Implementation of bio-CCS in biofuels production

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Implementation of bio-CCS in biofuels production

IEA Bioenergy Task 33 special project

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Front cover: STEPWISE unit for CO_2 capture in Luleå (Sweden). The STEPWISE project that has received funding from the European Union's Horizon 2020 research and innovation programme (grant agreement No. 640769). Picture courtesy of E. van Dijk (ECN, part of TNO).

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Abstract

In combination with other climate change mitigation options (renewable energy and energy efficiency), the implementation of CCS will be necessary to reach climate targets. If CCS is applied in with bioenergy processes (bio-CCS schemes), negative CO_2 emissions can be potentially achieved.

This study aims to provide an initial overview of the potential of biomass and waste gasification to contribute to carbon capture and sequestration (CCS) through the assessment of two example scenarios. The selected study cases (600 MW_{th} thermal input) represent two different routes to biofuels production via gasification which cover a relevant range of gasification technologies, biofuel products and CCS infrastructure conditions:

- Case 1: production of Fischer-Tropsch syncrude from high-temperature, entrained-flow gasification in Norway.
- Case 2: bio-SNG production from indirect gasification in The Netherlands.

The results show that the addition of CCS to a biofuel production value chain will roughly double the amount of mitigated CO_2 in both value chains, from 0.6 to 1.1 Mton/y while the overall biofuel production costs increasing by 10%.

The results of Case 1 show that under the conditions assumed, the cost of production of FT syncrude from woody biomass increases from 24.0 to 26.4 €/GJ (approximately by 10%), if the costs of CO_2 compression and cooling, transport and storage are included in the overall value chain. The analysis also shows that the economic impact of including CCS is very sensitive to the CO_2 transport cost, the overall FT syncrude production cost increased from 26.4 to 30.8 €/GJ (by 17%) when CO_2 transport cost increased from 0.09 to 0.36 €/ton/km. Possible compensation measures of the higher FT syncrude production costs resulting from the implementation of CCS include the reduction of feedstock supply costs, or the increase in the market value for bio-based LNG (by-product of the process), or the increase in the credits for CO_2 capture. To assess these effects, the following scenarios were examined: 1) 25 wt.% of the input woody biomass is replaced by sewage sludge with a gate fee of 10 €/ton; 2) the price of bio-based LNG is increased by 25%(from 20 to 25 €/GJ); or 3) the CO_2 credits are increased by 100% (50-100 €/ton).

As for Case 2, the results show that the production cost of bio-SNG increases by approximately 14%, from 19.6 €/GJ to 22.3 €/GJ, when adding CCS to the bio-SNG process. Transport and storage of CO_2 contribute with 5.3% to the total SNG production cost. By applying pre-combustion technology (amine scrubbing in this case) to indirect gasification, approximately 1/3 of the initial carbon contained in the biomass can be captured (the rest ending up in the bio-SNG product and the flue gas side of the indirect gasifier). The cost (and thus the origin) of biomass has an important effect on the production cost. Under the assumptions of this work, the threshold biomass price for the project to become financially feasible (NPV = 0) is approximately 8 €/GJ. The CO_2 price has also a dramatic effect on the financial viability of the project. Under the reference conditions considered in this study, a breakeven CO_2 price of around 30 €/ton has been determined. Therefore, it is necessary to modify the current CO_2 emission system to reward the negative emissions achieved by bio-CCS, so that the business case of bio-CCS can be improved. The economic feasibility of bio-SNG + CCS is also very sensitive to the price of the bio-SNG product. The breakeven cost of bio-SNG is 17.8 €/GJ according to the assumptions taken. Lastly, the investment cost has a dramatic effect on both the bio-SNG production cost and the ecomomic feasibility of the project. It is necessary to reduce the total investment costs below 1180 €/kW input for the project to become profitable. Thus, a significant effort needs to be performed in the coming years for the demonstration of bio-SNG at large scale in order to reduce the investment costs.

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Abbreviations

2DS	International Energy Agency's 2°C scenario
bcm	Billion cubic meter
CCS	Carbon capture and storage
CDM	Clean development mechanism
EFG	Entrained flow gasification
EGR	Enhanced gas recovery
EOR	Enhanced oil recovery
ETS	Emission trading system
FT	Fischer-Tropsch
FTS	Fischer-Tropsch synthesis
GHG	Greenhouse gas
IEA	International Energy Agency
LNG	Liquefied natural gas
Mtoe	Millions of tons of oil equivalent
NG	Natural gas
NPV	Net present value
OCAP	Organic CO_2 for assimilation by plants
SNG	Synthetic (or substitute) natural gas
TCI	Total capital investment
WGS	Water-gas shift reaction

1. Introduction

1.1 CCS – A NECESSARY TOOL FOR THE ENERGY TRANSITION

Carbon capture and storage (CCS) encompasses a group of technologies that can seize CO_2 emissions from fuel-based electricity generation and other industrial processes and prevent the CO_2 from entering the atmosphere by storing it underground (for example in depleted oil/gas fields or in deep aquifers) [1]. In view of the impending energy transition, the implementation of CCS, although costly, is considered necessary not only from the point of view of the "carbon budget" [2], but also from an economic point of view: the achievement of the scenarios derived from the Paris Agreement is expected to be 70% more costly if CCS is not considered [3][4]. In this sense, CCS technologies will complement and reinforce (rather than compete with) other mitigation options such as improvement of energy efficiency, or the use of renewables and nuclear energy.

The International Energy Agency (IEA) has set targets of 2 Gton CO_2/y capture in 2030, and 7 Gton CO_2/y in 2050. To put these numbers into context, the current overall global emissions are approximately 35 Gton CO_2/y. From this overall target, approximately 1.5 Gton CO_2/y CCS is expected to be captured and stored from bioenergy processes in 2050 [3]. The IEA 2DS scenario (which foresees an increase in the global temperature up to 2°C in 2100, so that the worst consequences of global warming can be avoided) considers that by 2050, 50% of gas-fired plants, 100% of new coal-fired power plants and 20% of power plants of bioenergy equipped will be equipped with CCS [3].

1.2 CCS APPLIED TO BIOENERGY: BIO-CCS

Bioenergy (more specifically, the high-efficiency application of biomass for heat, power and production of fuels and chemicals) is expected to play a vital role in the future energy system. According to the IEA's 2DS scenario, bioenergy will provide approximately 17% of the final energy demand in 2060 (with respect to the current 4.5%) [5]. According to this same scenario, the use of bioenergy can contribute to approximately 20% of the carbon savings in 2060.

Both CCS and bioenergy can be considered as a shortcut of the multi-million-years process of carbon storage in form of fossil fuels [3]. In the case of bioenergy processes, growing crops with high carbon uptake which are then prevented from natural decay is a process that can be considered as nearly neutral. If the CO_2 released by bio-based processes is captured and stored for example in geological formations (that is, if CCS is applied in combination with bioenergy processes), negative CO_2 emissions can be potentially achieved.

The main form of technical implementation of CCS in bioenergy processes (what in this report is referred to as "bio-CCS") does not differ substantially from pre-combustion CCS schemes applied to conventional industries (fossil fuel power production, steel production, or cement production), which is schematically depicted in Figure 1. This is the bio-CCS concept that is studied in this report. In this case, CO_2 is removed from a feed gas using commercial technologies such as physical absorption (e.g. Rectisol®, Selexol®, etc.), or chemical absorption (for example, amine scrubbing). The captured CO_2 is then conditioned (drying, compression) to be able to be transported. CO_2 transportation can be performed either in gas pipelines or shipped in liquefied form, and CO_2 is finally injected in geological formations (depleted oil and gas fields, depleted coal seams, aquifers). Other less conventional alternatives for CCS (not considered in this report) include CO_2 capture from air, geochemical storage (e.g. in olivine) or carbon storage as biochar.

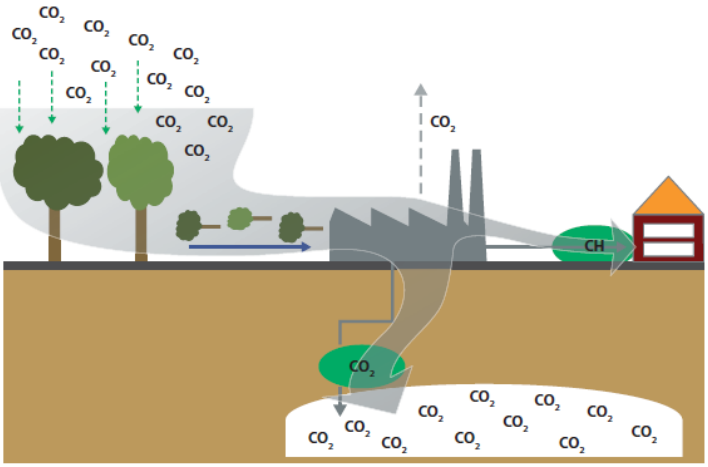


Figure 1. Negative emissions achieved by implementation of CCS to bioenergy processes [3].

1.3 INTEGRATION OF CCS IN BIOFUEL PRODUCTION

The development of a strong, competitive industry is necessary to achieve the ambitious biofuel targets set at European level. As an example, the European Union has set a share of 10% of the transport fuels from renewable sources in 2020 [6]. However, current biofuel production suffers from several challenges, namely reliable fuel supply, overall low energy efficiency and prohibitive high production costs. One of the main concerns about biofuel production is related to the biomass supply (including sustainability criteria, competition between food and energy, and land change use). The expected shift from 1st-generation to 2nd-generation biofuels produced from lignocellulosic biomass can overcome part of these issues. However, in 2014, only 0.06% of the European biofuel consumption (14.2 Mtoe) was provided by biofuels other than biodiesel, bioethanol or biogas [7]. One of the objectives of the 2015 EU draft directive on land use change is the promotion of advanced biofuels (2nd and 3rd-generation) by setting a non-binding target of a 0.5% share. A recent draft of the revised European Energy Directive proposes a minimum share of at least 1.5% of low-carbon fuels (including among others advanced biofuels) in 2021, which should increase to at least 6.8% by 2030 (at least 3.6% advanced biofuels). On top of this, the reduction of greenhouse emissions by using advanced biofuels should be at least 70% from 2021 onwards [7][8]. From these numbers, it is clear that biofuel production will play an increasingly relevant role in the mid-term and long-term energy scenarios.

The coupling of (advanced) biofuel production to CCS infrastructure has therefore a clear, straightforward advantage related to the potential of achieving negative CO_2 emissions, thus improving the sustainability of the use of advanced biofuels. Moreover, bio-CCS applied to biofuel offers an additional potential advantage with respect to bio-CCS applied to (conventional) power plants: the implementation of CCS is relatively easier due to the fact that the CO_2 capture unit might be already included in the biofuel process as part of the gas upgrading train to ensure that the feed gas to the synthesis unit (and thus the final biofuel product) complies with quality requirements (H_2/CO ratio). Therefore, the integration of the biofuel plant to the CCS infrastructure is limited to the addition of CO_2 conditioning (e.g. drying in the case of bioethanol production, compression).

1.4 SCOPE OF THIS STUDY

This report aims to provide an initial overview of the potential of biomass and waste gasification to contribute to carbon capture and sequestration (CCS) through the assessment of 2 example cases set in Norway and The Netherlands. The aim is to describe 2 possible biofuel routes based on gasification which allow for the implementation of CCS and estimate the overall costs and potential

impact that CCS applied to gasification-based biofuels processes can have on the greenhouse gas balance. The selected examples represent 2 different routes to biofuels production in countries which offer particularly good opportunities for the implementation of CCS. ECN (part of TNO) and SINTEF have cooperated on the execution of this project and have used their own expertise in gasification and biofuel processes for the setup of the cases. Detailed cost analyses, other locations and technological solutions other than mentioned in this exploratory study, as well as extrapolation of the results to a more global perspective, are topics beyond the scope of this project, and should be addressed in more detail in future work.

1.5 SELECTION OF STUDY CASES

This report analyses the implementation of CCS in two examples of biofuel pathways: Fischer-Tropsch syncrude and bio-SNG. The study cases, summarized in Table 1, have been selected to cover a representative range of gasification technologies, biofuel products and possibilities for CCS infrastructure.

Table 1. Overview of selected study cases considered in this report.

	Study case 1 (Chapter 2)	**Study case 2 (Chapter 3)**
Geographical location	Norway	The Netherlands
Gasification technology	High-temperature, entrained-flow	Medium-temperature, indirect gasification
Product	Fischer-Tropsch liquid fuels	Bio-SNG (Synthetic Natural Gas)
Applications	Transportation biofuels (automotive, aviation)	High-temperature heat production (industry), built environment, CHP, vehicle fuel (CNG, LNG for heavy-duty transport)
CO_2 capture	Pre-combustion (physical absorption with Selexol)	Pre-combustion (amine scrubbing)
CO_2 transport	Gas pipeline, boat	Gas pipeline
CO_2 storage	Depleted gas field, offshore	Depleted gas field, offshore

This document is structured as follows: Chapter 2 analyses the integration of CCS into production of liquid FT biofuels from high-temperature gasification, whereas Chapter 3 assesses the implementation of CCS into bio-SNG production. Chapter 4 analyses the economics of both study cases. Finally, Chapter 5 presents the conclusions and outlook of the work.

2. CCS applied to F-T syncrude production

2.1 WHY FISCHER-TROPSCH SYNCRUDE PRODUCTION?

The transport sector is a main contributor to climate gas emissions and needs to find a sustainable energy source for the replacement of liquid fossil fuels. In March 2011, the European Commission launched a new roadmap [9] for moving to a competitive low carbon economy in 2050 emphasized the role of liquid biofuels for aviation and heavy-duty trucks. This message is in line with a significant number of national and international policies stating the importance of biofuels in the future transport sector. Currently in Norway, aviation biofuels are considered as one of the most interesting approach for conversion of biomass to biofuels. Aviation is extremely important in Norway as both the population and economics of the country are more dependent on aviation compared to other countries due to long distances and scattered population. The aviation sector accounts for 4% of Norway's GDP as well both domestic and international travels are increasing [10]. In 2016, a bit over 1 billion litres jet kerosene was sold in the country [11].

In Norway, the National strategy for increased expansion of bioenergy [12] already stated that Norway should increase the biofuels share to approximately 7% from 2010. However, that was not implemented until EU's sustainability criteria were defined. Klimakur2020 [13] recommends biofuels as a part of the solution for reducing greenhouse gas emissions (GHG) and estimates potential CO_2 reductions of 1.7-1.9 million tons in 2020 and 3.8-7.7 million tons in 2030. The Nordic Energy Technology Perspectives report [14] underlines the significant future role of biofuels in all the Nordic countries where the share of biofuels used for transport by 2050 will vary from some 25% in the 2°C Scenario to 70% in the Carbon-Neutral high Bioenergy Scenario. The European Renewable Energy Directive sets the ambitious target of reaching a 20% share of energy from renewable sources by 2020 and a 10% share of renewable energy specifically in the transport sector, with a significant contribution from biofuels.

Early 2017, Norway has adopted an ambitious biofuels implementation plan for road transportation, with 7% supply in 2017 gradually increasing to 20% by 2020. Of which 1.5% and 8%, respectively, must be advanced biofuels. Marine and aviation were exempted, and separate obligations are to be adopted for these sectors. Later in 2017, 1% biofuel share in aviation fuels from 2019 was also adopted.

Avinor, the largest Norwegian airport operator has ambitious plans for implementing aviation biofuels in Norway. Avinor's goal is to cover 30% of the aviation fuel demand with sustainable fuels by 2030. Avinor has already demonstrated the application of biofuels in the airport fuelling system in Oslo Gardermoen airport from January 2016 [15].

Among several technological options [14][16] for producing liquid biofuels that meet or exceed current market specifications, entrained flow gasification (EFG) of biomass followed by the catalytic Fischer-Tropsch synthesis (FTS) offers a promising alternative due to:

- High-energy density as well as the high conversion of hydrocarbons to CO and H_2 in the EFG [17][18].
- High quality of the hydrocarbon products from the FTS (with no sulphur, nitrogen and oxygen) which is compatible with conventional refinery processes for upgrading to marketable biofuels that meet or exceed the oil-derived specifications [19] and do not require any modifications to refinery and distribution infrastructure or vehicle design.

The Fischer-Tropsch route to aviation fuels shows impressive GHG reduction potential. Several

studies, including a recent one [20] concludes that the Fischer-Tropsch route yields the highest GHG emission reduction of 86-104 % compared to fossil jet.

However, the progress in commercialization of this technology route has been limited mainly due to the belief that large scales required to achieve the economic viability [16][21], which is associated to high financial risks from large capital investments as well as to a complex logistics and high cost of feedstock supply. The effect of feedstock supply may be even more critical for countries like Norway where the costs of biomass transport is significant. In this context, decentralized production of FT products with further upgrading in conventional refineries offers a relevant strategy for improving the overall economics of liquid biofuels production since it reduces the capital investment by utilizing existing petrochemical infrastructure.

2.2 OVERVIEW OF THE PROPOSED CHAIN

Figure 2 shows the value chain analysed in this chapter, which considers the co-processing of woody biomass and sewage sludge for production of FT biofuels. The main conversion route includes thermal pre-treatment of the feedstock, oxygen-enriched entrained flow gasification (EFG) followed by syngas cooling and conditioning, Fischer Tropsch synthesis (FTS) and hydro-processing of the FTS products. Pre-treatment of the wood, which includes drying, torrefaction, grinding and pelleting. is decentralized, based on 10 plants with a capacity of 10.9 ton/h (output). The pre-treated feedstock is then converted to FT syncrude in an EFG-FTS plant with a capacity of 600 MWth, based on thermal input to the EFG. Sewage sludge is dried directly at the EFG-FTS plant using recovered heat from the main gasification and synthesis processes. The EFG-FTS plant with will produce 264-294 MW FT syncrude, which is then transported to an oil refinery for production of fuels. 24-30 MW bio-LNG and 90-180 MW heat will be also produced at the proposed plant. The plant will capture 23.5-27.7 ton/h CO_2 with Selexol system. The captured CO_2 will be transported to Utsira formation, which has been used for CO_2 storage since 2014. The studied value chain is described in more detail including methodology, assumptions and references in Chapter 2.3. The exchange rate used during conversion of reference data is 1 € = 1.2 $.

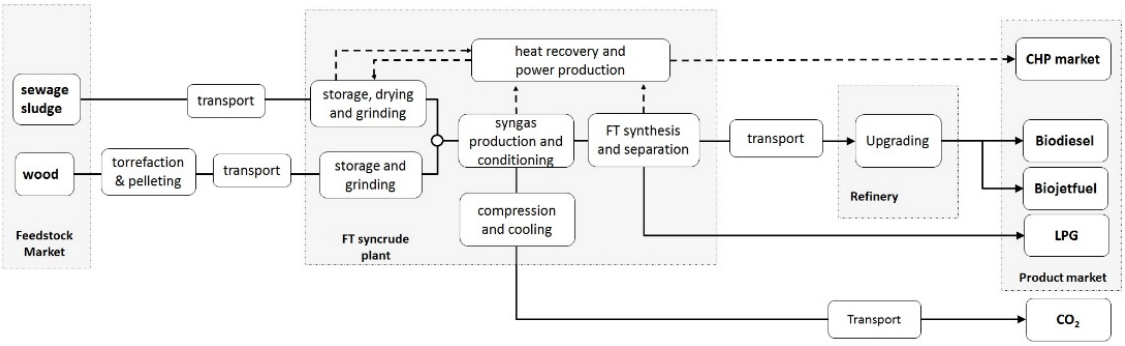


Figure 2. Overview of value chain model considered in this study case.

a) Location of the FT syncrude plant and timeline

The FT plant will be located at Follum forest industry site, near Oslo area. The FT products, naphtha, middle distillate and wax, will be transported to the Esso refinery in Hønefoss, located approximately at 7 km from the Follum site, for direct refining to diesel and jet fuel. The CO_2 is stored at the Utsira formation, located at approximately 800 km by boat. This formation has been used for CO_2 storage since 2014. The plant will be constructed in 2030.

b) Biomass feedstock

Entrained flow gasification is a flexible technology in terms of feedstock composition, subject to having sufficiently small particle size (below 0.5 mm) and moisture content (below 10% wt.). In

this study, we consider co-processing of logwood and sewage sludge. Sewage sludge is chosen because of its wide availability and the overall feedstock cost reduction possibility due to gate fee. To address the impact in the feedstock supply cost, this study consider three different cases for feedstock supply, i.e. 100, 75 and 50% mass fraction of wood in the feedstock.

The biomass cost considered includes logwood production and delivering to the decentralized torrefaction and pelleting plant and transport of the torrefied pellets to the FT syncrude production plant (that is, is the price at the plant gate). Table 2 shows the total feedstock supply cost to the plant for the three cases considered based on 0 and 10 €/ton gate fee for the sludge. Table 3 shows the assumptions used for the calculation of the total cost of the feedstock. These results show that the total supply cost is strongly dependent on the gate fee (negative production cost) charged for treating the sludge. As the gate fee increases from zero to about 10 €/ton, the cost of feedstock supply decreases by 35% when increasing the fraction of sludge from zero to 50%.

Table 2. Summary of biomass cost (€/GJ) for a 600 MW capacity (based on input energy) FT plant. The assumptions are based on Table 3.

Cases	100% wood	75% wood	50% wood
0 €/ton gate fee for the sludge	3.3	3.1	2.8
10 €/ton gate fee for the sludge	3.3	2.7	1.9

Table 3. Assumptions used to calculate the feedstock supply cost [22].

Biomass supply variables	Value
Logwood density	400 kg/m^3
Logwood availability	10 tons/ha
Production cost logwood deliver at road	28 €/ m^3
Torrefied wood pellets density	525 kg/m^3
Torrefied wood pellets energy density	10.1 MJ/m^3
Torrefaction dry mass yield	96 %

Biomass supply variables	Value
Production cost sludge	0 and 10 €/ ton
Transportation cost (fixed)	3 €/ m^3
Transportation cost (variable)	0.075 €/m^3/km

c) F-T syncrude plant

The calculations presented in this case study correspond to a 600 MW thermal input (~ 120 ton/h dry biomass) to the EFG to produce 270-290 MW of FT products, equivalent to 173-192 ton/year. The methodology, assumptions and references the calculations are based on are shown in Chapter 2.3. Pre-treatment of the wood is performed in 10 decentralized plants of about 10 ton/h output capacity. Depending on the type of catalyst and the operating conditions in the FTS, the composition (% wt.) of the FT products is in the range of 18.1-52.5 LNG (C_1-C_3), 8.2-13.8 iso-butane/n-butane (C_4), 23-27.3 naphtha (C_5-C_{10}), 10.1-33-6 middle distillate (C_{11}-C_{19}) and 0.5-16.4 heavy wax (C_{20+}). The total permanent investment and total operating costs for the FT plant are shown in Table 4.

Table 4. Total investment costs and total operating costs for the 600 MW_{th} FT plant considered in this study.

	Low	Average	High
Total Capital Investment cost (M€)	1035	1220	1460
Total annual operating cost (M€)	135	148	163

d) CO_2 capture

Depending on the feedstock composition and the operating conditions in the EFG, the FT plant will be able to capture 39 - 46% of the carbon contained in the inlet biomass (assuming that the carbon content in the logwood and the sludge are, respectively, equal to 48.8 and 33.6 % wt. on dry basis). The carbon balance of the FT process is shown in Figure 3. The figure indicates, that the carbon efficiency of producing FT products from biomass is quite high, ranging between 48.7 and 55.7% depending on the operating conditions in the EFG. The carbon lost in the feedstock pre-treatment, due to loss of combustible volatiles in the torrefaction process, represents only about 5% of the inlet carbon. In total, 23.5-27.7 ton/h carbon is removed from the syngas after EFG using physical absorption (see section 2.3).

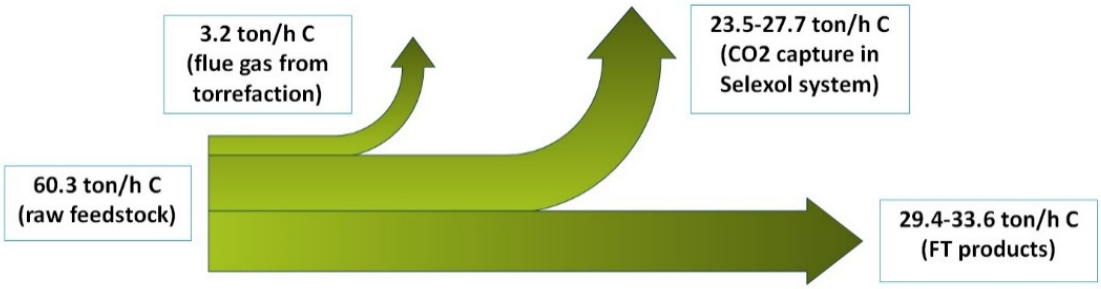


Figure 3. Carbon balance over the FT process and carbon capture efficiency.

The energy consumption in the physical absorption system, based on Selexol as solvent, includes electric power demand (55 – 70 kWh/ton CO_2). Energy losses in the solvent cooling process are (0.3 – 0.4 MJ/kg CO_2). The captured CO_2 is compressed and cooled to approximately 100 bar for pipeline transport.

e) CO_2 transport and storage

Figure 4 shows a schematic overview of the geographical integration of the value chain. The CO_2 storage site will be the Utsira formation, which has been used for reinjection of CO_2 from natural gas upgrading since 1996 [23] and for storage of the CO_2 generated at the Mongstad refinery since 2014. In this study case, FT plant is part of an industrial cluster of CO_2 sources in the Oslo area. The CO_2 streams from each individual industrial site will be transported by pipe to the Esso refinery in Tønsberg. The collected CO_2, including CO_2 captured at the refinery, will be transported by boat to the Utsira formation. The Utsira formation is located at approximately 800 km by boat from Tønsberg.

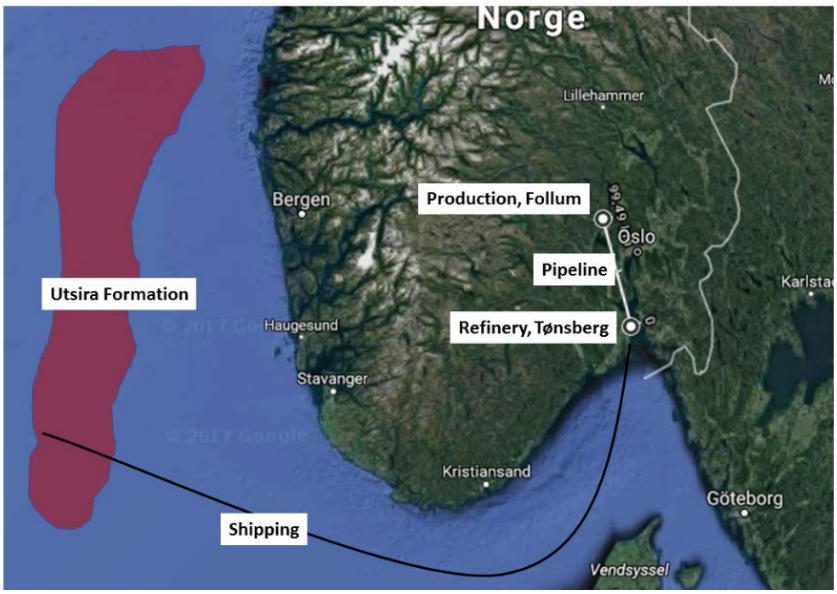


Figure 4. Schematic overview of the geographical integration of the value chain, including the FT plant, refinery for upgrading of FT products, and the CO_2 transport and storage site.

The CO_2 transport considered in this study are shown in Table 5. These values, based on recent results from Jakobsen et al. [24], assumed an annual capacity of 925 tons of CO_2, unit transport cost by pipe equal to 0.089 €/ton CO_2/km, total transport cost by boat for a distance of 730 km equal to 0.049 €/ton CO_2/km. The storage cost for the Utsira formation is assumed to be equal to the storage cost calculated by Jakobsen et al. [24] for the Johansen formation, that is 24.3 €/ton.

Table 5. Range of CO_2 transport costs considered in this study (reference value highlighted in green).

	By boat	By pipe
Transport cost (€/ton CO_2)	36.1	**11.1**

f) Market prices

The range of market prices considered is shown in Table 6.

Table 6. Economic parameters considered in this study.

	Value
CO_2 price (€/ton)	25-100
NG price (€/GJ)	5-10
Heat (district heating) (€/GJ)	16.2

2.3 FISCHER-TROPSCH PROCESS

2.3.1 General overview

Figure 5 shows the overall process block diagram of the FT syncrude production plant based on co-processing wood and sewage sludge. The main process steps include thermal pre-treatments of the woody biomass and the sewage sludge, for reducing the moisture content and the particles size of the feedstock, high-temperature oxygen-enriched EFG followed by syngas cooling and conditioning and FTS with separation of hydrocarbon products. The main product of the plant is the so-called FT syncrude, which is here defined as the mixture of hydrocarbons produced from the FTS with carbon number above 3 (iso-butane/n-butane, C_4, naphtha, C_5-C_{10}, middle distillate, C_{11}-C_{19}, and heavy wax C_{20+}). The plant includes co-production of liquefied natural gas (LNG) from the gas stream after separation, which is composed of hydrocarbon with carbon number 1-3. Further refining of the FT syncrude fractions to marketable liquid biofuels is on conventional refinery processes, has been excluded from the analysis in this work. Available heat from the syngas cooling and the FTS is here recovered for production of superheated steam, which is utilized for pre-treatment of the feedstock as well as for the gasification and water gas shift (WGS) processes. The net excess heat from the plant is exported for district heating.

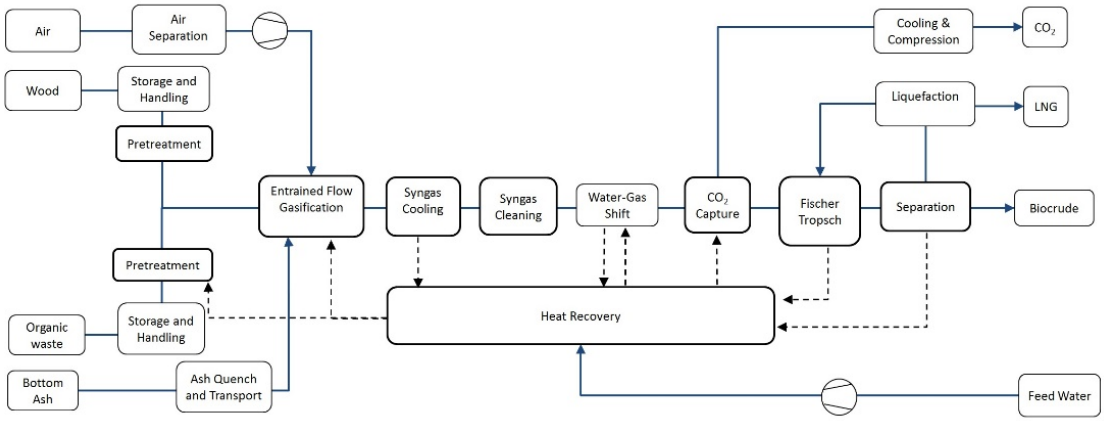


Figure 5. Overall process diagram of the FT plant considered in this work.

2.3.2 Feedstock pre-treatment

The process flow diagram of the complete feedstock pre-treatment system is shown in Figure 6. Pre-treatment of the logwood is performed in separate decentralized plants, which include chipping and screening, drying, torrefaction, grinding and pelleting. Bark, which has a higher ash content compared to stem wood, is not separated before chipping in order to increase the overall ash content in the input biomass to the entrained flow gasification. The heat produced from combustion of the volatiles released from torrefaction is used for heating the feedstock in the torrefaction reactor and preheating the drying gas before the woodchips dryer. Torrefaction of the woody biomass improves the grindability and energy density of the input feedstock to gasification leading to a better economic performance of the overall biocrude production compared to pre-treatment based on conventional drying only [25]. Pre-treatment of the sludge is integrated in the FT syncrude production plant and includes drying and grinding. Steam produced from the heat recovery system of the plant is utilized as the heating medium for drying the sludge.

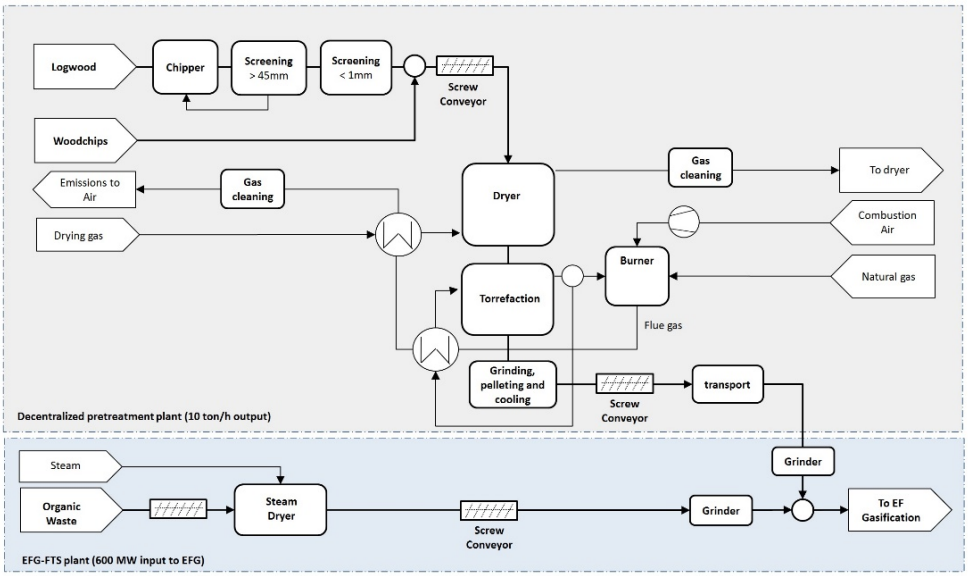


Figure 6. Process Flow Diagram of the feedstock pre-treatment system.

2.3.3 Entrained-flow gasification and syngas cooling and conditioning

Figure 7 shows the process flow diagram for the gasification and the syngas cooling and conditioning systems. Thermochemical conversion of the biomass to syngas is performed in an EFG operated with oxygen-enriched air and steam. The syngas from the EFG reactor is cooled with recovery of heat for production of superheated steam. The process design for the syngas cooling includes a

radiative and convective water-tube evaporation of saturated water, super-heating of saturated steam, gas-tube boiler and economizer for preheating the temperature of the feed water. After cooling, removal of particulate matter is performed with bag filters. Increase of the H_2/CO molar ratio of the syngas to the value required by FT synthesis is performed by complete water-gas shifting (WGS) of a fraction of the total syngas flow. Heat recovery after the WGS reactor is performed in a boiler with production of saturated steam. The temperature of the syngas in the boiler is kept above the saturation temperature to avoid water condensation. Removal of CO_2 and H_2S from the shifted syngas is performed in a Selexol system, shown in Figure 8. This technology is suitable for the range of CO_2 removal efficiencies required, which varies within 82-90% depending on the initial syngas composition and exhibits low H_2 and CO losses [26]. Selexol also allows pure pressure-swing process configurations and minimize the energy consumption for thermal regeneration in the range of CO_2 removal efficiencies considered. The Selexol system includes syngas cooling with free condensed water removal in a water knock-out drum, the absorber where the syngas is in direct contact with the lean Selexol solvent, and the solvent regeneration unit. Regeneration of the Selexol is performed in three flash drums, operating at 10, 6.5 and 1.1 bar. The flash gas from the first two flash drums contains considerable amounts of H_2 and CO and is therefore recycled to the absorber to minimize the losses of these components. The flashed gas from the near-atmospheric regeneration stage is a high-purity CO_2 stream, which is further compressed and cooled for storage in liquid phase. After regeneration, the lean Selexol is cooled by fresh water before entering the absorber.

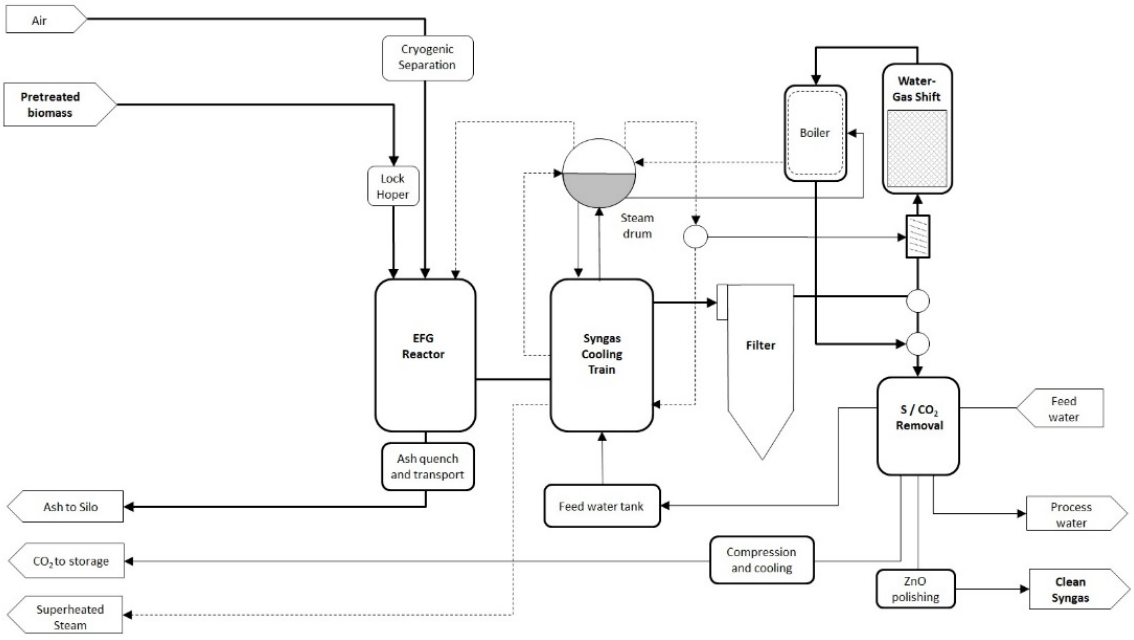


Figure 7. Process Flow Diagram of the entrained flow gasification and the syngas cooling and conditioning trains.

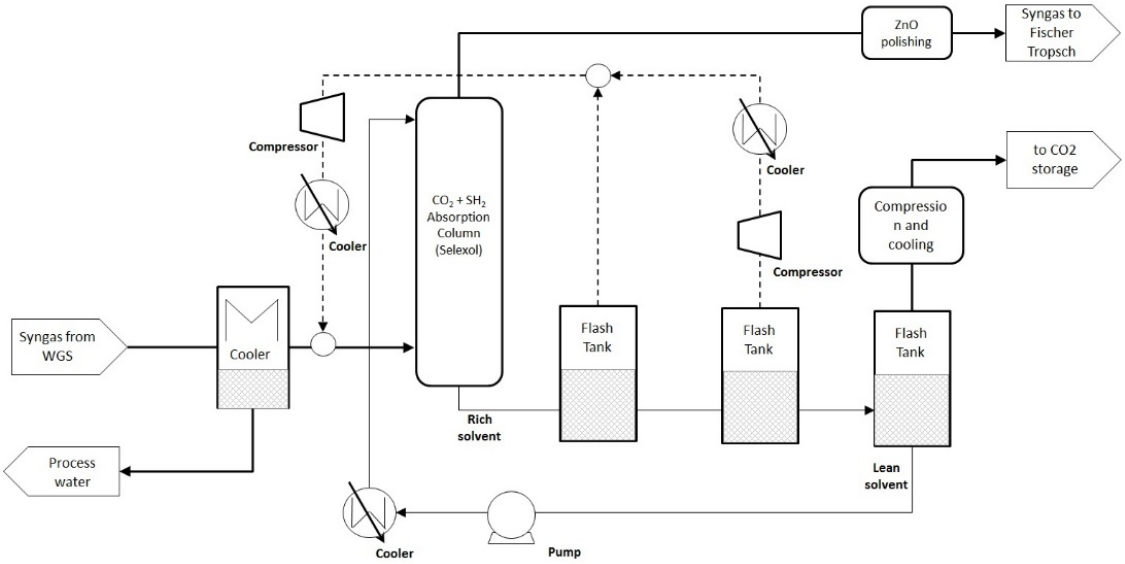


Figure 8. Process Flow Diagram of the CO_2 capture based on physical solvents (Selexol).

2.3.4 Fischer-Tropsch synthesis

Figure 9 shows the process design for FT synthesis and separation. The syngas stream after CO_2 capture is compressed by a booster compressor and fed into the FTS reactor. The overall FTS process is here specified based on the pressure and temperature along the catalyst bed, denoted by and, the CO conversion factor and as well the catalyst reactivity and selectivity to the different hydrocarbons products. Cooling of the FTS reactor is performed through evaporation in saturated-water tubes to achieve uniformity of the temperature inside the reactor. This avoids problems with catalyst deactivation due to sintering and coking as well as formation of significant amounts of undesirable methane in the product through methanation [27][28]. After synthesis, waxes, with carbon number equal to or above C_{20}, are separated directly from the FTS reactor. Middle distillate and naphtha, with carbon number C_{11}-C_{19} and C_5-C_{10}, respectively, are separated sequentially using water coolers. The remaining C_4 hydrocarbons and the LNG mixture, C_1-C_3, are separated based on refrigeration and cryogenic cooling, respectively. The cooling water after separation of middle distillates and naphtha is used as feed water for the heat recovery system.

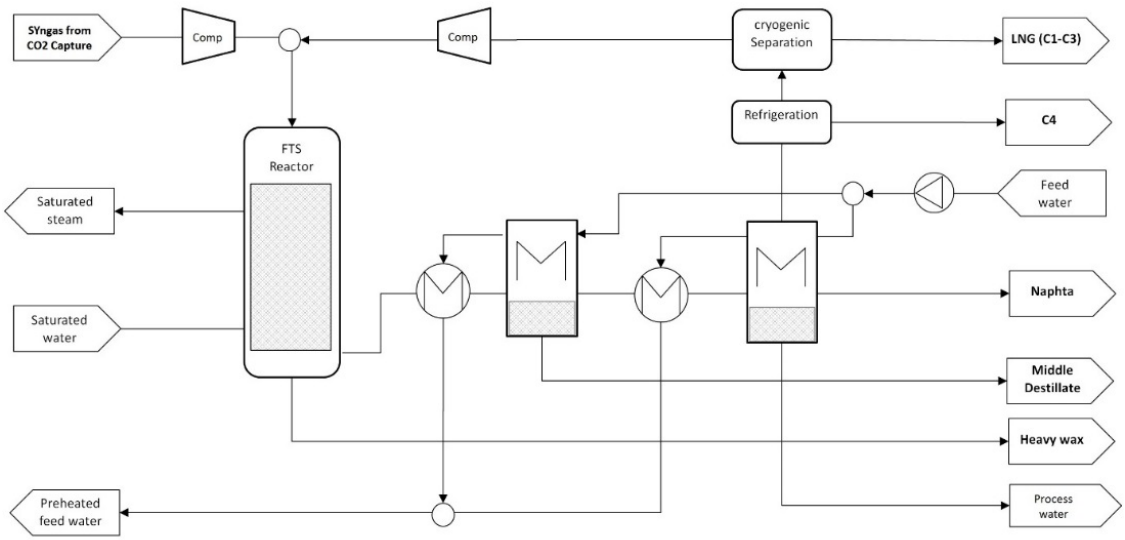


Figure 9. Process Flow Diagram of the FTS system and products separation.

3. CCS applied to bio-SNG production

3.1 WHY BIO-SNG PRODUCTION?

The Netherlands can be considered a traditional gas land. Approximately 38% of the primary energy demand (ca. 3200 PJ) is supplied by natural gas [29]. Moreover, the Netherlands have the most fine-meshed gas network in the world, with more than 12000 km of gas transmission lines [30]. Approximately 98% of the households are currently connected to the gas grid [31].

The Slochteren gas field in Groningen, one of the largest gas fields in the world, was discovered in 1959 and gas production started in 1963 [30]. From the initial 2600 billion cubic meter (bcm) reserves, there are less than 800 bcm remaining [32], which is approximately equivalent to 25 years consumption at current levels. The depletion of the gas field led to problems: since the 1980s, the area around the Groningen gas field has been hit by over 1000 earthquakes induced by gas drilling, which have been escalating in intensity over the last few decades [33]. In order to reduce the risk of earthquakes, the Dutch Ministry of Economic Affairs ordered in April 2017 a production cap of 21.6 bcm/y in the national gas drilling [29]. This amount is roughly half than the production in 2014, and it is very far from the 100 bcm/y gas production during the first decade of operation of the gas field. The combination of the depleting gas reserves and the production cap is a source of concern due to the prospects of increasing dependency of natural gas, the country thus shifting from being a gas exporter to a gas importer [29].

On top of this, the commitment resulting from the Paris agreement signed in 2016 implies the need for a severe reduction in CO_2 emissions (between -80 and -95% in 2050 with respect to 1990 levels). At national level, these targets have been compiled in the Energy Strategy prepared by the Dutch Government [34]. However, the Netherlands are still far from achieving this target: currently, only 5.9% of the total energy is covered by renewable sources [35]. As a comparison, the target was set at 14% renewables for 2020. Approximately 63% (80 PJ) of the current renewable energy is supplied by biomass, mostly in co-firing applications.

With this background, renewable methane produced from digestion, gasification or power-to-gas can play a significant role in a future CO_2-free energy system. Biomethane can replace fossil natural gas in sectors where other economic alternatives are difficult (e.g. high-temperature industrial heat, production of feedstock for chemical production, built environment). One of the main advantages of green gas compared to other renewable sources (solar, wind) is the possibility of storage, transport and use using existing infrastructure. Moreover, biomethane has a good potential for the balancing of the electricity grid (important issue in a scenario with increasing contribution of intermittent renewable sources). In the case of the Netherlands, the production of methane from biomass or power-to-gas will enable a faster and less costly energy transition. Liquefied green gas can also play a role in the transport sector, particularly in heavy duty vehicles and boats.

In 2011, the Dutch Ministry of Economic Affairs and 25 partners of the Green Gas Forum signed the Green Gas Deal [36], with the objective of developing a green gas market in the mid-term. A roadmap was outlined for the upscaling of biogas production and the development of new green gas technologies (biomass gasification, power to gas), with a target of 3 bcm of equivalent natural gas in 2030. As a comparison, the current production of biomethane is ca. 0.5 bcm/y. According to the Green Gas Forum, it would be possible to produce 5-6 bcm green gas using local (wet) biomass sources.

Anaerobic digestion is currently the main route for biomethane production in the Netherlands [36]. However, its current potential is limited, although it is expected that new developments (e.g. process upscaling, optimization of operating conditions, improved management of waste feedstock, selective

microorganisms, etc., implementation of large-scale seaweed cultivation, etc.) will contribute to the increase of potential and the reduction of production costs. Compared to digestion, gasification of dry biomass/waste can allow the large-scale production of methane. The production of bio-SNG from biomass gasification will thus contribute to the further deployment of the green gas sector. Moreover, the gasification platform enables good opportunities for synergies with the production of other fuels and chemicals, for example through the implementation of co-production schemes [37]. Although first promising steps have been taken in the commercialization of bio-SNG production (with the GoBiGas plant as main highlight [38]), further effort needs to be done to demonstrate the technology. Current projects for bio-SNG production from biomass gasification include, besides GoBiGas (Sweden), the GAYA project (France) [39] and the AMBIGO project (the Netherlands) [40]. The latter one will demonstrate at semi-commercial scale the combination of the technologies developed at ECN for the efficient production of bio-SNG, which will be described in more detail in Section 3.4.

3.2 CCS POTENTIAL IN THE NETHERLANDS

The Netherlands offers a favourable case for the implementation of CCS. Its geographical location is a strategic position between large CO_2 sources of Germany and France and storage reservoirs in the North Sea [3]. Moreover, a large fraction (>60%) of the CO_2 emissions come from large emitters (industry and power plants) [41]. Thus, clustered, large CO_2 sources are available. Due to its natural gas-related history, the Netherlands have abundant depleted gas fields, both onshore and offshore, thus a potential large storage capacity is available. Alternative sinks such as aquifers or depleted oil fields are also under consideration [3]. The transport distances are moreover relatively short (up to around 100 km). In addition to this, the extensive knowledge of oil and gas production together with the availability of large existing gas infrastructure can be potentially applied/reused for the deployment of CCS networks.

Figure 10 shows the potential CO_2 storage locations in The Netherlands. Among the candidate locations for CO_2 storage, there are two of them still on track: the offshore gas production site K12-B (operated by the former GDF Suez, currently Engie), and the offshore P18-4 site (operated by TAQA) [42].

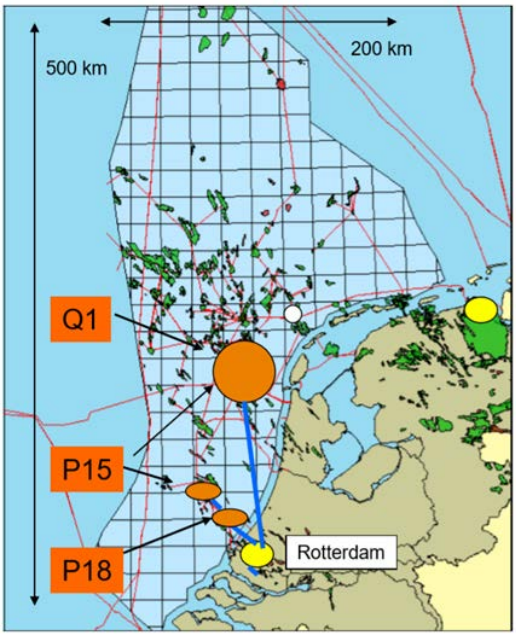


Figure 10. Storage options for CCS in The Netherlands: P18 (40 Mton capacity, 18 km distance); P15 (40 Mton capacity, 28 km), Q1 (200 Mton capacity, 110 km) [41].

Supported by these favourable conditions, CCS has been identified as a technology that in combination with other measures (electrification, increase of energy efficiency, deployment of renewable energy) can contribute to decarbonize the Dutch energy sector, thus achieving the ambitious CO_2 reduction objectives. The Dutch National R&D programme for CCS (CATO) [43][44] was started in 2004 as a result of this strategic interest. After the first (CATO-1, 2004-2008) and second phases (2010-2014) [3][44], the third phase of the CATO program started in November 2014 in order to further promote the knowledge transfer and the commercial deployment of a CCS network in The Netherlands.

Figure 11 depicts an example of the planning and development of the Carbon Compact Rotterdam CC(U)S network. A cluster of industrial CO_2 sources located around the Rotterdam harbour are connected to a CO_2 pipeline. Part of the CO_2 is transported for reuse in greenhouses (OCAP-CO_2 pipeline network) [43], whereas another fraction is transported to a CO_2 terminal. From the terminal, CO_2 can be either transported offshore for storage in depleted gas fields or applied for enhanced oil recovery (EOR) or enhanced gas recovery (EGR). Excellent examples containing the detailed description and cost estimation of the infrastructure for the transport and injection of CO_2 in depleted offshore gas reservoirs can be found elsewhere [46][47][48].

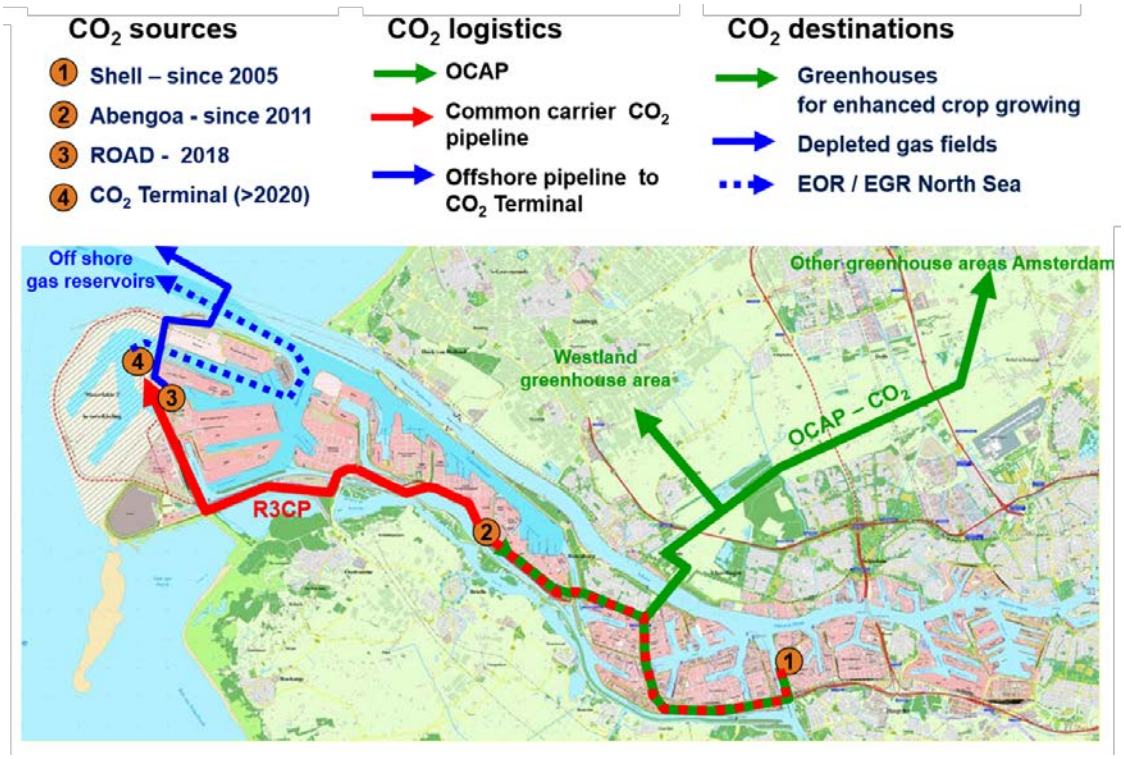


Figure 11. Example of development plans of CC(U)S network in the Netherlands: the Carbon Compact Rotterdam project [41].

The current perspectives for the deployment of CCS in The Netherlands look promising: despite the cancellation in 2017 of the ROAD project, the recently formed Dutch government announced ambitious targets for the deployment of CCS in industry towards 2030, with CCS aiming at contributing to 1/3 of the total emission reduction until 2030 [49]. Meanwhile, the Rotterdam Port is leading a project to lay the foundations for a CO_2 transport and storage infrastructure network, Dutch companies have been successfully engaged in a number European projects for cross-border CO_2 transportation projects, and a new Dutch CCS Roadmap, including the launching of the third phase of the CATO research program, is ongoing [44].

3.3 OVERVIEW OF THE PROPOSED CHAIN

Figure 12 plots the CCS chain analysed in this chapter. A 600 MW_{th} thermal input bio-SNG plant (~ 120 ton/h dry wood) located in the Netherlands (e.g. Rotterdam area) will produce 395 MW bio-SNG of Groningen-gas quality (~ 31.5 MJ/Nm^3). This plant will capture 73.5 ton/h CO_2 (0.55 Mton CO_2/year), which will be then transported onshore/offshore and be subsequently stored in a depleted gas field located in the North Sea. The whole chain will be described in Section 3.4.

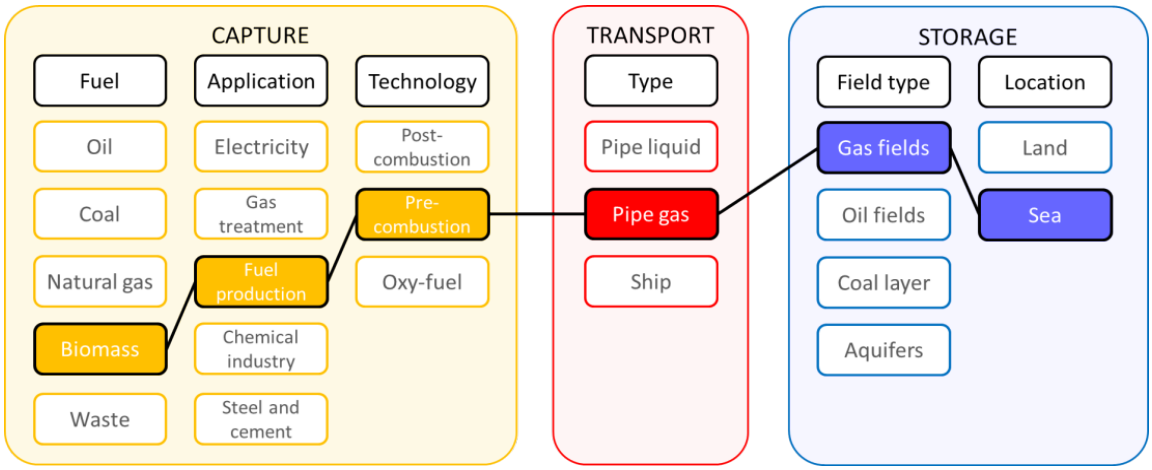


Figure 12. Overview of CCS chain considered in this study case (adapted from [3]).

a) Location of the bio-SNG plant and timeline

The bio-SNG plant will be located in The Netherlands, near the Rotterdam area. The Rotterdam area offers a favourable location for CCS due to the concentration of industrial CO_2 sources and due to the proximity of significant volumes of both onshore and offshore storage capacity [50]. For this reason, this industrial area has been already the focus for the implementation of a CCS cluster [50]. The plant will be constructed in 2030.

b) Biomass feedstock

Indirect gasification, the technology considered in this study case, is more flexible in terms of fuel supply than high-temperature gasification. The bio-SNG plant can use woody biomass (e.g. wood chips, wood pellets, forestry residues, forestry energy crops, demolition wood), agricultural residues (e.g. bagasse, straw, shells, pruning residues), and other waste feedstock (e.g. RDF, paper rejects, etc.).

In order to address the variation in biomass cost, 3 different sources for biomass will be considered in the chain for the sake of sensitivity analysis:

Case a1: Wood chips produced in Scandinavia or North America shipped to Europe (high biomass price).

Case a2: Reference case, biomass from European energy crops (medium biomass price).

Case a3: Agricultural residues from e.g. sugarcane bagasse from Brazil shipped to Europe (low biomass price).

The biomass cost considered includes production, pre-treatment and transport (that is, is the price at the plant gate). The range of biomass cost assumed in this work is summarized in Table 7.

Table 7. Summary of biomass cost considered in this model (assumptions based on [51][52]).

	Case a1	Case a2 (ref.)	Case a3
Biomass cost (€/GJ)	9.5	**6.5**	4.5 (= 2 + 2.5)

c) Bio-SNG process

The calculations presented in this case study correspond to a 600 MW thermal input (around 120 ton/h dry biomass) to produce 38.3 ton/h bio-SNG (395 MW or approximately 0.34 bcm/y of Groningen-gas quality). Section 3.4 describes in detail the bio-SNG process considered in this study and presents the assumptions and references used for the study.

d) CO_2 capture

The bio-SNG plant will be able to capture 33.3% of the carbon contained in the inlet biomass (assuming woody feedstock with 43 wt.% carbon, as received). The carbon balance of the bio-SNG process is plotted in Figure 13. As can be seen, the inlet carbon is roughly equally distributed in three streams. Approximately 28% of the inlet carbon ends up in the flue gas stream (see Section 3.4.2 for the description of the gasification technology). In principle, the CO_2 contained in the flue gas could be captured by applying extra post-combustion capture technology. However, this comes at the cost of increasing the investment and operational costs. Therefore, in our study case we only consider pre-combustion capture applied to the product gas used for the synthesis of bio-SNG. From the remaining product gas that will be directed to the upgrading and synthesis sections, approximately 45.9% of the carbon is removed for further CCS (33% of the inlet), the rest (39% of the inlet carbon) ending up in the bio-SNG product. In total, 73.5 ton/h CO_2 will be removed from the product gas using pre-combustion capture. In this study case, amine scrubbing (e.g. MDEA) will be applied.

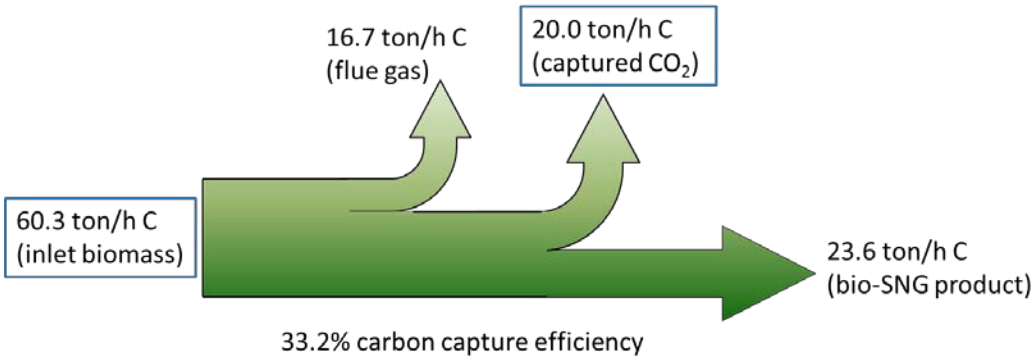


Figure 13. Carbon balance over the bio-SNG process and carbon capture efficiency.

The energy consumption of an amine scrubbing unit includes 2 sources: power demand (60 – 100 kWh/ton CO_2) and steam demand (0.02 – 0.04 MJ/kg CO_2) [51]. Based on average values from this literature source, we estimate that the energy penalty associated to the implementation of capture in the bio-SNG plant is approximately 2.3%. The captured CO_2 will be compressed in the plant to approximately 100 bar for pipeline transport.

The integration of bio-SNG production and CCS moreover, as considered in this study, offers a

particular, additional advantage to those of CCS described in Section 3.2: methane being the biofuel with the highest H/C ratio, the fraction of CO_2 that can be captured from biomass is higher with respect to other carbon-based biofuels. Moreover, if the gas is injected to the grid and afterwards used for large-scale power production or CHP, there is the possibility of extra CO_2 capture.

e) CCS infrastructure

In this study case, we assume that the bio-SNG plant is part of an industrial cluster formed by other CO_2 (mixed biogenic and non-biogenic) sources. This leads to the overall reduction of CO_2 transport and storage costs. Clusters for the cost-effective implementation of CCS in the Netherlands are described in references [3][50].

f) CO_2 transport

The compressed CO_2 stream will be transported in a gas pipeline over a distance of ~200 km (see Figure 14). A range of CO_2 transport costs (Table 8), as discussed in [51], is considered in the cost estimation:

Case b1: Project starting in 2030 (first 20 Gton CO_2 stored). No match of sources and sinks necessary, case economically more favourable.

Case b2: Project starting after the first 20 Gton CO_2 stored: match of sources and sinks necessary, less favourable case.

Case b3: Project starting in 2050. Higher marginal transport costs due to less economic source-sink matching, CCS applied to smaller sources, reduced economies of scale.

Figure 14. Example of CO_2 network considered for the CCS cluster of Rotterdam [50].

Table 8. Range of CO_2 transport costs considered in this study.

	Case b1 [51]	Case b2 (ref.)	Case b3
Transport cost (€/ton CO_2)	5	**10**	20

g) CO_2 storage

In the considered reference case, the CO_2 captured will be stored in an offshore depleted gas field in the North Sea. Offshore storage is more expensive than onshore storage. Sites such as the P18/P15 depleted gas fields and Q1 aquifers have been considered in the literature [46][47]. The effect of the storage location will also be considered in the analysis (Table 9):

Case c1: onshore carbon storage.

Case c2 (reference): offshore storage.

Table 9. Range of CO_2 storage cost considered in this study [51].

	Case c1	Case c2 (ref.)
CO_2 storage (€/ton)	5	**13**

h) CO_2 and bio-SNG prices

An important factor that will affect the feasibility of CCS in the future is the CO_2 price. The key obstacle to the implementation of bio-CCS is the absence of a price for stored biomass-based CO_2 (thus an economic value on 'negative emissions') in the current EU ETS system [51]. In this study we will assume that by the time the bio-SNG plant is operating (around 2030), bio-CCS has already been added in the CDM (Clean Development Mechanism) (as recommended in [51]), so that the derived economic incentive can be taken into account in the cost analysis. The range of CO_2 prices considered is shown in Table 10.

Table 10. Range of CO_2 price considered in this study.

	Case d1	Case d2 (ref.)	Case d3
CO_2 price (€/ton)	25	**50**	100

The selling price of the bio-SNG product is another crucial parameter for the economic feasibility of bio-SNG. For the price of bio-SNG we assume that the future price of the fossil equivalent natural gas will include a penalty cost associated to CO_2 emissions. Based on the emission factor of natural gas (56.1 kg CO_2/GJ [61]) and the CO_2 price (Table 10), we estimate the penalty price of natural gas, which in turn will determine the minimum price at which the bio-SNG can be competitive with fossil NG. In our study we will vary the base natural gas price (Table 11), taking into account that the reference price (current price, conservative case) is approximately 5 €/GJ.

Table 11. Range of natural gas prices considered in this study.

	Case e2 (ref.)	Case e3
NG price (€/GJ)	**5**	8

i) Total Investment Costs of bio-SNG plant

Table 12 summarizes the range of TCI considered in the analysis.

Table 12. Range of bio-SNG investment costs considered in this study.

	Case f1 (ref.) [58]	Case f2
Total Investment costs (€/kW_{th} input)	**1000**	2000

3.4 BIO-SNG PRODUCTION PROCESS

3.4.1 Introduction

The schematic layout of the proposed bio-SNG process is shown in Figure 15. The process is based on the application of indirect gasification, followed by cleaning and upgrading of the product gas and catalytic conversion to methane. Indirect gasification produces a N_2-free, hydrocarbon-rich product gas, which is very suitable for the production of bio-SNG. Moreover, the combination of the selected technologies (MILENA indirect gasification, OLGA tar removal and ESME methanation) [53][54][55] leads to an increase of the overall process efficiency, since the light aromatic hydrocarbons (BTX) are not removed from the gas, but converted to methane.

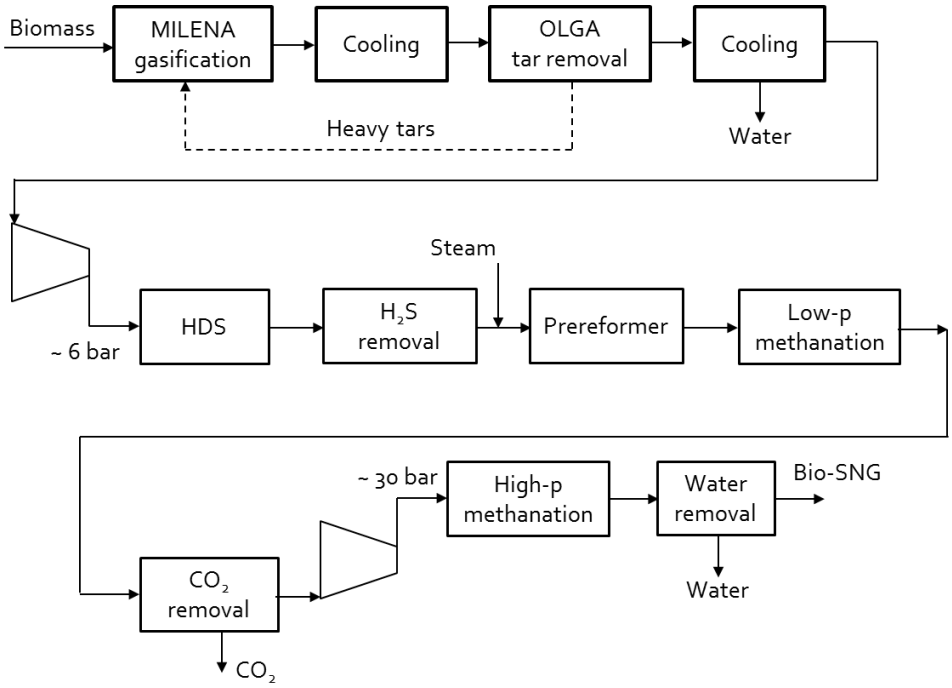


Figure 15. Schematic layout of bio-SNG production from indirect gasification of biomass considered in this work.

3.4.2 MILENA indirect gasification

Unlike direct gasification processes, in which the heat necessary for the endothermic gasification reactions to take place is supplied by the partial combustion of the biomass in the same chamber (thus leading to a dilution of N_2 in the product gas, and to the production of unburned carbon or char), in indirect gasification processes the stages of gasification and combustion are physically separated. This has two advantages: the resulting product gas is not diluted in N_2 (and can thus be used for synthesis applications), without the need for a costly air separation unit, and moreover complete conversion of the biomass can be achieved, since the produced char is used to produce heat for the gasification reactions. The implementation of this principle can be done in different ways, which have resulted in a number of technologies, such as the Battelle, FICFB and MILENA processes. The latter, which is the technology considered in this study, will be described in more detail in this section.

MILENA (Figure 16) consists of 2 reactors integrated in a single vessel: the gasification section operating at approximately 850°C is a fast fluidized bed (riser), where biomass is fed at the bottom. The fluidization of the riser is achieved by a small amount of added gas (e.g. steam, CO_2) and the product gas itself (resulting from the biomass devolatilization). The char and the bed material (e.g. sand, olivine) are separated from the product gas in a settling chamber. The solids fall then by gravity to the combustion reactor, which consists of a bubbling fluidized bed operating at approximately 920-950°C. Air, supplied as fluidization medium of the combustor section, oxidizes the char particles, thus resulting in the heating up of the bed material. Then, the hot bed material is transported back to the bottom of the riser via a circulation hole, thus enabling the heat transfer between the combustor and the riser stages [55].

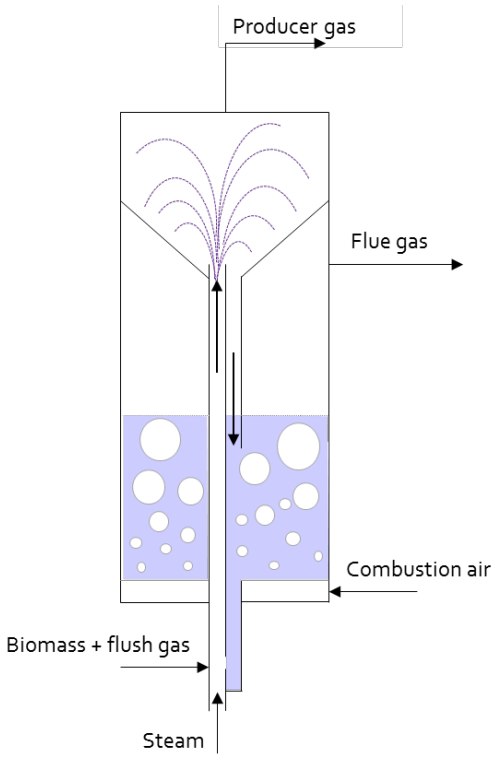


Figure 16. Schematic layout of the MILENA indirect gasifier [55].

The combustion of the char plus the tar recirculated from OLGA is enough to cover the heat demand for the endothermic devolatilization and gasification reactions taking place in the riser. Moreover, MILENA is a self-sustained process in the sense that if the gasification temperature decreases, less gas and more char will be produced, thus the oxidation of a larger fraction of char will result in extra heating of the bed material, which eventually will imply a higher temperature in the riser, thus reaching a new equilibrium point that tends to restore the initial conditions.

(Medium-temperature) indirect gasification is a suitable technology for the production of bio-SNG, since the product gas from the gasifier not only has a very low N_2 concentration (1-3 vol.%, dry), but also contains already a significant amount of methane (10-12 vol.%, dry basis) and other hydrocarbons, thus having a high heating value.

3.4.3 OLGA tar removal

A disadvantage of medium-temperature gasification (700-900°C) is the presence of relatively large amount of tar in the product gas. For synthesis applications, it is necessary to clean the gas from tars to avoid catalyst deactivation. In this process, the OLGA tar removal is considered.

OLGA is a commercial technology developed at ECN for the staged removal of tars from gasification gas based on oil scrubbing [56]. The key idea behind dust and tar cleaning is that the separation of dust and tars from the gas is carried out in such a way that a mixture of dust, tar and water is avoided, thus reducing the problem of wastewater treatment. In practice, this means that dust is removed at temperatures above the tar dew point (approximately 450°C), using a cyclone, and tar is removed at OLGA at temperatures above the water dew point (around 80°C). In the cyclone, part of the chlorine contained in the gasification gas in form of salts (e.g. KCl), which condense on the dust particles, will be also removed.

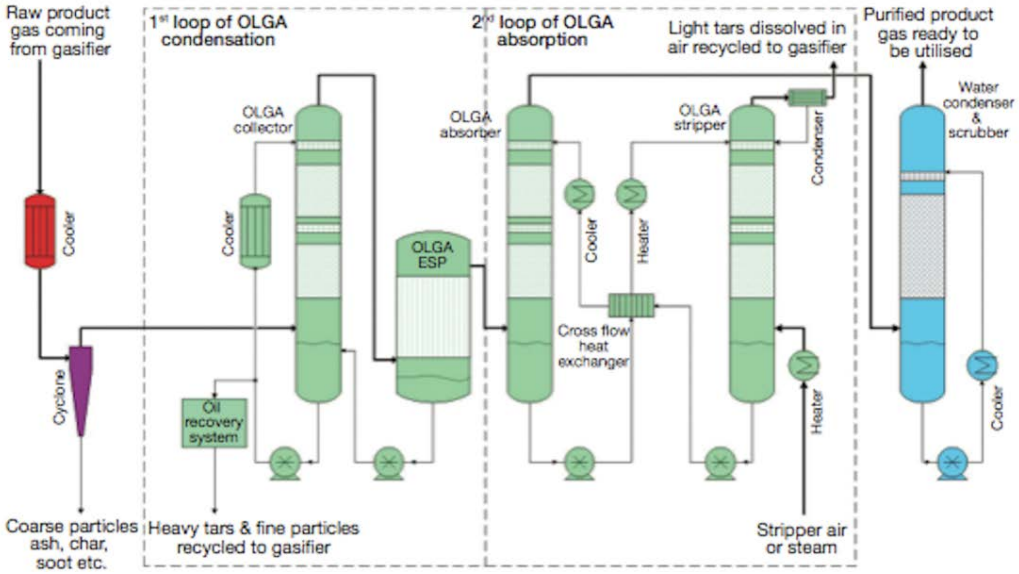


Figure 17. Schematic layout of the OLGA tar removal system [56].

The removal of tars in OLGA takes place in 2 stages. In the first scrubbing column (called collector), the inlet gas is counter-currently cooled with a washing liquid, as a result of which heavy tars are absorbed in the liquid. The remaining dust from the cyclone is also captured in the collector column. Due to the rapid cooling of the gas, aerosols are formed. These aerosols are afterwards removed in a wet electrostatic precipitator (ESP). An oil recovery system (ORS), heavy tars and dust are separated from the spent oil, thus keeping an appropriate viscosity of the oil, which is then recirculated to the top of the collector. The heavy fraction is then recirculated to the combustor side of the MILENA gasifier, so that the energy contained in the tars is used for additional heating up of the bed material.

In a second scrubbing column (called absorber) operating at ~ 80°C, the remaining light tar compounds (e.g. phenol, naphthalene) are washed out from the gas using oil from a second oil loop. The outlet gas is free from tar compounds heavier than toluene, but still contains a large fraction of benzene and toluene, as well as all the water (Table 13). The spent oil is then regenerated in a stripper column which uses air, nitrogen or steam as stripping medium. This stripping gas containing light tar compounds can then be recirculated to the gasifier.

After OLGA, a large fraction of the water contained in the gas is condensed in a gas cooler. Cooling at 40°C will result in a water concentration of ~ 7 vol.% (wet basis), whereas cooling at 20°C will result in a water content of ~ 2 vol.%. The condensate contains also a large fraction of the ammonia and HCl contained in the product gas.

Table 13. Composition of clean product gas from MILENA gasification of wood after OLGA tar removal (source: ECN-TNO experimental data).

Compound	Concentration unit	Concentration value
H_2	vol.%, dry	26 - 29
N_2	vol.%, dry	2 – 3
CH_4	vol.%, dry	11 - 13
CO	vol.%, dry	25 - 32
CO_2	vol.%, dry	20 - 28
C_2H_4	vol.%, dry	3 - 4
C_2H_6	vol.%, dry	0.1 - 0.3
C_2H_2	vol.%, dry	0.1 - 0.3
H_2S	ppmv, dry	100 - 200
COS	ppmv, dry	5 - 10
Benzene	ppmv, dry	5000 - 10000
Toluene	ppmv, dry	200 - 500
Water content	vol.%, wet	30 - 40

3.4.4 ESME system

After tar cleaning and cooling of the gas for water removal, the gasification gas still contains contaminants that can cause the deactivation of the downstream catalysts. For example, sulphur compounds such as H_2S (~100-200 ppmv in gas from wood gasification, dry basis), COS (5-10 ppmv dry), and other organic sulphur compounds such as thiophenes, thiols and thiophene derivatives. Therefore, the gas needs to be upgraded. In this study case, the ESME methanation system developed by ECN is considered [54].

The inlet product gas is firstly compressed to 6 bar. Then, the gas enters at 350°C a hydrodesulphurization unit (HDS), where a commercial CoMo catalyst converts the light aromatic sulphur compounds such as thiophenes, are converted to H_2S and COS, using part of the H_2 contained in the gas. The catalyst also hydrogenates organic nitrogen compounds such as pyridine into NH_3. Traces of organic chlorine compounds are also expected to be converted into HCl. Simultaneously, ethylene and acetylene (as well as other unsaturated C_3-C_5 hydrocarbons) are also hydrogenated to C_2H_6 and other equivalent C_3-C_5 saturated compounds. Given the right conditions, the HDS catalyst also promotes the WGS and methanation reactions. The hydrogenation reactions are exothermic, which results in an increase of the gas temperature by ~ 200°C. At the outlet of the HDS reactor, the only sulphur compounds remaining in the gas are H_2S and COS, which are then removed in a sorbent bed containing a zinc oxide or iron oxide adsorbent. Liquid absorption (e.g. amine scrubbing), is another suitable option at the large scale considered in this study case.

The next step in the upgrading train of ESME is the conversion of the benzene and toluene contained in the gas. For this, a pre-reformer unit is used, where a commercial Ni-based catalyst is used. Addition of steam to the inlet gas, as well as inlet temperatures above 400°C are required to prevent catalyst coking. Besides steam reforming of benzene and toluene, the catalyst also promotes WGS ($CO + H_2O \leftrightarrow CO_2 + H_2$), hydrogenation ($C_2H_6 + H_2 \rightarrow 2\ CH_4$) and methanation ($CO + 3\ H_2 \leftrightarrow CH_4 + H_2O$) reactions. Actually, in the case of prior removal of BTX from the gas (using for example a scrubber unit for the recovery of a bio-BTX product), the pre-reformer unit would act as a first methanation reactor. The combination of the reactions leads to an overall increase of the gas temperature. However, the mild pressure level (~ 6 bar) combined with the presence of CO_2 in the gas contribute to the attenuation of the temperature rise, thus avoiding the need for gas recycling. After gas cooling, the gas enters a methanation reactor, where CO and H_2 are further converted in the presence of a commercial nickel catalyst to CH_4 and H_2O, with additional WGS activity. At this point, approximately half of the dry gas flow is composed of CO_2, which is afterwards captured, for example by chemical absorption or physical absorption. Chemical absorption (e.g. amine scrubbing, regenerative solid adsorbents) is most suitable for the bio-SNG process due to the lower loss of hydrocarbons in the CO_2 stream. Bypassing part of the gas is an option to adjust the gas composition in such a way that the final bio-SNG product has a heating value similar to the natural gas it replaces (in this case, Groningen gas with a relatively low heating value, ~ 31.5 MJ/Nm^3).

After the CO_2 removal unit, the gas contains 56.9 vol.% CH_4, but also 1.4 vol.% CO and 25.6 vol.% H_2. Thus, it is not yet suitable for gas grid injection. Therefore, a second methanation step is required to further convert the last traces of CO (and H_2) to CH_4. For this, the gas is compressed to ~ 25-30 bar and fed to the high-pressure methanation train, composed of 2 methanation reactors with intermediate gas intercooling. After the high-pressure methanation unit, the raw bio-SNG contains 87.7 vol.% CH4, 0.08 vol.% H_2, 0.006 vol.% CO, 11.2 vol.% inert gases (N_2 + CO_2), and 0.9 vol.% water. The final upgrading of the bio-SNG gas consists of drying down to a level that prevents condensate formation, and odorisation to allow leak detection. After this, the produced bio-SNG can be injected in the grid.

3.5 INTEGRATION OF BIO-SNG PLANT IN THE CCS INFRASTRUCTURE

Once the CO_2 stream captured in the bio-SNG plant is available, the next step is to transport the captured CO_2. The selection of the optimal pipeline transport (gas or liquid) depends on the type of storage field, the transport distance and the amount of CO_2 transported [3]. Results from a cost model developed within the Dutch CATO-2 program revealed that gaseous CO_2 transport can be cost-effective if a small CO_2 stream is stored in a nearby reservoir pressure, such as depleted natural gas fields. On the contrary, liquid CO_2 transport is the most cost-effective option if large volumes are transported over large distances or if the CO_2 is stored in aquifers (fields with high reservoir pressure) [3].

In addition to this, the optimization of the CCS chain might encompass the implementation of CCS clusters in industrial areas, which would lead to the reduction of the CO_2 avoidance costs. A generic example of such CCS cluster is plotted in Figure 18. The basic idea behind is that the industries located in a certain area (e.g. power plants, steel and cement plants, chemical production, biofuel plants) would find synergies by applying optimal configurations of CO_2 transport infrastructure, sharing CO_2 separation/upgrading units and/or CO_2 storage sites. This idea is closely related to the concept of "bioenergy hubs", in which the combination of technologies (e.g. injection of H_2 produced from excess renewable electricity into biomass gasification plants for extra biofuel production, reuse of CO_2 captured in biogas/bio-SNG/biofuels plant in power-to-gas plants), or the implementation of shared infrastructure (e.g. common gas cleaning/upgrading) will lead to synergies, therefore to economies of scale and reduction of the costs of CO_2 avoidance [3][4]. Centralized configurations are a cost-effective option for relatively minor emitters (such is the case of bioenergy plants), because of economies of scale [3]. The optimal inlet pressure for onshore CO_2 pipeline transport is 90-120 bar, with supporting pumping stations installed at every ~ 100 km [3].

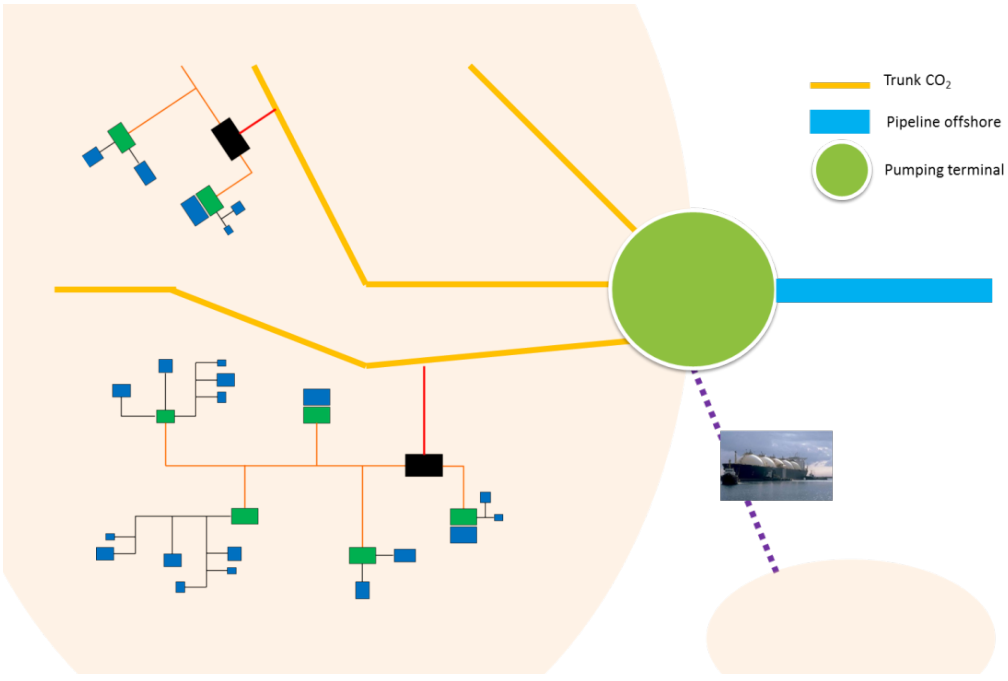


Figure 18. Schematic of CCS chain, including pumping terminals and offshore CO_2 transportation (based on and adapted from [3]).

4. Economic analysis of bio-CCS study cases

4.1 CASE 1: CCS APPLIED TO F-T PRODUCTION

4.1.1 Assumptions

Table 14 summarizes the parameters used for the economic analysis of CCS applied to FT syncrude production.

Table 14. Summary of technical and economic parameters used for the cost calculations for the reference case.

Plant process parameters		
EFG-FTS Plant size (input EFG)	600	MW thermal input
No. wood pre-treatment plants	10	Units
Wood pre-treatment plant size (output)	10.9	ton/h
Net electricity consumption	33	kWh per GJ input feedstock energy
FT syncrude production efficiency	44 – 49%	(LHV based)
LNG production efficiency	4 – 5%	(LHV based)
Heat production efficiency	15 - 30%	(LHV based)
Energy penalty CO_2 compression	4.5 - 7%	Electric power consumption
Plant availability	8000	h/year
Biomass cost	See Table 2	

Plant process parameters		
Carbon capture efficiency	39 - 46%	(based on inlet C mass) Depending on EFG operating conditions
CO_2 Transport distance: Pipe Boat	 125 800	 km km
Economic parameters		
Total Capital Investment [a]	2030	$€_{2016}$/kW input [57]
CO_2 compression and cooling, investment	60-80	€/kW output [51]
Total Plant Operational cost	8.6	€/GJ input [18][59]
CO_2 compression and drying, O&M	22-23	€/kW output/y [51]
Maintenance cost	2	% of the TCI per year
Administration	2	% of the TCI per year
Insurance	1	% of the TCI per year
Cost of biomass	See Table 2	€/GJ
Interest rate	5	% per year
Debt to equity ratio	70:30	-
Debt payment period	10	years, annuity

Plant process parameters		
Income tax rate	30	%
Average labour hourly rate	56.6	€/h
Operating labour burden	0.3	
Labour overhead factor (operators only)	20	%
Labour overhead charge rate	1.25	
Others		
Cost of electricity	0.13	€/kWh
Heat price	58	€/MWh
LNG price	10-25	€/MWh
CO_2 credits	25-100	€/ton

Notes: [a] Includes decentralized wood pre-treatment plant and FT syncrude production plant; [b] Based on input energy to EFG. Includes decentralized wood pre-treatment and FT syngas production plant.

Other financial parameters:

- Construction and commissioning period: 3 years.
- % required capital during construction: 30% in year 1, 50% in year 2 and 20% in year 3.
- Linear depreciation over 20 years.
- Exchange rate: 1 € = 1.2 $.

4.1.2 Effect of implementation of bio-CCS

The main economic results for FT syncrude production, with and without the application of CCS, are shown in Table 16. The total revenues include liquefied NG, exported heat to district heating and CO_2 credits. The reference values used for the economic calculations are summarized in Table 15. The production cost of FT syncrude increases approximately a 10%, from 24.0 to 26.4 €/GJ when adding cooling and compression, transport and storage of CO_2.

Table 15. Summary of input parameters for evaluation of the effect of implementing CCS in FT syncrude production.

	Without bio-CCS	With bio-CCS
Biomass price (€/GJ)	3.3[a]	3.3[a]
Investment costs (M€)	1205	1220[b]
CO_2 transport cost (€/ton)	-	47.2
CO_2 storage cost (€/ton)	-	24.3
CO_2 price (€/ton)	-	50
Heat price (€/GJ)	58	58
Natural gas price (€/GJ)	20	20

Notes: [a] Includes prices of logwood at road, transport of logwood to pre-treatment plant and transport of pellets to the FT syncrude production plant. It is assumed 100 wt.% woody biomass in the feedstock. [b] Adding the contribution of the CO_2 cooling and compression train.

Table 17 shows the avoided CO_2 per year in the FT syncrude plant annually with and without CCS. The table shows that the avoided CO_2 is about doubled by implementing CCS.

Table 16. Effect of addition of CCS on production cost of FT-syncrude.

	Without bio-CCS	With bio-CCS
Capital charges (€/GJ FT syncrude)	21.4	21.7
Feedstock supply (€/GJ FT syncrude)	6.2	6.2
Variable operating costs (€/GJ FT syncrude)	4.9	6.1
Fixed operating costs (€/GJ FT syncrude)	3.8	3.8
Maintenance costs (€/GJ FT syncrude)	3.1	3.2
Total revenue (€/GJ FT syncrude)	15.6	16.8
Total FT (€/GJ FT syncrude)	24.0	24.2
CO_2 transport (€/GJ FT syncrude)	-	1.5
CO_2 storage (€/GJ FT syncrude)	-	0.7
Total FT + CCS (€/GJ FT syncrude)	24.0	26.4

Table 17. Avoided CO_2 of F-T syncrude plant with and without CCS.

	Without bio-CCS	With bio-CCS
CO_2 avoided (kton/year)	604	1154

4.1.3 Effect of the cost of biomass

Table 18 shows the effect of feedstock price on the cost of FT syncrude in three scenarios, 100%, 75% and 50% wood in the feedstock, respectively. As the results show, substitution of 25% of the wood with sewage sludge will not decrease the overall costs significantly, while increasing the sewage sludge share further will increase the overall costs due to increased operating costs.

Table 18. Effect of the feedstock price on the FT syncrude price.

Feedstock composition [a]	**100% wood (ref)**	**75% wood**	**50% wood**
Capital charges (€/GJ FT syncrude)	21.7	19.3	17.9
Feedstock supply (€/GJ FT syncrude)	6.2	4.9	3.3
Variable operating costs (€/GJ FT syncrude)	6.1	5.6	7.7
Fixed operating costs (€/GJ FT syncrude)	3.8	3.5	3.2
Maintenance costs (€/GJ FT syncrude)	3.2	2.8	2.6
Total revenue (€/GJ FT syncrude)	16.8	12.0	9.3
Total FT plant (€/GJ FT syncrude) [b]	24.2	24.1	25.4
CO_2 transport (€/GJ FT syncrude)	1.5	1.4	1.3
CO_2 storage (€/GJ FT syncrude)	0.7	0.7	0.7
Total FT plant + CCS (€/GJ FT syncrude)	**26.4**	26.3	27.4

[a] It is considered a mixture of logwood and sewage sludge, where % are per unit mass, as received.

[b] Including CO_2 cooling and compression.

4.1.4 Effect of the price of CO_2

Table 19 shows the effect of CO_2 prices on FT syncrude price. By doubling the CO_2 price, a 5% reduction on FT syncrude price can be achieved, while decreasing the CO_2 price increases the FT syncrude production price by 2-3 %.

Table 19. Effect of the CO_2 price on the price of the FT syncrude.

CO_2 price (€/ton)	25	50 (ref)	100
Total FT plant + CCS (€/GJ FT syncrude)	27.1	**26.4**	25.1

4.1.5 Effect of the price of transport and storage of CO_2

Table 20 shows the effect of CO_2 transport cost and Table 21 shows the effect of CO_2 storage cost on the FT syncrude price. The increased transport costs increased the FT syncrude price by 5 and 16% respectively, while the storage cost did not have that significant effect.

Table 20. Effect of the CO_2 transport cost on the production cost of FT syncrude with CCS.

	CO_2 transport: 0.09 €/ton/km (ref)	CO_2 transport: 0.18 €/ton/km	CO_2 transport: 0.36 €/ton/km
Total FT syncrude (€/GJ FT syncrude)	24.2	24.2	24.2
CO_2 transport (€/GJ FT syncrude)	1.5	2.9	5.8
CO_2 storage (€/GJ FT syncrude)	0.7	0.7	0.7
Total FT syncrude + CCS (€/GJ FT syncrude)	26.4	27.9	30.8

Table 21. Effect of the CO_2 storage cost on the production cost of FT syncrude with CCS.

	CO_2 storage: 12 €/ton	CO_2 storage: 24.3 €/ton (ref.)
Total FT-syncrude (€/GJ FT-syncrude)	24.2	24.2
CO_2 transport (€/GJ FT syncrude)	1.5	1.5
CO_2 storage (€/GJ FT syncrude)	0.4	0.7
Total FT-syncrude + CCS (€/GJ FT syncrude)	26.0	26.4

4.1.6 Effect of the price of natural gas

As observed in Table 22, the economic feasibility of the FT syncrude production is also sensitive to the natural gas prices, as bio-LNG is one of the revenues produced. Increasing the natural gas price from 10 to 25 €/GJ results in the decrease of the FT syncrude cost by approximately 6%.

Table 22. Effect of the NG price on the production cost of FT syncrude with CCS.

NG price (€/GJ)	10	20 (ref)	25
Total FT syncrude (€/GJ FT syncrude)	25.2	24.2	23.7
CO_2 transport (€/GJ FT syncrude)	1.5	1.5	1.5
CO_2 storage (€/GJ FT syncrude)	0.7	0.7	0.7
Total FT syncrude + CCS (€/GJ FT syncrude)	27.4	26.4	25.9

4.1.7 Effect of the investment cost on the FT syncrude production price

Table 23 shows the effect of the FT plant's investment cost on the FT syncrude price. The plant investment costs have a significant effect (14-16%) on the FT syncrude price.

Table 23. Effect of the investment cost on the production cost of FT syncrude with CCS.

	Investment costs: 1035 €/kW input	Investment costs: 1220 €/kW input (ref.)	Investment costs: 1460 €/kW input
Total FT syncrude (€/GJ FT syncrude)	20.9	**24.2**	28.5
Total FT syncrude + CCS (€/GJ FT syncrude)	23.1	**26.4**	30.7

4.2 CASE 2: CCS APPLIED TO BIO-SNG PRODUCTION

4.2.1 Assumptions

Table 24 summarizes the assumptions taken for the study case.

Table 24. Summary of technical and economic parameters used for the cost calculations for the reference case.

Plant process parameters		
Plant size	600	MW thermal input
Specific plant cost	See Table 12	Future bio-SNG investment cost: ~ 1100 $\$_{2013}$/kW input [58]
Net electricity consumption	3%	of thermal input
Plant efficiency biomass-to-SNG	66%	(LHV based)
Energy penalty CCS	2.3%	Energy consumption reported in [50]
Net plant efficiency	63.7%	(LHV based)
Plant availability	85%	of the year

Plant process parameters		
Biomass cost	See Table 7	
Carbon capture efficiency	33.2%	(based on inlet C mass)
CO_2 compression and drying, investment	60-80	€/kW output [51]
CO_2 compression and drying, O&M	22-23	€/kW output/y [51]
CO_2 transport	See Table 8	€/ton
CO_2 storage	See Table 9	€/ton
CO_2 price	See Table 10	€/ton
Economic parameters		
O&M cost	3	% of the TCI per year [59]
Other fixed cost	2	% of the TCI per year
Interest	5	% per year
Capital charges	10	years, annuity
Cost of biomass	See Table 7	€/GJ
Cost of electricity	0.08	$€_{2017}$/kWh [60]

Other financial parameters:

- Added Value Tax Rate (VAT): 21%.
- Fractional interest rate: 7.2% (based on equity of 20% at IRR of 12% and 80% debt at 6% interest rate).
- Project life (depreciation period): 15 years.
- Exchange rate: 1 € = 1.17 $.
- Plant availability factor = 85%.
- Average US inflation rate 2013-2017: 1.34%.

4.2.2 Effect of implementation of bio-CCS

For the quantification of the effect of bio-CCS we consider that by the time the bio-SNG plant starts operation around 2030, bio-CCS will have an economic value (which implies changes in the current ETS system). The captured and stored CO_2 will thus become part of the plant revenues. Reference values (see Table 8-Table 12 summarizes the range of TCI considered in the analysis.

Table 12) have been used for the input parameters, summarized in Table 25. The investment costs and energy penalty account for the inclusion of the equipment needed for the capture and compression of CO_2.

Table 25. Summary of input parameters for evaluation of the effect of implementing CCS in bio-SNG production.

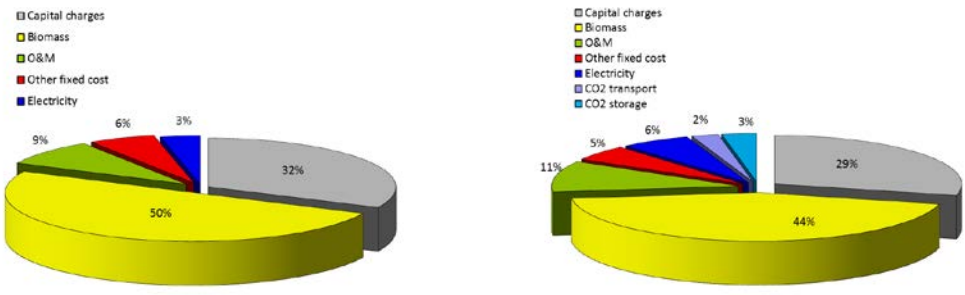
	Without bio-CCS	With bio-CCS
Biomass price (€/GJ)	6.5	6.5
Investment costs (M€)	600.4	612.4*
CO_2 transport cost (€/ton)	-	10
CO_2 storage cost (€/ton)	-	13
CO_2 price (€/ton)	-	50
Natural gas price (€/GJ)	20	20

*Contribution of the extra CO_2 compressor added.

Table 26 and Figure 19 summarize the results of the bio-SNG production cost with and without the application of CCS. As can be seen, the production cost of bio-SNG increases by approximately 14% when adding CCS. Transport and storage of CO_2 contribute with 5.3% to the total production cost. If CO_2 emissions are included in the CDM so that there is an economic value for negative CO_2 emissions, bio-CCS can significantly improve the business case of bio-CCS with respect to the base bio-SNG case.

Table 26. Effect of addition of CCS on production cost of bio-SNG.

	Without bio-CCS	With bio-CCS
Capital charges (€/GJ bio-SNG)	6.3	6.4
Biomass (€/GJ bio-SNG)	9.8	9.8
O&M (€/GJ bio-SNG)	1.7	2.3
Other fixed cost (€/GJ)	1.1	1.2
Electricity (€/GJ bio-SNG)	0.7	1.3
Total bio-SNG (€/GJ bio-SNG)	**19.6**	**21.1**
CO_2 transport (€/GJ bio-SNG)	-	0.52
CO_2 storage (€/GJ bio-SNG)	-	0.67
Total bio-SNG + CCS (€/GJ bio-SNG)	**19.6**	**22.3**



Bio-SNG without CCS Bio-SNG with CCS

Figure 19. Effect of CCS on the distribution of the production cost of bio-SNG.

Figure 20 plots the avoided CO_2 emissions in the base case (bio-SNG without CCS) and if CCS is implemented. The total avoided emissions have 2 contributions: the replacement of fossil natural gas (56.1 kg CO_2 emitted/GJ [61]) with equivalent SNG produced from biomass plus the additional capture of carbon in case CCS is implemented. As can be seen, the implementation of CCS into bio-SNG production roughly doubles the avoided CO_2 emissions with respect to the base case up to a total of approximately 1.1 Mton/y CO_2.

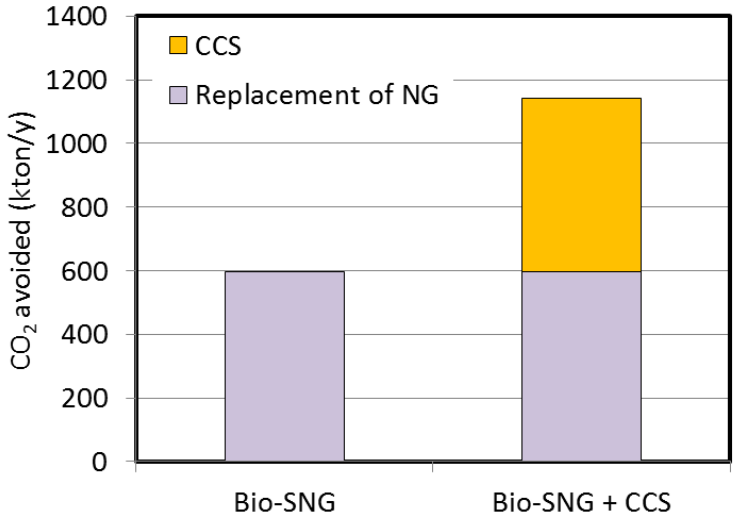


Figure 20. Effect of the implementation of CCS to bio-SNG production on the avoided CO_2 emissions.

For the evaluation of the economic feasibility of the study case proposed in this work and described in this section we have used the net present value (NPV). In Figure 21 it can be observed that under the conditions considered, and provided that by the time the bio-SNG enters into operation in ~2030 the current trading system has advanced in such a way that achieving negative CO_2 emissions has an economic value, implementation of CCS significantly improves the financial analysis of bio-SNG production.

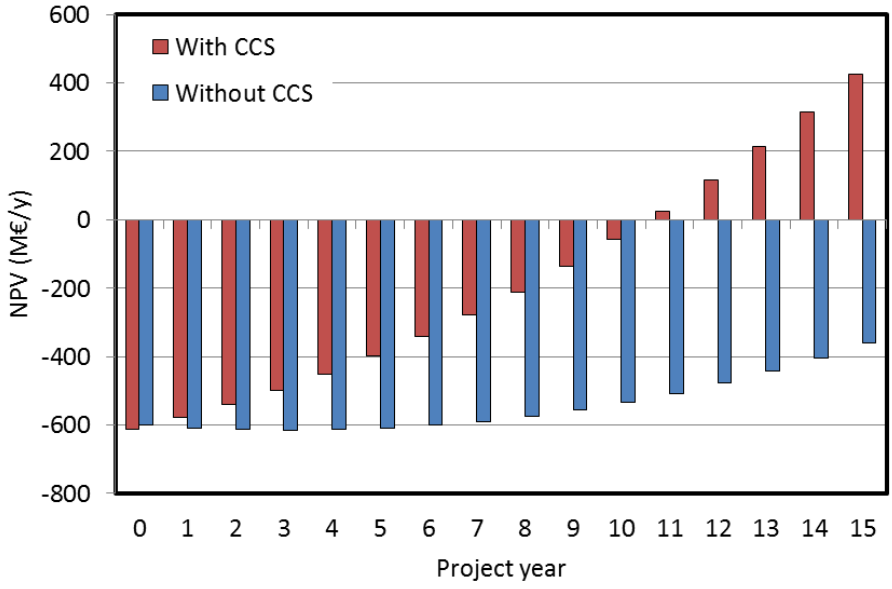


Figure 21. Effect of the implementation of CCS to bio-SNG production on the net present value (NPV) of the project.

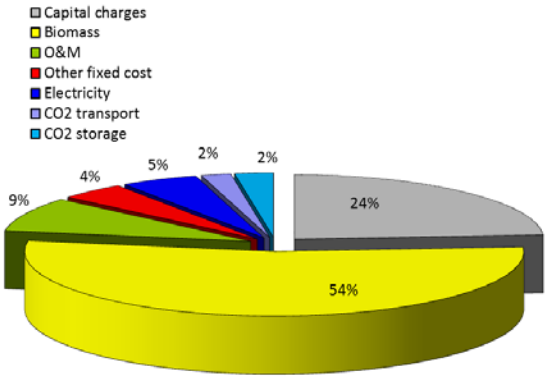
4.2.3 Effect of the cost of biomass

A number of sensitivity analyses have been applied to determine the most important factors affecting the bio-SNG-CCS case. The first parameter studied is the cost of the input biomass. Table 27 summarizes the input parameters used in the analysis.

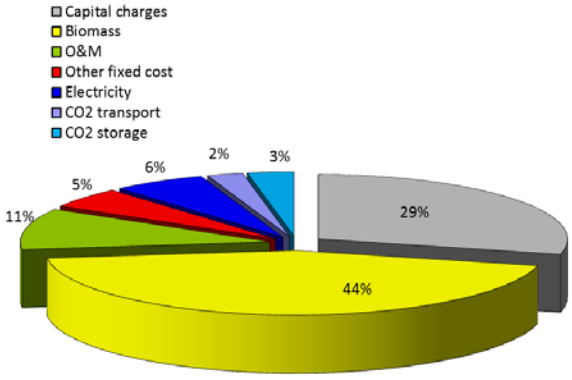
Table 27. Summary of input parameters for evaluation of the effect of the biomass cost in bio-SNG production + CCS.

Biomass price (€/GJ) (see Table 7)	**4.5**	**6.5 (ref.)**	**9.5**
Investment costs (M€)	612.37	612.37	612.37
CO_2 transport cost (€/ton)	10	10	10
CO_2 storage cost (€/ton)	13	13	13
CO_2 price (€/ton)	50	50	50
Natural gas price (€/GJ)	20	20	20

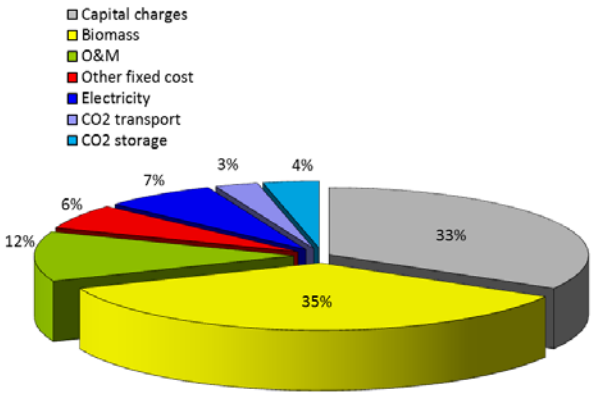
The results of production cost of bio-SNG are shown in Figure 21. Within the range of scenarios considered in this study, the production cost of bio-SNG + CCS can vary from -16.1% to + 20.2% with respect to the reference case. Biomass can contribute to 35%-54% to the total production cost depending on its origin. The dramatic effect of the biomass cost on the financial feasibility of the project can be seen in Figure 23. Reducing the biomass cost from 6.5 €/GJ (local energy crops, reference, red bars) to 4.5 €/GJ (inexpensive agricultural residues, green bars) implies a reduction in the payback period of 3 years, from 11 years to 8 years. The maximum biomass price to get the investment back in the plant lifetime period of 15 years (NPV = 0) is around 8 €/GJ.



(b) Biomass cost: 9.5 €/GJ



(b) Biomass cost: 6.5 €/GJ



(c) Biomass cost: 4.5 €/GJ

	Biomass price: 4.5 €/GJ	Biomass price: 6.5 €/GJ	Biomass price: 9.5 €/GJ
Total bio-SNG (€/GJ bio-SNG)	18.0	21.1	25.6
Total bio-SNG + CCS (€/GJ bio-SNG)	19.2	22.3	26.8

Figure 22. Effect of the biomass cost on the distribution of the production cost of bio-SNG + CCS.

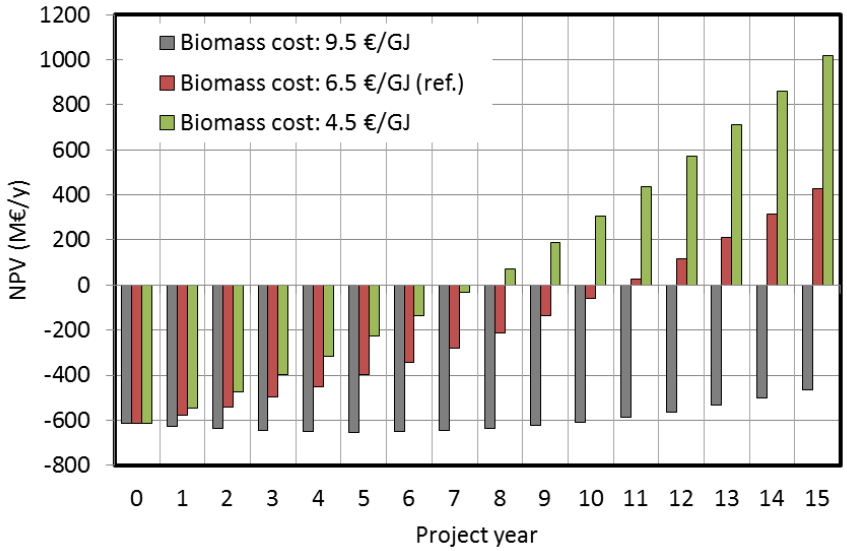


Figure 23. Effect of biomass price on the net present value (NPV) of the bio-SNG+CCS project.

4.2.4 Effect of the price of CO_2

The price of CO_2 does not affect the overall production cost of bio-SNG. However, it does have a dramatic effect on the economic viability of the bio-SNG + CCS project, as observed in Figure 24.

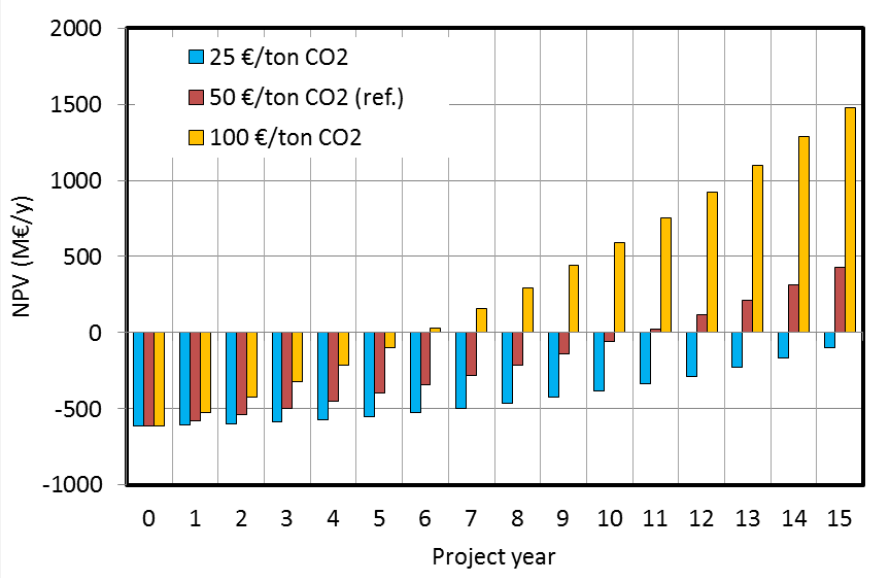


Figure 24. Effect of the price of CO_2 on the net present value (NPV) of the bio-SNG+CCS project.

In this work, the variation of the CO_2 price (see Table 10) has a double effect on the cash flow of the plant: not only are the plant revenues higher due to negative CO_2 emissions, but also the bio-SNG produced can be sold at a higher price (since the fossil natural gas is more expensive due to the penalty associated to CO_2 emissions). In this report, this effect has been quantified by adding a variable contribution to the final SNG price related to penalty to CO_2 emissions. If the CO_2 price is halved from the reference 50 €/ton to 25 €/ton, the investment cannot be recuperated within the project lifetime of 15 years. If the CO_2 price is doubled to 100 €/ton, the payback period can be reduced from 11 years to 6 years. Under the reference conditions considered in this study, a breakeven CO_2 price of approximately 30 €/ton (price at which the investment can be recovered at the end of the project life) has been determined.

4.2.5 Effect of the price of transport and storage of CO_2

Table 28 and Table 29 summarize the effect of the transport and storage of CO_2, respectively. As can be observed, there is just a marginal effect of the CO_2 transport cost on the overall bio-SNG production cost, leading to a variation of the final bio-SNG cost of -1.4% /+2.2% with respect to reference case when halving or doubling the CO_2 transport cost, respectively. On the other hand, the bio-SNG production cost is reduced by -2.2% if onshore storage is applied instead of offshore CO_2 storage.

Table 28. Effect of the CO_2 transport cost on the production cost of bio-SNG with CCS.

	CO_2 transport: 5 €/ton	**CO_2 transport: 10 €/ton (ref.)**	**CO_2 transport: 20 €/ton**
Total bio-SNG (€/GJ bio-SNG)	**21.1**	**21.1**	**21.1**
CO_2 transport (€/GJ bio-SNG)	0.26	0.52	1.03
CO_2 storage (€/GJ bio-SNG)	0.67	0.67	0.67
Total bio-SNG + CCS (€/GJ bio-SNG)	**22.0**	**22.3**	**22.8**

Table 29. Effect of the CO_2 storage cost on the production cost of bio-SNG with CCS.

	CO_2 storage: 5 €/ton	**CO_2 storage: 13 €/ton (ref.)**
Total bio-SNG (€/GJ bio-SNG)	**21.1**	**21.1**
CO_2 transport (€/GJ bio-SNG)	0.52	0.52
CO_2 storage (€/GJ bio-SNG)	0.26	0.67
Total bio-SNG + CCS (€/GJ bio-SNG)	4.8	4.9

4.2.6 Effect of the price of natural gas

The economic feasibility of bio-SNG + CCS is very sensitive to the price of the bio-SNG product. As background, current prices of natural gas in the Netherlands are around 5 €/GJ. Therefore, the commercialization of green gas currently needs strong subsidies (SDE+ program in the Netherlands). As observed in Figure 25, if the base price of natural gas is halved from 20 €/GJ to 10 €/GJ, the project is no longer economically feasible. Under the assumptions taken in this work, it has been determined that the breakeven cost of bio-SNG (i.e. for NPV = 0) is 17.8 €/GJ.

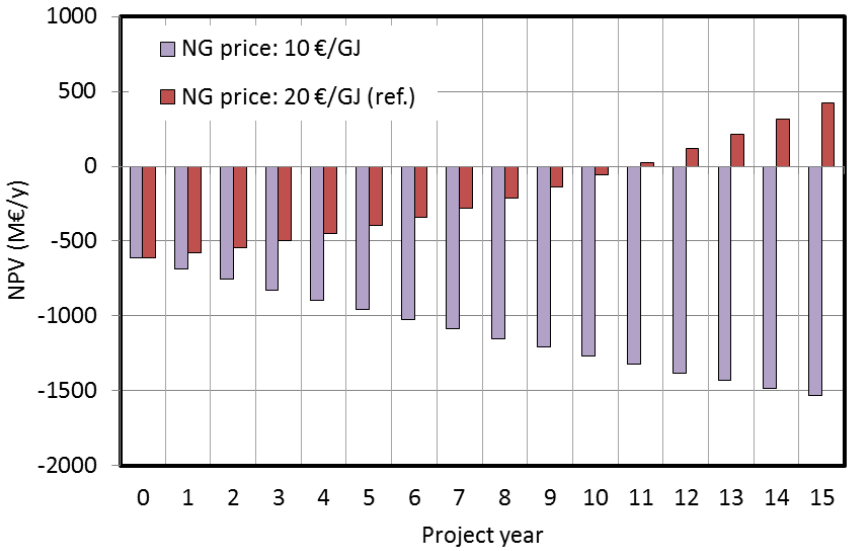


Figure 25. Effect of the price of natural gas on the net present value (NPV) of the bio-SNG+CCS plant.

4.2.7 Effect of the investment cost of bio-SNG

In Table 30 and Figure 26 it can be observed the dramatic effect of the investment cost on both the bio-SNG production cost and the ecomomic feasibility of the project, respectively. An increase by ~44% of bio-SNG production cost occurs when doubling the investment cost from 1000 €/kWh to 2000 €/kWh. Under the conditions assumed in this work, It is necessary to reduce the investment costs below 1180 €/kWh input to have a zero net present value on the project. To put this value into context, the current investment costs for bio-SNG production are ~ 6100 €/kWh input (Gobigas plant, approximately 230 M$ investment cost for 32 MW_{th} input [62]). Thus, a significant effort needs to be performed in the coming years for the demonstration of bio-SNG at large scale in order to reduce the capital costs of the process.

Table 30. Effect of the investment cost on the production cost of bio-SNG with CCS.

	Investment costs: 1000 €/kW input (ref.)	Investment costs: 2000 €/kW input
Total bio-SNG (€/GJ bio-SNG)	21.1	30.9
Total bio-SNG + CCS (€/GJ bio-SNG)	22.3	32.1

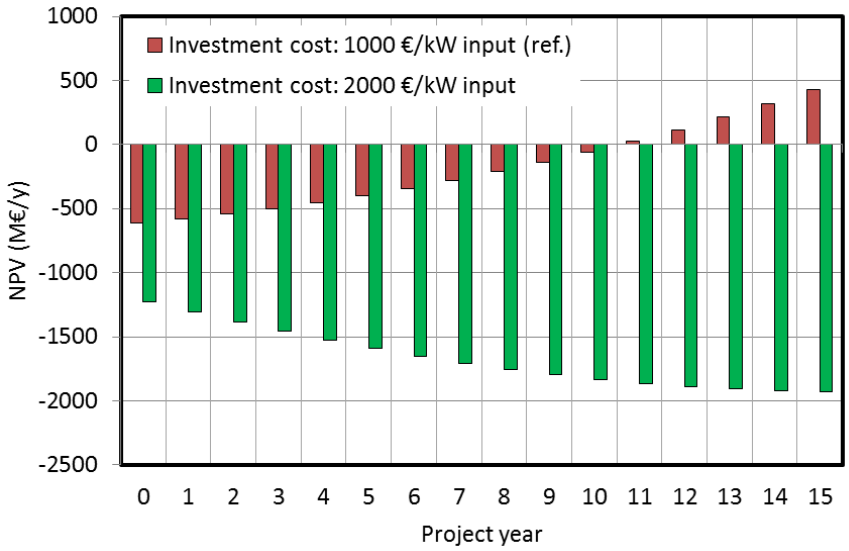


Figure 26. Effect of the total investment cost on the net present value (NPV) of the bio-SNG+CCS project.

5. Conclusions

This report has provided an initial overview of the potential of the application of CCS in biomass and waste gasification-based processes. Implementation of CCS in two examples of biofuel production pathways were studied: Fischer-Tropsch liquid fuels applied in Norway, and bio-SNG production in The Netherlands. The selected study cases cover a representative range of gasification technologies, biofuel products and options for CCS infrastructure.

An estimation of the overall costs and potential impact of bio-CCS on greenhouse gas balances has been presented. The results of this preliminary assessment study have identified opportunities and challenges for the implementation of bio-CCS schemes.

As a general conclusion, the results show that the application of CCS in biofuel production processes has a considerable impact on the reduction of greenhouse gas emissions. In both scenarios considered, the addition of CCS to a biofuel production value chain doubles the amount of avoided CO_2 from 0.6 to 1.1 Mton/y. This positive impact on the reduction of CO_2 emissions comes at a cost: the biofuel production price increases by 10-14%, as shown in Figure 27. Given the significant role of bioenergy expected in the future energy system, we conclude that with the right incentives, biofuel production coupled to CCS can be a powerful tool for CO_2 mitigation to reach the global climate targets. However, the analysis presented in this work shows that it is necessary to modify the current CO_2 emission system to reward the negative emissions achieved by bio-CCS. If CO_2 emissions are included in the CDM so that there is an economic value for negative CO_2 emissions, bio-CCS can significantly improve the business case with respect to the base case. More specific conclusions derived from each study case are further described below in this section.

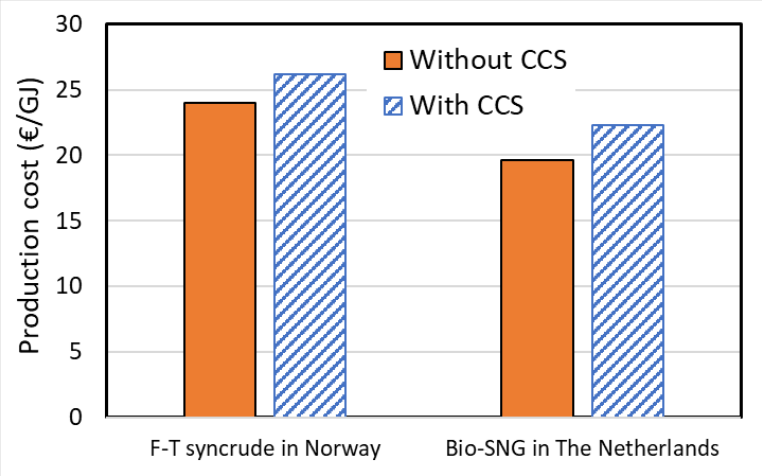


Figure 27. Summary of the effect of implementation of CCS on the production cost of biofuels as considered in this study.

Based on these first findings, future work should address topics that were out of the scope of this report, namely detailed cost analyses, the identification of other interesting value chains (combination of other locations and technology options), and the extrapolation of the results to a more global perspective.

The report has provided an overview for CCS, but it also shows the potential gasification has in providing an outlet for surplus power in the form of hydrogen. Although not considered in this report, it is good to mention that this produced CO_2 could be integrated in power to fuel/chemicals schemes.

5.1 CCS APPLIED TO FISCHER-TROPSCH PRODUCTION

The analysis showed that under the conditions assumed, the cost of production of FT syncrude from woody biomass increases from 24.0 to 26.4 €/GJ, approximately by 10%, if the costs of CO_2 compression and cooling, transport and storage are included in the overall value chain. The analysis also shows that the economic impact of including CCS is very sensitive to the CO_2 transport cost, the overall FT syncrude production cost increased from 26.4 to 30.8 €/GJ (by 17%) when CO_2 transport cost increased from 0.09 to 0.36 €/ton/km.

Possible compensation measures for the higher FT syncrude production costs incurred by implementing CCS include reduction of feedstock supply costs or increase in the market value for bio-based LNG, or the credits for CO_2 capture. In this report the following assessments are presented: 1) 25 wt.% of the input woody biomass is replaced by sewage sludge with a gate fee of 10 €/ton; 2) the price of bio-based LNG is increased by 25%(from 20 to 25 €/GJ); or 3) the CO_2 credits are increased by 100% (50-100 €/ton).

The results show that substitution of the wood with sewage sludge will not decrease the overall costs significantly due to increase in the operating costs and reduction in the revenues. By doubling the CO_2 price, a 5% reduction on FT syncrude price can be achieved. Compared to CO_2, the price of the natural gas had a more significant effect. 2% reduction can be achieved if the price of the natural gas increases by only 25%.

5.2 CCS APPLIED TO BIO-SNG PRODUCTION

The results show that under the conditions assumed, the production cost of bio-SNG increases by 13.8%, from 19.6 €/GJ to 22.3 €/GJ, when adding CCS to the bio-SNG process. Transport and storage of CO_2 contribute with 5.3% to the total SNG production cost. By applying pre-combustion technology (amine scrubbing in this case) to indirect gasification, approximately 1/3 of the initial carbon contained in the biomass can be captured (the rest ending up in the flue gas side of the indirect gasifier). The implementation of CCS production roughly doubles the avoided CO_2 emissions with respect to the base case up to a total of ~ 1.1 Mton/y CO_2.

The cost (and thus the origin) of biomass has an important effect on the production cost. Under the assumptions of this work, the threshold biomass price for the project to become financially feasible (NPV = 0) is around 8 €/GJ. The CO_2 price has also a dramatic effect on the financial viability of the project. Under the reference conditions considered in this study, a breakeven CO_2 price of ~30 €/ton has been determined, which indicates the need for the modification of the current CO_2 emission system to account for the negative emissions achieved by bio-CCS.

The economic feasibility of bio-SNG + CCS is also very sensitive to the price of the bio-SNG product. The breakeven cost of bio-SNG is 17.8 €/GJ according to the assumptions taken. The investment cost has a dramatic effect on both the bio-SNG production cost and the ecomomic feasibility of the project. Under the conditions assumed in this work, it would be necessary to reduce the investment costs below 1180 €/kW input for the project to become profitable. Thus, a significant effort needs still to be performed in the coming years for the demonstration of bio-SNG at large scale in order to reduce the capital costs.

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