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Scenario analysis of implementing a power-to-gas and biomass gasification system in an integrated steel plant: A techno-economic and environmental study

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ABSTRACT

Since the European Union's target a domestic greenhouse gas emission reduction of 80% till 2050, as compared to the value of 1990 (European Commission, 2011), there has been an increasing interest in greening large industrial processes. Thus, gas greening and alternative emission reduction processes are gaining importance. In this study, a gas greening system for an integrated steel plant, producing synthetic natural gas serving as a substitute for the fossil fuel-based gas, was investigated. The analysed system consisted of a Power-to-Gas unit combined with a biomass gasification plant, where carbon rich steel gases were used as a CO_2 source for methanation. To analyse the system, three extreme value scenarios and three constrained scenarios were defined and evaluated. The biomass gasification plant, set to a maximum nominal power of 105 MW_{th}, was the main limiting factor for the constrained scenarios. The assessment included a basic mass and energy balance, techno-economic analysis, sensitivity analysis, and CO_2 potential impact analysis. It was found that the main cost influencing factor throughout all six scenarios was the energy supply cost (electricity and biomass).

1. Introduction

The steel industry is one of the most important industries in Europe. With 223 Mt CO_2 emissions in 2010 [1], the steel industry is also one of the biggest greenhouse gas (GHG) emitters in the European Union.

In order to limit global temperature rise to a maximum of 2 °C, the European Commission published “A Roadmap for moving to a competitive low carbon economy in 2050”. This roadmap aims to achieve a GHG emission reduction of 80%–95% in the European Union till 2050, as compared to 1990 levels. The roadmap indicates that the industry sector has a reduction potential of 83%–87% of GHG emissions by 2050 [2].

Considering the increasing global steel demand and the well-developed and optimized conventional technologies used in the iron and steel industry, the GHG reduction target can only be achieved through fully novel technologies and processes.

In integrated steel plants, energy rich steel gases are produced during the steel production process. These gases (i.e. coke oven gas (COG), blast furnace (BF) gas, and basic oxygen furnace (BOF) gas) are mainly used as energy carriers within the steel industry. However, in an average integrated steel process, a significant proportion of the COx rich gases is not directly applied as fuel but utilized in combined heat and power facilities. Ramírez-Santos et al. [3] as well as Uribe-Soto et al. [4] refer to carbon capture and utilisation (CCU) as a possible way of reducing GHG emissions in a steel plant. Also, Uribe-Soto et al. [4] state that carbon capture and storage could be part of the solution for producing CO_2 emission free steel.

In this work, the steel production process is combined with biomass gasification and a Power-to-Gas (PtG) system, to capture and upgrade the existing steel plant gases. This would lead to the production of H_2 and CH_4 rich gas with renewable resources, which can substitute natural gas as the primary energy source. Additionally, these gases can be used as reducing agents for the steel production process, potentially providing a significant impact on GHG emissions from an integrated steel plant.

This system was chosen since currently available techno economic studies focus only on one upgrading possibility. Therefore, either biomass gasification or PtG is the research focus. Gassner and

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Maréchal [5], Arteaga-Pérez et al. [6], Hamedani et al. [7], Uribe-Soto et al. [4] and Schweitzer et al. [8] focus on the techno economic analysis of biomass gasification systems in different industry sectors. All of them found that costs can be reduced with larger plant sizes. E.g Ref. [5]. reported SNG production costs of approximately 60 € per MWh_{SNG} for a plant capacity of 150 MW_{th}. Out of this Uribe-Soto et al. [4] is relevant, since the focus of the paper is on thermochemical process use in steel plants. However, as already mentioned, none of them consider PtG as part of the solution. Nevertheless, studies like Gutiérrez-Martín and Rodríguez-Antón [9] focus on the techno-economic analysis of PtG systems for SNG production, but do not consider thermochemical conversion as part of their systems.

Therefore, this study aims to identify gas streams in the steel making process that are superior from an economic and ecological perspective and could be used as high-quality energy sources in an integrated steel plant. In order to achieve the same, basic energy and mass balance, techno economic analysis, and sensitivity analysis were conducted for possible scenarios. Since these scenarios were analysed with respect to European steel plants, the CO_2 greening potential was analysed with regard to the European CO_2 emission certificate trading and as part of an ecological analysis.

Since no data was available for material flows inside a steel plant, a theoretical steel plant was designed based on average specific values given by the Commission of the European Union [10] and the European Steel Association [11] (see section 2.1).

2. Technology description

A theoretical steel plant was designed to identify the steel gases and estimate their quantities in the overall process. The current usage of the steel gases was calculated and analysed, along with the amount and potential of the excess steel gases. Thereafter, a combined PtG and biomass gasification system was designed in order to increase the green potential of the excess steel gases. This section describes the different technologies used for the analysed system.

2.1. Integrated steel plant

Since the focus of this study is on greening the steel gases, the analysed steel plant system consisted of those five energy intensive plants in which the steel gases predominantly occur or are used as energy carriers. These are the sinter plant, the coke oven, the blast furnace, the basic oxygen furnace, and the hot strip mill. Fig. 1 provides an overview of the analysed system and its basic gas and material flows.

To calculate the relevant material and gas flows of the theoretical steel plant, data provided by the European Commission [10] and the European Steel Association [11], as presented in Table 1, was analysed. It was then used to calculate a theoretical steel plant, based on an annual crude steel production of 5.3 Mt and a natural gas consumption of 2.8 TWh. These are assumptions for the theoretical steel work. All other assumptions, calculations and values are based on the published data of the European Union and EUROFER which are mentioned above.

As shown in Fig. 1 and Table 1, three steel gases occur during the steel making process. While the COG has a high heating value (LHV), the values for BF gas and BOF gas are comparatively low. As can be seen from Table 2, this is due to the respective gas compositions. COG has a high amount of H_2 and CH_4 with high heating value, while BF and BOF gases mainly consist of CO, CO_2, and N_2 with comparatively low heating value. Since methanation needs CO_2 and CO rich gases, BF and BOF gases fit as carbon carriers for the methanation process.

Table 3 provides a short overview of the calculated amount of energy generated by the steel gases and where it is already used as fuel in a steel plant. It also shows the high amount of excess steel gases that are presumed to be used for electricity production. Beside the current usage, there is a high potential to use the steel gases for methanation and use the upgraded gas as a substitute to fossil fuel based natural gas.

2.2. Gas greening system

The gas greening system consists of a biomass gasification plant, an electrolyser, and a methanation plant. Since fossil fuel based natural gas is accountable for CO_x emissions, the main goal of the gas greening system is the production of a synthetic natural gas (SNG) with a respectively low ecological footprint. Since the methanation process needs a high amount of CO_x containing gases, it could either be operated with a mix of steel gases or with the gas produced from the biomass gasification plant. Both operation types were analysed in the scenarios (see section 3).

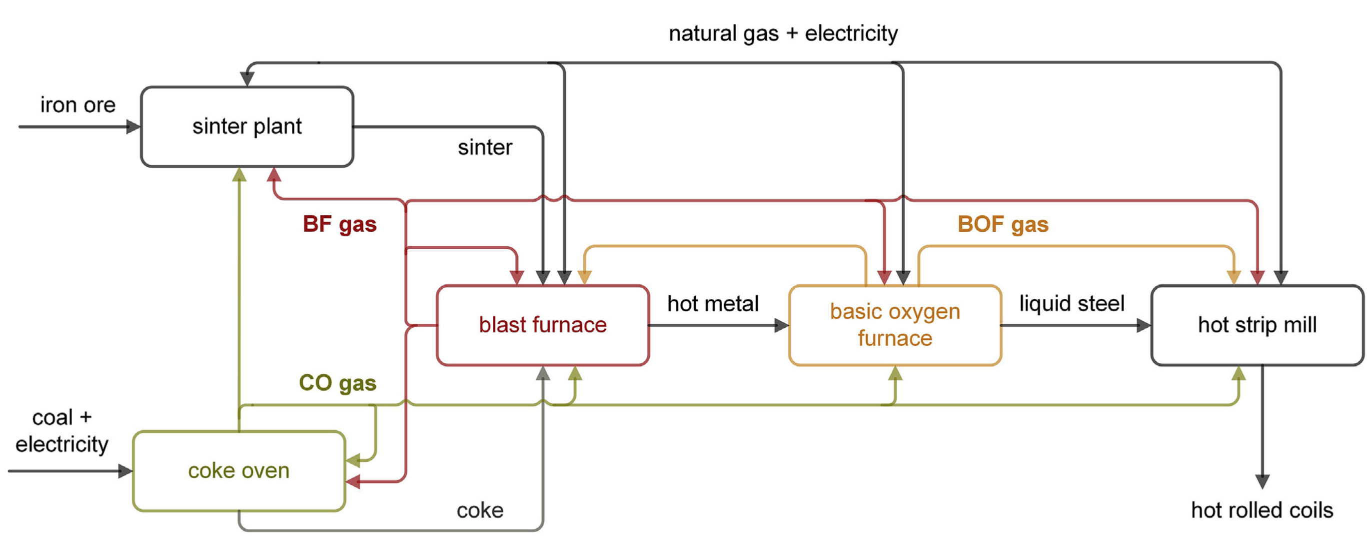

Fig. 1. Schematic of the integrated steel plant with considered material flows
COG = coke oven gas; BF Gas = blast furnace gas; BOF Gas = basic oxygen furnace gas.

Table 1
Steel gas relevant material, gas and energy flows [10,11].

	unit	min	max	average
sinter plant				
energy consumption				
COG/BF gas/natural gas	MJ/t sinter	35	185	67
COG	MJ/t sinter			49.3
coke oven				
output				
COG	MJ/t coke	6264	10,360	7652.2
energy consumption				
coal (dry)	kg/t coke	1220	1350	1267.5
BF Gas/BOF Gas/COG	MJ/t coke	3200	3900	3265.2
BF Gas	MJ/t coke			2224.9
COG	MJ/t coke			489.6
BOF gas	MJ/t coke			550.7
blast furnace				
input				
sinter	kg/t HM	116	1621	1314.2
coke	kg/t HM	282	515	324.9
energy consumption				
BF gas	MJ/t HM	1.2	2287	1622.1
COG	MJ/t HM	0.024	817	220.5
natural gas	MJ/t HM	0	819	7.8
BOF gas	MJ/t HM	0.124	259	0
output				
BF Gas	MJ/t HM	3377	6061	4608.7
	unit	**min**	**max**	**average**
basic oxygen furnace				
raw materials				
hot metal	kg/t LS	788	931	926.6
energy consumption				
natural gas	MJ/t LS	44	730	71.5
COG	MJ/t LS	0	800	49.4
output				
BOF Gas	MJ/t LS	350	700	525
hot strip mill				
input				
hot rolled coils	kg/t LS			1033.5
energy consumption				
COG	MJ/t LS			819.6
BF gas	MJ/t LS			92.9
BOF Gas	MJ/t LS			316.5
natural Gas	MJ/t LS			25.2

2.2.1. Biomass gasification

As part of the system an advanced dual fluidized bed steam gasification plant for the gasification of wood chips was chosen [12]. It consists of a steam blown gasification reactor and an air (or oxygen) blown combustion reactor, which provides the necessary heat for the overall endothermic gasification reactions. Additionally, the so-called Sorption Enhanced Reforming (SER) process allows for the production of a hydrogen-rich product gas via in-situ removal of CO_2 from the product gas [13,14]; Müller, Fuchs, Schmid, Benedikt, & Hofbauer, 2017; [15]. By using pure oxygen in the combustion reactor a nearly pure CO_2 stream can be gained as flue gas (oxySER) [16]. The gases can be utilized in further synthesis processes like methanation.

Table 3
Calculated steel gas generation and usage in the theoretical integrated steel plant based on the literature data from Ref. [10] and [11].

steel gases	unit	generation	consumption
COG			
coke oven plant	MWh/a	3,775,719	241,577
sinter plant	MWh/a		98,395
blast furnace	MWh/a		334,867
basic oxygen furnace	MWh/a		75,022
hot strip mill	MWh/a		1,204,378
balance integrated steel plant	MWh/a	1,821,480	
BF gas			
coke oven plant	MWh/a		1,097,802
sinter plant	MWh/a		
blast furnace	MWh/a	6,999,098	2,463,436
basic oxygen furnace	MWh/a		
hot strip mill	MWh/a		136,481
balance integrated steel plant	MWh/a	3,301,380	
BOF gas			
coke oven plant	MWh/a		271,724
sinter plant	MWh/a		
blast furnace	MWh/a		
basic oxygen furnace	MWh/a	797,302	
hot strip mill	MWh/a		465,068
balance integrated steel plant	MWh/a	60,510	

Table 4
Biomass gasification syngas quality [19].

syngas		
LHV	**MJ/Nm³**	**14.1**
H_2	vol-%	72
CO_2	vol-%	5
CO	vol-%	10
CH_4	vol-%	11
C_xH_y	vol-%	2

The main gasification reactions can be described by Eq (1) and Eq (2) [17,18].

$$C + H_2O \rightarrow CO + H_2 \quad \Delta H = +131\ \text{kJ/mol} \tag{1}$$

$$C + CO_2 \rightarrow 2CO \quad \Delta H = +172\ \text{kJ/mol} \tag{2}$$

An important gas phase reaction that goes along with the steam gasification process is the water gas shift reaction described in Eq (3) [18].

$$CO + H_2O \rightarrow CO_2 + H_2 \quad \Delta H = -41\ \text{kJ/mol} \tag{3}$$

As shown in Table 4, the syngas has a high LHV, which originates from the high hydrogen and methane content. Consequently, the

Table 2
Overview of the average steel gas characteristics [2,10,11].

parameter	unit	blast furnace gas	coke oven gas	basic oxygen furnace gas
CO	vol-%	22.15	6	60.9
H_2	vol-%	3.6	61	4.3
CO_2	vol-%	22.45	2	17.2
N_2	vol-%	51.8	2	15.5
CH_4	vol-%	0	25	0.1
C_xH_y	vol-%	0	4	0
LHV	kJ/Nm^3	3266	18,055	8184
	kWh/Nm^3	0.91	5.02	2.27
specific emission value	t_{CO2}/GJ_{LHV}	0.2681	0.0485	0.1823

syngas is suitable for methanation and as a substitute fuel.

The product gas of the biomass gasification plant used in the scenarios, was either only syngas or syngas combined with the exhaust gas of the combustion reactor. For the scenarios where the exhaust gas was part of the product gas, a 100% CO_2 content is predicted.

For more information on dual fluidised bed gasification see the following review [20].

2.2.2. Electrolyser

In a water electrolyser, water is split into hydrogen and oxygen through a redox reaction. The total reaction is described in Eq (4) [21].

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2 \tag{4}$$

The partial reactions of the redox reaction vary depending on the electrolyser construction. Currently three main types of electrolysers are available, the alkaline electrolyser cell (AEC), the proton exchange membrane electrolyser cell (PEMEC), and the solid oxide electrolyser cell (SOEC). For this paper, a PEMEC, described below, was used for the gas greening route.

A PEMEC uses a proton conducting membrane as electrolyte, which also separates the anode and cathode area. The water enters and the oxygen leaves the system at the anode side, while the hydrogen leaves the system at the cathode side. H^+ ions are exchanged through the polymer membrane [15,22].

The material used for the membrane is usually a perfluorosulfonic acid polymer (e.g. Nafion). PEMEC is commonly operated within temperatures of 60 °C–90 °C [23].

The partial reactions are described in Eq (5) and Eq (6).

Anode reaction:

$$2H_2O \rightarrow 4H^+ + O_2 + 4e^- \tag{5}$$

Cathode reaction:

$$4H^+ + 4e^- \rightarrow 2H_2 \tag{6}$$

Compared to AEC, PEMEC has higher cell efficiency, higher power density, and flexible operating conditions. However, the materials used for the system (e.g. platinum), its complexity, and later introduction have led to a higher capital expenditure (CAPEX) than AEC. Another disadvantage is its shorter lifetime compared to AEC. Further research is focusing on material optimization, reducing the complexity, and on scale-up, which should lead to a reduction of CAPEX [15].

For more information on electrolysers, see the review from Ref. [24].

2.2.3. Methanation

Methanation can be separated into chemical and biological methanation. Since biological methanation is only considered as an option for small scale plants, a chemical methanation was chosen for the system [25].

The methanation process is a catalytic exothermic gas reaction and therefore, the equilibrium can be influenced by increasing the pressure and shifting it to the product side. The main reactions are shown in Eq (7) and Eq (8) [25].

$$CO_2 + 4H_2 \rightleftharpoons CH_4 + 2H_2O \quad \Delta H = -165\ \text{kJ/mol} \tag{7}$$

$$CO + 3\,H_2 \rightleftharpoons CH_4 + H_2O \quad \Delta H = -206\ \text{kJ/mol} \tag{8}$$

For more information on catalytic methanation, see the review from Ref. [26].

3. Description of the scenarios

In order to get conclusive results for the years 2020, 2030, and 2050, six scenarios were analysed for each year. The scenarios 1 to 3 are extreme value scenarios, while scenarios 4 to 6 are limited by defined system boundaries representing constraints.

3.1. Extreme value scenarios

The extreme value scenarios were analysed to get results and relevant orders of magnitude for the potential of a biomass gasification and implementation of PtG into an integrated steel plant, as defined in Table 3. They aim for a potential overview, without any limitations in capacities of the different parts of the gas greening system. Further, in order to not distort either the biomass gasification plant nor the electrolyser, H_2 is produced equally by both. Additionally, this provides nearly equal powers for the two systems. In scenario 1, the fossil fuel based natural gas was replaced by SNG, without any overproduction, while the aim of scenarios 2 and 3 was a full conversion of the CO_x content of different steel gases by methanation to reach a maximum GHG emission reduction. Excess heat from gasification and methanation, as well as electricity from gasification and oxygen from electrolysis is utilized as revenue stream. Fig. 2 shows the scheme of the biomass gasification and PtG implementation with specific gas and water flows. As shown in Fig. 2, the product gas of the biomass gasification plant is used directly in the integrated steel plant as energy carrier. The COx and hydrogen streams are converted to synthetic methane in the methanation unit.The energy and mass balance of the gas greening system for scenarios 1–6 is summarised in Table 8.

3.1.1. Scenario 1: Full substitution of fossil fuel based natural gas with SNG produced by upgrading steel gases

In scenario 1 the fossil fuel based natural gas was substituted by SNG. The SNG was produced by methanation of the CO and CO_2 from the steel gases. Since it was found, that every steel gas alone could provide enough CO and CO_2 to produce sufficient SNG, the steel gas with the lowest heating value (i.e. the BF gas) was chosen for methanation to reach a maximum upgrade of the CO_x fraction.

3.1.2. Scenario 2: Maximum CO_x greening of the BF and BOF gases

This scenario aims for a maximum CO_x greening by methanising the BF and BOF gases. Since COG has a high heating value and not every integrated steel plant contains a coke oven, the COG was not taken into account for the gas greening route of this scenario.

3.1.3. Scenario 3: Maximum CO_x greening of all steel gases

To get results for the full potential of an integrated steel plant, scenario 3 aimed for a full CO_x greening throughout the process by capturing all CO and CO_2 contents of all occurring steel gases and methanising them to get SNG.

3.2. Constrained scenarios

The main limiting factor for the scenarios 4 to 6 was the power of the biomass gasification plant, which was set to a maximum nominal power of 105 MW_{th} with 8322 full load hours per year. This limitation was set due to a lack of installed capacity and experience in this technology segment and the potential availability of biomass fuel for plant operation in the anticipated central European location for the scenarios.

Scenario 4: Methanation of the hydrogen rich biomass gasification product gas.

Since the gasification product gas contains a high amount of H_2, this scenario focused on the biomass gasification potential of the

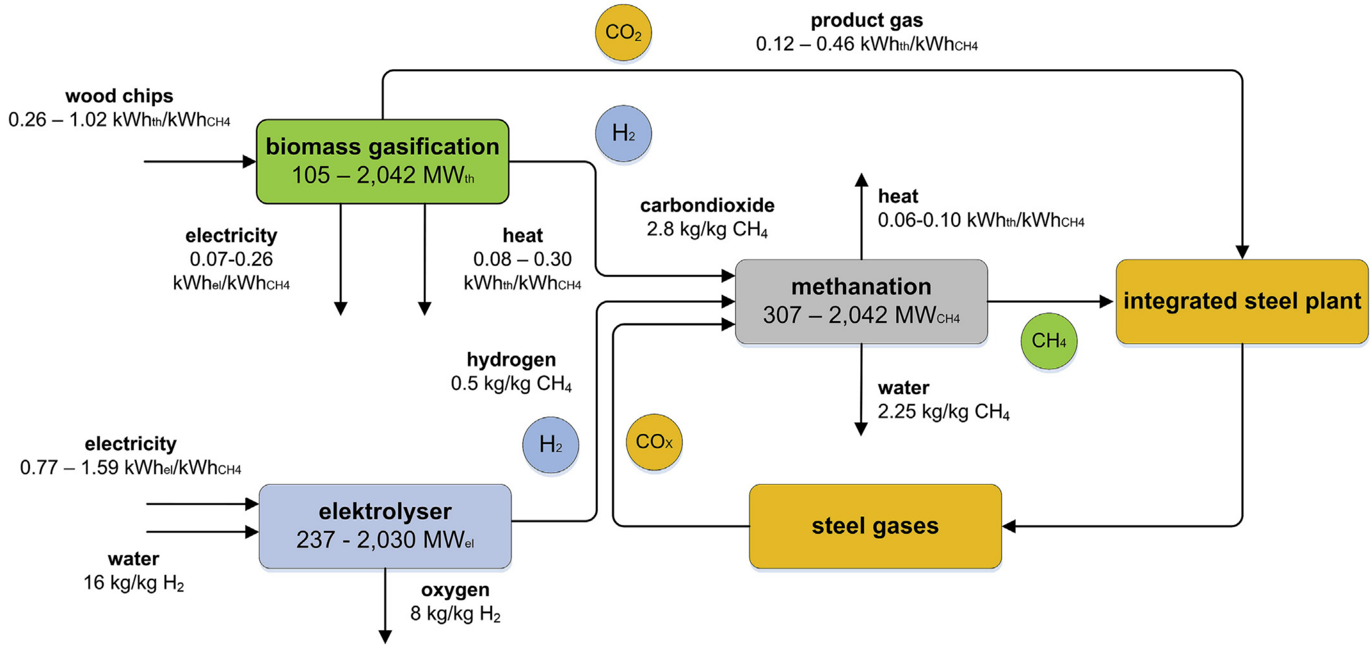

Fig. 2. Schematic of the extreme value scenarios (1–3) and of scenario 6
Scenario 1 and 6 uses BF gas, scenario 2 BF and BOF gas and scenario 3 BF gas, BOF gas and COG as steel gases.

105 MW_{th} plant. After gasification and gas cleaning, the product gas was upgraded by methanation. Due to the high amount of H_2 in the product gas, an extra source (i.e. electrolyser) was not necessary. Heat and electricity from the biomass gasification plant is utilized as revenue stream. Fig. 3 shows the basic scheme of the combined methanation and biomass gasification process for this scenario.

3.2.1. Scenario 5: Methanation of the CO_x content of the combustion reactor exhaust gas

As mentioned in section 2.2.1 the SER process with oxyfuel combustion (OxySER) was used for biomass gasification and to produce a nitrogen-free flue gas from the combustion reactor. Scenario 5 aimed at using the product gas of the gasification reactor directly as an energy carrier for the steel plant and the exhaust gas, which is presumed to only consist of CO_2, of the combustion reactor as CO_2 source for the methanation. The necessary H_2 was produced by the electrolysers only. To avoid separation of N_2 in the product and exhaust gas, an OxySER process was used. The oxygen needed for the OxySER process was provided by the by-product O_2 of the electrolysis. Heat and electricity from biomass gasification as well as the excess oxygen from electrolysis is sold. For further information on OxySER steam gasification, see the following review [16]. Fig. 4 shows an overview of the process.

3.2.2. Scenario 6: Full substitution of fossil fuel based natural gas with SNG by upgrading the BF gas and limiting the biomass gasification plant to 105 MW_{th}

This scenario is based on scenario 1. The SNG was produced by methanation using the CO_x content of the BF gas. The necessary H_2 was provided by the biomass gasification plant and the electrolysers. Since the biomass gasification plant was limited to 105 MW_{th}, the proportion of hydrogen produced by gasification was 14% while the electrolysers provided the remaining 86%. Fig. 2 shows an overview of the system.

4. Methodology

A techno-economic analysis was carried out for all scenarios by analysing the investment and specific production costs. Afterwards, all possible incomes and cost reductions due to CO_2 emission

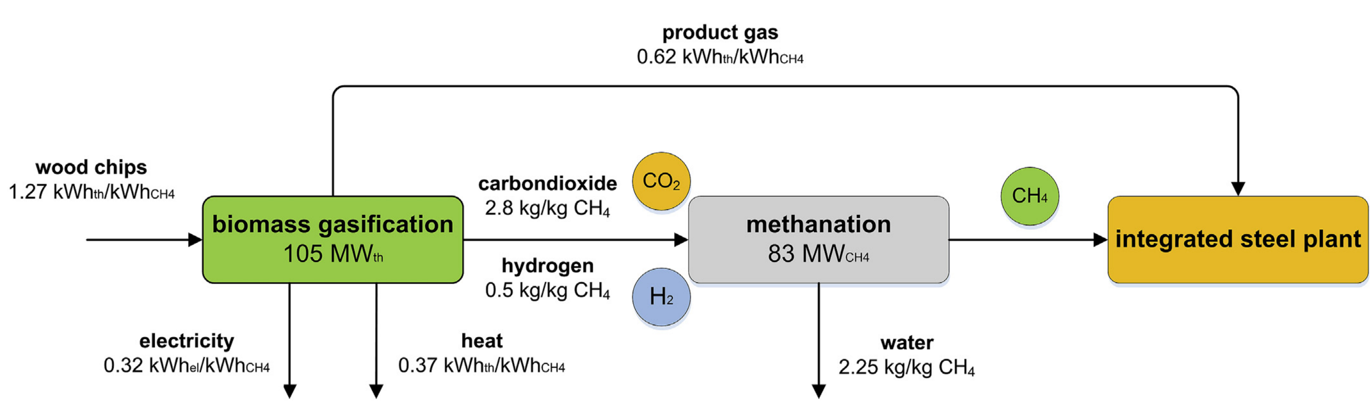

Fig. 3. Schematic and specific process parameters for scenario 4.

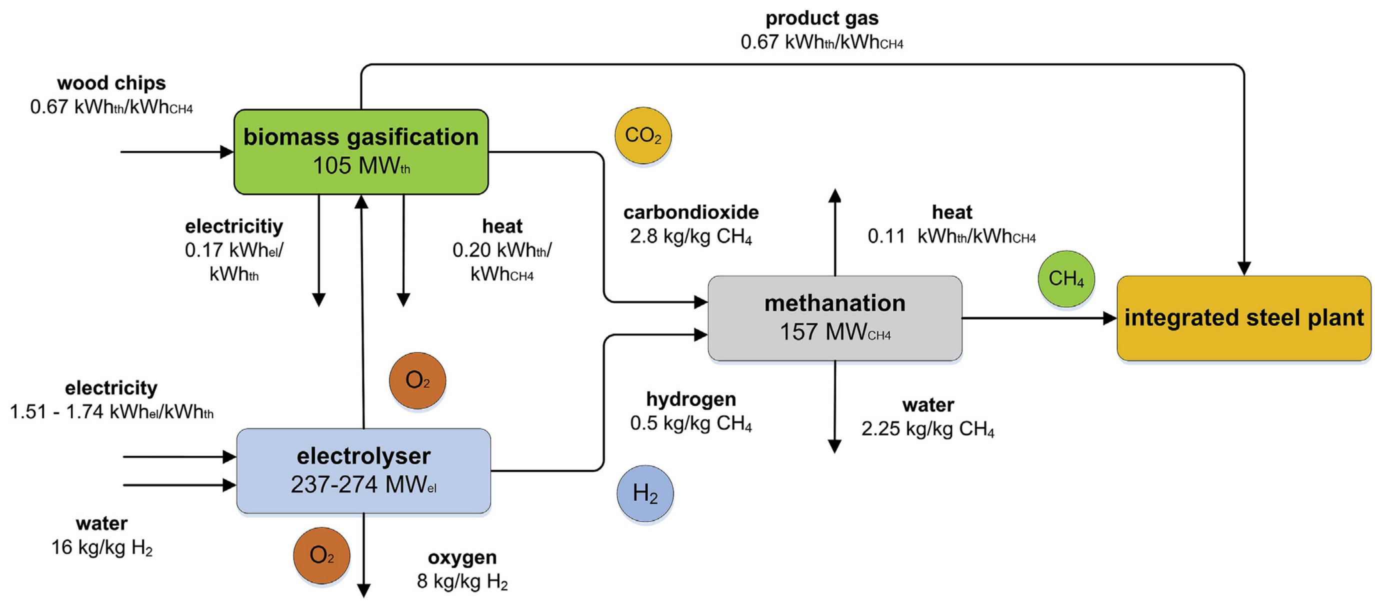

Fig. 4. Schematic and specific process parameters for scenario 5.

savings were determined. In the end, a sensitivity analysis was performed.

4.1. Investment costs

For analysing the specific production costs, the investment costs must be calculated. To do so, the scenarios mentioned in section 3 were modelled and the energy and mass flows were analysed. The investment costs data for the main components of the gas greening system are summarised in Table 5.

As shown in Table 5, Albrecht et al. [29] states a constant efficiency for methanation. However, since methanation is a key factor of the PtG system, Albrecht et al. [29] found a decrease in the CAPEX due to a high increase in installed capacities and technological learning effects. A rapid CAPEX reduction was assumed till 2050 assuming a high potential of PtG implementation in industry and electricity storage [31].

The same effect occurred when considering electrolysers. Since all PtX (Power-to-Gas, Power-to-Liquid, Power-to-Hydrogen, etc.) systems need electrolysers, a high cost reduction over the years due to an increase in installed capacities and a technological learning effect was stated by Ref. [28]. In contrast to methanation, a significant increase in efficiency due to research and development is expected for future installations.

Since biomass gasification is not a key part of all PtX systems, these cost reduction effects were not taken into account for the techno economic analysis of the biomass gasification plant. Following this assumption of the CAPEX, reductions for 2030 and 2050, as shown in Table 5, are more conservative.

The initial investment costs I_0 were calculated from Eq (9) [32].

$$I_0 = CAPEX*size \tag{9}$$

Additionally, a scaling factor with $x_f = 0.86$ [33], engineering costs with 15% of I_0 [34], and building costs with 20% of I_0 were assumed. The total investment costs I were calculated by summing the initial investment, the building, the planning, and other costs.

The scaling factor describes a cost reduction factor that reduces the specific costs for plant upscaling compared to the base scale. It is described in Eq (10) [35].

$$I_{new} = I_0 \left(\frac{Power_{new}}{Power_0}\right)^{x_f} \tag{10}$$

The annuity I_K of the investment costs was then calculated from Eq (11) [36].

$$I_K = I_{new}*a$$

with

$$a = \frac{(1+i)^n*i}{(1+i)^n - 1} \tag{11}$$

In Eq (11), n describes the years of operation and i the interest rate. The annuity was calculated with an interest rate of 5% [37].

Table 5
Data for the investment costs modelling of the main components.

		biomass gasification	electrolyser	methanation
base scale	MW	25	2	6.3
CAPEX 2020	€/kW	2400	1320[b]	660
CAPEX 2030	€/kW	2200[a]	650[b]	600
CAPEX 2050	€/kW	1900[a]	300[a]	233[a]
efficiency 2020	$\%_{LHV}$	37	68	83
efficiency 2030	$\%_{LHV}$	43[a]	71	83
efficiency 2050	$\%_{LHV}$	50[a]	75[a]	83[a]
lifetime	years	20	15	15
$OPEX_{pl}$ [c]	%	1.5[a]	1.5	2
source		[27]	[28]	[29]

[a] Assumption were made according to the data of [27–29] by using the learning curve method of the Store&GO project deliverable 7.5 [30].
[b] Based on the range given in Ref. [28] and adapted with values given from experts.
[c] Operational cost for operation, maintenance, tax, etc. in % of investment costs.

4.2. Operational costs

The operational costs (OPEX) consist of material costs and costs for operation, maintenance, tax, etc. The costs for operation, maintenance, tax, etc. were considered with the $OPEX_{pl}$ values mentioned in Table 5 and calculated as per Eq (12).

$$OPEX_{operation} = I_{new} * OPEX_{pl} \quad (12)$$

The material costs consist of electricity, wood chip, and water costs. Table 6 shows an overview of the assumed material costs.

The wood chip price for 2020 was assumed to be the same as 2018. The costs for 2030 and 2050 followed a linear extrapolation based on the historic trend of the wood chip prices in Austria. The water price was assumed to be constant for the investigated period.

4.3. Levelised cost of energy

The levelised cost of energy (LCOE) or specific costs describe the costs associated with the production of SNG. Factors like degradation, capacity, etc. over the plant lifetime are included in the LCOE. It was calculated from Eq (13), where $P_{SNG,y}$ describes the annual SNG production, y indicates the annual basis and n describes the number of years of operation [40].

$$LCOE = \frac{I_0 + \sum_{y=1}^{n} OPEX}{\sum_{y=1}^{n} P_{SNG,y}} \quad (13)$$

4.4. Sensitivity analysis

A sensitivity analysis was conducted for the most important cost factors stated in sections 4.1 and 4.2. The following factors were analysed for their impact on the specific production costs referring to the SNG production of the gas greening route:

- CAPEX for the electrolyser,
- CAPEX for the methanation,
- CAPEX for the biomass gasification plant,
- OPEX electricity and
- OPEX biomass fuel.

All factors were varied with ±25%, ±50%, ±75%, and ±100%. A sensitivity analysis for annual operational hours was not evaluated, since it is expected that the integrated steel plant is operated continuously on maximum full load hours.

4.5. Cost reduction potentials and incomes through side products

Besides the costs, there are several cost reduction and income potentials that must be considered. The possible cost reduction factor is the CO_2 certificate cost. Currently the *European Union Emission Trading System* do not provide a possibility to reduce CO_2 certificate relevant emissions by greening fossil CO_2, as long as the new produced gas has not the purpose of long-term storage. However, a reform of the *Emission Trading System* is crucial to reach climate goals [41]. Following, it could be possible to reduce necessary CO_2 certificate by utilising fossil CO_2 emission that are hardly reducible in steel plants in the near future and is therefore discussed in this section.

Since the European Union is intending to increase the CO_2 certificate price, the cost reduction potential is low for the 2020 analysis and high for 2050. However, since the CO_2 emissions are caused by natural gas as well as by the utilisation of steel gas, the CO_2 emissions caused by natural gas were calculated with an emission factor of 55.4 t_{CO2}/TJ_{CH4} [42].

Revenues from the sale of O_2, heat, and electricity were considered as income factors. Since several processes of the gas greening route may need O_2, only the surpluses were considered under the income factors. The electricity, however, was assumed to be completely sold, since it is produced from a biomass plant and therefore can attain a higher price compared to electricity from other sources. Table 7 shows the specific income or cost reduction for the considered factors.

As shown in Table 7, the CO_2 certificate price was varied for the considered years, while the incomes from electricity, heat, SNG, and oxygen were not. This follows from the assumption that the CO_2 certificate price rise has a larger impact on the overall system, while the change in electricity, heat, and oxygen prices should not influence the results in this order of magnitude.

5. Results and discussion

The following section compares the techno-economic aspects of the scenarios by using the energy and mass balances. Following from the techno-economic analysis, results of the sensitivity analysis and the CO_2 greening potential have been discussed.

5.1. Energy and mass balance

Table 8 provides the mass and energy values of the gas greening system for the analysed scenarios. It also presents the total energy balance, which describes the substitution rate of fossil fuel based natural gas by SNG and unused product gas for the defined steel plant (see Table 3). The power of the two most energy intensive plants of the gas greening system for the year 2050 is shown in Fig. 5.

Scenario 1 shows, that at least 220–275 MW power would be necessary, for both the biomass gasification plant as well as the electrolyser system, to fully substitute fossil fuel based natural gas (see Table 8 and Fig. 5). To produce the necessary amount of SNG, 496 million Nm^3 per year of the excess BF gas would be used. This corresponds to 13.6% of the excess BF gas. With this system, 221 Mio. Nm^3 SNG and 835 Mio. Nm^3 H_2 are produced throughout a year to fully substitute fossil natural gas. However, the necessary biomass gasification power of 275 MW_{th} would potentially impose logistic problems in sustainable wood chips supply.

For the extreme value scenarios 2 and 3, the energy and mass balance analysis demonstrates that a full CO_X utilisation by converting all steel gases to SNG is even higher and therefore not feasible due to the power requirements of the electrolyser and the biomass gasification. This is because a mid-sized steel plant would need at least 1.8 GW_{el} of electrolysis and 2 GW_{th} of biomass gasification power to fully green the BF and BOF gases (see Table 8 and Fig. 5).

The necessary amount of H_2 and therefore also the necessary capacitiesof the greening system are lower by using the H_2 rich COG. This originates from the high H_2 content of COG which is

Table 6
Material costs for the years 2020, 2030 and 2050.

		2020	2030	2050	source
electricity	€/MWh_{el}	50	70	80	[38]
wood chips	€/MWh_{th}	34	37	42	[39]
water	€/m^3	1.15			averaged water charges in the nine provincial capitals in Austria basis January 2018

Table 7
Income and cost reduction factors for the gas greening system.

income/cost reduction		2020	2030	2050	source
electricity	€/MWh_{el}	105			green electricity feed in tarif for large scale biomass in Austria basis January 2018
heat	€/MWh_{th}	55			av. energy price in the seven biggest district heating grids in Austria basis January 2018
oxygen	€/t_{O2}	50			average oxygen bottle price for industrial scale basis January 2018
CO_2 certificate	€/t_{CO2}	15	40	76	[43]

Table 8
Energy and mass balance of the gas greening system for scenarios 1 to 6.

	unit	scenario					
		# 1	# 2	# 3	# 4	# 5	# 6
electrolyser							
power electrolyser 2020	MW_{el}	273	2027	1988	0	274	641
power electrolyser 2030	MW_{el}	254	1883	1846	0	254	595
power electrolyser 2050	MW_{el}	237	1757	1723	0	237	555
hydrogen production	Mio. Nm^3/a	417	3098	3038	0	418	979
methanation							
power methanation	MW_{th}	307	2008	2042	83	157	404
methane production	Mio. Nm^3/a	211	1644	1673	33	95	302
biomass gasification plant							
power biomass gasification	MW_{th}	275	2042	2002	105	105	105
product gas production	Mio. Nm^3/a	580	4303	4219	222	222	222
steel gas usage							
BF gas	Mio. Nm^3/a	496	3639	3639	–	–	677
BOF gas	Mio. Nm^3/a	–	27	27	–	–	–
COG	Mio. Nm^3/a	–	–	110	–	–	–
Substitution potential [a]	**%**	**100**	**267**	**223**	**27**	**65**	**100**

[a] Includes the substitution of the fossil fuel based natural gas as well as the upgraded steel gases that are further missing as energy source for the power plant.

higher than necessary for the methanation of the CO_x content of the gas. The excess hydrogen can be used for methanation of the BOF and the BF gases. Following the necessary biomass gasification power, electrolyser power and therefore also the substitution potential of scenario 3 is lower than in scenario 2. However, even though the required power is lower than in scenario 2, the necessary electrolyser power of 1.7 GW_{el} and 2 GW_{th} is significantly higher compared to scenario 1 (see Table 8 and Fig. 5).

Further, the excess 10.3 TWh_{SNG} of scenario 2 and the excess 9.8 TWh_{SNG} in scenario 3 would still be considered as fossil according to current European legislative framework.

For the constrained scenarios 4 to 6, only 6 can substitute the full demand of fossil fuel based natural gas as shown in Table 8 and Fig. 5. This is due to the limiting factors in these scenarios as mentioned in section 3.2. It was found that Scenario 4 has no need for a H_2 production by electrolysis, since the H_2 content of the product gas of the biomass gasification plant is high enough to fully methanise the occurring CO_2 and CO components. However, the limited biomass gasification plant size results in a comparatively low substitution rate. Even though, scenario 4 was analysed to get the potential of the biomass gasification plant. As can be seen in Fig. 5 and Table 8, the biomass gasification plant on it's one has the potential to substitute up to 27% of fossil fuel based natural gas by green SNG. This would correspond to a SNG production of 0.3 MWh/a and a usage of 0.4 MWh/a of H_2 free product gas from gasification.

Scenario 5 is limited by the biomass gasification plant and its COx output as carbon carrier for methanation. As described in section 3.2.2, carbon source in this scenario is the exhaust gas of the combustion chamber of the dual fluidised bed reactor, while H_2 is supplied by electrolysis. Since biomass gasification is limited to 105 MWth, the produced SNG by methanizing the exhaust gas from the combustion chamber allows a production of 1.2 MWh_{SNG}/a which corresponds to a 65% substitution (see Fig. 5 and Table 8).

Scenario 6 gives the future potential of the gas greening system with constrained conditions by limiting the biomass gasification to 105 MWth and substituting 100% of the fossil fuel based natural

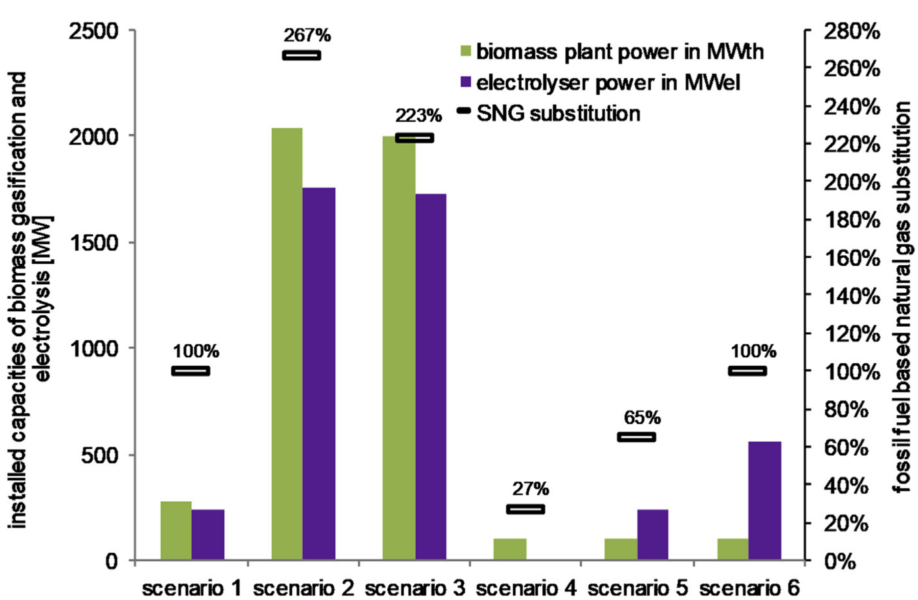

Fig. 5. Power overview of the biomass gasification plant and the electrolysers for the year 2050.

gas. Therefore, 14% of hydrogen demand is covered by gasification and the remaining 86% by electrolysis. The BF gas was used as a carbon carrier, since it has the highest specific GHG emission factor. In order to achieve complete substitution of fossil fuel based natural gas, 677 million Nm^3 per year of the BF gas was used for methanation, corresponding to 18.6% of the excess BF gas. This would lead to a production of 3.0 TWh SNG per year.

Since scenario 6 is the only scenario under constrained conditions that has the potential to cover the full demand of SNG this was chosen as the favorable scenario from an energy and mass flow perspective. Further, due to high predicted investments and potentials for PtG technologies it can be expected, that the 555 MW_{el} electrolyzer power needed to provide the H_2 from electrolysis as shown in Table 8 is reailizable till 2050 [44].

5.2. Techno-economic assessment

Fig. 6 gives detailed specific costs, incomes, and cost reduction potential of the SNG production based on the heating value of the produced SNG in $kWhCH_4$ for 2020, 2030, and 2050. The specific costs include the costs for electricity, water, biomass fuel, and annuities as well as operation, maintenance, and others. It also includes possible revenues by selling by-products and potential cost reduction by savings of CO_2 certificates. As presented in Fig. 6, scenario 4 has the lowest total specific costs since the main cost driver, the electricity needed for the electrolysis, is not considered. In fact, biomass gasification plants, unlike PtG systems, have already been implemented in commercial operation, e.g. GoBiGas in Gothenburg till 2018 [45]. The specific cost of producing hydrogen from biomass gasification is half as large as compared to electrolysis based on the considered cost structures in the scenarios. However, as shown in Fig. 5, scenario 4 also has the lowest fossil fuel based natural gas substitution rate at 27%. Therefore at least four 105 MWth biomass gasification plants would be necessary for producing the equivalent SNG in order to fully substitute fossil fuel based natural gas. Considering the high amount of biomass fuel needed for 400 MW installed capacity, the logistical costs would most likely lead to a significant rise in specific costs. Moreover, it can be expected that a full substitution of fossil fuel based natural gas through biomass gasification cannot be achieved in a sustainable way. Considering these aspects, scenario 4 is less suitable for application in a gas greening system as compared to the other constrained scenarios.

Comparing scenarios 1 to 3 with 5 and 6, 1 to 3 seem feasible considering only the techno-economic analysis. However, the comparatively low specific costs result from large plant sizes in the extreme value scenarios and therefore, from scaling factors that have a cost reducing effect on large plants (see Eq (10)). As presented in section 5.1, the required plant sizes would exceed common technical scales of the applied technologies and are therefore not feasible for implementation into an integrated steel plant, but bear potential for the time horizon of 2050.

Fig. 6 depicts that the major proportion of the costs for the extreme value scenarios and scenarios 5 and 6 are the electricity and biomass fuel costs. The shares of costs for the extreme value scenarios are ~30% biomass fuel costs and ~60% electricity costs. The constrained scenarios 5 and 6 are limited due to the biomass gasification plant. Further, the impact of electrolyser power compared to the biomass gasification power is higher in scenario 5 and 6 as in 1–3. It can be seen in Fig. 6 that this is due to the higher proportion of electricity costs as part of the specific costs as compared to the biomass fuel. For scenario 5, the share is between 70% and 75% for electricity and around 15% for biomass fuel for the analysed years. Scenario 6 has an even higher proportion of electrolyser power compared to the biomass gasification power. This leads to a cost share of up to 87% electricity costs and <1% biomass fuel costs for the year 2050.

However, as compared to scenarios 1 to 3, 5 and 6 show that the combined electricity and biomass fuel costs are at ~90% of the total specific costs. Scenario 4 can be considered as an outlier as it has a biomass fuel share of 60%–70% of the specific cost factors. This originates from the left out electrolyser unit, which leads to a low substitution rate and to lower specific costs since electricity is the main cost driver. As can be seen in Fig. 6, income potentials include cost reduction due to lower CO_2 emissions as well as the income from selling by-products. Throughout all scenarios in 2020, the income from selling side products exceeds the cost reduction potential due to lower emissions, while in 2050 the exact opposite happens. This follows the assumption that due to a need for a massive reduction of CO_2 emissions till 2050, the CO_2 certificate price will rise to an estimated 76 €/t_{CO2}, based on literature, in 2050 as compared to the 15 €/t_{CO2} in 2020.

Since no data of real steel works were available, possible additional system technologies that would be necessary due to steel gas cleaning for the gas greening system were not considered. Further, the appearance and composition of steel gases are plant specific and can therefore vary significantly between plants with the same production capacity.

5.3. Sensitivity analysis

A sensitivity analysis was conducted to investigate the influence of different cost factors on the specific costs.

5.3.1. Extreme value scenarios

As can be seen in Fig. 7, the extreme value scenarios show similar trends upon varying the parameters. The variation of OPEX for electricity has the highest impact on the sensitivity of all extreme value scenarios. This is due to the high share of electricity costs and high demand of electricity that are already mentioned in the previous sections. Biomass fuel has the second biggest impact on variations in OPEX. Both variations have nearly the same effect throughout the analysed years.

However, variation in CAPEX reveals a different trend. While the CAPEX variation of methanation has no significant impact on the generation costs for SNG throughout the analysed years, the CAPEX of the biomass gasification plant does have an impact. Also, while the CAPEX variation of the electrolyser has a significant impact in 2020, it has no significant impact in 2050. This follows from the assumption that the CAPEX of the electrolysers will sink significantly throughout the years due to technological improvements and market development. However, this significant CAPEX reduction is not expected to happen for the biomass gasification plant, which explains its impact on the sensitivity analysis for each year.

5.3.2. Constrained scenarios

As shown in Fig. 8, scenario 4 is a special case due to the exclusion of the electrolyser system. Following, the only factors influencing the sensitivity analysis of this scenario is the CAPEX variation of the biomass gasification plant as well as the OPEX of the biomass fuel.

However, following the variations in the parameters, as shown in Fig. 8, there is a difference between the sensitivity analyses of the analysed years. While the impact of the OPEX variation is nearly constant for the analysed years, the impact of the CAPEX variation decreases over the years. This is caused by learning effects, and therefore leads to a decrease in CAPEX over the years (see Table 5).

Since the systems in scenarios 5 and 6 have a high electrolyser

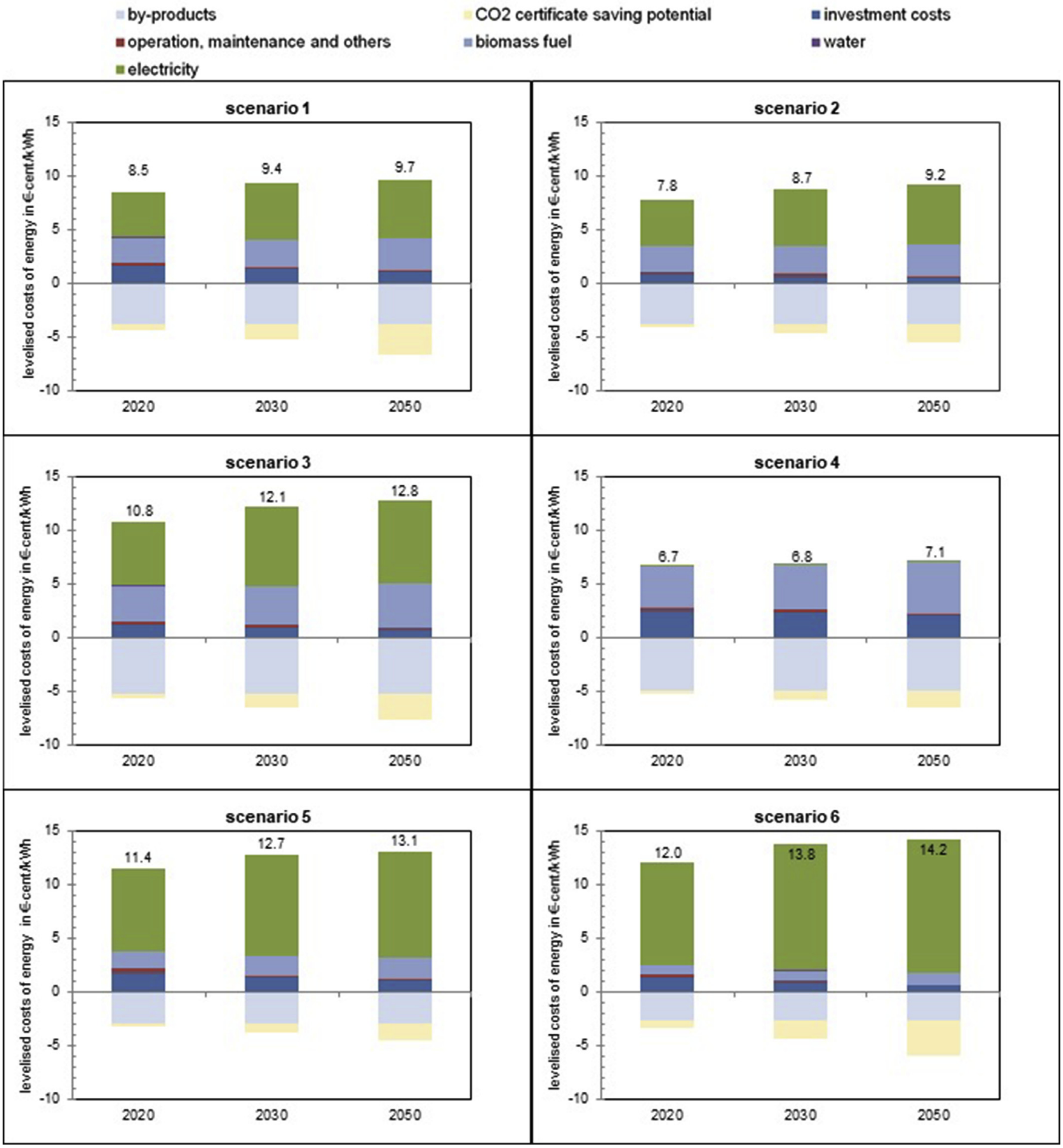

Fig. 6. Detailed levelised costs of energy for the scenarios 1 to 6 for the years 2020, 2030 and 2050.

power as compared to the biomass gasification plant power, with up to ±80% variability in the specific costs, variation in OPEX of electricity has the most significant impact on the sensitivity analysis, as shown in Fig. 9. This is in contrast to scenarios 1 to 3 where the CAPEX variation for the different plants as well as the OPEX variation of the biomass fuel had no significant impact for the analysed years.

5.4. CO_2 greening potential

As shown in Fig. 6, there is potential significant cost reduction due to savings from CO_2 emission greening, provided that the electricity used for the electrolysers comes from renewable energy sources and the regulations on emission trading significantly change from the status quo. Depending on the scenario, it is possible to green CO_2 emissions by substituting fossil fuel based

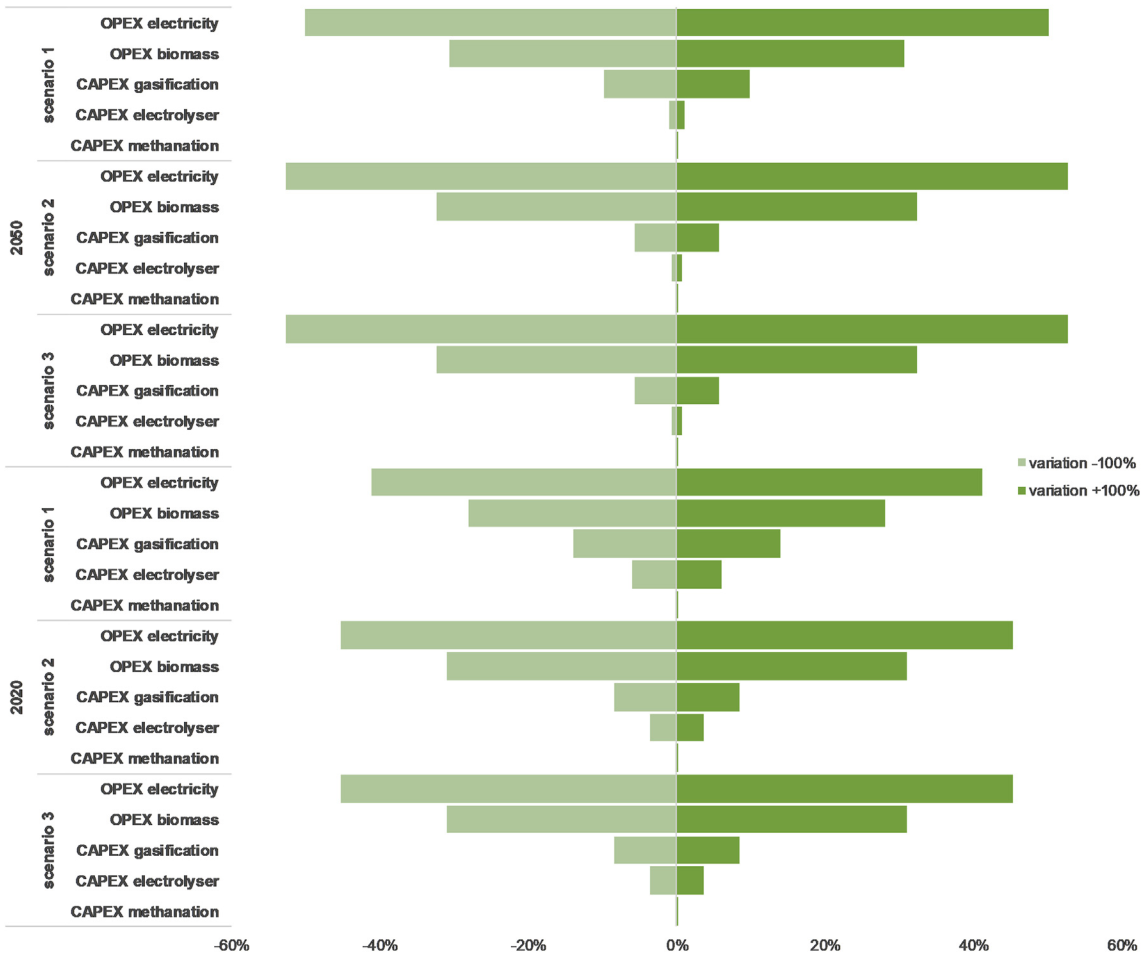

Fig. 7. Sensitivity analysis for the scenarios 1 to 3 for the year 2020 and 2050.

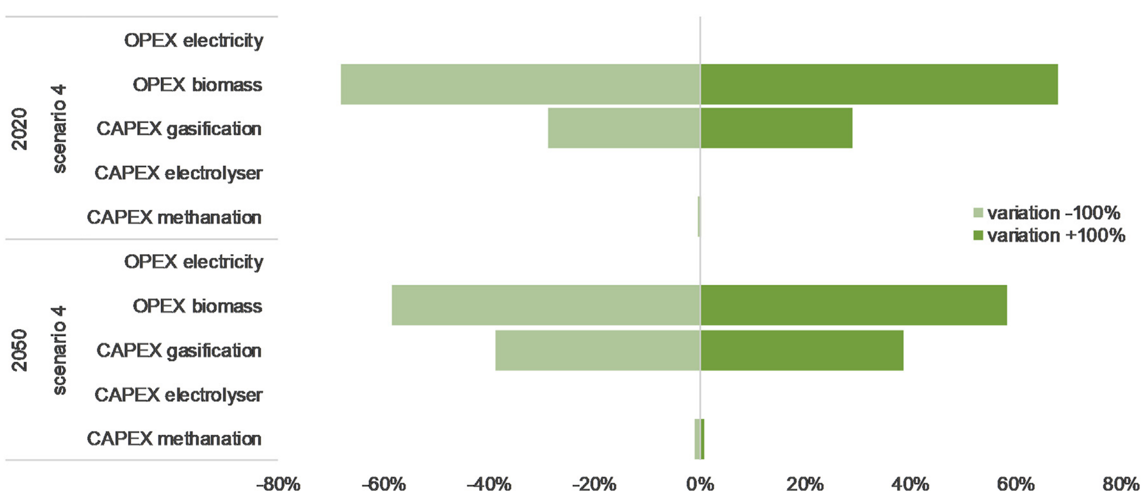

Fig. 8. Sensitivity analysis for the scenarios 4 for the year 2020 and 2050.

natural gas with a greener SNG as well as by greening the steel gas emissions. Fig. 10 presents the possible CO_2 emission greening for different scenarios.

As can be seen, the extreme value scenarios have the highest greening potential with up to 4.1 Mt_{CO2} per year. This follows, from the assumption of upgrading the entire steel gases, without any limitation.

The scenarios 4 and 5, on the contrary, green CO_2 emission by just 0.3 to 0.4 Mt_{CO2} per year. This is due to the low substitution rate of 27% for scenario 4 and 65% for scenario 5, as given in Table 8, and due to the non-utilisation of steel gases. However, these scenarios reflect effective reductions as the COx input for methanation originates from biogenic sources.

Scenario 6 has a slightly higher CO_2 greening potential than

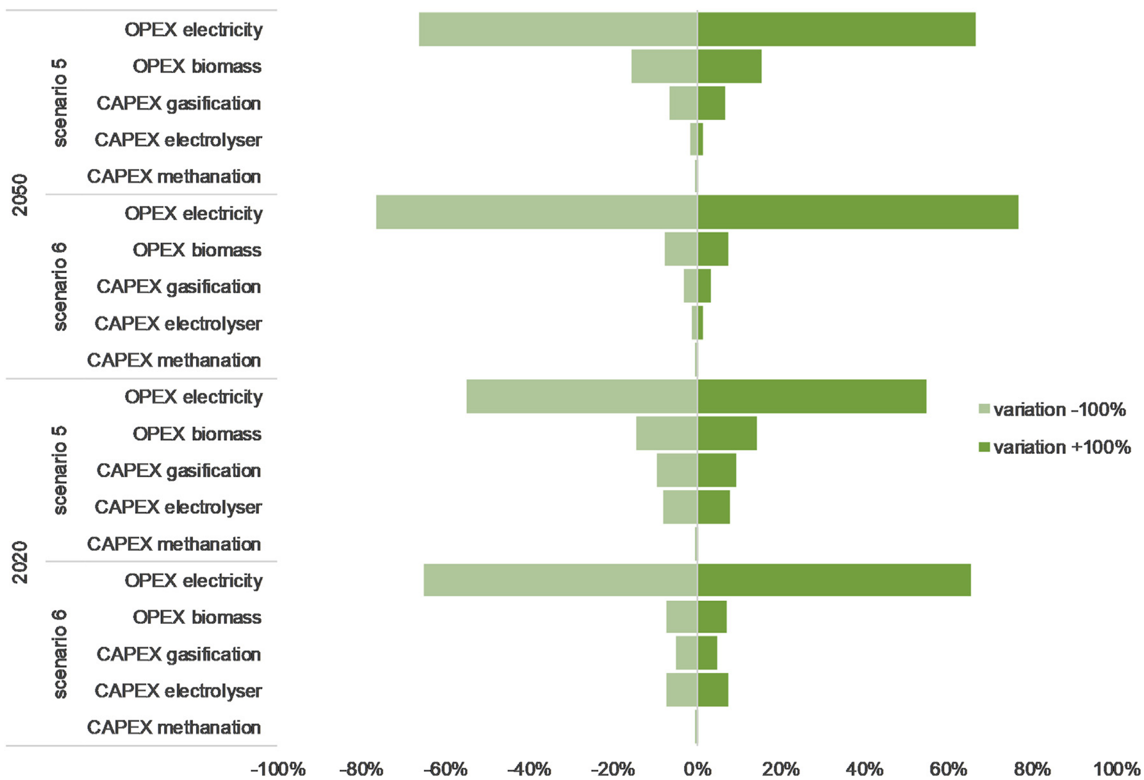

Fig. 9. Sensitivity Analysis for the scenarios 5 and 6 for the year 2020 and 2050.

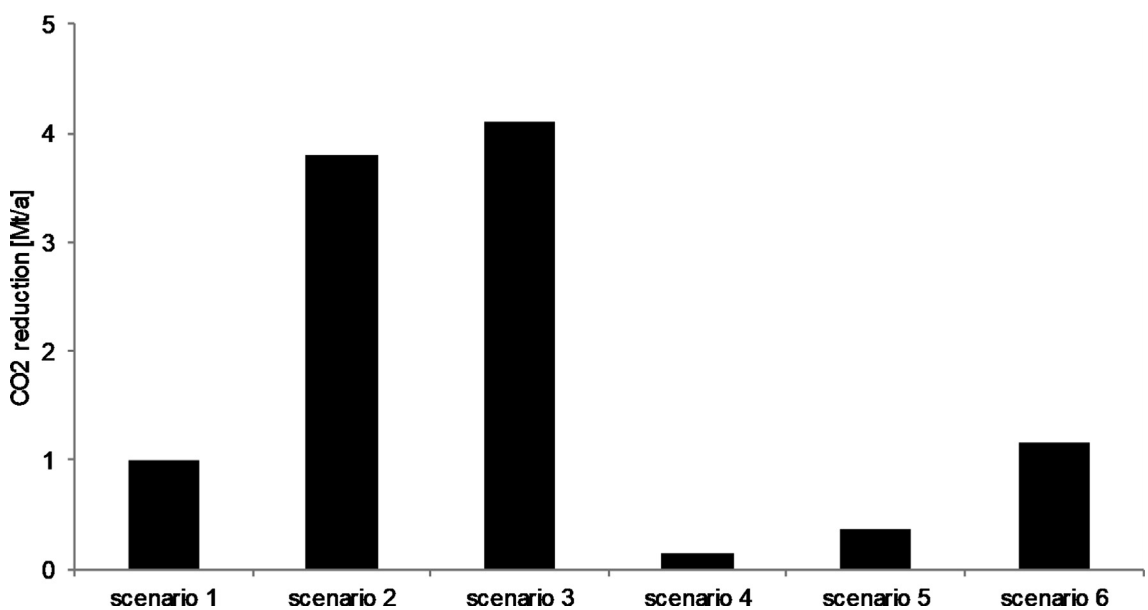

Fig. 10. Overview of the CO_2 greening potentials of the analysed scenarios.

scenario 1 due to higher BF gas usage on account of a smaller biomass gasification plant. Compared to scenario 1, scenario 6 uses three percentage points more of the available BF gas for the SNG production.

6. Conclusion and outlook

Six scenarios were analysed to gather information about a potential gas greening system for an integrated steel plant. It was shown that a combined biomass gasification and PtG system has a high theoretical CO_2 greening potential of up to 4.1 Mt per year for the emission-heavy steel production, if regulations are changed as mentioned before. However, as long as the captured CO_2 comes from fossil fuels and fossil carbon is the primary energy source with "delayed" release of CO_2 into the atmosphere, detailed assessments would be required to calculate actual CO_2 savings. A CO_2-neutral energy source is only achieved when the electrical input power and absorbed CO_2 originates from renewable sources. Furthermore, the amount of electrical power and biomass necessary for a greening of 4.1 Mt would exceed the technical possibilities many times.

Since a biomass gasification plant of 105 MW_{th} seems realisable and reasonable in the medium term, scenario 4 was identified as the most promising constrained scenario for an industrial implementation of the system among the evaluated ones from the technoeconomic point of view. This was justified from the fact that its specific costs can be up to half of the specific costs of other scenarios. From the mass and energy balance and the CO_2 greening perspective, scenario 6 was favorable. This results from its high greening rate compared to the other constrained scenarios and since it is the only constrained scenario, capable of fully substitute fossil based natural gas. However, since the CO_2 reduction in scenario 6 is 20% when comparing to the total CO_2 emissions of the steel gases and the fossil fuel based natural gas (see Fig. 10) and below 20% when considering the whole steel plant emissions, other emission reduction options will be necessary to reach the climate goals. Therefore, SNG and hydrogen could be used as reduction agents and could be an alternative for the emission-heavy coking process [46].

As per the techno-economic assessment, if the two gas greening options, biomass gasification and water electrolysis via renewable electricity input, are benchmarked against each other for providing hydrogen as an upgrading agent for CO_x rich gases from steel plants, biomass gasification is more feasible due to lower specific costs based on the evaluated scenarios. However, supplying a sustainable biomass feedstock to fuel the enormous capacities is a major constraint.

The comparison with the fossil fuel based natural gas prices shows that the specific production costs of SNG from the gas greening system are significantly higher in most of the presented cases. The presented values are specific production costs and the real market prices of SNG could be much higher in many cases due to various taxes or dues. Nevertheless, a change in regulations could shift the balance in favour of SNG.

The analysis demonstrates that a techno-economic improvement as well as a higher CO_2 greening can be achieved by a larger system scale. However, since electricity cost is the main cost driver and since it is expected that electricity will be more expensive in the future, improvements in system efficiency could have a large impact on the techno economic feasibility. Therefore, further improvements on electrolyser and biomass gasification technologies could reduce the specific costs.

To be more specific, the anticipated PEMEC could potentially be replaced by the SOEC since it provides a higher efficiency, particularly if high thermal integration of high temperature electrolysis and methanation is considered. Additional performance gains can be expected by co-electrolysis of H_2O and CO_2 with SOEC [47,48]. The biomass gasification plant could be improved by changing operating conditions, for example by changing the bed material to a catalytically active one. This could lead to a higher hydrogen content in the product gas, higher product gas yield due to improved reaction rates and therefore to a reduced electrolyser power requirement [49].

Besides improving the efficiency of the system to lower the specific costs, a change in existing regulations and markets, especially in terms of emission trading, structures could influence the economic feasibility of the presented process in a positive way.

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