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Next generation cogeneration system for industry – Combined heat and fuel plant using biomass resources

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HIGHLIGHTS

- A cogeneration system producing biofuels, heat and electricity is investigated.
- By-product CO_2 of biogenic origin is captured and sequestrated or seasonally stored.
- Stored CO_2 is used in co-electrolyser for storage of surplus renewable electricity.
- Performance of cogeneration system is compared with oil, natural gas and wood boilers.
- Cogeneration system avoids fossil carbon emissions and may have negative heat price.

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ABSTRACT

The requirement for sustainable development has prompted the researchers to explore solutions for better utilization of renewable energy resources in the future. Biomass is a promising resource and it can be converted to multiple products and services including fuels, chemicals, heat and electricity via different conversion routes. Hence, replacement of fossil-based services with biomass-based services is critical to mitigate fossil CO_2 emissions, and innovative design of new and efficient energy conversion systems is necessary. Different industries need heat for their operations at different temperature levels. Today, these demands are satisfied using conventional natural gas boilers by imposing a CO_2 tax to account for their emissions. In this study, we discuss the potential of replacing conventional boilers with a combined heat and fuel (CHF) plant design which utilizes lignocellulosic biomass in thermochemical conversion to generate heat for different industrial sectors together with biofuels cogeneration. Heat is generated due to the exothermic nature of the thermochemical conversion processes that operate at high temperatures. Gasification process produces syngas which is converted into fuels such as synthetic natural gas, Fischer-Tropsch crude, methanol and dimethyl ether and electricity. Different scenarios are evaluated considering the CO_2 produced via this system is either released, sequestrated, or stored and used in a co-electrolysis unit in which surplus renewable electricity available during summer is converted into additional syngas. A parametric analysis has been performed considering type and size of plants, CO_2 tax, and purchase and transportation costs of wood to compare the price of heat for the industrial sectors. Natural gas and wood boilers are used as the basis to calculate the breakeven CO_2 tax values for the same heat prices for the proposed CHF systems. The results of this study present a state-of-the-art renewable energy system as an alternative to conventional boilers.

1. Introduction

Today's research community is focusing on a future world without fossil resources due to the undesired rates of emissions, diminishing fossil reserves, uncertainties in energy supplies, rising demand for power, heat, transportation fuels and raw products together with the need for sustainable economic growth. Measures such as energy and resource efficiency and rapid development and market introduction of renewable energies especially in industrial sector are possible solutions to achieve a sustainable future. Biomass as a renewable carbon source has a big role to play in this context. It can be used in the manufacturing process of all carbon-based products, including liquid hydrocarbon fuels to

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replace fossil-based products and services (Henrich et al., 2015). Combined production of heat, electricity, and transportation fuels from biomass creates promising opportunity to satisfy part of their corresponding markets (Fahlén and Ahlgren, 2009).

Industrial heat demand constitutes two-thirds of industrial energy demand and one-fifth of global energy consumption, and is directly related to the most of the industrial CO_2 emissions as the majority of industrial heat is provided via fossil-fuel combustion (Conti et al., 2016). Within the global industrial heat demand growth, the corresponding CO_2 emissions is estimated to account for a quarter of global emissions by 2040 (Bellevrat and West, 2018). In Europe, industries consume 25% of input energy for heat production, for which they use electricity and natural gas are their primary energy suppliers. Combined heat and power (CHP) plants are quite common to provide heat (Werner, 2006).

Since many industrial processes require high temperature heat, many renewable heat technologies are limited by temperature barrier. Solar collectors or geothermal sources can provide low temperature heat and are limited by geological location. Electricity can also be converted into heat via different technologies such as heat pumps that can provide low temperature heat for residential heating (Naegler et al., 2015). As a renewable energy source, biomass combustion systems are capable of providing high temperature process heat but they are responsible for a significant portion of the exergy losses in the overall system (Woudstra and van der Stelt, 2003).

Biomass conversion via gasification may be the key to satisfy the heat demand at different temperature levels while enhancing the efficient use of limited biomass resources. The gasification process generates excess heat when producer gas is cooled down after the gasification stage. It is also possible to recover more surplus heat via extensive heat integration methods (Egeskog et al., 2009; Gassner, 2010). Excess heat from gasification can be used in many different ways; for electricity production via gas or steam turbine, for process integration with biochemical production process, for biomass drying, and for integration with an energy-intensive industrial site (Holmgren, 2015). Different configurations provide different amounts of heat and exhibit different CO_2 emissions.

Damartzis and Zabaniotou (2011) have reviewed the studies on the integrated design of biomass gasification processes to produce different biofuels by considering their energetic performance and CO_2 emissions. Caliandro et al. (2014) and Sharma et al. (2017) analyzed the potential of producing electricity using woody biomass in an integrated gasification and solid oxide fuel cell – gas turbine (SOFC-GT) hybrid system. Pihl et al. (2010) showed a hybrid structure where existing combined cycle gas turbine (CCGT) and fluidized bed (FB) gasifier are combined with a steam cycle integration. Gassner (2010) proposed an integrated system in which woody biomass is converted to SNG (synthetic natural gas) and the excess heat is used to produce electricity considering different options for carbon capture and sequestration (CCS). Their work showed that in the presence of surplus electricity during summer, integration of electrolysis unit results in higher profit for the conversion of wood into SNG.

Many studies considered the heat integration between a gasification plant within a pulp and paper mill (Consonni et al., 2009; Isaksson et al., 2012; Wetterlund et al., 2011; Andersson and Harvey, 2007). Some other studies focused on integrated biomass gasification systems with district heating system (Hannula and Kurkela, 2011; Huisman et al., 2011). Holmgren et al. (2016) investigated the gasification systems connected to the district heating systems of industrial clusters, producing biofuels and considering CCS. Werner (2006) performed an analysis to identify the potential of using cogeneration of biofuels and heat (CBH) in district heating in Europe.

A few studies considered the integration between gasification systems and the industrial clusters. Hackl and Harvey (2010) replaced a natural gas boiler of a chemical cluster site in Sweden with biomass gasification system. The concept showed that the cost and CO_2 emissions are improved when compared to stand-alone plants. Arvidsson et al. (2012) integrated SNG production via different gasification systems into an industrial cluster. The benefit of excess heat integration into the clusters' heat demand was explained, but economics and emissions were not investigated. Johansson et al. (2013) studied the integration of FT fuel via gasification pathway into an existing mineral oil refinery, and evaluated the performance in terms of economic and greenhouse gas emissions indicators.

CHP plants will no longer be attractive with the rapid energy transitions across Europe and the globe. Intermittent renewable power from wind and solar energy will shape future energy supply with their high shares. Therefore, surplus production of power will occur more often with increasing shares of variable renewable energy sources, that will increase energy storage requirements. Fuel storage systems and existing gas distribution networks are large and convenient facilities with proven and available technologies and it enables a seasonal storage of renewable energy (Sinn, 2017).

Biomass is a source of carbon for seasonal storage of surplus renewable electricity and has a potential to mitigate fossil CO_2 from industry. Literature review showed that overall system integration between biomass gasification, carbon capture and sequestration (CCS) and power to gas (P2G) concepts is not widely investigated aiming to supply industrial heat. The goal of this paper is to assess the possible replacement of conventional (oil, natural gas, and wood) boilers with a combined heat and fuel (CHF) plant in which biomass gasification technologies are used to cogenerate industrial heat and variety of fuels (synthetic natural gas (SNG), Fischer-Tropsch (FT) crude, methanol (MEOH) and dimethyl ether (DME)) and CO_2 as a side product. Different scenarios are evaluated considering the CO_2 produced via this system is either released to atmosphere, sequestrated, or stored and used in a co-electrolysis unit in which surplus renewable power is converted into more biofuel. Industrial heat prices are calculated assuming CO_2 reduction subsidies. A parametric sensitivity analysis is performed to investigate robustness of different scenarios to plant size, CO_2 tax and price of wood based on economics and potential CO_2 reduction. The heat market is dependent on multiple aspects such as primary energy supply, heat demands, heat carriers, prices of resources, plant investment and CO_2 tax. The current price of heat delivered from the conventional boilers is accounted as a basis for the calculation of breakeven CO_2 tax that should be imposed on conventional boiler heat.

2. Design methodology

The design methodology in this work is based upon building a process flow superstructure of different biomass-to-fuels thermochemical conversion pathways. This allows to assess different candidate technologies defined in the literature that includes the corresponding flowsheet models. For each possible technology, separate energy-flow, energy-integration, economic and LCA (life cycle assessment) models are developed, as outlined in (Gassner and Maréchal, 2009a). The energy-flow model provides the information about the chemical and physical conversions from feedstock to product, and their energy (heat and power) requirements are derived from mass and energy balances. The corresponding hot and cold streams are then used to build energy-integration model to compute the heat recovery potential in the system by using pinch analysis approach (Maréchal and

Kalitventzeff, 1998). Considering heat cascade constraints and material flows defined in the process, the minimum energy requirement and optimal utility system integration scheme is calculated with regard to minimum operating cost (Gassner and Maréchal, 2009a). The economic model includes operating and investment cost which is calculated for the preliminary sized process equipments considering the correlations in the literature (Turton, 2009; Ulrich and Vasudevan, 2003). In LCA model, each material and energy flows are associated to a LCI (life cycle impact) Ecoinvent unit process (Ecoinvent, 2018). The thermo-environomic model consists of all these models and provides necessary information for impact assessment and energy demand profile to solve the energy integration optimization problem. The overall problem is formulated as a Mixed-Integer Linear Programming (MILP) model that is implemented in LuaOSMOSE computational framework (Yoo et al., 2015).

3. Process description

3.1. Industrial heat demands by sector and quality

Different industrial sectors have different heat demands depending on their activities. The chemicals, food, minerals, pulp and paper and raw metals industries are the most heat demanding sectors (Kantor et al., 2018). Process heat can take up to 95% of total energy demand in some industrial sectors. Temperature quality for industrial heat demands is classified as high temperature (⩾400 °C), medium temperature (100–400 °C) and low temperature (⩽100 °C). Process operations such as melting, distillation, cracking, evaporation, and drying require heat at high and/or medium temperature, while low temperature heat is used for space heating and domestic hot water production. Food industry such as dairies and breweries, mainly requires low and medium temperature heat (pasteurization process around 80 °C, drying process around 260 °C) while pulp and paper industry requires medium temperature heat above 100 °C for washing processes. Production of plastic materials have a temperature level of 180–290 °C. High temperature heat demands mostly appear in chemicals, metals, and minerals production, reaching over 600 °C for chemical industry while steel production has furnaces operating above 800 °C and cement kilns operates around 1500 °C (Naegler et al., 2015; Kantor et al., 2018). High temperature heat demands in Europe has a share of 43%, while medium and low temperature demands accounts for 27% and 30%, respectively (Werner, 2006). Fig. 1 shows the final energy demand for process heating in industry by temperature level for Switzerland (Fleiter et al., 2017).

The usability of the heat can be expressed by the temperature at which the heat is available. There is opportunity to integrate biomass gasification process with heat-demanding industrial processes at high and medium temperature levels. Low temperature heat demand is not considered in this study where heat pumps exhibit better performance.

3.2. Typical boilers in industry

Boilers use variety of fuels including natural gas, oil, coal and other resources such as biomass (Garcia et al., 2012). Heat transfer occurs via heat carriers such as flue gases, air and water. Steam is widely used in industry to convey heat energy for process operations due to its excellent heat transfer properties, price and safety. Without it, industrial sectors could not perform as they do today since they have a high use of steam boiler. Based on the flow of the medium, boilers can be categorized into different types, such as fire-tube or water-tube steam boilers. Fire-tube boilers are ideally used to provide large and constant amount of steam. Water-tube steam boilers are widely used where steam demand and pressure requirements are high. They can provide very high steam temperature up to 650 °C. Fire-tube boilers have an economic advantage over water-tube boilers due to their relatively low cost (Fleiter et al., 2016). In Europe, natural gas has the highest share (70%) to fuel the steam boilers and is followed by oil (15%), electricity (10%) and biomass (5%). In spite of the low use of biomass fired boilers in Europe, some countries such as Denmark favors the use of biomass boilers and according to one report (Fleiter et al., 2016), biomass-fired boilers are becoming more competitive.

To define the problem scale, boilers used in the industry can be grouped according to their sizes: very small to small 1–5 MW_{th}, small to medium, 5–25 MW_{th} and medium to large 25–50 MW_{th} (Fleiter et al., 2016). According to the report from U.S. Office of Energy Efficiency and Renewable Energy, the average size of industrial boiler is around 10.5 MW_{th} (Energy and Environmental Analysis Inc., 2005). The chosen boiler sizes for this study are presented in Table 1. Steam boilers fired by natural gas combining different sizes are chosen as a representative proxy for the European boiler population (Fleiter et al., 2016). Fire-tube and packaged type of natural gas boilers operating at 15 bar are assumed to be the basis for this study, and the corresponding process model of the boiler is developed in the simulation environment. Other conventional boiler types such as wood and oil boilers are also studied in this study (Table 1). For the wood boiler model, air preheating is included where air inlet temperature to the wood boiler is assumed to be 25 °C lower than the temperature level at which heat is provided. The corresponding investment costs are calcu-

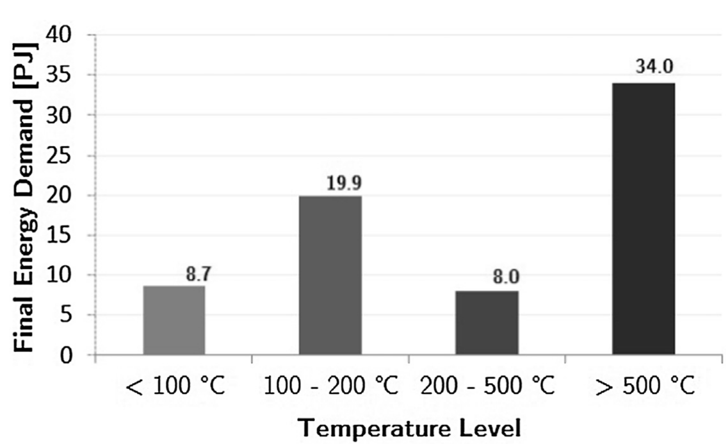


Fig. 1. Final energy demand for process heating in industry by temperature level for Switzerland in 2012 (adapted from Fleiter et al., 2017).

Table 1
Selected characteristics of common natural-gas, oil and wood boilers, adapted from (Fleiter et al., 2016).

Capacity [MW_{th}]	Scale	Thermal Efficiency [%]			Investment [x10^{-5}, CHF][a]		
		Natural Gas	Oil	Wood	Natural Gas	Oil	Wood
2.5	Very Small	91	92	85	2.23	1.90	8.94
7	Small	91	92	85	6.24	5.32	25.0
20	Medium	91	92	85	17.8	15.2	71.5
35	Large	91	92	85	31.2	26.6	125.2

[a] Authors' own calculation.

lated by using the equipment cost correlations for industrial steam boilers (Ulrich and Vasudevan, 2003) considering the boiler type, fuel, pressure and heat duty.

3.2.1. CO_2 tax on heating and process fuels

Switzerland has introduced CO_2 tax on the use of fossil fuels in heating and industrial process to promote more efficient use of fossil fuels and renewable energy sources. According to the working paper of Betz et al. (2015), the initial CO_2 tax was 12 CHF/ton of CO_2 in 2008, 60 CHF/ton of CO_2 in 2016. It has increased over time reaching 96 CHF/ton of CO_2 in 2018 with the current legislation. Maximum rate is put to 120 CHF/ton with the current legislation. This CO_2 levy corresponds to 0.215 CHF per kg of natural gas (0.0164 CHF/kWh) additional to the bare price of natural gas.

3.2.2. Surplus electricity availability during summer

Aiming long term reduction in CO_2 emissions, Swiss energy system is gradually transitioning into a system where the nuclear energy is ceased, and the dependency on fossil resources is cut down. The future energy scenario defined by the Swiss government in its Energy Strategy 2050 forecasts surplus electricity production during summer due to high penetration of renewable energy sources (RES) in the system. Around 4.9 TWh electricity has to be stored which corresponds to 7.7% of the annual production (Energyscope, 2018). For Germany, energy surpluses up to 154 TWh per year are predicted until 2050. This corresponds to about 20% of the German gross electricity production in 2012 (Thema et al., 2016). For the supply security, energy has to be balanced between periods with high renewable generation and low power demand and periods with low renewable generation and high demand (Sterner, 2009). Negative electricity prices have been allowed in the countries covered by the European Power Exchange (EPEX), i.e., France, Germany, Austria and Switzerland, in the countries covered by Nord Pool, i.e., Denmark, Estonia, Finland, Latvia, Lithuania, Norway, and Sweden, as well as in Belgium and the Netherlands (Steurer et al., 2017). Candra et al. (2018) claims that the higher the share of stochastic RES, the more often the price will be 0 EUR/MWh. The electricity market should be adapted to cope with large share of renewables and put subsidies for the price of electricity when there is an excess production (Pollitt and Anaya, 2016). Due to the high share of fluctuating generation capacities (RES), electricity prices will become more volatile. Moreover, extremely high and extremely low prices will occur. Extreme prices are electricity prices equal to/below 0 EUR/MWh and those above 100 EUR/MWh. The anticipated ratio between the two extremes will create new opportunities for market newcomers and new technologies, e.g. storage systems. Severe extreme prices can be anticipated in Europe from 2026 onwards (Perez-Linkenheil, 2019).

3.3. Process superstructure of biomass gasification pathways

The process modeling and simulations are performed using flowsheeting software Belsim VALI (Belsim, 2018). The lignocellulosic biomass resource used in the case study is the mixture of hardwood (57%) and softwood (43%) chips collected in Switzerland (Steubing et al., 2014). Characteristics of the woody biomass are shown in Table 2.

Fig. 2 shows the superstructure for the different configurations of combined heat and fuel plants. The main process conversion blocks are biomass pretreatment, gasification, syngas cleaning and processing, fuel synthesis and fuel upgrading. Depending on the synthesis reaction and the corresponding reactor technology, fuel upgrading consists of the production of different fuels such as SNG, FT fuels, MEOH and DME. Different technological options for each step are shown in Fig. 2, and more details about the process operating conditions are provided in Table 3.

Biomass pretreatment step has air drying and optional pyrolysis unit which can operate in order to reduce the heat for gasification. Torrefaction, a different type of pyrolysis, mainly couples with entrained flow type gasifier to reduce the electricity consumption for grinding of biomass to fine particles. Different gasification technologies such as atmospheric or pressurized circulated fluidized bed (CFB) and entrained flow (EF) with indirectly heated, steam-blown and directly-heated, steam-O_2 blown options are considered for the production of producer gas (syngas). Depending on the gasification technology, producer gas has different H_2/CO ratios which will be further processed to synthesize biofuels. Air drying, pyrolysis/torrefaction and gasification are endothermic processes requiring heat supply. Before the fuel synthesis, impurities such as tar, metals and sulfur in the producer gas are removed by cold gas cleaning, filter, and sand beds. Then, to meet the requirement for optimal reactant stoichiometry for the fuel synthesis reactions, the gas composition is altered by optional water-gas shift reaction (WGS), and CO_2 removal/capture units. The technologies considered for CO_2 capture are chemical absorption with monoethanolamine (MEA) and pressure swing adsorption (PSA). The off-gases and the solid carbon along the processing steps, including, if necessary, some fraction of producer gas are burnt to satisfy the heat demand of the thermochemical conversion pathway. In the superstructure, power recovery expansion turbines are also included for all gas streams with a pressure of 25 bar. These can contribute to a reduction of the electricity consumption in the thermochemical conversion pathways. Steam network is optimized for each CHF plant configuration using header, draw-off and condensation pressures as decision variables.

3.4. Approach for scenario development

In order to assess the performance of different scenarios of the integrated biomass gasification systems with multiple products,

Table 2
Characteristics of woody biomass.

Proximate Analysis		Ultimate Analysis	
LHV_{Wood}	18.6 MJ/kg_{dry}	C	51.1 wt%
Humidity	50 wt%	H	5.8 wt%
Ash content	0.6 wt%	O	42.9 wt%
		N	0.2 wt%

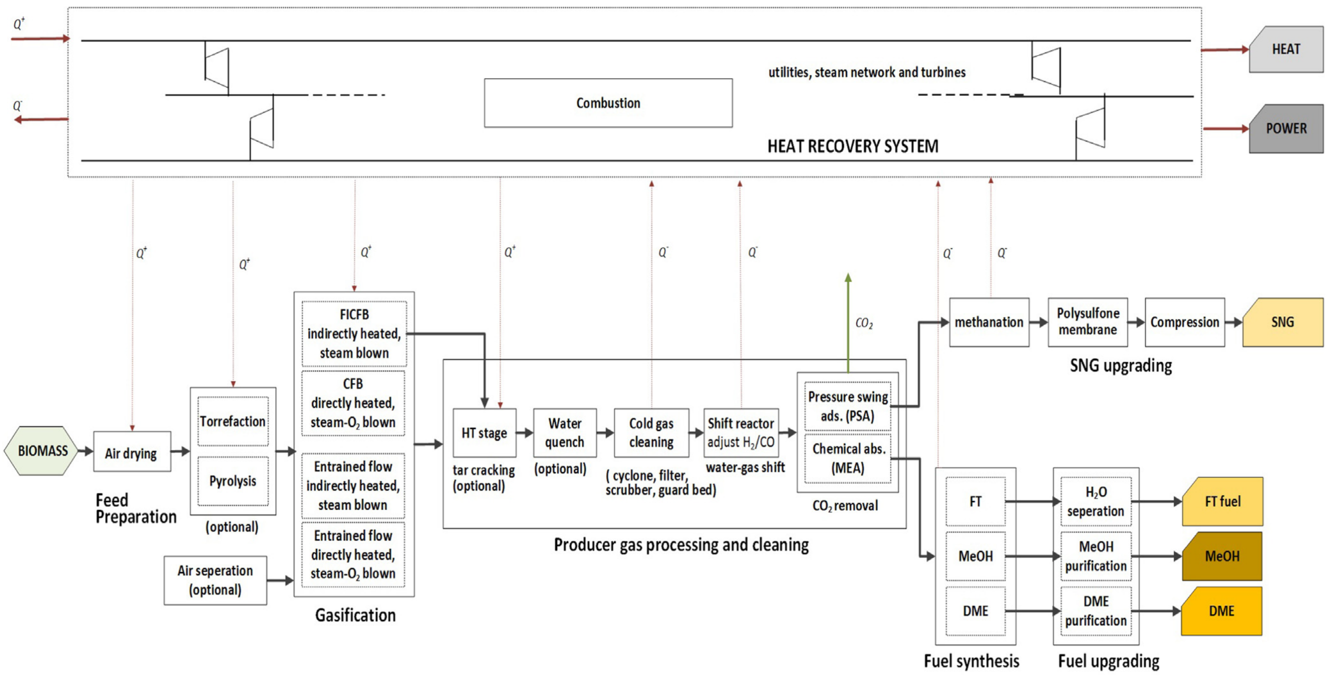


Fig. 2. Superstructure of biofuels production plants (dashed lines show investigated alternatives for different process steps).

system boundaries should be defined. The biomass gasification system has three inputs:

1. biomass,
2. investment cost of the proposed plant design,
3. electricity which can have three difference sources: (a) electricity purchased from the grid, (b) renewable electricity produced in the system as a co-product, and (c) renewable electricity from the grid which is produced in excess amount during summer season (price of electricity = 0 CHF/kWh).

The system outputs are:

1. the heat cogenerated at a certain temperature level (assumed to be at 200 °C),
2. the cogenerated biofuel: stored and distributed renewable energy,
3. the renewable electricity produced in the system as the co-product,
4. CO_2 in one of the following forms: (a) CO_2 released to atmosphere, (b) CO_2 captured and sequestrated, (c) CO_2 captured and stored in a pressurized tank to use in a co-electrolysis unit to produce more biofuel.

The process performance is measured by the cost of heat produced through the designed CHF system. The amount of heat is defined by the overall energy conversion efficiency and the quality of the process integration based on the selected energy conversion technologies. Four different CHF plant operation schemes are shown in Fig. 3.

To determine the thermodynamic performances of the proposed designs, chemical and overall energy efficiency terms are defined as shown in Eqs. (1) and (2), respectively:

$$\epsilon_{chem} = \frac{LHV_{Fuel} \cdot \dot{m}_{Fuel}}{LHV_{Wood} \cdot \dot{m}_{Wood}} \tag{1}$$

$$\epsilon_{tot} = \frac{LHV_{Fuel} \cdot \dot{m}_{Fuel} + \dot{E}^- + \dot{Q}^-_{Heat}}{LHV_{Wood} \cdot \dot{m}_{Wood} + \dot{E}^+} \tag{2}$$

where LHV is the lower heating value per unit mass (MJ/kg), $\dot{m}$ is the mass flow rate of the stream (kg/s), $\dot{Q}^-_{Heat}$ is the heat produced from the system (MW), and $\dot{E}^-$ (and $\dot{E}^+$) represents electric power consumed (produced) in the system (MW).

3.5. Cost of heat calculation

The calculation for cost of heat has the following elements: (1) investment cost of the proposed plant, (2) cost of wood, (3) operating cost, (4) revenues from biofuels and oxygen sell, and (5) costs related to CO_2.

$$c_{Heat} = \frac{c_{AI,Base} + c_{Wood,T} + c_{OP} - (c_{Fuel} + c_{O_2}) - c_{CO_2}}{\dot{Q}_{Heat}} \tag{3}$$

$$c_{Wood,T} = (c_{Transport} + c_{Wood}) \cdot \dot{Q}_{Wood} \cdot h \quad [\text{CHF/yr}] \tag{4}$$

$$c_{OP} = c_R + c_L + c_M \quad [\text{CHF/yr}] \tag{5}$$

where $c_{AI,Base}$ is the annualized investment cost in CHF/yr, and it represents the overall investment cost for case I, where only CHF plant is considered. $c_{Wood,T}$ is the total cost of wood resource in CHF/yr, which has two elements namely, cost of transportation ($c_{Transport}$) and market price of wood (c_{Wood}). For more details on the calculation of transportation cost of wood, see Appendix A.1. c_{OP} is the operational cost that includes: (1) c_R – cost of resources consumed during the plant operation, such as electricity purchased, water consumption and FAME consumption (only for SNG production) in CHF/yr, (2) c_L – labor costs in CHF/yr, and (3) c_M – annual operation and maintenance cost in CHF/yr. The maintenance cost of units is assumed to be 5% of the total investment cost per year. c_{Fuel} is the revenue generated by selling the biofuels in the market, and c_{O_2} is the revenue generated by selling the side product of co-electrolysis unit (i.e., oxygen) in the market. There are several elements related to costs of CO_2, as shown by following equations.

$$c_{CO_2} = c_{CO_2 emissions,local} - c_{CO_2 substitution} + c_{CO_2 sequestration} + c_{CO_2 storage} + c_{CO_2 co-electrolysis} \tag{6}$$

Table 3
Characteristics of biofuels production plants.

Section	Specification	SNG	FT	MEOH	DME
Drying	Technology	Air drying			
	Air inlet temperature [°C]	200			
	Wood outlet humidity [%]	20	10	30	25
Torrefaction	Temperature [°C]	–	250	–	–
Pyrolysis	Temperature [°C]	–	–	–	260
Gasification	Heating mode	Indirectly heated	Directly heated	Indirectly heated	Directly heated
	Gasification type	FICFB	EF	FICFB	CFB
	Temperature [°C]	850	1350	850	850
	Pressure [bar]	1	30	25	1
	Agent	Steam	Steam-O_2	Steam	Steam-O_2
	Steam preheat T [°C]	300	400	450	400
	Steam to biomass ratio	0.5	0.6	0.38	0.6
Air seperation	Technology	–	Cryogenic distillation	–	–
	Energy consumption [kJ/kg O_2]	–	1080	–	–
Tar cracking	HTS temperature [°C]	–	1350	1350	950
	HTS heating mode	–	Directly heated	Directly heated	Directly heated
Water quench	Temperature [°C]	–	750	–	–
Gas cleaning	Filter temperature [°C]	150			
	Filter pressure drop [mbar]	100			
	Flash temperature [°C]	25			
Water gas shift	Temperature [°C]	200	300	312.7	443.1
CO_2 removal	Technology	TSA & PSA	MEA[a]		
	Amount CO_2 removed	95%			
Synthesis	Technology	Internally cooled Fluidized bed reactor	Multi-tubular, Fixed bed reactor	Multi-stage Fixed bed reactor	Slurry phase Reactor
	Catalyst	Ni/Al_2O_3	$Co/Zr/SiO_2$	$Cu/ZnO/Al_2O_3$	ACZ & HZSM-5
	Temperature [°C]	320	220	315	277
	Pressure [bar]	5	25	85	50
Upgrading	Technology	Polysulfone membrane for H_2 sep., compression	Private data	Flash, distillation (2x)	Flash, distillation (3x)
Fuel specifications		96 vol% 25 °C, 50 bar	Liquid fuels 25 °C, 1 bar	99.4 vol.% 25 °C, 1 bar	99.88 vol% 25 °C, 1 bar
Steam Network	Header pressures [bar]	70	115.4	56	110, 45
	Super-heating ΔT [°C]	274	200	200	250, 200
	Draw-off pressures [bar]	16.69, 6.02, 1.95	15, 8, 2.3	17, 6.5, 2.8	17, 6.3, 1.98
	Condensation pressure [bar]	0.03	0.07	0.02	0.07
Adapted source		Gassner and Maréchal (2009b)	Peduzzi (2015)	Tock et al. (2010)	Tock et al. (2010)

[a] For MEA absorption, reboiler heat demand is fixed at 3.3 MJ/kg CO_2 separated at 150 °C, 20% of the heat duty is recoverable between 90 °C to 40 °C. Electricity consumption is fixed at 25 kJ/kg CO_2 (Heyne and Harvey, 2014).

$$c_{CO_2 sequestration} = c_{CO_2 inv,sequestration} + c_{CO_2 op,sequestration} - c_{CO_2 avoidance,sequestration} \tag{7}$$

$$c_{CO_2 storage} = c_{CO_2 inv,storage} + c_{CO_2 op,storage} \tag{8}$$

$$c_{CO_2 co-electrolysis} = c_{CO_2 inv,co-electrolysis} \tag{9}$$

where (1) $c_{CO_2 emissions,local}$ represents local CO_2 emissions tax due to the plant operation, (2) $c_{CO_2 substitution}$ is tax benefit due to CO_2 avoided via substitution of fossil fuels by biofuels (local CO_2 tax is imposed on the fuels from fossil resources, both on fossil fuel production and use phase). For the substitution of biofuels with fossil fuels, it is assumed that 1 unit of SNG substitutes 1 unit of NG, 1 unit of FT fuels substitutes 1 unit of diesel fuel, and 1 unit of MEOH replaces same amount of fossil derived MEOH. The equivalent CO_2 emissions for the production and use phase of fossil substitutes are shown in see Table 5, (3) $c_{CO_2 sequestration}$ is a premium for avoiding CO_2 emissions due to CO_2 sequestration, investment cost for compressing CO_2 to transport in the pipeline, related operating cost, (4) $c_{CO_2 storage}$ is cost related to CO_2 storage with investment cost for a pressurized tank and operating cost of storing CO_2, and (5) $c_{CO_2 co-electrolysis}$ is the investment cost of co-electrolysis unit. Further, operating cost of electrolysis unit includes cost of steam consumption which is included in the other operational cost (c_{OP}) of the overall system. The consumed electricity is assumed to be free as excess amount is produced during summer.

The economic performance indicators such as annual capital investment and the production costs are evaluated with the economic data depicted in Table 4. The environmental impact of the each process design is assessed in terms of equivalent CO_2 emissions using the GWP100a impact category, which is Global Warming Potential impact assessment method for time-horizon of 100 years (Stocker et al., 2013). Related emission factors are gathered from the Ecoinvent Life Cycle Inventory database version 3.4 (Ecoinvent, 2018) and presented in Table 5.

4. Process performance

Several scenarios have been proposed in order to assess the performance of the renewable CHF systems with regard to the conventional design. The functional unit in all these scenarios is the amount of heat provided. The study is parametrized by considering the type and size of plants, CO_2 tax and cost of wood for different biofuels production scenarios. For this, a comparative analysis is done by calculating the cost of heat and breakeven CO_2 tax values that would make the new system more profitable when compared to the conventional natural gas boiler and wood boiler. The approach of CHF systems is illustrated by different cases, and analysis results are presented in the following paragraphs.

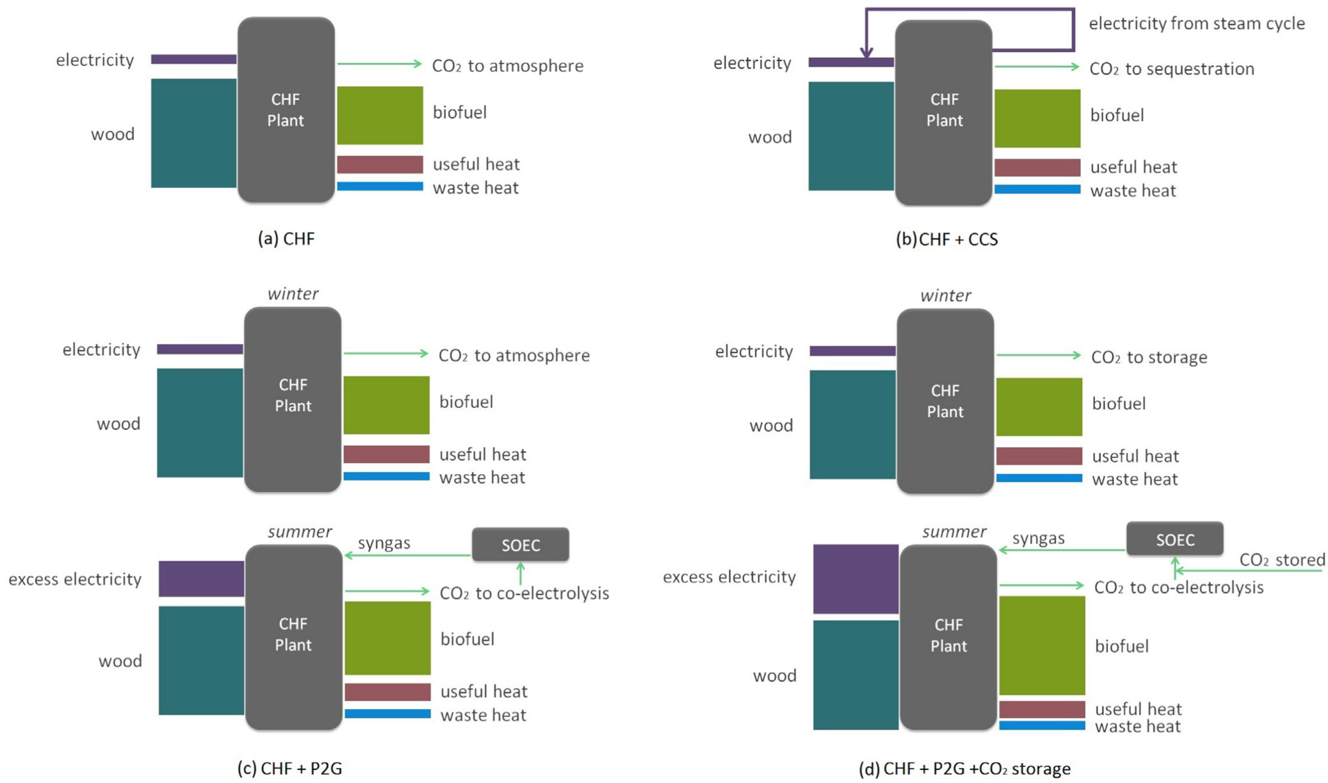


Fig. 3. Conceptual CHF plant operation schemes: plot (a) – Case I (CHF), plot (b) – Case II (CHF+CCS), plot (c) – Case III (CHF+P2G), plot (d) – Case IV (CHF+P2G+CO_2 storage).

Table 4
Assumptions for the economic performance evaluation.

Parameter	Value	Source
CEPCI index (2017)	567.5	CEPCI, 2017
Biofuel plant yearly operation, h [h/year]	7884	
Electrolysis plant yearly operation [h/year]	2628	
Expected lifetime [years]	20	
Interest rate [%]	6	
Operators[a]	4 per shift[b]	Gassner and Maréchal (2009b)
Salary [CHF/yr]	91070	Gassner and Maréchal (2009b)
Market price of wood [CHF/kg]	0.146	la forêt (2017)
Market price of electricity [CHF/kWh]	0.0749	Quarterly report on european electricity markets (2017)
Market price of natural gas [CHF/kWh]	0.024	Swissgas, 2018
Market price of heating oil [CHF/kWh]	0.086	Migrol (2018)
Market price of SNG [CHF/kWh]	0.056	Haro et al. (2016)
Market price of FT fuels [CHF/kWh]	0.089	Landälv et al. (2017)
Market price of MEOH [CHF/kWh]	0.083	Methanex (2018)
Market price of DME [CHF/kWh]	0.105	Mařík et al. (2017)

[a] Full time operation requires three shifts per day. One operator corresponds to 4.56 employees with a working time of 5 days per week and 48 weeks per year.
[b] Data is available for a plant size of 20 MW_{wood}. For different plant capacity, an exponent of 0.7 with respect to plant capacity is used.

Table 5
Emission factors from Ecoinvent v3.4 (Ecoinvent, 2018).

Parameter	Value
Wood chips production [kg $CO_{2,eq}$/kg $_{dry}$]	0.037142
Electricity mix, CH [kg $CO_{2,eq}$/kWh]	0.1176
Water [kg $CO_{2,eq}$/kg]	0.0002
NG production and combustion, CH [kg $CO_{2,eq}$/MWh]	241.7
Heating oil production and combustion, CH [kg $CO_{2,eq}$/MWh]	311
Wood production and combustion[a], CH [kg $CO_{2,eq}$/MWh]	11.8
Diesel production and combustion, CH [kg $CO_{2,eq}$/MWh]	315
Methanol production and combustion, CH [kg $CO_{2,eq}$/MWh]	318.9

[a] Ecoinvent (Ecoinvent, 2018) has non-zero emissions in IPCC 2017 GWP indicator for the combustion of wood (3.67 kgCO_2,eq./MWh).

4.1. Case 0: conventional natural gas and wood boilers for heat production

Conventional natural gas and wood boilers proposed in Table 1 are taken as basis for the calculations. Oil boiler is considered only for CO_2 reduction comparison. It is not considered in the breakeven CO_2 tax calculations due to highest heat price (Fig. 4) and CO_2 emissions (Table 5).

4.2. Case I: CHF plants

This cogeneration scenario is the base case, where heat and biofuels are coproduced and electricity is purchased from the current electricity grid. Different plant sizes of 2.5, 7, 20 and 35 MW heat

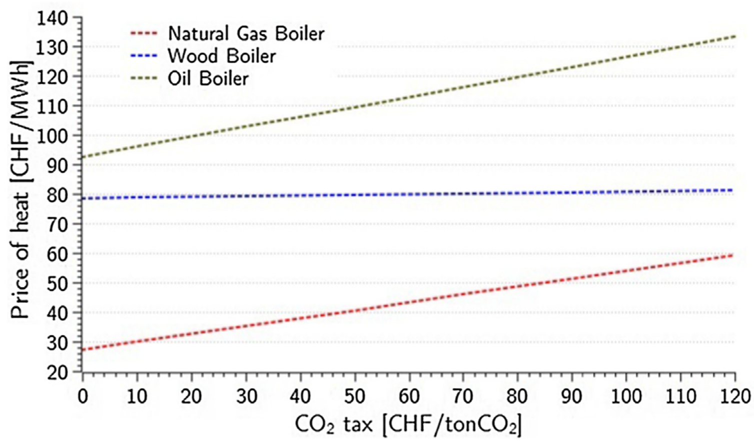


Fig. 4. Case 0 – conventional oil, natural gas and wood boilers.

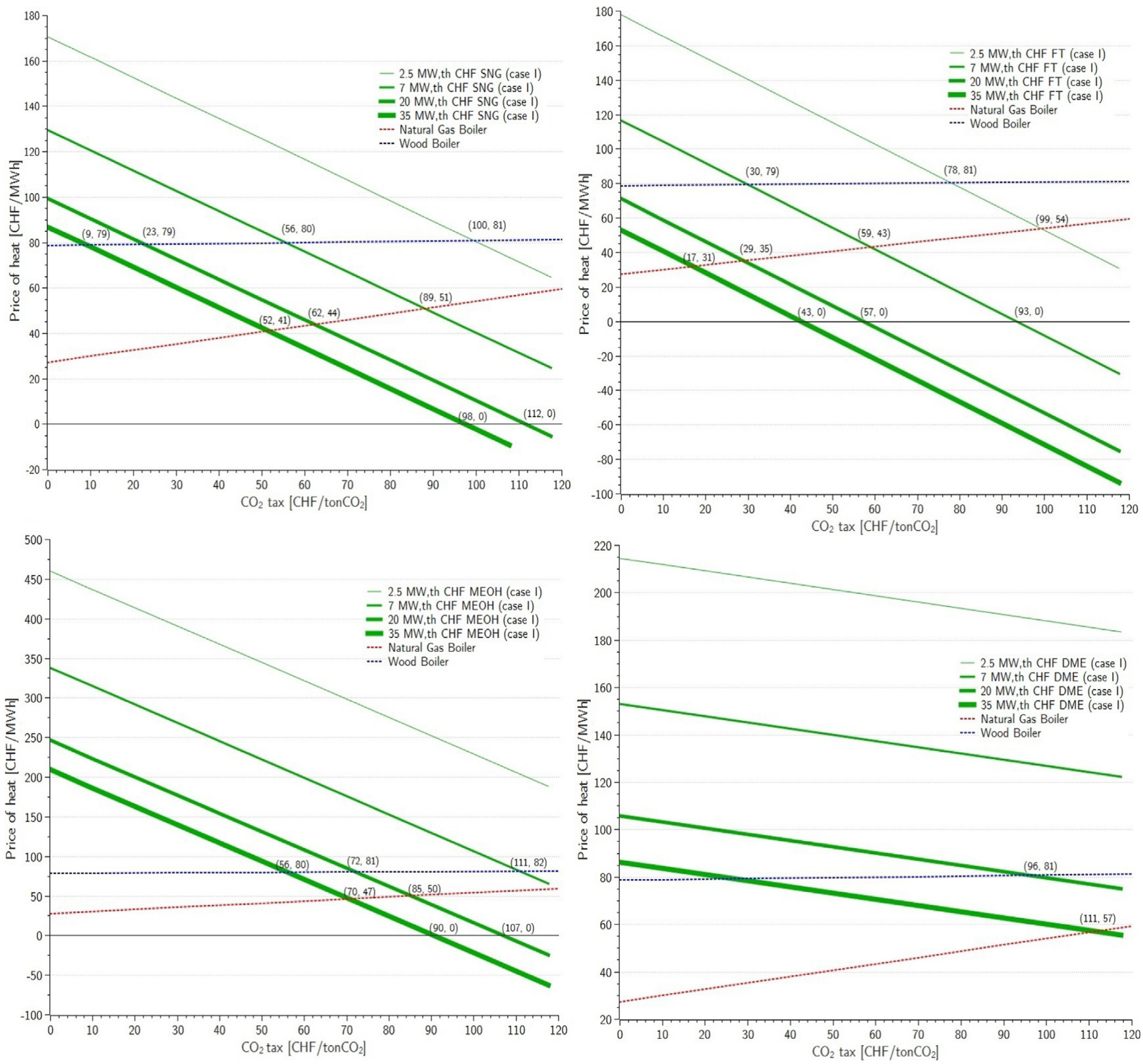


Fig. 5. Case I: CHF (SNG, MEOH, FT and DME) with different plant sizes.

(as proposed in Table 1) with one of the SNG, FT, MEOH and DME cogeneration options are chosen, and CO_2 is released to atmosphere assuming the corresponding emissions are carbon neutral (Fig. 3). Fig. 5 shows breakeven CO_2 tax for equal heat prices by natural gas and wood boilers, and CHF plant (heat and SNG; heat and FT; heat and MEOH; heat and DME).

As seen in Fig. 5, for 20 MW heat and SNG plant, one needs to pay 62 CHF/MWh breakeven CO_2 tax for the conventional natural gas boiler to provide heat at 44 CHF/MWh. On the other hand, for a conventional wood boiler, the heat price would be 79 CHF/MWh. If we replace a conventional natural gas and wood boilers with the proposed CHF plant, it cogenerates 20 MW heat and

Table 6
Performance of different fuel (CHF SNG, FT, MEOH and DME) production scenarios in Case I with plant size of 2.5 MW heat production for the breakeven CO_2 tax values comparing to natural gas boiler.

	Heat-SNG	Heat-FT	Heat-MEOH	Heat-DME
Wood [MW]	18.00	31.70	54.30	18.90
Biofuel [MW]	11.80	13.85	28.85	8.93
Net electricity [MW]	0.70	1.71	5.97	2.17
ϵ_{chem} [%]	63.10	43.68	53.12	47.24
ϵ_{tot} [%]	73.71	48.92	52.01	54.23
CO_2 produced [ton/h]	2.29	1.45	6.64	2.13
Breakeven CO_2 tax [CHF/ton CO_2]	123	99	168	349

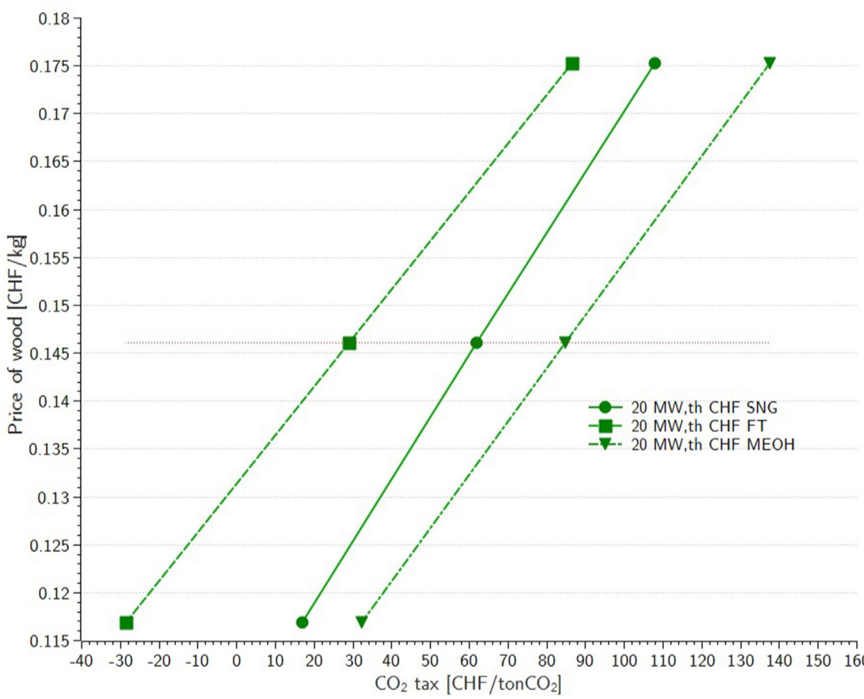


Fig. 6. Sensitivity analysis with wood price.

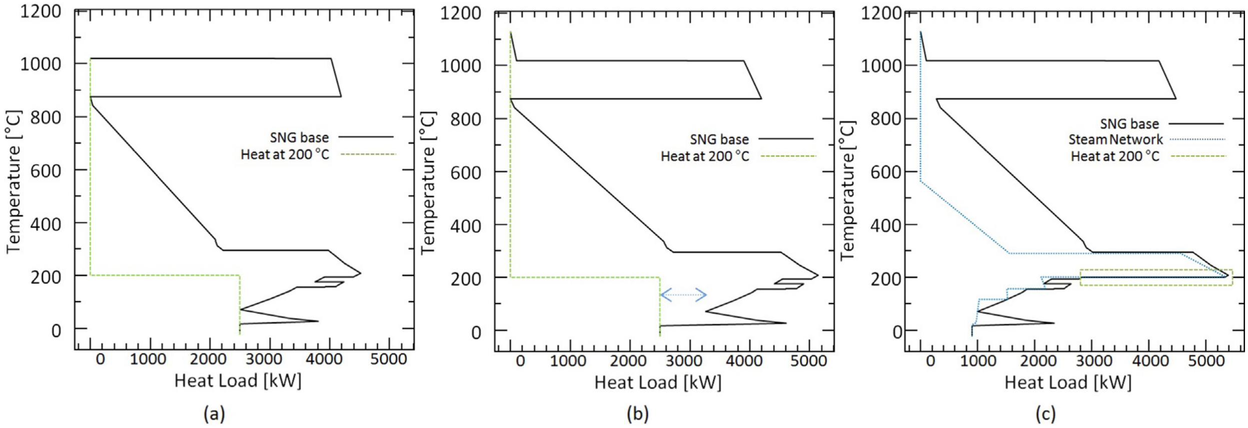


Fig. 7. Integrated composite curves for case I (Plot a) and Case II (Plots b and c) for CHF SNG plant with 2.5 MW size (Plot b represents Case II without electricity production).

93 MW SNG (see Table A.2). With today's CO_2 tax of 96 CHF/MWh in Switzerland, the price of heat from CHF SNG plant with heat capacities of 7, 20 and 35 MW will be lower than traditional wood and natural gas boilers. With increase in plant size, heat is becoming cheaper for the same CO_2 tax. The reason is that the plant investment cost per unit production decreases with increase in the plant size. For large size of CHF SNG plants (20 and 35 MW), the heat prices are negative due to large production and sell of green fuel and corresponding benefits of CO_2 substitution for fossil CO_2 at higher CO_2 tax values. For different CHF plants, it can be observed that CHF FT configuration is the best choice and it is followed by CHF SNG, CHF MEOH and CHF DME plants. Table 6 highlights the overall process efficiency for all types of CHF plants. Due to different fuel synthesis processes and different gasification technology in the CHF systems, biomass input varies to provide same amount of heat. Therefore, amount of fuel cogenerated changes thus effecting the price of heat.

To determine the effect of variabilities in the market wood price, a sensitivity analysis is performed for some scenarios of 20 MW CHF plants with SNG, FT and MEOH production. The intersection points in Fig. 5 where the heat prices of CHF plants are equal to the heat price from natural gas boiler are selected as basis. The market prices of wood are changed ±20 % from the base market price of 0.146 CHF/kg. Fig. 6 shows the corresponding CO_2 tax

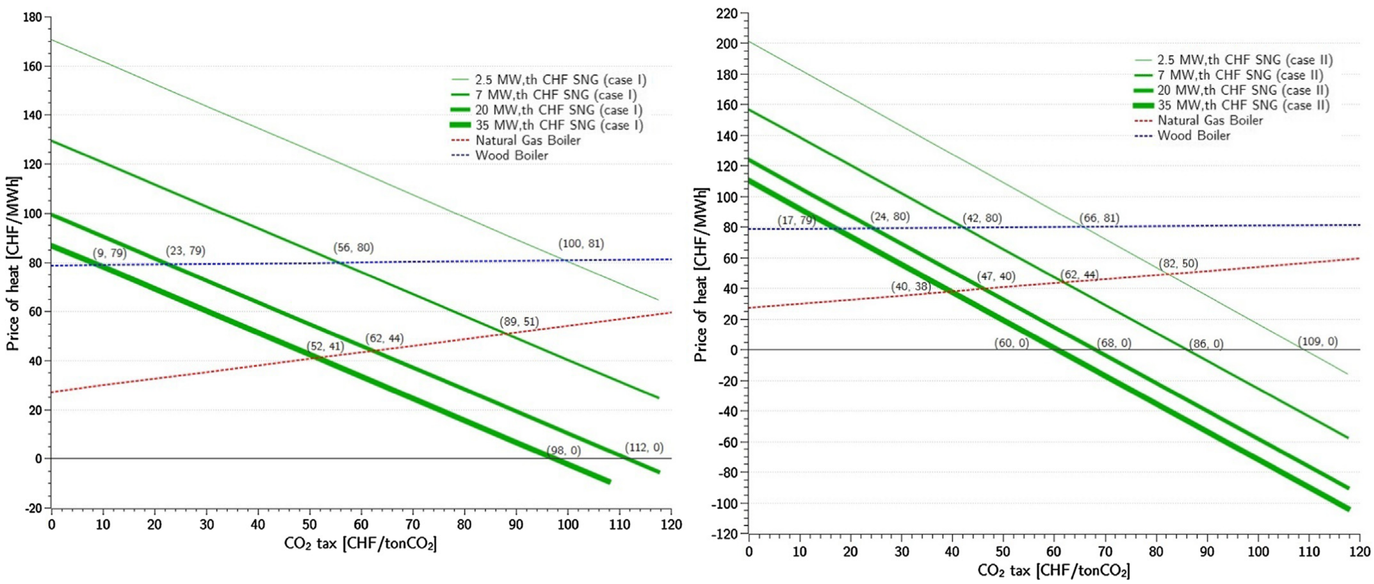


Fig. 8. Comparison of Case I and Case II: CHF SNG with all plant sizes.

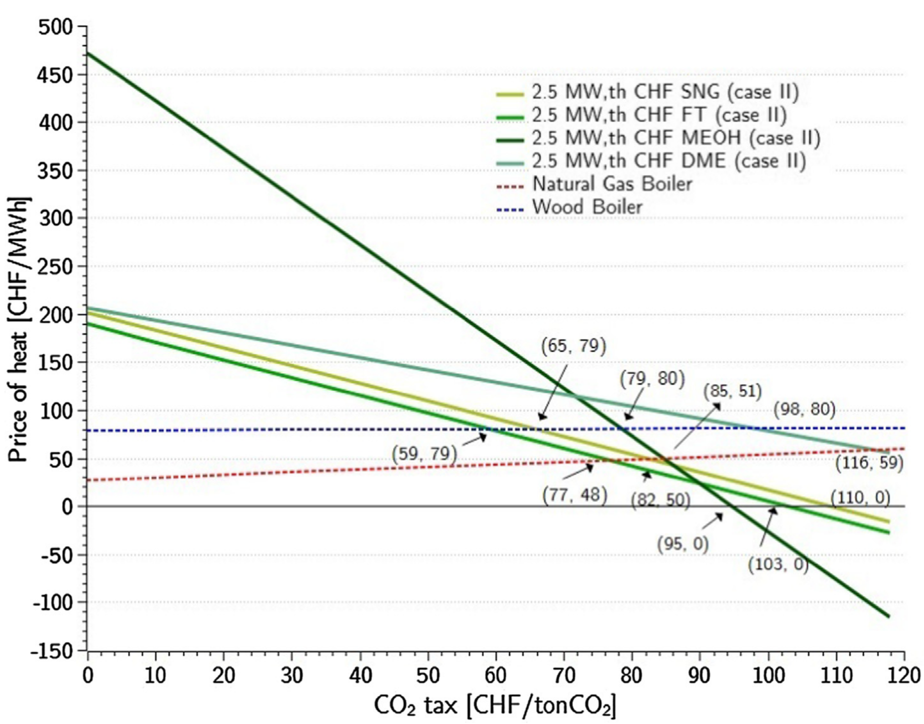


Fig. 9. Case II: CHF SNG, FT, MEOH and DME systems of 2.5 MW size.

values which should be imposed on fossil CO_2 emissions of natural gas boiler to provide the heat at same price. When the wood price is higher, increased CO_2 tax will make equal heat prices from natural gas boiler and CHF plant. When the market price of wood drops, the heat price of the CHF plant will be same as heat price of natural gas boiler at lower CO_2 tax. It is determined from the Fig. 6 that 20 MW CHF FT with lower wood price can provide heat for free with the same price of natural gas. The heat price from 20 MW CHF FT plant with the current wood price is 35 CHF/MWh (see Fig. 5).

Fig. 7(a) shows the integrated composite curve for CHF SNG plant of 2.5 MW heat and one can see that the proposed design is well heat integrated with a total efficiency of 73.71%. Case II is taking into account the long-term storage of captured biogenic CO_2 in the enhanced oil recovery sites. For transporting CO_2 to the storage sites, pipeline network is assumed to be in place for compressed CO_2 (200 bar, 25 °C (Li et al., 2011; Lazic et al., 2014)). Hence, captured CO_2 is compressed to 200 bar to meet the specifications of CO_2 transport pipeline. Before the injection, the compressed CO_2 is cooled down to 25 °C and heat is recovered in the system (Li et al., 2011). As Fig. 7(b) depicted, recovered heat can be used in a Rankine steam cycle to generate mechanical power. One can see the integrated composite curve of SNG, heat and electricity production configuration in Fig. 7(c). For this specific system, overall efficiency reaches 75.48%. Furthermore, energy expenses are reduced due to the co-production of renewable electricity and use in the system. This will reduce the price of heat with a significant rate as well as environmental impact.

4.3. Case II: CHF plants with CO_2 Capture and Sequestration (CCS)

As mentioned above, CHF plant have CO_2 sequestration option in case II. Due to CO_2 tax on fossil carbon in Switzerland, the proposed scenario is assumed to have a premium for CO_2 sequestration. Fig. 8 compares the case I and case II for CHF SNG plants of all sizes. As expected, the CHF systems with sequestration are performing better then CHF systems only. For 20 MW plant size, breakeven CO_2 tax for the conventional natural gas boiler is 47 CHF/MWh to provide heat at 40 CHF/MWh. While the CHF plants in Case I would produce more expensive heat than the natural gas boiler for the same CO_2 tax.

Fig. 9 presents variations in heat price and breakeven CO_2 tax values for 2.5 MW next generation CHF plants (with SNG, FT, MEOH or DME biofuel production), natural gas boiler and traditional wood boiler. Table 7 shows the performance of CHF plants at breakeven CO_2 tax values. Comparing the CHF plants in Case I,

Table 7
Performance of different processes (CHF SNG, FT, MEOH and DME) in Case II for plant size of 2.5 MW heat production.

Process parameters	Heat-SNG	Heat-FT	Heat-MEOH	Heat-DME
Wood [MW]	18.00	31.70	54.30	18.90
Biofuel [MW]	11.80	13.85	28.85	8.93
Electricity consumed [MW]	1.42	1.80	6.32	2.33
Electricity produced [MW]	0.91	0.17	2.13	1.49
Net electricity [MW]	0.51	1.63	4.19	0.84
ϵ_{chem} [%]	63.10	43.68	50.65	45.13
ϵ_{tot} [%]	75.48	49.03	51.30	57.96
CO_2 sequestrated [ton/h]	2.29	1.45	6.33	2.04
Breakeven CO_2 tax [CHF/ton CO_2]	82	77	85	116

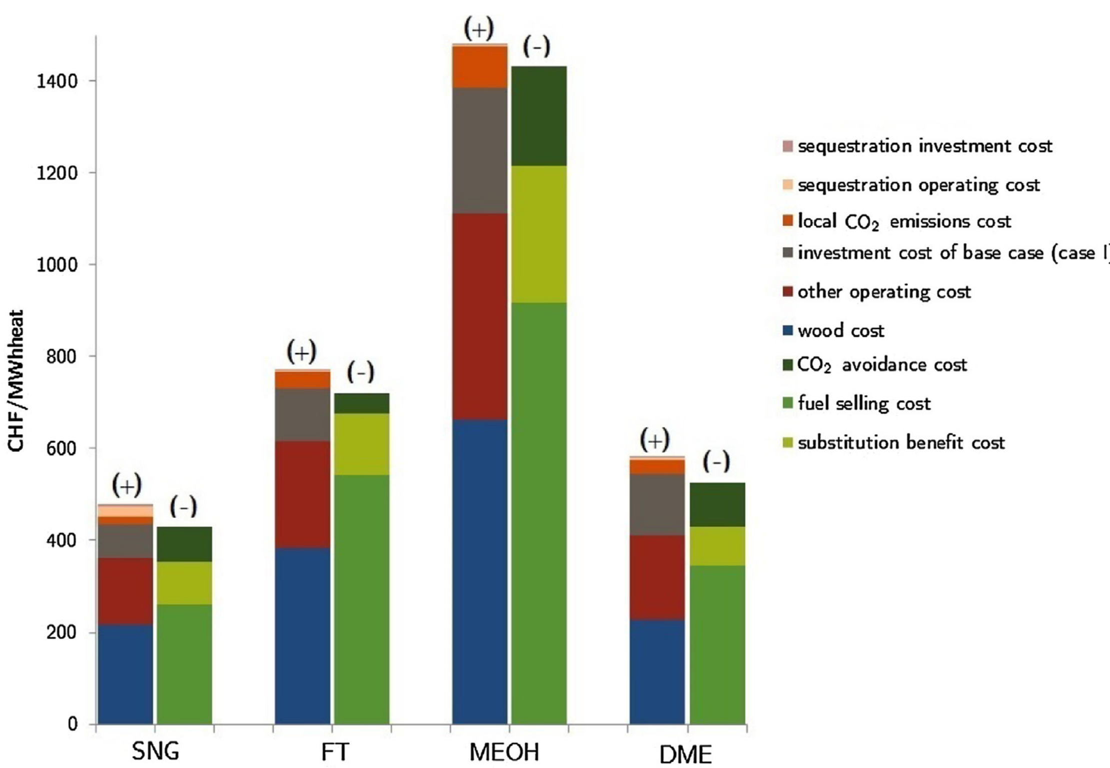


Fig. 10. Heat cost build-up for CHF SNG, FT, MEOH and DME plants of 2.5 MW size in Case II. (Positive sign represents the expenses, negative sign represents the incomes.)

the price of heat is reduced dramatically when CO_2 sequestration is considered. With a CO_2 tax of 96 CHF/ton CO_2 (Switzerland,2018), very small size (2.5 MW) CHF SNG, FT and MEOH plants provide heat at prices lower than natural gas boilers. After CO_2 tax of 90 CHF/ton CO_2, CHF MEOH plant starts to perform better than CHF FT and SNG configurations. This is due to the large amount of wood used in the system thus producing more biofuel and replacing more fossil fuel. At the end, reduction in the heat price is proportional to the benefits from CO_2 sequestration and fossil carbon substitution. For bigger sizes, the heat would be free from the CHF plants with carbon capture and sequestration systems integrated. The cost build-up of different CHF scenarios, where heat price lines for biofuels production route intersects heat price line for natural gas boiler, is presented in the Fig. 10.

Fig. 11 shows the integrated composite curves for CHF SNG, FT, MEOH and DME plants for case II. Recovering heat from the cooling operation before transporting compressed CO_2 into the pipeline allows to produce renewable electricity through Rankine cycle. The produced electricity is used in the system, and the deficit in the electricity is covered by the grid electricity. Integration of steam cycle allow us to reduce the exergy losses from the system.

4.4. Case III and Case IV: CHF plants with Power-to-Gas (P2G) and CO_2 storage

As discussed earlier in Section 3.2.2, new energy policy scenario (NEP) for the future Swiss energy system in 2050 forecasts surplus (or waste) electricity production during summer due to high penetration of solar photovoltaics (PV), wind and geothermal energy. Power-to-Gas systems can be used as a strong way to seasonally store electricity. Therefore, co-electrolysis unit is integrated to obtain maximum production of biofuels using excess electricity during 4 months of summer in both cases III and IV. Co-electrolysis unit uses CO_2 and steam inputs to produce a syngas with 75 vol% of hydrogen (Wang et al., 2018). Produced syngas is then injected into the fuel synthesis reaction. Lifetime of a co-electrolyser is assumed to be 15 years with only 4 months operation in summer (Caliandro et al., 2014). In Case III, CO_2 captured during 4 months of summer operation of CHF plant is sent to the co-electrolyser. In Case IV, CO_2 is captured and stored in a pressurized tank in liquid form at 25 °C and 50 bar during the winter operation (8 months) of CHF plant, and the stored CO_2 is fed into the co-electrolyser together with the CO_2 captured during summer opera-

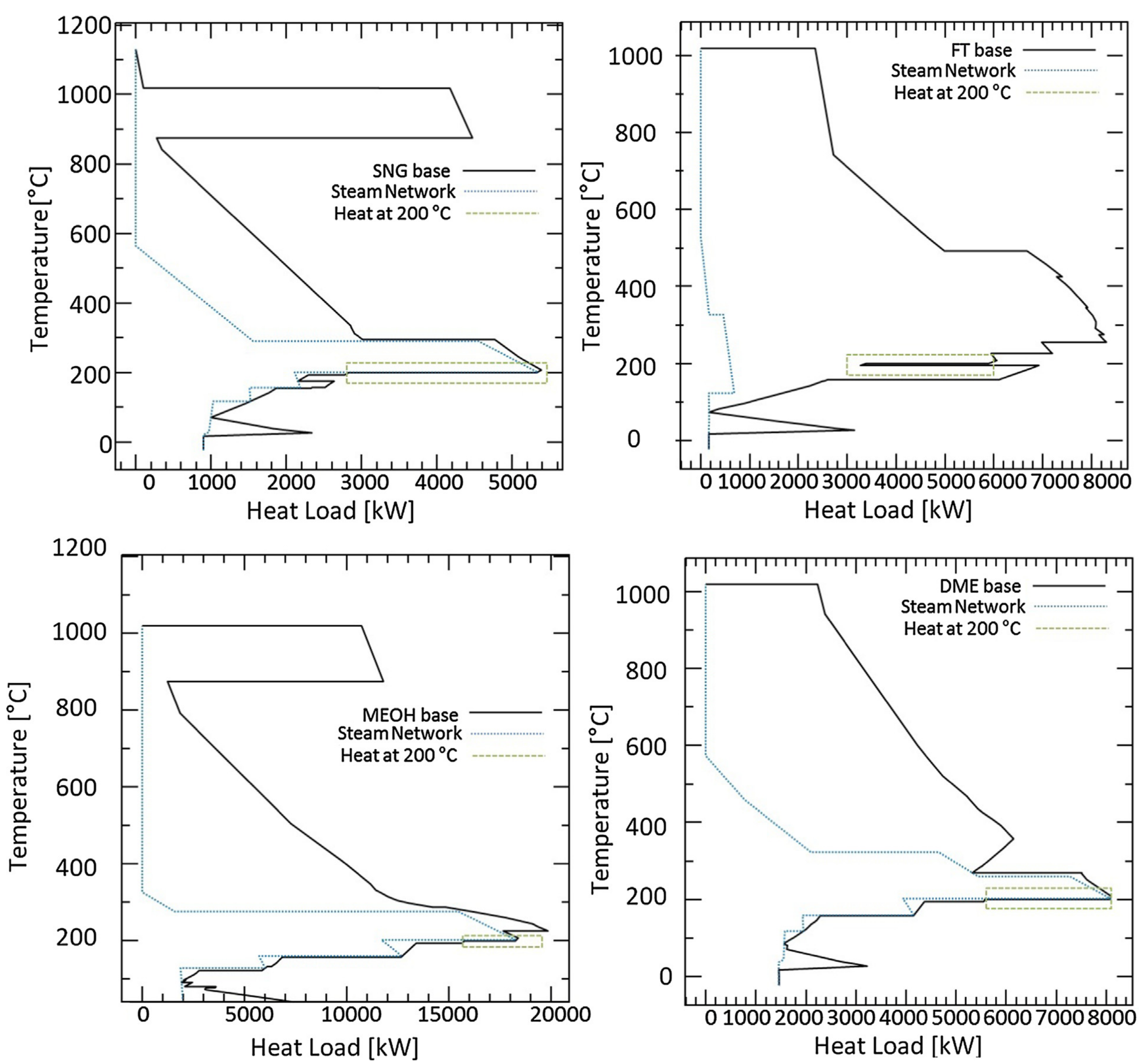


Fig. 11. Integrated composite curves of CHF SNG, FT, MEOH and DME plants in Case II for 2.5 MW plant size.

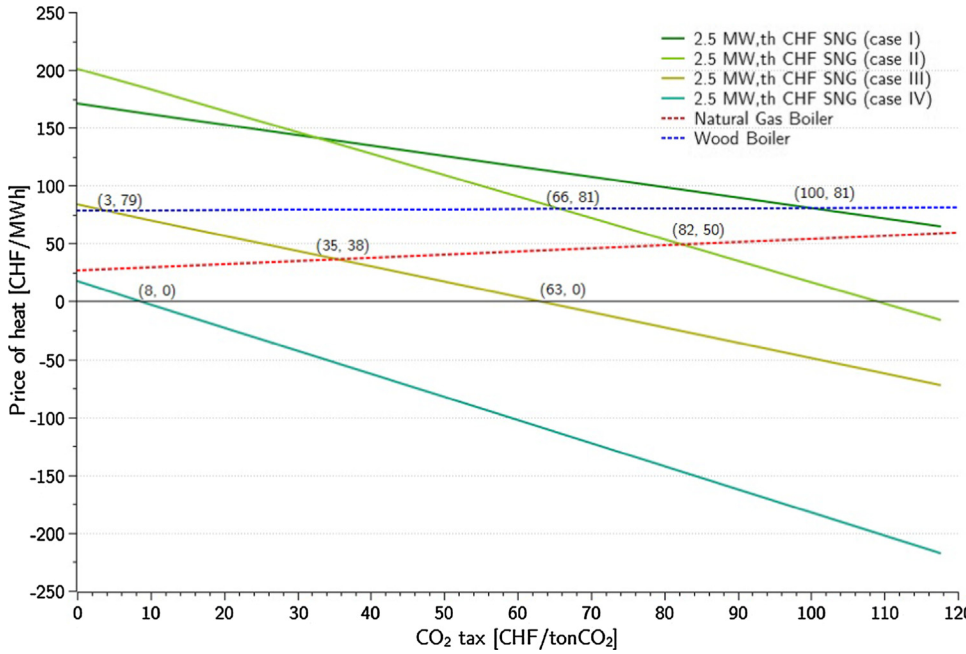


Fig. 12. Case I, II, III, IV comparison for 2.5 MW CHF SNG plant.

Table 8
Performance of CHF SNG plant in Cases I, II, III and IV for plant size of 2.5 MW heat production.

Process parameters	Case I	Case II	Case III-Summer	Case IV-Summer
Wood [MW]	18.0	18.0	18.0	18.0
Biofuel [MW]	11.8	11.8	23.54	44.61
Electricity consumed [MW]	0.70	1.42	15.78	43.20
Electricity produced [MW]	–	0.91	–	–
Net electricity [MW]	0.70	0.51	15.78	43.20
ϵ_{chem} [%]	63.10	63.10	130.8	247.81
ϵ_{tot} [%]	73.71	75.48	79.54	80.31
CO_2 produced [ton/h]	2.29	–	–	–
CO_2 sequestrated [ton/h]	–	2.29	–	–
CO_2 to co-electrolysis [ton/h]	–	2.29	2.29	6.39

tion. The overall amount of electricity required for the integrated cogeneration system is available from the PV panels for zero cost with no resource emissions according to the scenario 2050 for Swiss Energy Transition (Codina Gironès et al., 2018; Kannan, 2015). In Fig. 12, it can be seen that for a very small size of CHF SNG plant, integration of co-electrolysis unit lead to a great reduction in heat prices for both cases III and IV, having negative values for higher CO_2 tax. Table 8 shows the performance of CHF SNG plants in all cases considered at breakeven CO_2 tax values. Fig. 13 compares the heat cost build-up for 2.5 MW CHF SNG plants in all cases where heat price lines intersects heat price line for natural gas boiler.

5. Conclusions

The ultimate goal for a sustainable development is the replacement of fossil based services with biomass based services. For the energy transition, CO_2 emissions have to be decreased, energy conversion efficiency has to be increased, and fossil resources have to be gradually replaced by renewable resources. Hence, the heat demand for industrial plants needs to be satisfied by renewable energy sources instead of using conventional natural gas boilers. This study proposes a new system approach for the design of cogeneration plants, which utilizes woody biomass as energy resource in the thermo-chemical conversion processes to produce heat at required temperatures for different industrial sectors while cogenerating biofuels. A by-product of the proposed CHF plant is biogenic CO_2 that is separated during the production. The CO_2 can be sold as a product, sequestrated or used in power to fuel process for the long term storage of renewable intermittent electricity. In the future, electricity demand is expected to increase due to the addition of end-use devices such as heat pumps and electric mobility and with the increase in population. The future electricity system should be ensured for cost-effectiveness, security of supply and climatic impact. To achieve this, some measures including more renewable installations, efficiency improvements and additional electricity storage should be considered. With the penetration of renewable electricity, surplus electricity during summer period is forecasted in most studies. Seasonal storage of this renewable surplus electricity is possible with the conversion of electricity into fuel via the proposed CHF system in this study. The produced biofuel can be stored in tanks so that it can be used in combined cycle power plants to produce electricity at any time during the year.

Based on life cycle inventory of the fossil product, it is possible to calculate the fossil carbon (CO_2 emissions) substituted by each unit of carbon in the bio-products or fuels. This value is indeed the amount of fossil CO_2 not emitted and replaced by CO_2 captured by the photosynthesis as biogenic carbon. As the biomass harvests carbon from the atmosphere, the performance of the proposed CHF systems can be studied on the basis of the amount of fossil CO_2 emission avoided per unit of atmospheric CO_2 converted by the photosynthesis. The oil boiler is taken as basis which has the highest fossil CO_2 emissions. First, it is considered that natural gas and wood boiler substitutes an oil boiler. Referring to Fig. 14, 1 unit of

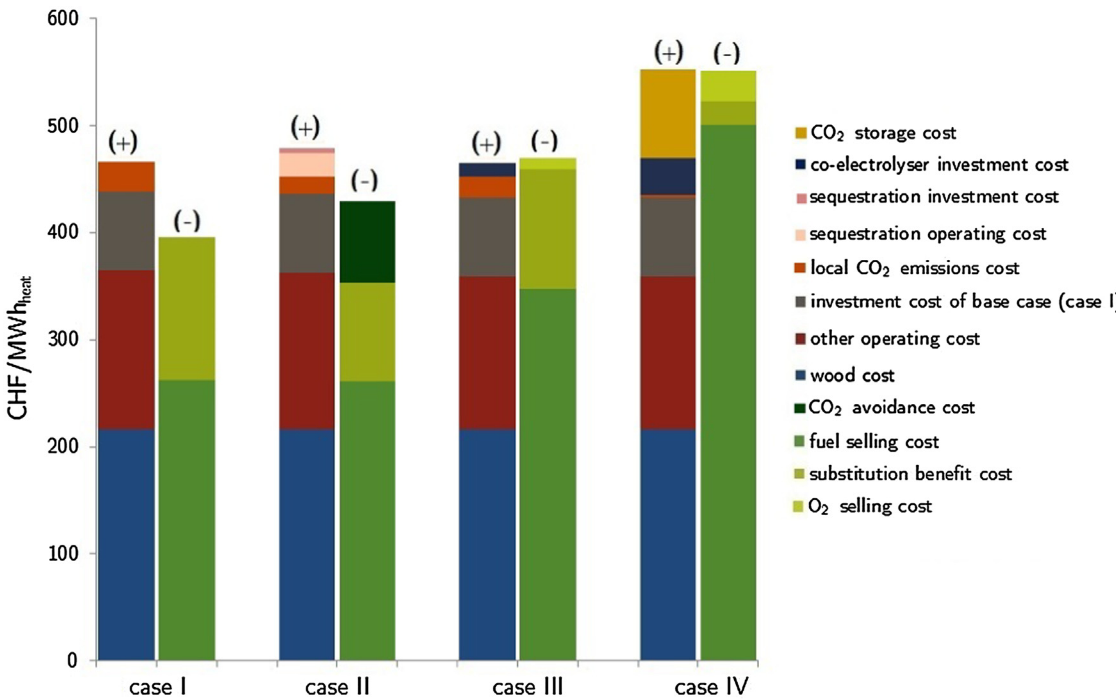
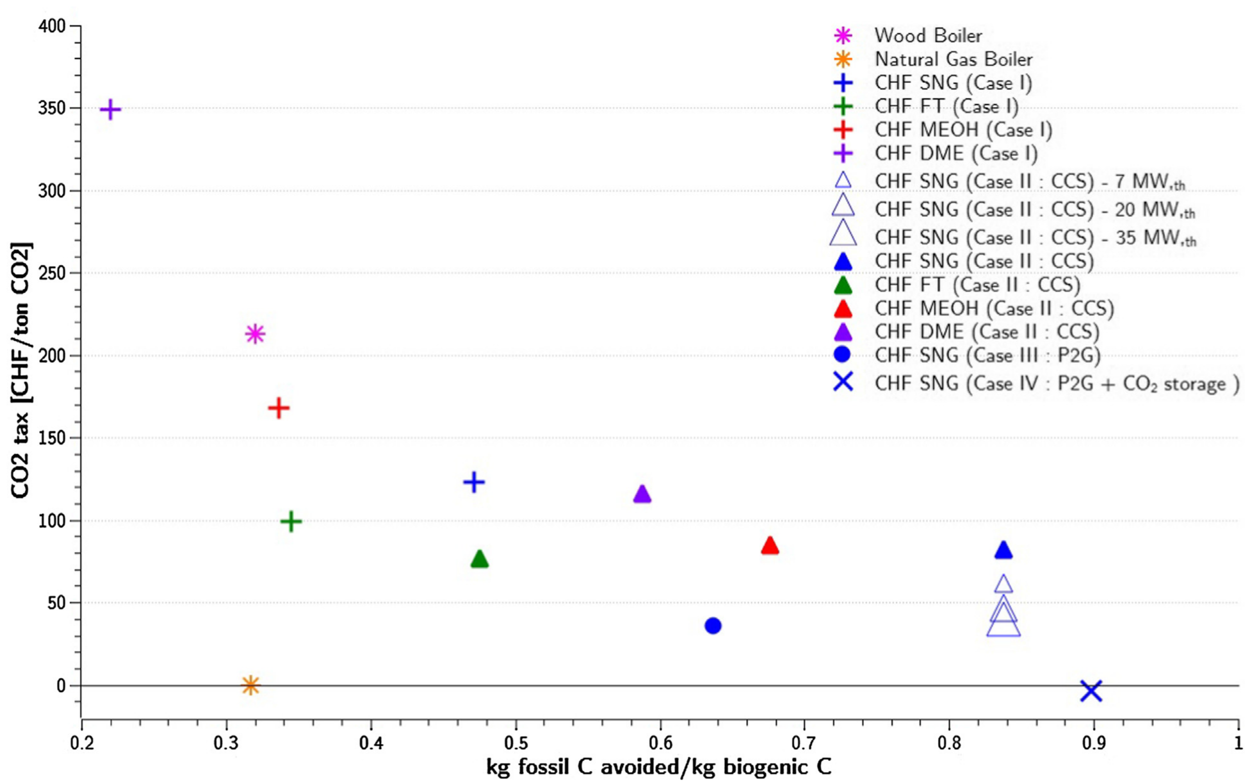


Fig. 13. Heat cost build-up for CHF SNG plant of 2.5 MW size for all cases. (Positive sign represents the expenses, negative sign represents the incomes.)



*The boiler size: 2.5 MW_{th}. Heat is substituted with the heat from the oil boiler.
**CO_2 tax represents the tax values when calculated heat price from the proposed CHF system is equal to the heat price from natural gas boiler.
***For the natural gas boiler, x axis is *kg fossil C avoided/kg C in natural gas (compared to oil boiler).*

Fig. 14. Carbon savings comparison between technologies.

carbon in the natural gas and wood avoids 0.31 and 0.32 units of fossil carbon emissions, respectively. To produce heat from wood boiler at the same price of natural gas boiler, one should put very high CO_2 tax on natural gas boiler (213 CHF/ton CO_2).

Summing-up the substituted fossil carbon for CHF SNG plant in Case I, 1 unit of biogenic carbon entering the CHF system avoids 0.48 units of fossil carbon emissions. For 1 unit of CO_2 captured by the photosynthesis, the CHF SNG plant avoids therefore 50% more CO_2 than the wood combustion. In addition, if one considers the CO_2 sequestration for CHF SNG plant (Case II), one unit of biogenic carbon entering the proposed CHF system would avoide 0.84 units of fossil carbon emissions. In this case, the wood used in the CHF plant is avoiding 2.63 times more fossil CO_2 emissions than the wood used in a boiler. Varying CHF SNG plant size between 2.5, 7, 20 and 35 MW heat duty, it is clear that bigger plant would provide heat at lower price. Similar to 2.5 MW CHF SNG plant, CHF FT, MEOH and DME plants have large CO_2 savings when compared to the conventional boilers. For Case III, the co-electrolysis is used in addition to CHF SNG plant for the CO_2 captured during summer. In this case, 1 unit of biogenic carbon avoids 0.64 units of fossil carbon emissions. If co-electrolysis unit is also used for the CO_2 captured and stored during winter and CO_2 captured during summer, then the carbon saving ratio would be 0.9 while the heat price is negative.

The results demonstrate that integrated approaches such as heat and fuel cogeneration using wood, have a higher potential for CO_2 mitigation and therefore have to be prioritized with respect to combustion for heat supply. Imposing a carbon tax greatly penalizes conventional natural gas boilers without CO_2 capture and favors biomass based processes.

CHP plants will no longer be attractive with the rapid energy transitions across Europe and the globe. Intermittent renewable power from wind and solar energy will shape future energy supply with their high shares. The current research is searching solutions for long-term storage of electricity, and promising solutions are batteries, pump hydro storage, compressed air energy storage and power-to-X concepts. Hydrogen storage can be seen as an option for long-term storage however it has high costs, security issues and fuel cells have short lifetimes. Storage of biofuels is cheaper option and the environmental impact is also relatively small. Fuel storage systems are large and convenient facilities with proven and available technologies. Biomass cogeneration systems which cogenerates heat and fuel together, and uses co-electrolysers to boost biofuels production when electricity is surplus, provide a good solution for long-term electricity storage. In the way towards a sustainable future, providing heat for industrial processes via next generation cogeneration using biomass resource, appears to be a competitive transitional solution for mitigating climate change. Since the results are highly dependent on the market, uncertainties should be accounted for a more reliable analysis and more detailed technical study should be performed to establish this technology on a real large scale plant.

Declaration of interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A

A.1. Transportation cost of wood resource

Logistics cost of wood increases as the size of heat supply increases and the transport distance is another criteria which depends on the location of the plant and availability of biomass supply. Steubing et al. (2014), performed a study to analyze average biomass supply distances in Switzerland considering plant size, location and biomass availability scenarios. The plant location is chosen to be Bellinzona, Switzerland with longest transport distance. The function to calculate the average driving distance used in this study is taken from Peduzzi et al. (2013).

$$d_{Average} = t_1 \dot{Q}_{Wood}^{t_2} \quad [\mathrm{km}] \tag{A.1}$$

Here, $d_{Average}$ is the average distance in km, $\dot{Q}_{Wood}$ is the thermal plant capacity, calculated based on dry wood input in kW, and t_1, t_2 are the parameters calibrated for the case 'baseline scenario for Bellinzona, Switzerland' as shown in Table A.1. The cost of transportation is estimated by calculating the number of lorries required to transport the biomass satisfying the nominal plant capacity.

$$c_{Transport} = \frac{N_{Lorry} \cdot c_{Lorry}}{\dot{Q}_{Wood} \cdot h} \quad [\mathrm{CHF/kWh}_{Wood}] \tag{A.2}$$

$$N_{Lorry} = \frac{m_{Wood}}{m_{Lorry}} \tag{A.3}$$

$$m_{Wood} = \frac{\dot{Q}_{Wood} \cdot h}{LHV_{Wood} \cdot 1000} \quad [\mathrm{ton/yr}] \tag{A.4}$$

$$c_{Lorry} = \frac{d_{Average} \cdot e_{Lorry} \cdot c_{Diesel}}{LHV_{Diesel} \cdot \rho_{Diesel}} \quad [\mathrm{CHF/lorry}] \tag{A.5}$$

The transportation cost for each lorry (m_{Lorry} = 10 ton) is related to the total fuel consumption (e_{Lorry}), diesel market price (c_{Diesel}) and average distance covered ($d_{Average}$). The total fuel consumption of a lorry (e_{Lorry}) is calculated for the case where the fully-loaded lorry transports the biomass to the plant, unloads and returns to the biomass collection site empty to make another trip. All the parameters used in the wood transport cost model are presented in Table A.1.

Table A.1
Parameters used in wood transport cost model.

Symbol	Parameter	Value	Unit	Source
t_1	in the calculation of $d_{Average}$	18.455	km/kW$_{th}$	Peduzzi et al. (2013)
t_2	in the calculation of $d_{Average}$	0.1776		Peduzzi et al. (2013)
e_{Full}	Fuel consumption (loaded lorry)	10.67	MJ/km	Peduzzi et al. (2013)
e_{Empty}	Fuel consumption (empty lorry)	8.37	MJ/km	Peduzzi et al. (2013)
e_{Lorry}	Total fuel consumption (e_{Empty}+e_{Full})	18.99	MJ/km	Peduzzi et al. (2013)
LHV_{Diesel}	Lower heating value of diesel	42.791	MJ/kg	Peduzzi et al. (2013)
ρ_{Diesel}	Density of diesel	0.832	kg/l	Peduzzi et al. (2013)
c_{Diesel}	Diesel market price	1.71	CHF/l	Switzerland diesel prices (2018)

A.2. Summary for different scenarios

Tables A.2 and A.3.

Table A.2
Performance of different fuel (SNG, FT, MEOH and DME) production scenarios in Case I heat production for the breakeven CO_2 tax values comparing to natural gas boiler.

	SNG				FT			
Plant Size (Heat Output [MW])	2.5	7	20	35	2.5	7	20	35
Wood [MW]	18.00	49.80	142.10	249.00	31.70	88.8	252.5	441.8
Biofuel [MW]	11.80	32.47	92.63	162.36	13.85	38.78	110.28	192.96
Net electricity [MW]	0.70	1.93	5.54	9.65	1.71	4.80	13.65	23.88
Breakeven CO_2 tax [CHF/ton CO_2]	123	89	62	52	99	59	29	17
	MEOH				DME			
Plant Size (Heat Output [MW])	2.5	7	20	35	2.5	7	20	35
Wood [MW]	54.3	152.00	433.00	760.00	18.90	53.00	150.50	264.00
Biofuel [MW]	28.85	80.75	229.97	403.73	8.93	25.04	71.09	124.72
Net electricity [MW]	5.97	16.72	47.64	83.64	2.17	6.10	17.31	30.37
Breakeven CO_2 tax [CHF/ton CO_2]	168	119	85	70	349	237	149	111

Table A.3
performance of SNG CHF plant in Case II for different sizes of heat production.

Plant Size (Heat Output [MW])	2.5	7	20	35
Wood [MW]	18.00	49.80	142.10	249.00
Biofuel [MW]	11.80	32.47	92.63	162.36
Net electricity [MW]	0.51	1.36	3.88	6.81
Breakeven CO_2 tax [CHF/ton CO_2]	82	62	47	40

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