERATION OF POWER AND METHANOL FROM BIOGENIC RESIDUES: A TECHNO-ECONOMIC-ASSESSMENT

Andreas Hanel[1]*, Carlos F. Alemán Tijerino[1], Sebastian Fendt[1], Hartmut Spliethoff[1]

[1]Technical University of Munich, TUM School of Engineering and Design, Chair of Energy Systems, Garching, Germany

*Corresponding Author: andreas.hanel@tum.de

ABSTRACT

Supplying the chemical and energy industry with sustainable energy carriers is key for a successful transition to a climate-neutral economy. Currently, as most of the basic chemicals are based on fossil sources, the transition of chemical processes on an industrial scale cannot be achieved only by electrification and efficiency-increasing measures. Substituting carbon demands by biomass or waste as feedstock is identified as an important factor of the ongoing transition. Among the possible products, methanol has been recognized as one of the most promising intermediate products. Simultaneously, the electricity sector will need flexible power delivery to balance volatile renewable power generation. While each problem has been individually investigated to a certain extent, a comprehensive examination addressing both issues through a unified process has not been extensively explored. Here a simulation-based case study on how polygeneration of methanol and electricity from residual biomass could be used in a system serving way is shown. The specific production costs are calculated by modelling the process of a 100 MW and a 250 MW entrained flow gasification-based polygeneration plant in Aspen Plus®, followed by a state-of-the-art economic assessment. While the methanol synthesis is scaled to 100% of the thermal feedstock input, the electricity production via syngas-fuelled gas turbine is limited to 20% of the total capacity. This ensures a constant methanol production while simultaneously being able to offer regulating power to the electricity market. The results of the specific production costs range between 0.87-1.13 € kg^{-1} for methanol and 0.42-0.93 € kWh^{-1} for electricity, depending on the system boundary conditions. While in the case of methanol production, the costs are in a comparable range as suggested in existing literature, the electricity costs are quite high due to the expensive gasification and gas conditioning process. However, due to the increasingly frequent high price peaks on the spot market for electricity, the high production costs can reach an economic range. This demonstrates how polygeneration of methanol and power can be used to increase the viability of biomass or waste utilisation in large-scale plants in a volatile overarching energy system. Further evaluation of the results regarding, e.g., CO_2 abatement costs and further business case possibilities are considered. An analysis of methanol production and end-of-life emissions as CO_2 abatement costs shows that, at well over 200 € t_{CO2}^{-1}, there is no direct competition with German national and European certificate trading. Nevertheless, it can be summarised that the polygeneration of electricity and methanol from biogenic residues can represent a business case if the overall system is considered.

1 INTRODUCTION

The need for an energetic transition from fossil fuels to a carbon-neutral economy has become critical in the face of the pursuit of energetic independence and the goal of reducing greenhouse gas emissions. With the energy sector contributing a substantial 73.2% of global greenhouse gas emissions, there is an undeniable urgency for a comprehensive transformation across all economic sectors (Our world in data, 2020). Various technologies have emerged as critical players in this transition, focusing on harnessing renewable resources sustainably. Wind turbines, PV modules, hydro-power stations, geothermal energy plants, and solar thermal plants have become pivotal in decarbonising electricity and heat supply. Simultaneously, bio-fuels and synthetic products from Power-to-X technologies, such as hydrogen and E-fuels, have gained prominence as alternatives to traditional fossil fuels, particularly in the transport

https://doi.org/10.52202/077185-0171

sector. In particular, methanol (MeOH) stands out as a promising alternative with high decarbonisation potential, especially in the chemical industry and transportation. The global demand for MeOH has nearly doubled in the last decade (Kang et al., 2021), driven partly by its versatility and increasing interest in green production. While conventional MeOH production relies on fossil carbonaceous feedstock, green production routes involve bio-methanol or E-methanol derived from captured CO_2 and hydrogen produced from renewable energy sources.
Additionally, an increasingly discussed topic is the demand for large-scale power plants for a secure electricity supply. However, these plants still have to be operated fossil-free in the long term. In this context, the research conducted in this study aims to evaluate synergy effects between the two fields of research: large-scale synthetic energy carrier production and large-scale flexible power supply. Here, polygeneration is a concept analysed in the context of increasing fossil power plant efficiencies.

The potential of polygeneration processes, where multiple products can be produced, offers economic advantages and synergistic effects, especially within fluctuating markets, as it is expected for the electricity supply in future energy systems. In the topic of polygeneration, particularly in the production of MeOH and electric power, limited studies are available in the literature. In (Jana and De, 2015) a polygeneration model for producing electrical power, ethanol, cooling and heating in India was techno-economically assessed using Aspen Plus. Rice straw is used as a feedstock for a downdraft gasifier and a combined cycle gas turbine is used for power production. Results show that such an approach can be economically feasible. In (Bai et al., 2018) a novel approach using solar energy to drive gasification of cotton stalks is studied. The resulting syngas is used to produce methanol. Unreacted syngas from the methanol synthesis is used for electricity generation through a combined cycle. In (Salman et al., 2017), waste biomass is used in a polygeneration model to produce DME, heat and power using a dual-bed gasifier and combined heat and power system. Overall, an energetic efficiency of up to 71% is reported. In (Puig-Arnavat et al., 2014) a woodchips/almond shells fed trigeneration model for cooling, heating and electricity production is modelled in EES. The small to medium scale (500 kW-2 MW) model produces electricity via an internal combustion engine. Additionally, to the research presented, there are already review articles on polygeneration systems. (Tabriz et al., 2023) offers a review of biomass-driven polygeneration concepts and future perspectives. Biomass undergoes two major conversion routes in these systems: anaerobic digestion and gasification. The gasification route is preferred due to the intermediate syngas production step for systems producing syngas-derived fuels (such as methanol, hydrogen, DME, or FT-Fuels).
The literature shows how biomass polygeneration concepts can be very versatile and diverse. However, no study using entrained flow gasification for methanol and power generation from biogenic residues in the European market context can be found.

2 STATE OF THE ART AND METHODS

The approach in this paper can be roughly divided into two steps:

- Process modelling using the process simulation software Aspen Plus® (see section 2.1).
- State-of-the-art cost estimation (see section 2.2)

2.1 Process Simulation

The concept of a MeOH-power polygeneration plant consists in a simplified way of the main parts: (1) syngas production, (2) MeOH synthesis and (3) power generation, where the syngas production can be subdivided into (1a) feedstock pretreatment, (1b) gasification and (1c) gas conditioning. A simplified flowsheet of the evaluated process is shown in Figure 1. The process simulation is done in Aspen Plus® and is based on previous works by the authors, which are already published (Dieterich et al., 2024; Hanel et al., 2022). Nevertheless, this section summarises the considered sub-processes and their implementations.

 https://doi.org/10.52202/077185-0171

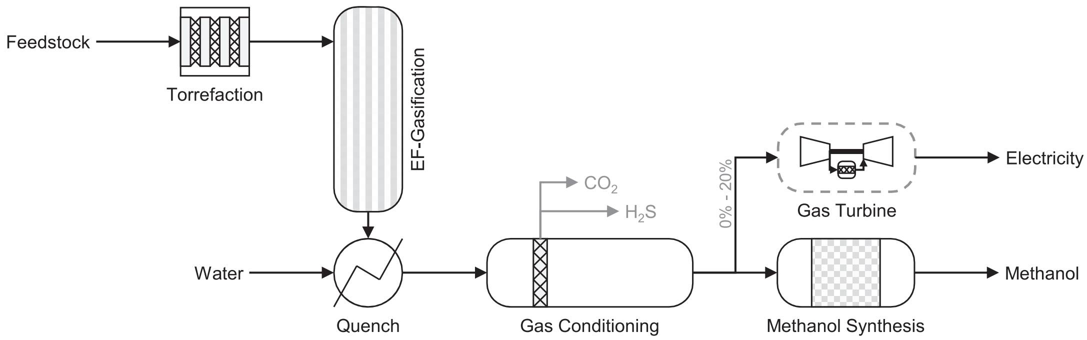

Figure 1: Simplified flowsheet of a combined power-MeOH polygeneration plant

2.1.1 Pretreatment: A generic feedstock is used (see (Hanel et al., 2022)), which is why a torrefaction process is included for considering feedstock pretreatment. This step is needed, as entrained-flow gasification relies on a pulverised, dry fuel. Torrefaction of biomass is a thermal pyrolytic conversion method where biomass is slowly heated between the temperatures of 200-300°C under atmospheric non-oxidative conditions. The technique, results in a solid low moisture product with improved thermal characteristics and homogeneity compared to raw biomass (van der Stelt et al., 2011). The process typically results in 70% of the biomass mass retained into a coal-similar structure, which conserves around 90% of the original energy content (Bergman et al., 2005). In this work, the pretreatment consists of hot air drying (at 80°C), torrefaction (at 250°C) and grinding.

2.1.2 Gasification: The second process step, gasification, produces a gas known as product gas or raw gas. Its composition varies based on factors like gasification agent, temperature, pressure, and residence time, typically containing mixtures of CO, CO_2, H_2, CH_4, NH_3, N_2, and H_2S (Higman and Burgt, 2008). If rich in CO and H_2, it is referred to as synthesis gas or syngas, though this term is not precise, as syngas has a defined H_2:CO ratio for specific fuel or chemical synthesis (Kaltschmitt et al., 2016). Entrained-flow gasification is used in this case as it has proven to be a robust concept for large-scale synthesis gas production in existing studies and plants. The high-temperature raw gas is cooled down by a full-water-quench to stop the reactions, while simultaneously a first cleaning step of the gas is performed. The gasification reactions take place in an oxygen atmosphere at 37 bar and an outlet temperature of 1500°C. After the water quench the raw gas leaves the gasifier unit at 200°C.

2.1.3 Gas Conditioning: After quenching the raw gas, the gas is characterised by its H_2:CO ratio and its pollutants. Specific H_2:CO ratios are crucial for achieving high efficiencies in synthesising various products. Additionally, all unwanted and harmful substances must be extracted for further downstream applications, as they act as catalyst poisons or lead to unwanted emissions. Therefore, the gas conditioning step mainly consists of two parts: (1) setting the right H_2:CO ratio and (2) gas cleaning. Those two steps are realised using the Water-Gas-Shift reaction to achieve the aimed H_2:CO ratio, followed by an acid-gas-removal unit. The final H_2:CO ratio is set to be 2.1:1. The conditioned synthesis gas can then be used for methanol synthesis or power generation.

2.1.4 Methanol Synthesis: On an industrial scale, the most relevant process technology for methanol synthesis is the so-called Low-Pressure Methanol Process (Ott et al., 2012). This catalytic process from syngas to MeOH is used for the presented work. For the reactor a multi-tube design is chosen, filled with a $Cu/ZnO/Al_2O_3$ catalyst. The single reactor design achieves high conversion rates by utilising a recycle stream, while being operated at 65 bar and 235°C. The methanol output has a purity of >99.5 wt.-% methanol. On the operational side, to ensure safe operation for the methanol synthesis, the reactor input stream is at least in a range between 80% and 100% of the total syngas stream, thus allowing part load operation.

2.1.5 Power Generation: To generate power from syngas, various technologies and process variants are available today. For the polygeneration concept evaluated in this work a gas turbine was selected as the

https://doi.org/10.52202/077185-0171

power generation technology. Given the high fuel input capacities and the flexibility required for the different process configurations, a gas turbine is considered more appropriate than a gas engine. Furthermore, significantly lower emissions can be achieved. The gas purity requirements for gas turbine use are fulfilled, given that clean syngas for methanol synthesis is already available. The gas turbine's maximum capacity is set to be 20% of the total available syngas stream. When using syngas as fuel for gas turbines, several aspects must be considered. Syngas significantly varies from natural gas (mostly composed of methane) regarding flammability limits, flame velocity upon combustion, composition, and heating values. Typical LHV of syngas range from 6 to 25 MJ kg^{-1}, in comparison to 50 MJ kg^{-1} for natural gas (Mahinpey et al., 2023). A single-cycle gas turbine electricity generation is chosen due to its simplicity and lower investment costs than combined cycle systems. The gas turbine is modelled following the example of (Lan et al., 2018) and (Kim et al., 2010) which model a M701F and a GE7FA turbine respectively. The cooling system simulation is based on suggestions in (Liu and Karimi, 2018).

2.1.6 Model variants: The analysis of the polygeneration plant will be based on two capacity classes of the overall plant: 100 MW and 250 MW, each based on the LHV of the feedstock at the gasifier inlet. Furthermore, as already discussed, the possibility of fully utilising the synthesis gas for methanol synthesis and the combined methanol and power generation will be considered. The maximum amount of syngas that can be used to generate electricity is 20%, which means that at least 80% methanol is always synthesised. Thus, the gasifier can be operated at maximum capacity. Steady-state conditions are always considered, whereby in addition to the 0% and 20% power generation scenarios, intermediate stages are also considered in 5% increments. The peak power of the gas turbines levels at 4.4 MW and 12.6 MW for the 100 MW and 250 MW case respectively.

2.1.7 Key performance indicators: For analysing the technical and energetic results, three key performance indicators (KPIs) are used. The definitions of the KPI energetic efficiency μ, carbon conversion efficiency (*CCE*), and hydrogen conversion efficiency (*HCE*) are defined based on (Hanel et al., 2022).

$$\mu = \frac{\dot{E}_{product} + P_{el}}{\dot{E}_{feedstock} + P_{aux} + \dot{Q}_{cool}} \tag{1}$$

$$CCE = \frac{\dot{n}_{C,product}}{\dot{n}_{C,feedstock}} \tag{2}$$

$$HCE = \frac{\dot{n}_{H,product}}{\dot{n}_{H,feedstock}} \tag{3}$$

Here, $\dot{E}_i$ is defined as the energetic flow based on the lower heating value and the respective mass flow ($\dot{m}_i \cdot LHV_i$), $\dot{Q}_{cool,}$ is the cooling heat demand, $\dot{n}_i$ are the mole flows of Carbon and Hydrogen and P_i are the electrical output power ($_{el}$) and the power demand of the auxiliaries ($_{aux}$).

2.2 Economic Evaluation

The economic evaluation is carried out through the estimation of investment and production costs for different polygeneration configurations. A subsequent comparison with market prices is executed. With an expected accuracy of -30% to +50%, the cost estimation corresponds to a class 4 category (feasibility study) in the Process Industry Cost Estimate Classification Matrix of the American Association of Cost Engineering. An equipment factored methodology is used for this purpose based on suggestions and applications in (AACE, 2005; Dieterich et al., 2024; Peters et al., 2004). The Total Purchased Equipment Cost (TPEC) of all the required equipment represents the estimation basis of the equipment´s Total Installed Costs (TIC) and the Indirect Costs (IC) of the whole plant. Together, these costs represent the Fixed Capital Investment (FCI). The Total Capital Investment (TCI) of the plant is determined by adding the FCI and the Working Capital (WC), which represents the required capital needed to start operating the plant (Peters et al., 2004). The respective cost types and factors retrieved from literature are shown in Table 1. These factors vary depending on the prevailing state of the matter of each process step.

https://doi.org/10.52202/077185-0171

Following literature suggestions, the FCI of the Power Generation unit is calculated differently:

$$FCI_{PG} = TPEC_{PG} \cdot 1.8 \cdot 1.1 \tag{4}$$

The factor 1.8 considers the installation and complete "plant" costs of a gas turbine plant based on the equipment price (Pauschert, 2009). The factor 1.1 considers a 10% cost increase for the adaptation of existing gas turbines to burn hydrogen-rich fuels (Öberg et al., 2022). The working capital for this process step is set to 5% of the TCI of the power generation unit.

The most relevant methods used for all TPEC estimations include scaling of historical data, empirical correlations from literature and the Aspen Plus Economic Analyzer (APEA).

Besides the TCI the second major cost type calculated is the Total Product Cost (TPC) for operating the plant, producing, and selling the product (Peters et al., 2004). The different cost subcategories that add up to the TPC are once again calculated through a series of factors. The calculation scheme used is based on state-of the-art guidelines found in (Peters et al., 2004). The relationships can be seen in Table 2.

The cost for purchasing or renting land are not considered in this study. The depreciable investment, the FCI, is linearly depreciated over a period of 10 years. The required project capital (TCI) is fully financed with external capital, therefore financing costs of the project derive from the loan interests. An annuity loan over a 10-year repayment period at a 5% interest rate is assumed. The sum of the interest component of each annuity divided over the repayment period represent the yearly financing costs. 8000 yearly full load hours are assumed for the plant and used to adjust TPC on an hourly basis. A plant lifetime of 20 years is set. Due to depreciation and financing costs, the first 10 years of the project result in higher costs. Therefore, the average TPC over the 20 years is used for further assessment.

Table 1: Factors for estimation of Total Capital Investment TCI in % based on (Peters et al., 2004)

Type of cost	Share of TPEC Solid	Solid -fluid	Fluid
TIC	**269**	**302**	**360**
Purchased-equipment delivered[a]	100	100	100
Purchased-equipment installation	45	39	47
Instrumentation and controls	18	26	36
Piping	16	31	68
Electrical systems	10	10	11
Buildings	25	29	18
Yard improvements	15	12	10
Service facilities	40	55	70
IC	**128**	**126**	**144**
Engineering and supervision	33	32	33
Construction expenses	39	34	41
Legal expenses	4	4	4
Contractor's fee	17	19	22
Contingency	35	37	44
TCI	**467**	**503**	**593**
FCI = TIC+IC	397	428	504
Working capital (15% of TCI)	70	75	89

Table 2: Factors for estimation of Total Product Costs TPC based on (Peters et al., 2004)

Type of cost	Share	Base
Variable costs		
Raw material	see[b]	-
Operating labour (OL)	see[c]	-
Operating supervision (OS)	15%	OL
Utilities and catalysts	see[d]	-
Maintenance and repair (M&R)	5%	FCI
Operating supplies	15%	M&R
Laboratory charges	15%	OL
Patents and royalties	15%	TPC
Fixed charges		
Deprecation	see[e]	-
Taxes	2%	FCI
Financing costs	see[f]	-
Insurances	1%	FCI
Plant overhead costs		
Plant overhead costs	60%	OL/OS/M&R
Administration		
Administrative costs	20%	OL/OS/M&R
Distribution / marketing		
Distribution & marketing expenses	3%	TPC
Research / development		
Research and development	5%	TPC

[a] Incl. equipment, process machinery, pumps, etc.
[b] Feedstock demand incl. transportation
[c] Estimated workers times avg. labour costs (D 2019)
[d] Hourly requirements of utilities and catalysts
[e] Linear depreciation of the FCI over a 10-year period
[f] Interest rate on external capital: 5%

https://doi.org/10.52202/077185-0171

3 RESULTS

In the following sections, the results of the technical/energetic modelling (section 3.1) and cost estimation (section 3.2) will be presented. A discussion of these outcomes will take place in section 4. An overview of the results is summarised in Table 3 and Table 4.

Table 3: Summary of the technical/energetic and economic results of the techno-economic evaluation for the 100 MW and the 250 MW case

Parameter	Unit	Split fraction				
		0%	5%	10%	15%	20%
100 MW plant						
μ	-	0.38	0.37	0.35	0.34	0.33
CCE	-	0.40	0.38	0.36	0.34	0.32
HCE	-	0.55	0.52	0.49	0.47	0.44
$costs_{MeOH}$	€ kg^{-1}	1.13	1.09	1.10	1.10	1.11
$costs_{el}$	€ kWh^{-1}	-	0.93	0.71	0.64	0.61
250 MW plant						
μ	-	0.38	0.37	0.35	0.34	0.33
CCE	-	0.40	0.38	0.36	0.34	0.32
HCE	-	0.55	0.52	0.49	0.47	0.44
$costs_{MeOH}$	€ kg^{-1}	0.90	0.87	0.88	0.88	0.89
$costs_{el}$	€ kWh^{-1}	-	0.60	0.48	0.44	0.42

Table 4: Results of the investment costs (TCI) for the 100 MW and the 250 MW case

	Unit	100 MW	250 MW
Syngas	M €	171.2	325.2
MeOH	M €	32.8	68.2
Power	M €	9.8	17.8
Sum	M €	213.8	411.2

3.1 Technical Results

The technical and energetic results of the 100 MW and the 250 MW plant variants are shown in Figure 2. Figure 2a depicts the overall energetic efficiency for both plant scaling variants and various process configurations. It shows the intermediate stage of pure syngas provision (from pretreatment to gas conditioning) and the five stages of polygeneration. The split fraction indicates the syngas portion forwarded to the gas turbine for power generation. Note that the cooling heat demand is considered in the calculations, as mentioned in subchapter 2.1.7. It is noticeable that syngas provision can operate with over 50% energetic efficiency. The subsequent methanol synthesis reduces the efficiency to about 40%, with an increasing split fraction and power generation causing a further decline. This is due to the lower efficiency of power generation compared to MeOH synthesis. The lower efficiency of the smaller gas turbine in the 100 MW variant compared to the 250 MW variant is almost imperceptible, as only 20% of the total syngas stream can be used. The highest difference of about 0.4%-pts. can be seen in the 15 and 20% split fraction cases. Energetically, in all cases, the evaluated process routes have a higher cooling than heating demand. The temperature levels for heat dissipation and heat utilization are not considered in this work.

Analogous to the energetic efficiency, Figure 2b shows the *CCE* and *HCE* for the same process variants. Overall, the same pattern can be observed: An increase in the split fraction leads to decreasing efficiency for both the carbon and the hydrogen conversion. However, the methanol synthesis and the syngas gas turbine have the same molecular conversion rates for booth plant sizes at each split fraction.

A more detailed discussion of the influence of specific subsystems and a further discussion of the gasification and gas conditioning step can be found in (Hanel et al., 2022).

https://doi.org/10.52202/077185-0171

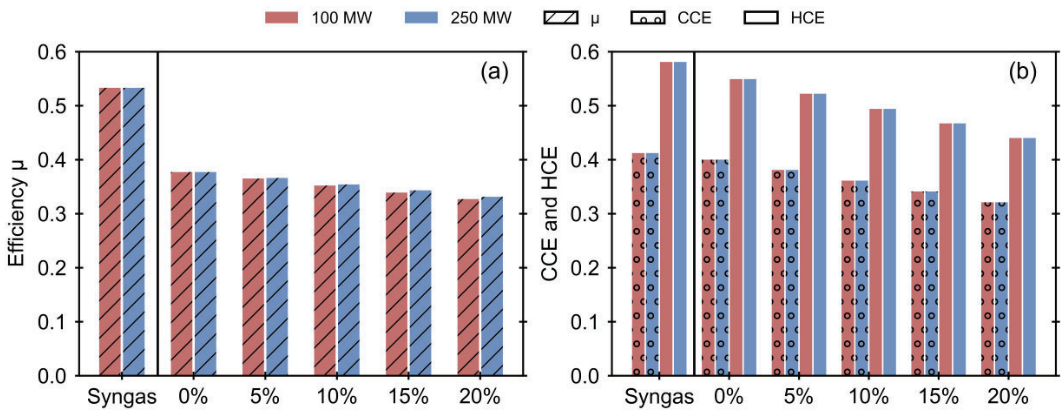

Figure 2: Efficiency (a) and carbon and hydrogen conversion efficiency (b) of the polygeneration concept at different steady states of methanol to power generation shares.

3.2 Economic Results

Based on the process model and the energetic/technical results from section 3.1, this section shows the results of the economic analysis. Firstly, Figure 3 shows the proportionate weighting of the individual subsystems in the TCI estimate for the overall plant. At just over 80%, the most significant cost factor is the synthesis gas supply. The gasifier is the most significant cost factor in comparison to all subsystems at around 40% of the TCI. While the pretreatment of the feedstock, gas treatment and methanol synthesis have a similarly large influence, the gas turbine is the smallest element at less than 5%. This is also because it is only designed for a maximum volume flow of 20% of the syngas stream. In the next step, based on the plant costs and the operational costs, the specific production costs of the products methanol and electricity can be calculated. Figure 4 shows the specific production costs as a function of the plant size (capacity) and the operating mode (split fraction). For this purpose, the total costs were allocated to the products in proportion to the synthesis gas utilisation. It can be seen that the specific costs for both electricity and methanol are significantly lower in the case of the 250 MW plant. In total, based on the plants TCI as shown in Table 3, 2.5 times the output is achieved for only 1.92 times the costs. Regarding the operating states (split fraction), the costs for methanol alone (0% split fraction) are the highest, as the gas turbine must also be financed here without being utilised. Thus, passive costs of the power generation unit (insurance, taxes, depreciation etc.) are allocated to the methanol product if no electricity is produced. Accordingly, the specific costs for methanol initially fall with the use of the gas turbine. As the efficiency of electricity generation using a gas turbine is lower than that of methanol synthesis, the cost curve for MeOH falls with increasing electricity production or even rises slightly with higher splitting fractions. This is due to the changing proportion of fixed costs that must be allocated to methanol production.

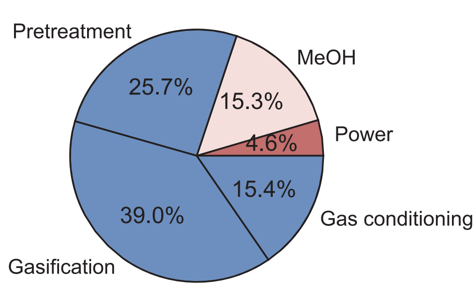

Figure 3: Sub-process share of TCI estimation for the 100 MW case

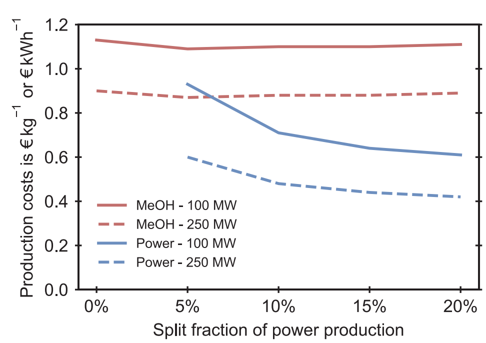

Figure 4: Specific production costs of MeOH and power for different split fractions

https://doi.org/10.52202/077185-0171

4 DISCUSSION

A critical examination and validation of most of the model and its performance results is largely provided in previous works in (Dieterich et al., 2024; Hanel et al., 2022) for most of the process steps. As a new sub-system, only the gas turbine has been added to the process model.
Regarding the power generation unit, a highly strained diffusion combustion was modelled. The question whether blowout occurs or if the combustion mode is the adequate for modelling purposes requires a more in-depth understanding of the combustion thermodynamics in syngas-fuelled gas turbines. Based on literature research, the presented syngas turbine model is satisfactory for the TEA purposes of this paper. Furthermore, with efficiencies of 30 and 34%, the performance results for a steady-state operated syngas turbine at rated capacity are within state-of-the art values.
Thus, this section will focus on the discussion of the economic results of the model through comparison of the estimated production prices with meaningful market values.

4.1 Methanol

Methanol is the main product of the assessed polygeneration plant. In the European market, it is almost exclusively produced from natural gas. Specially in the last years, the price of natural gas has suffered significant fluctuations, impacting the price in the European market. The monthly average prices in Europe from January 2019 to August 2023 are plotted in the bars of Figure 5. The lowest methanol production costs of the model (1.09 € kg^{-1} for the 100 MW and 0.87 € kg^{-1} for the 250 MW) are plotted in the same graphic. While above market prices, the model values are still in the same order of magnitude, with possible production costs below 1 € kg^{-1}. Considering that the market value reference is based on fossil methanol, the higher prices are to be expected. Interesting is however the comparison with already established biomethanol projects that also follow the gasification route. In Figure 6 this comparison is provided for different scenarios. The horizontal lines provide the cost ranges for two different categories: first, methanol produced with low-cost biomass in red (raw material cost below 6 € GJ^{-1}) and second, methanol produced with high-cost biomass in blue (raw material cost between 6 and 15 € GJ^{-1}). The bars on the left side represent the production prices for 100 and 250 MW processes at different polygeneration configurations. Note again that for a split fraction of 0, the methanol costs are slightly higher and then fall for a SF of 5% to slightly increase again with higher split fraction. For biomass prices below 6 € GJ^{-1}, the cheapest established Bio-methanol projects produce at a cost of 0.327 € kg^{-1} while the highest at 0.714 € kg^{-1} (IRENA AND METHANOL INSTITUTE, 2021) The production costs of the 250 MW model are only 21-26% higher than the last value, depending on the split fraction.
The bars on the right represent the estimated production costs considering different raw material prices. In this specific case, the estimated production costs for 100 and 250 MW are given for a methanol-only configuration, where no power generating unit is considered at all. With access to low-cost biomass (either 0 € GJ^{-1} or 6 € GJ^{-1} depending on the cost category) the 250 MW model cost estimate lies within the range of established biomethanol projects for both raw material cost categories.

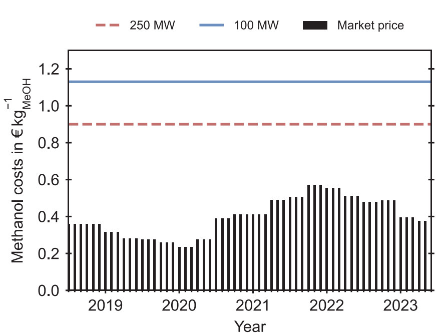

Figure 5: MeOH market prices as listed on Methanex (Methanex European posted contract prices - MEPCP) (Methanex, 2023)

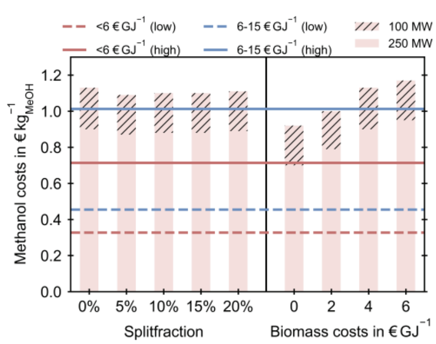

Figure 6: MeOH production costs and scenarios taken from (IRENA AND METHANOL INSTITUTE, 2021)

https://doi.org/10.52202/077185-0171

4.2 Electricity

A direct comparison with average electricity prices is not appropriate for the assessment of the economic viability of the power production of the project. This commodity exhibits high fluctuating prices that can vary strongly within the day and over seasons. As a secondary co-product in the developed concept, electricity is intended to be sold for peak load coverage, where electricity prices are significantly higher. Plotted in Figure 7 are the day-ahead-prices of two summer and two winter weeks in 2022 and 2023. The lowest production costs achieved (0.61 € kWh^{-1} and 0.42 € kWh^{-1} for 100 and 250 MW respectively) are in the same order of magnitude of the actual peak load electricity prices. The 250 MW model production costs lies below some of the market prices in August 2022, where war in Ukraine and possible COVID consequences distorted market prices. A comparison with typical electricity production technologies (LCOE of gas turbines, coal, and bioenergy in Europe) suggest that a solely electricity production via gasification is not an economically viable alternative. Nonetheless, it is to be mentioned that the use of the heat at the turbine outlet (flue gas temperature of 662°C in the simulations) is not considered in this paper. The economic benefit of selling this heat could further reduce the overall cost of power generation.

4.3 CO_2 Abatement Costs

To explore business case possibilities, the CO_2 abatement cost for different scenarios are calculated. These values represent the price CO_2 certificates should have for the processes to have a business case c.p. The CO_2 Abatement Costs (AC) for replacing a cheaper, more contaminating technology (index 1) by a more expensive cleaner technology (index 2) is defined as:

$$AC = \frac{Extra\ costs}{Savings\ in\ CO_2} = \frac{\mathrm{Cost}_{(2)} - \mathrm{Cost}_{(1)}}{\mathrm{CO}_{2(1)} - \mathrm{CO}_{2(2)}} \tag{5}$$

Valid in the German market, are two types of CO_2 trading systems. On the one side, the European Emissions Trading System (ETS) and on the other side the German National Emissions Trading based on the Fuels Emissions Trading Act (nEHS). The former considers emissions in the industrial production and the latter considers emissions that occur upon combustion of the fuel.
Two different emission calculation scenarios are thus presented. One for comparison with the European and other for the German emission systems. Following assumptions are met for the considered scenarios:

1. Well2Gate: The cheaper technology is fossil methanol based by 90% on natural gas and 10% on coal. The biomethanol production utilizes 100% $\mathrm{CO_2}$-neutral $\mathrm{CH_4}$ and electricity. For comparison with ETS.
2. End-of-life: This scenario is for comparison with the German Trading Emission System as it considers only the end-of-life emissions upon combustion of the methanol.

Given that the abatement costs depend on the price of the cheaper more contaminating technology (fossil methanol), different average market prices lead to AC variations in different years. In Figure 8 the abatement costs for the years 2019, 2020, 2022 and an average between 01.2019-08.2023 are plotted for both scenarios. The vertical lines represent the actual CO_2 prices in the ETS in 2022 (81.04 € t^{-1}.) and in the nEHS (30 € t^{-1} in 2023). For all cases, the End-of-Life scenario requires the lowest CO_2 prices to make a business case out of the methanol production. Assuming average methanol market price of 0.4 € kg^{-1}, the CO_2 prices that would be required in the German trading system for the 250 MW model are 342.3 € t^{-1}. These are 11.41 times as high as the present costs. Therefore, more than a 10-fold increase in the German CO_2 prices would be required to make the concept more attractive. Considering a carbon-neutral 250 MW polygeneration process, the required prices in the European trading system would be 415.8 € t^{-1}. These costs are 5.13 times as high as the 2022 costs. Thus, a 4.13-time increase of the European CO_2 prices could lead to an emissions-connected business case. However, the influence of many other variables could allow for a business case at even lower CO_2 prices. Current emission costs can be referred to the easiest abatement methods, thus future CO_2 emissions reductions will automatically lead to higher costs per emitted ton.

https://doi.org/10.52202/077185-0171

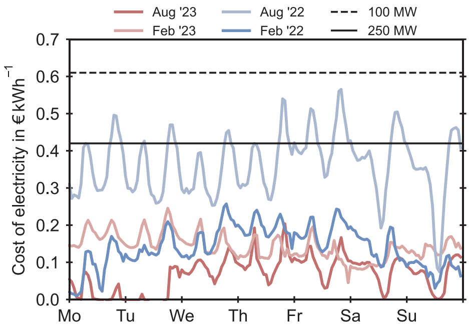

Figure 7: Comparison of electricity market prices (*Bundesnetzagentur | SMARD.de*) and electricity production costs

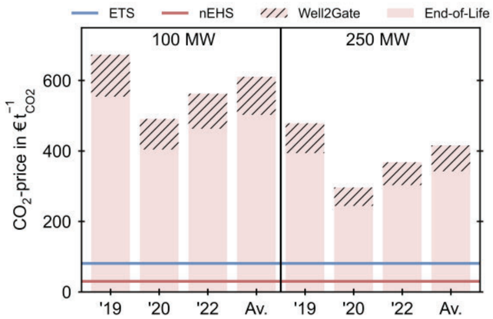

Figure 8: CO_2 abatement costs in comparison to CO_2 prices based on ETS (EU) and nEHS (D)

5 SUMMARY AND OUTLOOK

The proposed Aspen Plus model for a methanol/power polygeneration plant from residual biomass delivers adequate simulation results for different static system configurations. The modularized Aspen Plus model is subdivided in three main parts: First, syngas production via entrained flow gasification, followed by a methanol synthesis via low-pressure MeOH process and power generation via syngas-fuelled gas turbine.

A techno-economic assessment for two different model capacities (100 and 250 MW) shows that efficiency performance indicators like overall energetic efficiency, hydrogen conversion efficiency and carbon conversion efficiency are virtually independent of the selected capacity of the simulation. The highest energetic efficiency losses occur in the syngas production, with almost half of the energy contained in the feedstock lost in form of heat. The high efficiency losses through power production result in further energetic efficiency reduction with increasing fraction of syngas destined to power production. This results in overall process energetic efficiencies between 0.33 and 0.38. In absolute terms, the heating demand is always significantly lower than the required cooling demand for each process step. Nonetheless, the temperature levels at which heat is provided is not assessed.

The economic assessment of the polygeneration plant shows that a 2.5-fold increase in the gasifier capacity results in a 1.9 increase of the total capital investments (TCI) from 213.8 to 411.2 M €. The main cost factor, with around 80% of the TCI originates from the syngas production, mainly from the entrained flow gasification step (39%). The share of investment cost for the methanol synthesis (around 15%) and the power production (around 5%) are significantly lower.

The high costs of the clean syngas production are reflected in the high costs of electricity production with 0.42-0.93 € kWh^{-1}, which are not competitive with already established electricity production technologies but can be economically feasible in just very specific peak load prices.

The main product of the polygeneration plant is methanol, with an operating capacity of 80-100% of the syngas stream. With production prices ranging between 0.87-1.13 € kg^{-1}, the methanol production lies slightly above already established biomethanol projects. However, it was concluded, that with very low-cost biomass availability (either 0 or 6 € GJ^{-1} depending on the raw material cost category), the 250 MW model can produce biomethanol within existent biomethanol plant cost ranges.

Further business case possibilities could be given with a significant price increase of CO_2 certificates, in the range of around 200-650 € kg^{-1} depending on the current MeOH market price, emission trading system and emission calculation assumptions.

Further research should assess possible profits or cost reductions through the economic use of excess heat of the syngas turbine flue gas, heat integration within process steps and alternative use of low-cost biomass like sewage sludge or digestate. Polygeneration of alternative synthetic fuels instead of electricity could also provide a more meaningful integration of processes, where valuable syngas with high quality standards can be used in a more economical way. Alternatively, raw gas before upgrading could be used for electric purposes, thus, saving significant costs of gas treatment.

https://doi.org/10.52202/077185-0171

NOMENCLATURE

FCI	fixed capital investment	(M €)
IC	indirect investments	(M €)
KPI	key performance indicator	(-)
MeOH	methanol	(-)
MR	maintenance and repair	(€ h^{-1})
OL	operating labour	(€ h^{-1})
OS	operating supervision	(€ h^{-1})
TCI	total capital investment	(M €)
TPEC	total purchased equipment cost	(M €)
TIC	total installed costs	(M €)
TPC	total product costs	(M €)

Subscript

aux	auxiliaries
C	carbon
el	electricity
H	hydrogen
PG	power generation

REFERENCES

AACE, 2005. *Cost Estimate Classification System – As Applied in Engineering Procurement, and Construction for the Process Industries*: *TCM Framework: 7.3 – Cost Estimating and Budgeting.* AACE International Recommended Practices 18R-97. https://www.costengineering.eu/Downloads/articles/AACE_CLASSIFICATION_SYSTEM.pdf.

Bai, Z., Liu, Q., Gong, L., Lei, J., 2018. *Thermodynamic and economic analysis of a solar-biomass gasification system with the production of methanol and electricity.* Energy Procedia 152, 1045–1050. https://doi.org/10.1016/j.egypro.2018.09.118.

Bergman, P.C., Boersma, A.R., Zwart, R.W., Kiel, J.H., 2005. *Torrefaction for biomass co-firing in existing coal-fired power stations.* BIOCOAL, Netherlands. https://www.ecn.nl/docs/library/report/2005/c05013.pdf.

Bundesnetzagentur | SMARD.de.

Dieterich, V., Hanel, A., Bastek, S., Spliethoff, H., Fendt, S., 2024. *Entrained flow gasification-based biomass-to-X processes: A techno-economic assessment.* Energy Conversion and Management 301, 118061. https://doi.org/10.1016/j.enconman.2024.118061.

Hanel, A., Dieterich, V., Bastek, S., Spliethoff, H., Fendt, S., 2022. *Entrained flow gasification-based biomass-to-X processes: An energetic and technical evaluation.* Energy Conversion and Management 274, 116424. https://doi.org/10.1016/j.enconman.2022.116424.

Higman, C., Burgt, M., 2008. *Gasification,* 2nd ed. Elsevier Science & Technology, Oxford, 452 pp.

IRENA AND METHANOL INSTITUTE, 2021. *Innovation Outlook: Renewable Methanol,* Abu Dhabi. www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jan/IRENA_Innovation_Renewable_Methanol_2021.pdf.

Jana, K., De, S., 2015. *Techno-economic evaluation of a polygeneration using agricultural residue--a case study for an Indian district.* Bioresource technology 181, 163–173. https://doi.org/10.1016/j.biortech.2015.01.060.

Kaltschmitt, M., Hartmann, H., Hofbauer, H., 2016. *Energie aus Biomasse.* Springer Berlin Heidelberg, Berlin, Heidelberg.

Kang, S., Boshell, F., Goeppert, A., Prakash, S.G., Landälv, I., Saygin, D., 2021. *Innovation outlook*: *Renewable methanol.* International Renewable Energy Agency, Abu Dhabi, 122 pp.

https://doi.org/10.52202/077185-0171

Kim, Y.S., Lee, J.J., Kim, T.S., Sohn, J.L., Joo, Y.J., 2010. *Performance analysis of a syngas-fed gas turbine considering the operating limitations of its components.* Applied Energy 87, 1602–1611. https://doi.org/10.1016/j.apenergy.2009.09.021.

Lan, W., Chen, G., Zhu, X., Wang, X., Liu, C., Xu, B., 2018. *Biomass gasification-gas turbine combustion for power generation system model based on ASPEN PLUS.* The Science of the total environment 628-629, 1278–1286. https://doi.org/10.1016/j.scitotenv.2018.02.159.

Liu, Z., Karimi, I.A., 2018. *Simulating combined cycle gas turbine power plants in Aspen HYSYS.* Energy Conversion and Management 171, 1213–1225. https://doi.org/10.1016/j.enconman.2018.06.049.

Mahinpey, N., Farooqui, A., Abdalla, A., Asghari, K., 2023. *Power generation from syngas*, in: Advances in Synthesis Gas : Methods, Technologies and Applications. Elsevier, pp. 289–319.

Methanex, 2023. *Historical Methanex Posted Price*. www.methanex.com/about-methanol/pricing/.

Öberg, S., Odenberger, M., Johnsson, F., 2022. *Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems.* International Journal of Hydrogen Energy 47, 624–644. https://doi.org/10.1016/j.ijhydene.2021.10.035.

Ott, J., Gronemann, V., Pontzen, F., Fiedler, E., Grossmann, G., Kersebohm, D.B., Weiss, G., Witte, C., 2012. *Methanol*, in: Ullmann's Encyclopedia of Industrial Chemistry. Wiley.

Our world in data, 2020. *Global greenhouse gas emissions by sector*. https://ourworldindata.org/ghg-emissions-by-sector.

Pauschert, D., 2009. *Study of Equipment Prices in the Power Sector*: *ESMAP technical paper no. 122/09.* ESMAP papers. http://hdl.handle.net/10986/17531.

Peters, M.S., Timmerhaus, K.D., West, R.E., 2004. *Plant design and economics for chemical engineers,* 5th ed. McGraw-Hill, Boston, 988 pp.

Puig-Arnavat, M., Bruno, J.C., Coronas, A., 2014. *Modeling of trigeneration configurations based on biomass gasification and comparison of performance.* Applied Energy 114, 845–856. https://doi.org/10.1016/j.apenergy.2013.09.013.

Salman, C.A., Naqvi, M., Thorin, E., Yan, J., 2017. *A polygeneration process for heat, power and DME production by integrating gasification with CHP plant: Modelling and simulation study.* Energy Procedia 142, 1749–1758. https://doi.org/10.1016/j.egypro.2017.12.559.

Tabriz, Z.H., Khani, L., Mohammadpourfard, M., Akkurt, G.G., 2023. *Biomass driven polygeneration systems: A review of recent progress and future prospects.* Process Safety and Environmental Protection 169, 363–397. https://doi.org/10.1016/j.psep.2022.11.029.

van der Stelt, M., Gerhauser, H., Kiel, J., Ptasinski, K.J., 2011. *Biomass upgrading by torrefaction for the production of biofuels: A review.* Biomass and Bioenergy. https://doi.org/10.1016/j.biombioe.2011.06.023.

ACKNOWLEDGEMENT

This study was carried out in the framework of the projects VERENA (project no.: 03EE5044B) sponsored by the Federal Ministry for Economic Affairs and Climate Action (Germany). The financial support is gratefully acknowledged.

https://doi.org/10.52202/077185-0171