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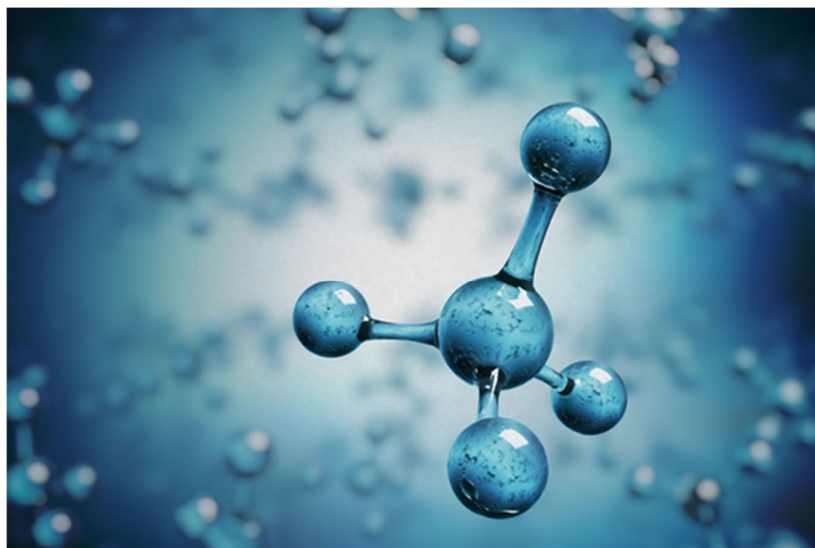
**Demand for Renewable Hydrocarbons in 2030  
and 2050**

**Energy Transition**

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## Executive Summary

### ***Aim of this study***

The continues growth in transportation and the sector's dependence on fossil hydrocarbons make it challenging to reduce greenhouse gas (GHG) emissions. According to European Environment Agency (EEA), GHG emissions from transport have increased every year since 2014, reaching at 29% above 1990 levels in 2018. The chemical industry is another sector in the economy that relies on fossil hydrocarbons. Next to meeting its energy demand, this sector uses about half of its fossil fuel demand as feedstock. These fossil resources are used as raw material for a variety of widely used products like plastics, fertilisers, solvents, detergents, or tyres in the chemical and plastics industries.

To mitigate climate change and reach the overall goal of net-zero emissions both transport sector and the chemical industry should move away from fossil hydrocarbons and substitute these with renewable options to the extent possible. This study analyses the future hydrocarbon demand from these sectors and investigates how the demand can be fulfilled by renewable hydrocarbons. Renewable hydrocarbons are defined as renewable carbon sources that can avoid or substitute the use of fossil carbons. These cover all types of sustainable biomass and CO<sub>2</sub> feedstocks from point source as well as direct air capture.

### ***Approach/methodology***

The analysis concentrates on the EU and the Netherlands for 2030 and 2050. A baseline scenario is developed for fuel demand to reflect the current EU decarbonisation trajectory based on the agreed EU policies up to 2030. It builds on the PRIMES Baseline transport fuel projections. For the Netherlands, KEV 2020 projections are used for 2030, with some adaptations<sup>1</sup>. The scenario narrative, in this study, introduces ambitious GHG emission reduction targets for 2050. It also assumes high electrification for road transport. Table 1 recaps the main scenario parameters and the assumptions for Europe and the Netherlands for 2050.

Table 1 Main scenario parameters and assumptions of the future scenario narrative in this study.

	EU	Netherlands
<i>Fuel demand</i>		
Transport, excl. aviation and maritime	PRIMES Baseline 2018	Up to 2030, KEV 2020 2030 projections kept constant up to 2050
Aviation and maritime	PRIMES Baseline 2018	KEV, 2020 projections up to 2030. 2050 demand builds on the KEV projections, applying PRIMES 2016 relative increases between 2030-2050 Maritime fuel demand builds up on KEV, extrapolation
<i>Electrification and H<sub>2</sub> shares in different transport modes in 2030</i>		

<sup>1</sup> These adaptations relate to incorporating the Climate Agreement ambitions for renewable fuels in transport for 2030. Next to that, the newly published consultation regarding the implementation of the REDII in the Netherlands is taken into account.

	EU	Netherlands
	Same as PRIMES Baseline 2018	Same as KEV 2020
<i>Electrification and H<sub>2</sub> shares in different transport modes in 2050</i>		
Light duty vehicles	45% (1% H <sub>2</sub> )	90% passenger & company cars; 15% non-road machinery
HDVs	25% (10% H <sub>2</sub> )	70% vans; 79% busses (30%); 50% trucks (5% H <sub>2</sub> )
Rail	100%	100% electrification
Inland shipping	5% (10% H <sub>2</sub> )	10% electrification (5%)
GHG emission targets		
Road transport (excl. international maritime & aviation)	Zero	Zero
International maritime	50% reduction in 2050 compared to 2008	
International aviation	50% reduction in 2050 compared to 2005	

The chemical industry analysis covers the key chemical building blocks on which the bulk of the chemical industry is based. These are methanol, olefins (ethylene, propylene, butadiene) and aromatics (benzene, toluene, and mixed xylenes). Dimethyl-ether (DME) is also included to this study as it is expected to be relevant for the chemical sector in the future, mainly because of the possibility to convert DME into olefins. Other important building blocks that do not require a carbon source, like ammonia and urea and chlorine are excluded from this study. The analysis concentrates on the production volumes rather than the consumption of these chemical building blocks. This is done to address the chemical industry in Europe and the Netherlands, and their ambitions to reduce the fossil hydrocarbon dependency. The future production volumes for the EU are based on the growth patterns from the IEA, 2020 evaluation of the petrochemical industry. For the Netherlands, KEV2019 assumptions are used up to 2030. Beyond 2030, the volumes are extrapolated. The scenario narrative is to substitute 15% of each chemical building block with renewable drop-in hydrocarbons in 2030, increasing to 30% in 2050. A comprehensive and consistent assessment of 37 value chains, producing renewable hydrocarbons using both bio-based and e-based (power-to-x) production pathways, is conducted. The levelized costs of production of these value chains are calculated using a large number of literature references for the techno-economic data. Moreover, a coarse cradle-to-gate assessment is conducted using the same methodology across the value chains.

### ***EU-wide conclusions***

#### *Transport sector*

**The renewable hydrocarbon deployment will need to be increased by a factor of 10 in 2050 even with significant electrification of road transport.** The existing policy framework results in around 12% increase of renewable hydrocarbons in 2030 compared to 2015 in Europe. Reducing GHG emissions in transport (excluding international maritime and aviation) to zero and also reducing the GHG emissions in aviation and maritime by 50% will require an increase of

renewable hydrocarbons with a factor of 10 compared to 2030 in Europe. Even with high electrification, the demand for renewable hydrocarbon in road transport stays high, almost half of the total renewable hydrocarbon demand. The other half will be used in aviation and maritime in 2050. Figure 1 illustrates the demand for renewable fuels in the transport sector, including international aviation and maritime.

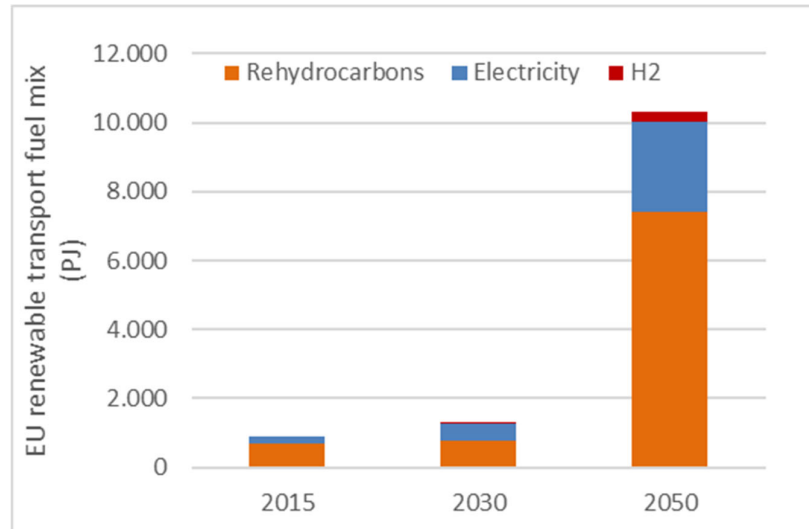


Figure 1 EU transport sector (including international maritime and aviation) renewable fuel mix in 2015, 2030 and 2050 (PJ)

**A significant shift or a drastic transformation of the vehicle fleet can be necessary by 2050.** There will be no fossil hydrocarbons in road transport. All fuels consumed in road transport will need to be based on renewable hydrocarbons. This requires either high demand for drop-in renewable fuels, mainly diesel substitute suitable for the existing internal combustion engines, or a drastic transformation of vehicle fleet to run on other types of renewable fuels like methanol, DME and LNG. The high demand for drop-in diesel substitute and the renewable value chains producing a mixture of diesel, gasoline and naphtha makes it particularly challenging. A share of the vehicle fleet can be shifted from compression ignition engine to spark ignition engine to use drop-in gasoline. This may be more difficult in marine sector as the lifetime of the ships are much longer (up to 40 year) and most ships are based on diesel engine. This problem can be address with ships built with multifuel engines.

**All renewable hydrocarbon options are needed to meet the high renewable hydrocarbon demand in 2050.** Results show that around 12 EJ primary biomass will be needed if these targets are to be met with biobased hydrocarbons alone. This amount corresponds to more than 90% of the sustainable biomass supply potential considered in this study or around 40% of the EU biomass potential highlighted by some other literature. In case the renewable kerosene is to be met via power-to-jet fuel choice, this requires around 1010 TWh renewable electricity and 143 Mt CO<sub>2</sub> as feedstock in 2050. It should be noted that when also direct electrification is included the total renewable electricity demand by 2050 increases up to 1732 TWh. In 2018, the total electricity generation was 2484 TWh

*Chemical industry*

**The production of the European high value chemicals (HVCs) is expected to become less competitive in the market compared to US and Asian markets and therefore shrinks up to 2050. For methanol, however, the production in Europe is assumed to grow.** The main reasons for the increase in the demand relate to two applications: methanol use as a fuel additive and its use as an intermediate for producing olefins and aromatics. However, the demand numbers presented in this study for the case of methanol may be significantly lower as the requirements for olefins might be larger.

CO<sub>2</sub> emissions related to production and supply of chemical building blocks can be reduced by substituting a fraction of these with the renewable hydrocarbon options. **Results on costs show that there is a tendency that favours the deployment of bio-based systems in comparison to e-based systems. Costs of E-based processes are factor 2-5 higher than the bio-based processes.** Among the value chains, methanol and DME production via biogas routes appear the most favourable ones, however, highly dependent on feedstock price. The levelized production costs of these routes are comparable to the market prices of fossil references. Figure 2 recaps the calculated ranges for different renewable-based hydrocarbon value chains.

**E-based routes can become comparable to the biomass value chains when supplied by cheap electricity, reduced CAPEX and continues operation across the year.** For instance, results show that the production cost of e-methanol production becomes comparable to biobased routes when the renewable electricity price is very low (0-10€/MWh) and a 50% CAPEX reduction is implemented (see Figure 2). Improvements can be further reached if renewable electricity supply is maintained through the year. E-based systems highly suffer from costs associated to CAPEX when the systems are not running.

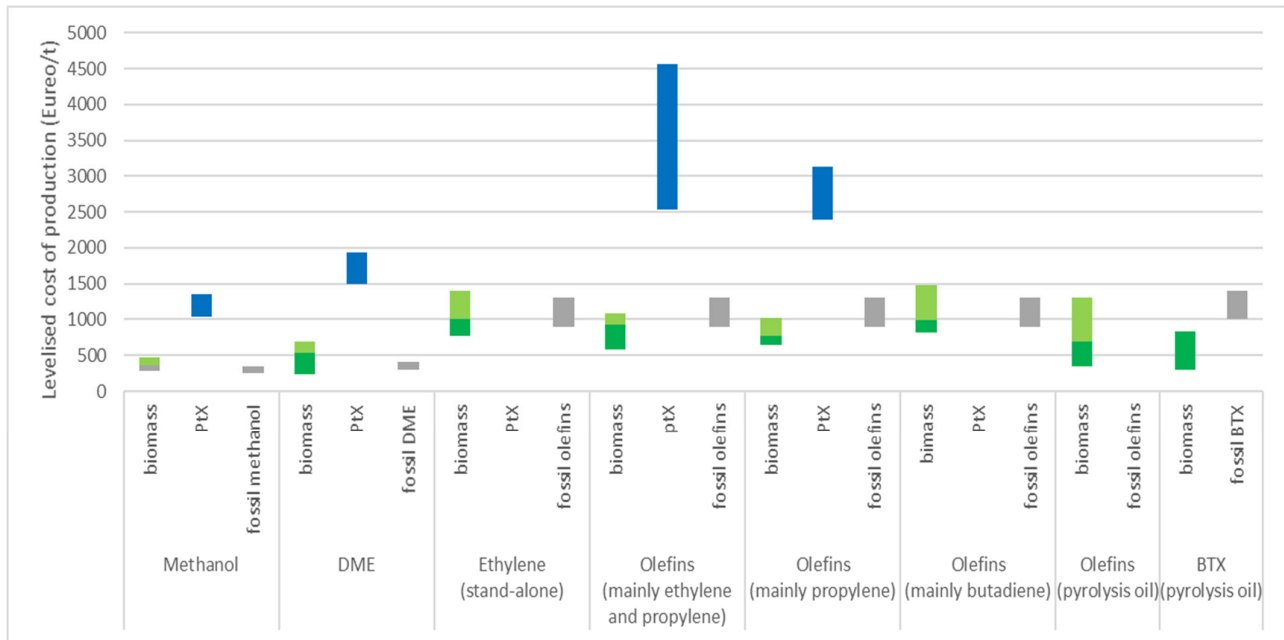


Figure 2 Levelised production cost of renewable hydrocarbon options for the chemical industry (€/t). Dark green refers to cost range with biomass price of 38-45 €/t for solid biomass and 9 €/t for wet biomass. Light green illustrates the high range with biomass price of 100 €/t. Mostly low costs relate to biogas-based value chains. In PtX options (blue bars), low costs relate to continuous operation (8000 hr) and high costs refer to 4000 hr operation

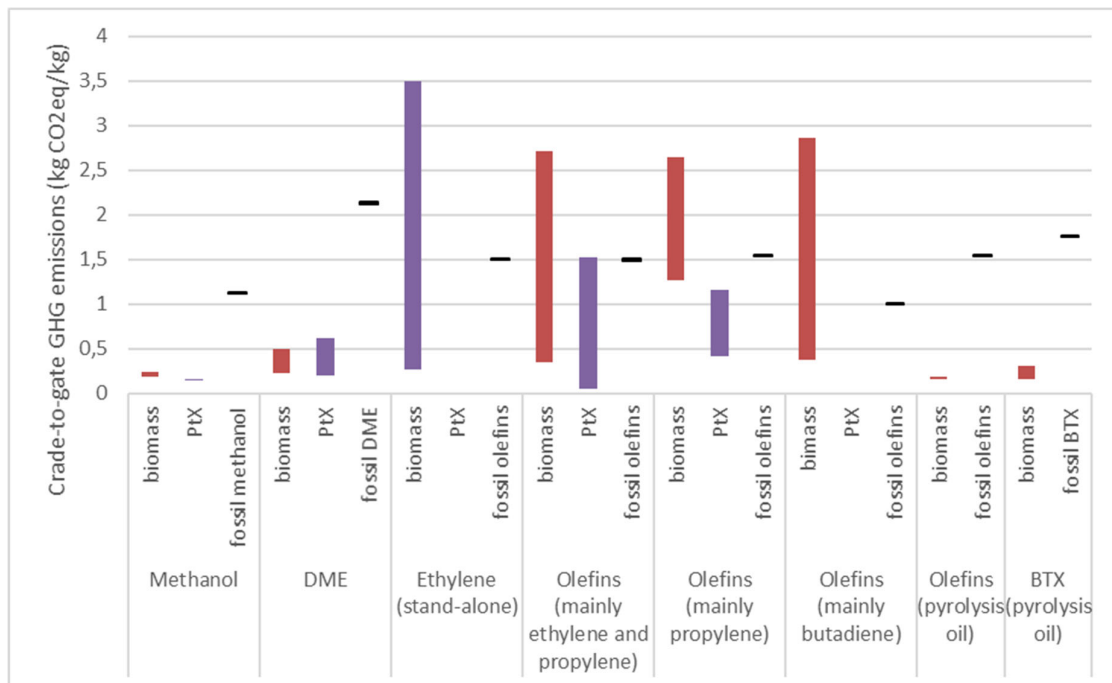


Figure 3 Coarse cradle-to-gate GHG emissions of the renewable bulk chemical building blocks (kg CO<sub>2</sub>eq./kg)

**Renewable based value chains result in 78-87% GHG emission reductions when compared with the fossil counterparts according to a cradle-to-gate analysis.** GHG emissions from renewable hydrocarbons relate, mainly, to fossil fuels used to meet the process steam and electricity demand. The results suggest that the system with the highest emission reduction potential are e-based routes (see Figure 3). These value chains result in more than 85% emission reduction. In this study e-based routes are assumed to use renewable electricity; therefore, related CO<sub>2</sub> emissions are counted as zero. The CO<sub>2</sub> as feedstock is also considered to have zero emission in a cradle-to-gate assessment. There are many discussions about what method to use and how to define the GHG emission factors for different CO<sub>2</sub> resources. The allocation of GHG emissions to the use phase is also important. When emitted to the atmosphere biomass embedded CO<sub>2</sub> is considered as carbon neutral and accounted zero. How the accounting will be done, when the e-based routes are from CO<sub>2</sub> feedstock that is fossil based, remains to be decided. The European Commission is expected to clarify this point by December 2021 with an amending act at least for the transport sector.

**Biomass potential in Europe seems sufficient to substitute 15% and 30% of demand for chemicals with renewables in 2030 and 2050, respectively. A 100% substitution, however, will require around 85% of the EU biomass potential. When also demand from the transport sector is considered** a significant amount of import from outside of the EU will be required.

**Total requirement of renewable electricity to meet 30% of chemicals demand by e-based hydrocarbons is around 16-61GW by 2050.** This can however be much larger if the amount of chemicals to be replaced by renewables is larger. **In case 100% of fossil substitution is envisioned, 50-200GW of renewable electricity supply is required.** This may represent up to 23% of the projected renewable power generation in the Europe in 2050.

### ***Conclusions for the Netherlands***

#### *Transport sector*

**The draft policy framework on the adoption of the REDII directive is a good step forward in reducing the GHG emissions from the transport sector.** The renewable hydrocarbon supply will need to be tripled in 2030 compared to 2019 (see Figure 4). Between 2030 and 2050, this amount will again need to be increased by a factor of 2 to achieve zero emissions in transport, excluding international maritime and aviation. This can be achieved only when 70% of the total energy demand of road transport and non-road machinery comes from direct electricity.

**International aviation and maritime sector renewable hydrocarbon demand will be much larger than road transport in 2050.** When international maritime and aviation renewable hydrocarbon demand is added, the demand for total renewable hydrocarbon becomes more than 20 times the current renewable fuel supply in the transport sector, to achieve a zero-emission transport (excluding international maritime and aviation) and a reduction of CO<sub>2</sub> emissions from the international aviation and maritime sectors by 50% in 2050. Figure 4 presents the transport sector fuel mix in the Netherlands.

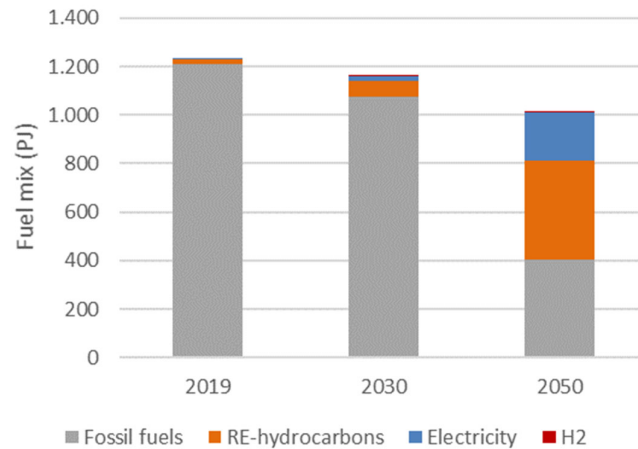


Figure 4 Dutch transport sector fuel mix (including international maritime and aviation) in 2019, 2030 and 2050 (PJ).

In 2050, the international aviation and maritime sectors account for around 70% of the total renewable hydrocarbon demand. This depicts a notable change compared to 2019, where the renewable hydrocarbons, in the form of biofuels, were used completely in road transport.

Figure 5 illustrates the share of the renewable hydrocarbon demand from the different transportation modes.

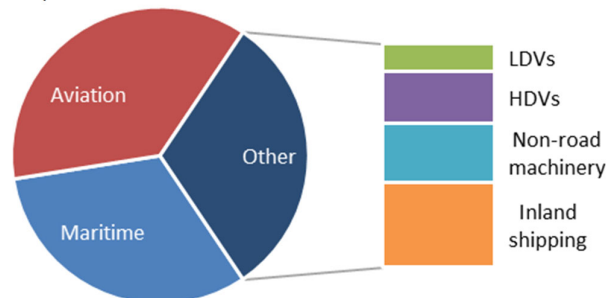


Figure 5 Renewable hydrocarbon demand per transport mode in 2050 in the Netherlands

In 2050, there should be no fossil fuels consumed in transport, excluding international maritime and aviation. This means that either all renewable hydrocarbons need to be drop-in, or the vehicle fleet will need to be adapted to use new types of renewable hydrocarbons like MeOH, DME, CNG/LNG, next to use of battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs).

**A significant amount of solid biomass and/or biofuels will need to be imported to the Netherlands.** When all renewable hydrocarbons are supplied via biomass, the total primary biomass demand will be in the range of 800-900 PJ in 2050. These correspond to more than 2 times the total biomass potential in the Netherlands. However, the national potential appears to satisfy only 10-30% of the



total demand of woody and grassy feedstocks. The rest is to be imported from the EU and/or outside.

When the total aviation demand in 2050 is to be met via e-kerosene, this will require around 87 TWh renewable electricity. When also direct electrification is included the renewable electricity demand for transport sector reaches to 143 TWh in 2050. For comparison, the renewable electricity generation in the Netherlands in 2019 was around 22,5 TWh and it is projected to grow up to 92 TWh in 2030 according to KEV (2020). The amount of CO<sub>2</sub> that needs to be captured in 2050 to produce the total e-kerosene will be around 14 Mt CO<sub>2</sub>. This CO<sub>2</sub> amount is approximately 2 times the amount of CO<sub>2</sub> that is allowed by the aviation sector in 2050 to meet the 50% GHG emission reduction target.

#### *Chemical industry*

Conclusion for the chemical industry in the Netherlands are almost identical to those presented for Europe above. The main differences rely on resources use. In this case, **biomass potential in the Netherlands seems not to be sufficient to cover renewable chemicals production**. The results suggest that there would be requirements for biomass imports, both for the chemical industry as feedstock and for the transport sector.

**Green electricity requirements in the Netherlands to substitute 30% of the fossil chemicals in 2050 is 3-12 GW if all renewable hydrocarbons are to be e-based.** This would be 3-46% of the projected renewable electricity generation in the Netherlands in 2050 (TenneT & Gasunie, 27-126GW).

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# 1 Introduction

## 1.1 Background and objectives

The 2015 Paris Agreement sets the goal of keeping global warming well below 2°C, and pursuing efforts to limit the increase to 1.5°C. The European Union (EU) has strengthened its ambitions to reduce greenhouse gas (GHG) emissions in the European Green Deal, which aims for climate neutrality by 2050. In the Netherlands, the Dutch government has set the goal of reducing GHG emissions by 49% by 2030 compared to 1990 (the Climate Agreement) and considers increasing this to 55%. Furthermore, the Netherlands aims to reduce CO<sub>2</sub> emissions by 95% by 2050. Reaching these goals entail a massive change – the transformation away from a fossil fuel-based economy to a more circular economy driven by renewable energy.

The transport sector is growing and so are its GHG emissions. The sector's dependence on fossil hydrocarbons makes it one of the most challenging to decarbonize. Electrification of road and rail transport is one of the promising ways to decarbonise and reduce the GHG emissions in these transportation modes. However, the need for hydrocarbons is likely to remain. It appears more difficult, for instance, to electrify long-distance heavy-duty vehicles (HDVs) and inland shipping. Moreover, sectors like maritime and aviation, with increasing fuel consumptions, will continue to use hydrocarbons.

Another sector in the economy that will continue to rely on hydrocarbons is the chemical industry. The chemical industry is not only using significant amounts of energy to run its processes, but also requires carbon feedstocks to manufacture a broad range of carbon-based products. Not all the carbon remains stored in these products and substantial amounts are released to the atmosphere as CO<sub>2</sub> after decomposition or incineration.

This study analyses the future hydrocarbon demand and investigates how this demand can be fulfilled by renewable hydrocarbons. Some of the questions this study addresses are as follows:

- What is the total production capacity of chemical building blocks in Europe and the Netherlands by 2030 and beyond?
- What is the total demand for renewable carbons in transport and the chemical industry?
- What are the future supply prospects (technical and economic) regarding bio-based and synthetic carbon-based chemical products and energy carriers to meet the demand?
- Which value chains are the most promising in the 2030-2050 time frame and what are other promising novel routes (possibly with lower TRL) to produce these energy carriers and chemical products?
- What are the energy requirements, costs and GHG emission reduction potentials?

## 1.2 Report outline

Two major sectors are analysed in this report – the transport sector and the chemical industry. Chapter 2 presents the transport sector assessment results. This chapter provides information about the status of transport sector, including the policy context. Results of this chapter include the renewable hydrocarbon demand and the order of the magnitude demand for renewable resources in 2030 and 2050. Chapter 3 focuses on the chemical industry, more specifically the large chemical building blocks, namely, methanol, DME, olefins (ethylene, propylene, butadiene) and aromatics (toluene, xylene, and benzene, also referred to as BTX). It introduces the scenario set up to define future production volumes and the demand for renewable hydrocarbons in 2030 and 2050. Chapter 4 concentrates on the renewable supply options and the assessment of a wide range of biobased and renewable electricity and CO<sub>2</sub> feedstock-based value chains. In this chapter, the sustainable supply potential of renewable resources is introduced. This is followed by the introduction of the approach to defining the promising value chains. Chapter 5 provides the detailed results of the assessment for the different chemical building blocks. It presents the levelized cost of production and a coarse life cycle GHG emissions of the different value chains. Finally, chapter 6 discusses the key findings and chapter 7 presents the overall conclusions.

## 2 Transport sector

### 2.1 Transport sector in the European Union and the policy context

The transport sector is the only major EU sector where GHG emissions are continuously increasing. In 2017, transport, including international aviation and shipping, was responsible for 27% of the total GHG emissions in the EU (EEA 2020). According to European Environment Agency, GHG emissions from transport have increased every year since 2014, reaching at 29% above 1990 levels in 2018. GHG emissions from aviation increased the most, by an average of over 3% each year since 2013. GHG emissions from shipping peaked in 2008, followed by a reduction of almost 25% up to 2015, in large part due to the economic recession and improvements in energy efficiency. Since 2015, these emissions have been gradually increasing, amounting to 146 MtCO<sub>2</sub>eq in 2017. Figure 6 illustrates a historical overview of the GHG emissions since 1990 for different transportation modes.

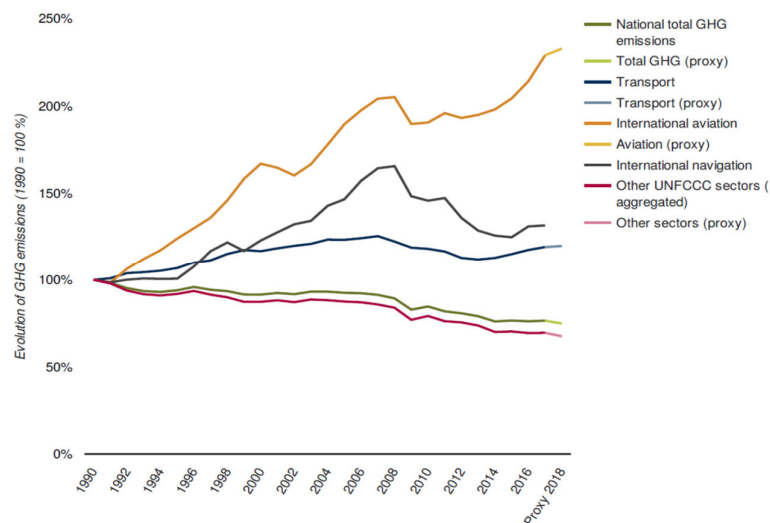


Figure 6 EU greenhouse gas emissions in the transport sector (EEA, 2020)

The growth in energy consumption in the transport sector is hampering efforts to reduce GHG emissions. The EU has adopted a comprehensive energy policy framework to facilitate the energy transition and to deliver on the EU's commitments to the Paris Agreement. One of the most comprehensive policy packages, Clean Energy for All Europeans, consists of eight legislative acts setting the European energy targets for 2030. The new legal framework sets an EU binding target of at least 32% for renewable energy sources in the EU's energy mix and of at least 32,5% energy efficiency by 2030. The recast Renewable Energy Directive (EU) 2018/2001 (hereafter REDII) (The European Parliament, 2018) sets the policy framework for renewable energy. This directive also sets the regulatory framework for the use of renewable transport fuels in the EU for the period 2021-2030 and introduces an EU obligation on fuel suppliers in Europe. The most relevant aspects of this directive for this study are as follows:

- Share of renewable fuels in road and rail transport to reach 14% by 2030 (energy based).
- A 7% cap on food and feed crop-based biofuels. If a Member State caps crop-based biofuels at a level lower than 7%, then it can reduce the overall 14% target.
- Sub-mandate to biofuels produced from Annex IX A type feedstock<sup>2</sup> (0,2% in 2022; 1% in 2025; 3,5% in 2030). Fuels may be double counted to achieve this target, which de facto implies that the targets are only 0,1%, 0,5% and 1,75%.
- Cap on biofuels produced from Annex IX B type feedstock (mainly used cooking oil and animal fats) of 1,7%<sup>3</sup> of transport fuels. These fuels may be double counted to arrive at a contribution of 3,4%.
- High ILUC risk biofuels will be phased out towards 2030 unless they are certified as being low ILUC risk

This energy and climate legislation is expected to reduce GHG emissions by more than 40% in 2030 compared to 1990. In 2019, the European Parliament and the European Council endorsed the long-term EU objective of climate neutrality by 2050. As part of the European Green Deal, the Commission proposed to raise the 2030 GHG emission reduction target to 50-55%. In December 2020, the European Council agreed on the 55% target. This new target is likely to affect the role of renewable fuels in transport sector. So, the targets and the ambitions levels set within REDII may need to be increased.

## 2.2 Transport sector in the Netherlands and the policy context

GHG emissions from the Dutch transport sector accounted for more than 18%<sup>4</sup> of the total GHG emissions in 2019 (PBL, 2020). Among the transportation modes, the GHG emission contribution of international maritime fuels is the largest. This differs from the EU, where road transport plays the major role. Figure 7 illustrates the evolution of GHG emissions in the Dutch transport sector. The GHG emissions related to the bunker fuels sold in the Netherlands for international shipping and aviation increased between 2000 and 2007 but has since fallen. Despite this decrease, the total GHG emissions from these sectors are 18% higher than the 1990 levels.

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<sup>2</sup> These feedstocks consist mainly of wastes and residues.

<sup>3</sup> For Malta and Cyprus this 1.7% cap is not applicable.

<sup>4</sup> Including land use related emissions.

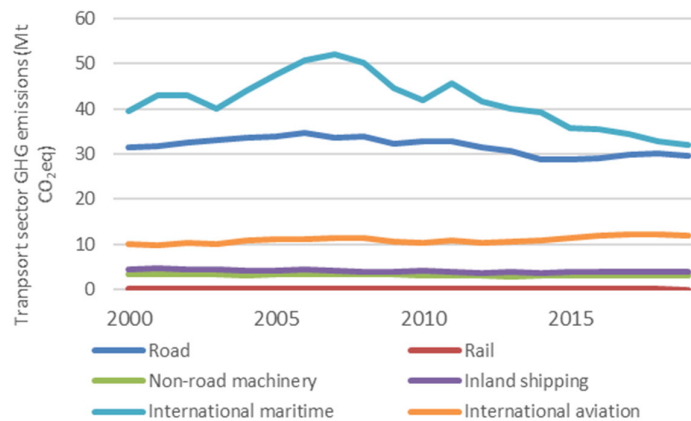


Figure 7 GHG emissions in the Dutch transport sector (Mt) (PBL, 2020)

Figure 8 presents the final energy consumption in different transport modes in the Netherlands. Bunker fuels sold to the international maritime sector represents the largest share in final energy consumption in transport. The Netherlands was responsible for around a quarter of the sales for international shipping in the EU in 2018. The aviation bunker fuel sale in the Netherlands was around 8% of the European fuel sales for international aviation (PBL, 2020). The sales of bunker fuels for international aviation grew on average 3% per year between 2012 and 2018.

More than 90% of the fuel consumption in road transport is from fossil fuels. Biofuels comprised 7,4% of the fossil gasoline and diesel consumed for road and rail transport<sup>5</sup> in 2019. The electricity use was around 1,95 PJ in road transport and 5,6 PJ in rail transport (PBL, 2020).

According to the Dutch Emission Authority (Dutch Emissions Authority, 2020a), the renewable fuel obligation for 2019 is achieved and the physical supply of biofuels to the Dutch transport market was around 32,5 million gigajoules (GJ). Around 78% of this physical supply was from double counting biofuels (based on wastes and residues).

<sup>5</sup> This is according to KEV. The total of biofuels is 33 PJ.

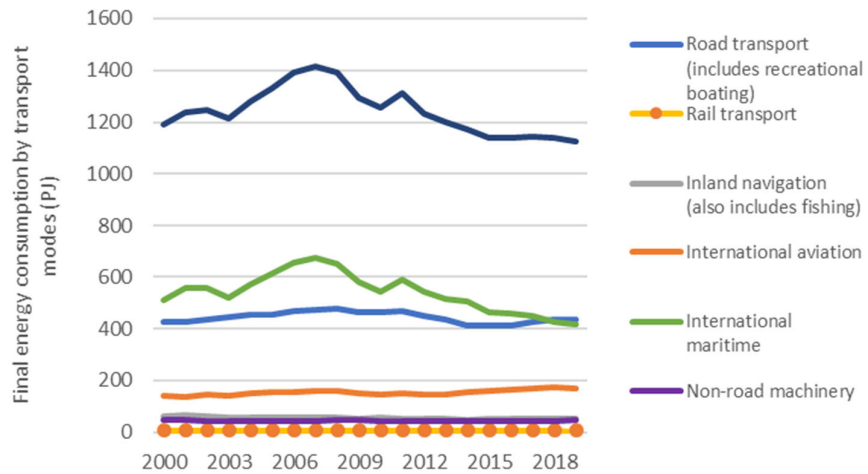


Figure 8 Final energy consumption in the Netherlands by transport mode

**Policy context**

Renewable energy is supported through yearly obligations. The companies in the Netherlands are obliged to supply part of the fuel from renewable energy to the market. This concerns petrol and diesel for transportation, including road and rail vehicles and non-road machinery and recreational boating (Dutch Emissions Authority, 2020b). The annual obligation is used alongside other measures to reduce CO<sub>2</sub> emissions from the transport sector, such as increasing the efficiency of transport and stimulating electric driving. The yearly obligation for renewable fuels is presented in Table 2. Next to biofuels, electricity is also supplied to achieve these obligations and the renewable share of this electricity is registered to meet the obligation.

Table 2 Renewable fuel obligations for transport up to 2020

	2019	2020
Total	12,5% (includes double counting)	16,4% (includes double counting)
Minimum advanced biofuels	0,8%	1%
Maximum conventional biofuels	4%	5%

The Dutch Climate Agreement has laid down ambitions and targets for renewable fuels for road transport and inland shipping. These include:

- 100% of new cars sold to be emissions-free by 2030.
- A maximum of 27 PJ renewable fuels will be used in road traffic in supplement to the 2030 scenario of the National Energy Outlook (PBL, 2017), in addition to the use of electricity and hydrogen. Thus, a total of 60 PJ renewable fuels is considered for 2030.
- The national government will reserve 200 million euros to increase the production and innovation of sustainable advanced biofuels and renewable synthetic biofuels.



- Within the passenger transport sector, some 15,000 Fuel Cell Electric Vehicles (FCEV) are expected by 2025, potentially growing to 300,000 vehicles by 2030.
- A strategic foundation for accelerated growth to achieve the realisation of 50 hydrogen-refuelling stations, 15,000 FCEV passenger cars and 3,000 heavy vehicles with a hydrogen fuel cell by 2025, as towards 2030 and 2050, in particular.
- The use of sustainable energy carriers, including hybrid electric, hydrogen and sustainable biofuels, including Hydrotreated Vegetable Oil (HVO), to ensure at least 5 PJ of sustainable energy carriers are implemented in inland shipping.
- In the run-up to zero-emissions vessels, the focus will be on a blending percentage of 30% biofuels for inland shipping vessels.

More recently, the energy and transport regulations are being amended to transpose REDII to the national law. As part of this implementation, the Dutch government issued a draft ordinance (IenW,2020a) in December 2020. The main elements of this ordinance are summarised in Table 3.

Table 3 Main elements of the draft decision regarding renewable fuels in transport as part of the implementation of REDII

	REDII implementation
End users subject to the obligation	<ul style="list-style-type: none"> <li>- Diesel, gasoline, and heavy fuel oil supplied to</li> <li>- Road and rail transport</li> <li>- Non-road mobile machinery,</li> <li>- Agricultural tractors and forest machines,</li> <li>- Recreational boating (when not at sea).</li> <li>- Inland shipping, including inshore fishers</li> </ul>
Time period covered <sup>6</sup>	2022-2030
Obligation level	16,4% in 2020, increasing to 27,1% in 2030 (based on energy content, including multiple counting)
Limit to conventional biofuels	Limited to 1,2% of the total diesel and gasoline consumed in transport Palm oil us is not allowed due to iLUC risk
Limit to biofuels from Annex IX-B feedstocks	Use of biofuels from used cooking oils and animal fats are limited to 8,4% of the total diesel and gasoline consumed in transport. This includes double counting. Thus, they are limited to 4,2% in physical terms (energy content).
Sub-target for advanced biofuels from Annex IX-A feedstocks	1,5% in 2022, increasing to 7% in 2030. This number includes double counting. Thus, in physical terms it is 3,5%.
Other renewable fuels	This category includes: <ul style="list-style-type: none"> <li>- Renewable electricity in road transport (counted 4 times its energy content)</li> <li>- Gaseous renewable fuels produced from renewable electricity such as hydrogen</li> <li>- Liquid renewable fuels produced from renewable electricity</li> </ul>

<sup>6</sup> There has been another decision for 2021.

	REDII implementation
	<ul style="list-style-type: none"> <li>- Liquid biofuels from crops that do not entail a risk of agricultural land expansion (i.e., catch and cover crops)</li> <li>- Biofuels from Annex IX- A list feedstocks</li> </ul>

## 2.3 Approach/methodology for demand projections and the scenario set up

### 2.3.1 Fuel demand in 2030 and 2050

In this study, a baseline scenario (referred to as “the Baseline”) was developed for fuel demand to reflect the current EU decarbonisation trajectory based on the agreed EU policies up to 2030. This scenario projects the achievement of energy and climate 2030 targets and illustrates the impacts of these targets on the long-term energy and GHG evolution. It builds on the ‘EU fuel demand’ presented in the baseline scenario in the Communication from the Commission “A Clean Planet for all - A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy” (Runge-Metzger, 2018). The Baseline scenario in this study includes the same protections as PRIMES baseline up to 2030. Beyond 2030, it presents a different pathway that is consistent with the targets limiting global warming to well below 2 °C or 1.5 °C. Fuel demand projections for the Netherlands is based on the KEV 2020, however, with the following adaptations.

For 2030, KEV projections are not aligned with the Dutch Climate agreement ambitions. In this study, we increased the amount of renewable fuels in transport sector to 65 P in 2030. We kept the rest of the projections the same as KEV 2020.

For 2050, we considered a significant amount of direct electrification, mainly in road transport. In the following we briefly present the fuel demand projections for the EU the fuel demand projections for the Netherlands.

#### **Fuel demand in the EU**

Table 4 presents the results of the PRIMES baseline projections for 2030 and 2050. Important to mention is that the PRIMES baseline scenario is part of the Clean Planet for All Communication. While the road transport activity is projected to increase up to 2050, the fuel consumption in road and rail transport is projected to be reduced. There are two reasons for that. First, it relates to the efficiency gains in transport sector. The PRIMES projections include the possible effects of CO<sub>2</sub> emissions standards for light duty vehicles and for heavy goods vehicles, and other initiatives adopted recently that increase the efficiency of the transport system. The second reason relates to the electrification. In the baseline scenario, 8% of the total vehicle fleet is projected to be electric vehicles (EVs) in 2030. This increases to around 35% of the car stock to be EVs and another 4% is fuel cell electric vehicles (FCEVs) in 2050.

In the Baseline scenario air transport activity, including international aviation, is projected to increase significantly (43% during 2015-2030 and 101% for 2015-2050). Energy efficiency is already a strong driver in the Baseline scenario. Energy efficiency covers a combination of measures related to aircraft technology and

design, air traffic management and operations, improved occupancy rates, etc. Even so, the fuel demand increases by 22% during 2015-2050. Direct electrification corresponds to around 3,8% of road and rail transport in 2030, increasing to 14,8% in 2050 in baseline scenario.

International maritime transport activity at EU level is also projected to continue growing in the baseline scenario. The increase is mentioned to be 21% during 2015-2030 and 51% during 2015-2050. In this scenario, important improvements of energy efficiency are foreseen. This is triggered by the implementation of the Energy Efficiency Design Index adopted at global level by International Maritime Organisation (IMO). Total fuel consumption is projected to increase by 27,5% between 2015 and 2050. The share of marine diesel oil is projected to increase over time, while natural gas provides around 11% of energy demand by 2050 driven by the Sulphur Directive (Directive 2012/33/EC) and the assumed availability of refuelling infrastructure for LNG.

Table 4 EU28 total fuel demand by 2030 and 2050 according to PRIMES baseline, 2018

	2030	2050
	PJ	PJ
Transport sector fuel mix (excluding both EU and international aviation and international maritime)	10,940	8,910
International aviation fuel mix, including intra-EU flights <sup>7</sup>	2,397	2,723
International Maritime fuel mix	2,508	2,927

### **Fuel demand in the Netherlands**

The transport fuel demand in the Netherlands in 2030 is based on the KEV 2020 projections. In the absence of a comprehensive future projection *for 2050, the 2030 fuel consumption is kept constant up to 2050<sup>8</sup> for road and rail transport, inland shipping, and non-road mobile machinery*. This is based on the assumption that a possible increase in transport fuel demand can be compensated by efficiency improvements in the transport fleet. The transport fuel demand in the future will be largely determined by population trends, macro-economic developments and the distribution of the population and employment in the Netherlands. There are many uncertainties that will influence the future development of mobility, such as the evolution of new transport modes and systems (i.e., controlled and coordinated autonomous driving) and changes in behaviour in general and in relation to the new modes of transport. Furthermore, the possible future implications of COVID or any other pandemics makes it more complicated to make applaudable future projections.

Figure 9 presents the details of the energy consumption in the transport sector, according to the recent KEV 2020 projections. The transport sector consists of road

<sup>7</sup> International aviation figure refers to both intra-EU and extra-EU flights. In the rest of the document this is referred to as international aviation.

<sup>8</sup> According to PRIMES baseline projections the final energy consumption in Dutch transport will increase by 2% between 2030 and 2050.

and rail transport, non-road mobile machinery, inland navigation, fishing, also recreational boating.

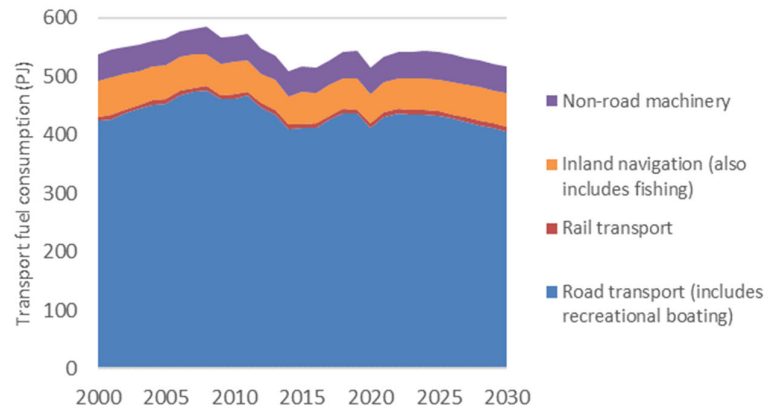


Figure 9 Transport sector energy consumption up to 2030 according to (PBL, 2020)

Figure 10 presents the bunkering fuel consumption in the aviation sector up to 2050. The projections up to 2030 are derived from KEV 2020 (PBL, 2020). Projections beyond 2030 are calculated using the *average yearly increase considered in PRIMES 2016 projections for the Dutch aviation sector*. As shown in Figure 10, the projection after 2030 is quite conservative when compared with the increase considered in the KEV between 2025 and 2030. According to KEV 2020 projections, beyond 2020 the maritime sector bunkering appears to grow at a small pace. Therefore, the average yearly growth between 2020 and 2030 is assumed to continue up to 2050. Figure 11 illustrates the maritime bunkering projections considered in this study.

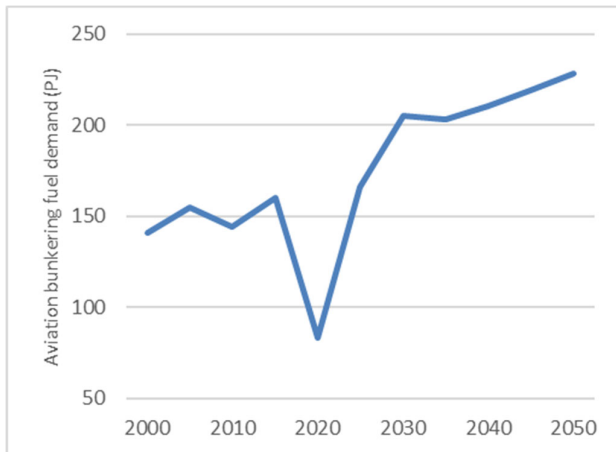


Figure 10 Bunker fuel demand in aviation up to 2050 (PJ).

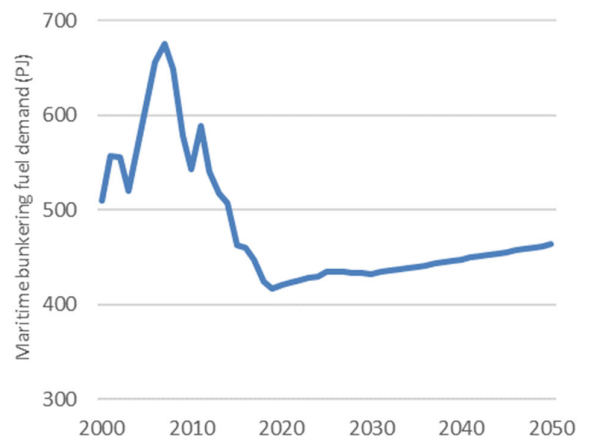


Figure 11 Maritime bunkering projections up to 2050 (PJ).

## 2.4 Scenario set up for transport sector

### 2.4.1 GHG reduction targets for EU28 and the Netherlands

In this study a future is sketched where the CO<sub>2</sub> tailpipe emissions are reduced significantly in the transport sector. The goal is set to reduce CO<sub>2</sub> emissions from transport (excluding international aviation and maritime) to zero. For international aviation and maritime, the CO<sub>2</sub> reduction target is set to 50% compared to 2008 level for maritime and to 2005 level for aviation. The targets for the aviation and maritime sectors are in line with the International Civil Aviation Organization (ICAO) and International Maritime Organization (IMO) ambitions for 2050.

#### **EU**

While the 2030 framework has been set by the relevant legislations, the 2050 framework has yet to be decided. As part of the scenario set-up for this study, the following assumption are defined:

- Zero tailpipe emissions from the transport sector in the EU, excluding bunker fuels, by 2050, means that the fuels used in road and rail transport and inland navigation will need to be 100% carbon free or/and from renewable sources. Figure 12 illustrates the historical and the future projected emissions according to the PRIMES baseline scenario. The orange dot in the figure shows the target set in this study.

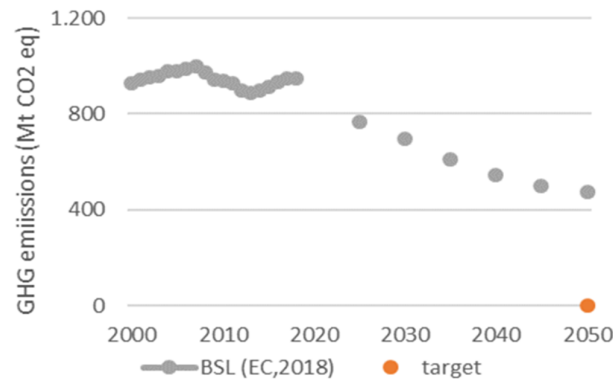


Figure 12 EU transport sector historic GHG emissions and future CO<sub>2</sub> reduction targets. Historic GHG emissions are derived from (EEA, 2020)

- Reducing GHG emissions in the aviation sector is one of the biggest challenges as this sector has been projected to grow significantly. According to the EU (2018) Baseline scenario air transport activity including international extra-EU flights, is projected to increase significantly (43% during 2015-2030 and 101% for 2015-2050).

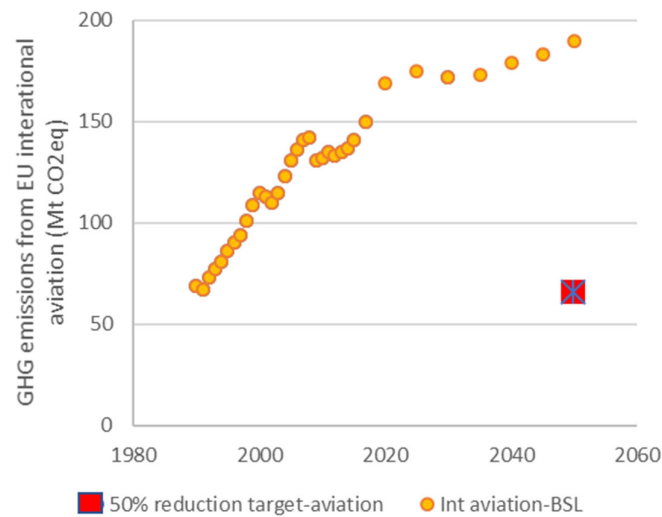


Figure 13 EU28 Aviation sector GHG emissions and the target for 2050

- A study commissioned for the European Parliament's ENVI Committee shows that to stay below 2°C, the target for EU aviation for 2030 should not exceed 39% of its 2005 emission levels and should be 41% lower compared to 2005 emission levels in 2050. The sector itself indicated an ambition of 50% emission reduction by 2050 compared to 2005. In this study we consider a future where the CO<sub>2</sub> reductions will be 50% compared to 2005 levels. This is in line with aspirational ambitions of the International Civil Aviation Organization (ICAO). Figure 13 presents the GHG emissions according to PRIMES Baseline scenario and shows the 50% target set in this study.
- The maritime<sup>9</sup> sector is projected to increase its transport activity and so the fuel use. As a result, the emissions from EU international maritime sector are projected to increase by 34% during 2005-2050 (equivalent to 19% increase over 2008-2050) in the baseline scenario (EC,2018). In this study, a 50% CO<sub>2</sub> emission reduction by 2050 (compared to 2008) is set. This target is in line with the International Maritime Organization (IMO) strategy. Figure 14 illustrates the baseline projections (in green dots) and the set ambitions within this study.

<sup>9</sup> In the PRIMES Baseline scenario, important improvements of energy efficiency are foreseen, also triggered by the implementation of the Energy Efficiency Design Index adopted at global level by International Maritime Organisation. Energy intensity of EU international shipping, measured as tons of oil equivalent per million tonnes-kilometres, is projected to decrease significantly, by 10% during 2015-2030 and 16% for 2015-2050. The share of marine diesel oil would increase over time, while natural gas would provide around 11% of energy demand by 2050 driven by the Sulphur Directive and the assumed availability of refuelling infrastructure for LNG.

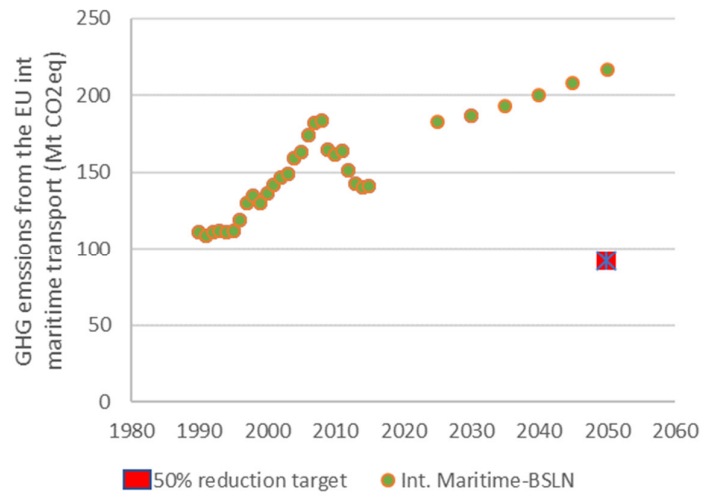


Figure 14 EU international maritime transport GHG emissions

**The Netherlands**

The 2030 framework is set in line with the KEV 2020 projections. For 2050, the transport sector, including road and rail transport, non-road machinery, inland shipping, recreational boating and fishing, is assumed to have zero tailpipe emissions. Figure 15 illustrates the historical GHG emissions and the emission projections from KEV 2020 (PBL, 2020) up to 2030. This figure also shows how ambitious the GHG emission reduction target is in this study for 2050.

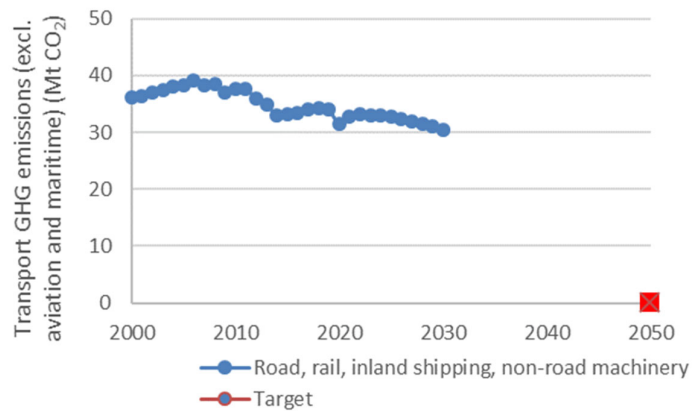


Figure 15 Dutch transport sector (excluding aviation and maritime bunkering) GHG emissions and the 2050 target

The GHG emissions related to the aviation and maritime bunkering in the Netherlands is presented in Figure 16. This figure also illustrates the 50% GHG emission reduction targets set for the aviation and maritime sectors. The emissions up to 2030 are derived from the KEV 2020 projections. Beyond 2030 are based on our own calculations.

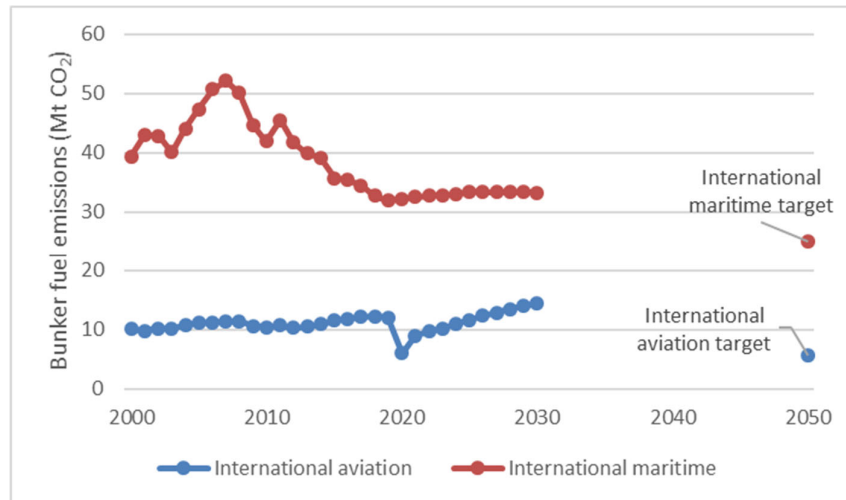


Figure 16 GHG emissions related to the aviation and maritime bunkering in the Netherlands.

#### 2.4.2 Role of electrification and other scenario assumptions

This report aims to quantify the future renewable hydrocarbon demand. One of the key elements that will affect this is the demand side management. Further efficiency improvements in the vehicle fleet, changes in travel modes and connected and coordinated autonomous driving are among the options to reduce the total demand. These demand side options are not included in the description of this scenario. Only energy efficiency improvements due to the existing policy framework considered within the PRIMES Baseline scenario and KEV 2020 (PBL, 2020) projections are included to this study.

Another key element that affects the future role of renewable hydrocarbons is the deployment of zero emission vehicles (ZEVs). ZEVs refer to battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs). The main scenario assumptions related to electrification of transport sector are introduced in Table 5 for the EU and for the Netherlands. The 2030 electrification projections are kept the same as in PRIMES Baseline and KEV 2020.



Table 5 Main scenario assumptions for the EU28

	EU28		
	2030	2050	
Final energy demand in road+ rail + domestic navigation	PRIMES baseline	Derived from PRIMES baseline	
Light duty vehicles			
<i>share of electrification</i>		45%	
<i>share of h<sub>2</sub></i>		1%	
HDVs			
<i>share of electricity</i>		25%	
<i>share of h<sub>2</sub></i>		10%	
Inland shipping			
<i>share of electricity</i>		5%	
<i>share of h<sub>2</sub></i>		10%	
Rail transport			
<i>share of electricity</i>		100%	
Maritime sector final energy demand			Derived from PRIMES baseline
Aviation final energy demand			Derived from PRIMES baseline
Efficiency of BEVs as a ratio to ICE	1,94	2	
Efficiency of BEVs as a ratio to ICE	1,07	1,4	

Table 6 Main scenario assumptions for the NL

	2030	2050
Final energy demand in road+ rail + domestic navigation	KEV (202)	Own projections
Direct electricity as share of total fuel demand in		
<i>passenger cars</i>		90%
<i>company cars (light duty)</i>		90%
<i>vans</i>		70%
<i>trucks</i>		50%
<i>buses</i>		70%
<i>rail</i>		100%
<i>non-road machinery</i>		15%
<i>inland shipping</i>		10%
H <sub>2</sub> use		
<i>inland shipping</i>		5%
<i>buses</i>		30%
<i>trucks</i>		5%
Efficiency of BEVs as a ratio to ICE		2
Efficiency of FCEVs as a ratio to ICE		1,4

## 2.5 Renewable hydrocarbon demand and supply

### 2.5.1 EU28 renewable hydrocarbon demand & supply options

According to PRIMES baseline the renewable hydrocarbon demand from transport sector will be limited to less than 5% of the total fuel demand (including aviation and maritime) in 2030. When only road and rail transport is considered they correspond to 7,5% of the total fuel demand. These hydrocarbons consist of liquid and gaseous biofuels.

The demand for renewable hydrocarbons will need to be increased significantly up to 2050 to achieve carbon neutrality in road, rail, and inland shipping and to reduce CO<sub>2</sub> emissions from aviation and maritime sectors. According to the scenario framework introduced in the previous section, this will mean increasing the 2030 renewable hydrocarbon demand by a factor of 10. Figure 17 illustrates the fuel mix for 2030 and 2050 for the European Union. Renewable hydrocarbons will be required mainly for road transport in 2015 and 2030. In 2050, in addition to road, rail and inland shipping, maritime and aviation sectors will require substantial amounts of renewable hydrocarbons (See Figure 18). A considerable amount of direct electrification is assumed in road transport. The electricity demand from battery electric vehicles (BEV) are calculated to be above 2500 PJ. This corresponds to around 20% of the EU28 net electricity generation in 2017. Still, the renewable hydrocarbon demand of this transportation mode is considerably high, almost half of the total renewable hydrocarbon demand.

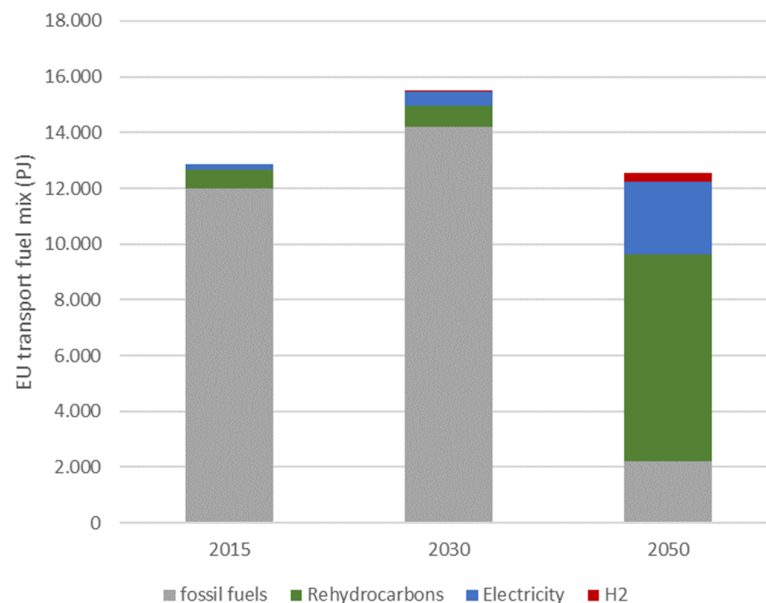


Figure 17 Transport sector fuel mix in the EU28 (includes all transport modes, including international aviation and maritime)

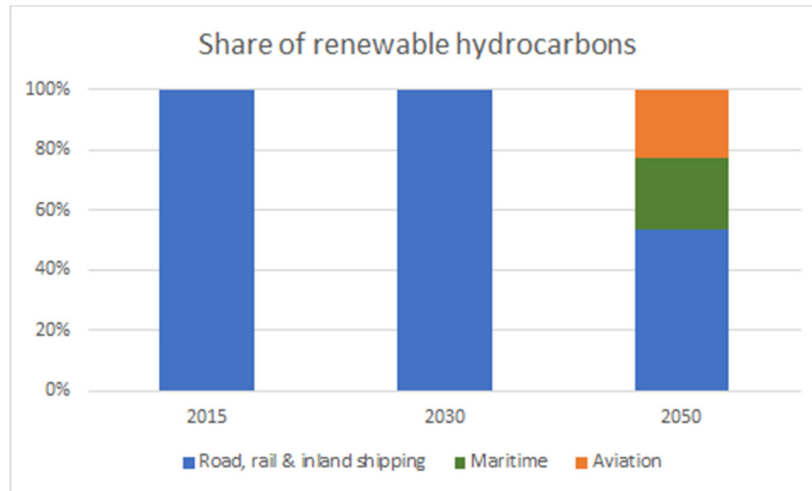


Figure 18 Renewable hydrocarbon demand shares in different transport modes in EU28

### **Renewable fuels supply**

There are many routes and technologies that can supply renewable hydrocarbons. The availability, suitability and the prices of feedstocks play a key role in the future deployment of these renewable fuels. For synthetic fuels from non-biological origin (also referred to as e-fuels) this relates to the availability and cost of renewable electricity and CO<sub>2</sub>. Next to that, the market readiness of the technologies, the fuel match of the existing vehicle fleet and the additional costs to adapt these vehicle fleet are among other important aspects impacting the role of different renewable fuel options. To define the order of the magnitude of the demand for biomass resources we construct 2 possible development pathways:

- 1 Pathway 1 considers a future where the vehicle fleet stays comparable to current types that are based on the ICE. The blending limits stay as they currently are, and the fuels will either need to be blended with gasoline and diesel or will need to be drop-in.
- 2 Pathway 2 focuses on a future where the vehicle fleet is adapted in accordance with the low cost and high biofuel output renewable fuel production options. This pathway assumes that the vehicle fleet will be adapted to the different supply options.

The results are presented in Figure 19. Both cases consider an equal amount of first generation (1G) biofuels and fatty acid methyl ester (FAME) or hydrotreated vegetable oil (HVO) produced from used cooking oil and animal fats. These amounts take into account the existing regulations regarding the cap on conventional biofuels and biofuels produced from used cooking oil (UCO) and animal fats. These caps are assumed to continue until 2050. The main difference between the two cases relates to the type of renewable fuels. Case 1 assumes that half of the demand for

REDII introduced below caps/limitations for 2030:

- 1G biofuels to be kept in 2020 limits, not exceeding 7% of the final energy consumption in road and rail transport
- Biofuels from Annex IX A list (mainly UCO and animal fats) limited to max

renewable kerosene in aviation sector is met via alcohol-to-jetfuel (AtJ) value chain and the other half from Fischer Tropsch kerosene production. These value chains also produce diesel and gasoline which are used to meet the renewable hydrocarbon demand in road transport and shipping. The total renewable fuels generated via these value chains do not suffice to meet the total renewable hydrocarbons and since there is no further demand for renewable kerosene other value chains that produce drop-in fuels suitable for the shipping sector are considered. These are renewable LNG and the supply of a mix of diesel, gasoline and HFO via HTL route or pyrolysis route. Due to higher yields HTL was used for the calculations.

Case 2 focuses on the technologies with higher yields. Renewable kerosene demand in this case is fully met via the AtJ value chain. Produced gasoline and diesel are assumed to be used for the road transport. In this study, Dimethyl Ether (DME) is proposed as an alternative to diesel fuel that can be used by cars and trucks. For inland shipping, equal amounts of renewable LNG, MEOH and DME are calculated. Also, for the maritime sector, a mixture of 1G biofuels, lignocellulosic ethanol BioDME bio-LNG and bio MeOH are considered. Figure 19 illustrates the two “illustrative cases”.

A common complexity in both cases relates to the high demand for drop-in diesel substitute and the renewable value chains producing a mixture of diesel, gasoline, and naphtha. For both cases we assumed that the vehicle fleet can be shifted from compression ignition engine to spark ignition engine to use gasoline. This may be more difficult in the maritime sector as the lifetime of ships are much longer (up to 40 year) and most ships are based on diesel engine. This problem can be address with ships built with multifuel engines.

It is necessary to highlight that these calculations do not provide the optimal fuel mix. Defining the cost-optimal mix will require a different modelling exercise. These two illustrative cases have been defined to roughly assess the renewable feedstock requirements to meet the renewable hydrocarbon demand. For instance, when the demand is to be met by biomass only, the results show that around 12EJ primary biomass will be needed. This amount is more than 90% the EU28 total biomass supply potential introduced in Chapter 4, and 40% of the maximum supply potential introduced in literature. There is a wide range in literature for the biomass potential for Europe and globally. The total biomass potential in the EU is in the range of 17-31 EJ and 8-21 EJ in 2050, according to Strengers and Elzenga (2020) and Ruiz et al. (2015), respectively. The solid biomass import potential to the EU from other regions of the world is estimated to be around 0,5-0,9 EJ in 2050, according to Ruiz et al. (2015). The sustainable biomass potential derived from the EU-funded S2Biom project and the EU-funded Biomass Policies project indicates a total biomass potential of around 13 EJ in 2030 and 2050. The breakdown of this potential into feedstock types are presented in Chapter 4. Biomass will also be demanded from other sectors, namely power and heat and also the chemical industry. Demand from the chemical industry is discussed in Chapter 5 in this report.

Results from this study show that if, the renewable kerosene demand in aviation sector is to be satisfied via power-to-x (PtX) option, this will require around 1010

TWh renewable electricity and 143 Million tonne CO<sub>2</sub><sup>10</sup>. For comparison, this amount corresponds to around 40% of the most favourable industrial point source sector CO<sub>2</sub> emissions in 2015 and around 50% to 70% of the projected emissions from these industries (see Chapter 4 for the CO<sub>2</sub> availability as feedstock). Next to that, the total CO<sub>2</sub> that is allowed to be emitted to the atmosphere by aviation sector is calculated as 65,5 Mt to meet the 50% GHG emission reduction by 2050. The total renewable electricity demand will increase to more than 1700 TWh when also the direct electrification of road transport is considered.

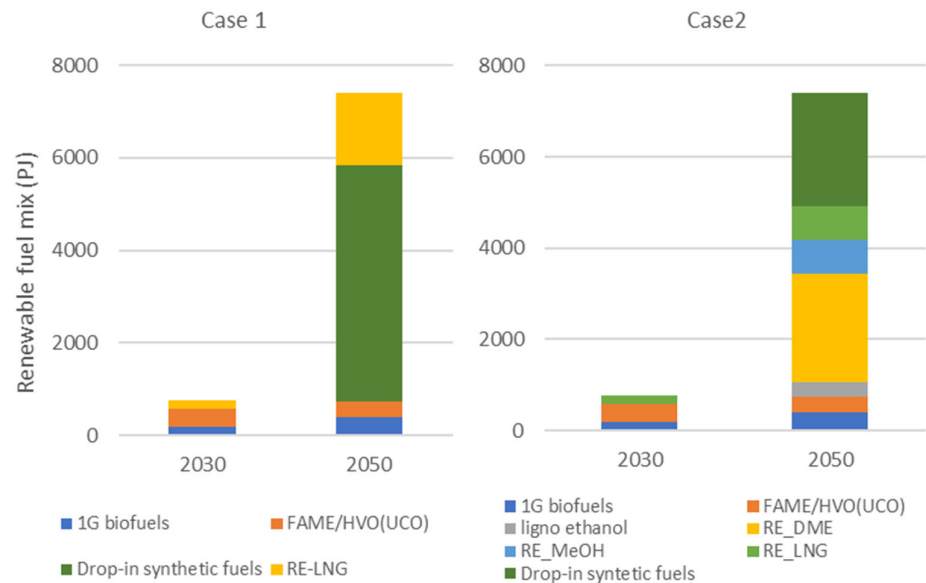


Figure 19 Supply of renewable fuel mix for transport according to case 1 and case 2(P).

## 2.5.2 The renewable hydrocarbon demand in the Netherlands and supply options

Figure 20 illustrates the fuel mix in the Netherlands for 2019. It also shows the projections for 2030 and 2050. As stated in the scenario description, the 2030 dataset is based on the KEV 2020 (PBL, 2020) projections with some adaptations. The Climate Agreement sets a goal of 65 PJ renewable fuel in 2030. The KEV 2020 (PBL, 2020) indicates the total amount of biofuels in transport sector to be around 33 PJ and the amount of electricity in road transport to be around 12,6 PJ<sup>11</sup> of which only 4,15 PJ<sup>12</sup> can be accounted towards the 2030 renewable fuel obligation. In this study, the remaining 28 PJ is added to 2030 projections, replacing the fossil hydrocarbons. The rest of the projections are kept the same as KEV 2020 (PBL, 2020) projections. It is important to mention that the uncertainty around the electrification projections of road transport in 2030 is high. This is also highlighted in the KEV 2020.

<sup>10</sup> CO<sub>2</sub> conversion efficiency is assumed as 0,082 Mt CO<sub>2</sub>/PJ<sub>kerosene</sub>

<sup>11</sup> According to the KEV 2020 (PBL, 2020) this corresponds to around 1 million passenger cars by 2030.

<sup>12</sup> The renewable share of the electricity mix in 2030 is projected to be around 70%. This implies that the renewable share of electricity consumed in road transport will be around 8.8 PJ. According to the KEV only 47% of this can be registered as renewable obligation.

For 2050, we assumed a significant increase in direct electrification of transport sector as introduced in section 2.4.2 Table 6.

According to our results, the renewable hydrocarbon demand in 2030 is around 3 times the consumption in 2019. To achieve a zero-emission transport (excluding international maritime and aviation) and a reduction of CO<sub>2</sub> emissions from the international aviation and maritime sectors by 50% in 2050, the total renewable hydrocarbon demand will need to be more than 20 times the current renewable fuel supply in transport sector as a whole. Figure 21 illustrates the share of the renewable hydrocarbon demand from the different transportation modes. In 2050, the aviation and maritime sectors account for around 70% of the total renewable hydrocarbon demand. This depicts a significant change compared to 2019, where the renewable hydrocarbons, in the form of biofuels, were used completely in road transport. Renewable hydrocarbon demand in transport, excluding aviation and maritime, increases by a factor of 2 when compared to 2030.

The decrease in total hydrocarbon demand in 2050 relates to the efficiency gains due to direct electrification and use of H<sub>2</sub>.

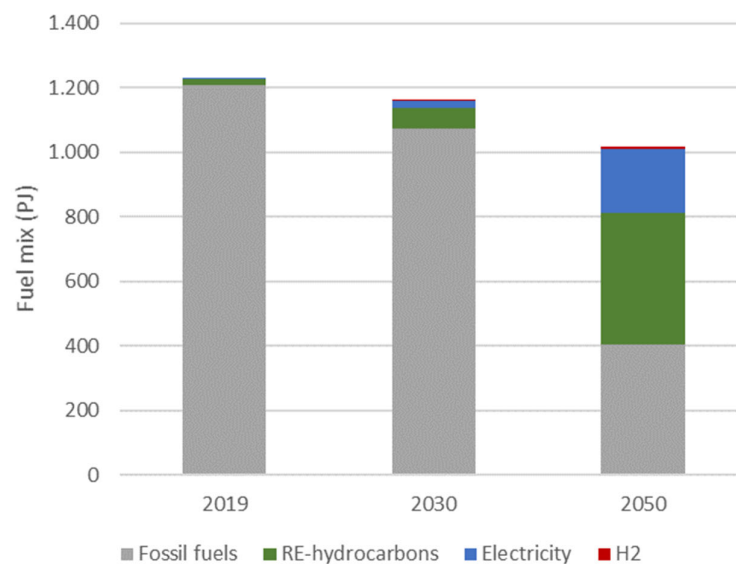


Figure 20 Transport sector fuel mix in the Netherlands (all transport modes, including aviation and maritime) (PJ).

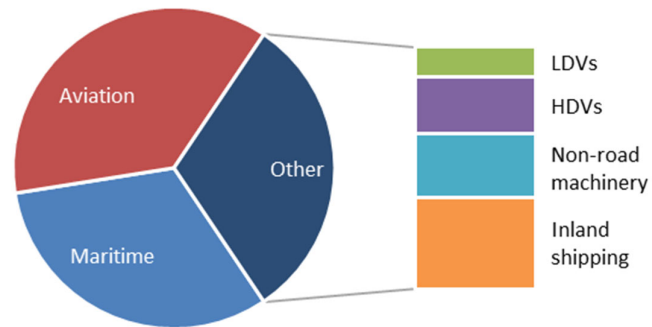


Figure 21 Renewable hydrocarbon demand share in different transport modes in 2050.

### Supply of renewable hydrocarbons

The supply of renewable hydrocarbons in 2030 is based on the recently issued consultation document regarding the decision on the implementation of REDII in the Netherlands (IenW, 2020). Figure 22 illustrates 2030 renewable fuel supply for two possible options. This figure is built up on the KEV 2020 (PBL, 2020) projections.

Option 1 assumes other renewable fuels to be completely advanced biofuels from Annex IX, list A. Option 2 considers other renewable fuels to be fully direct electrification of road transport, indicated as RE-E. These two options present the two extremes to illustrate the impacts. In Option 1 the total renewable hydrocarbon demand is 61 PJ. Together with the renewable electricity the

total amount of renewable fuels adds up to 65 PJ. This amount corresponds to the Climate agreement ambitions. In option 2, the total amount of renewable hydrocarbons is reduced to 40 PJ due to energy savings resulting from the electrification of road transport. When renewable electricity is also included this adds up to 51 PJ. Electrification in option 2 is 2,5 times of the KEV 2020 (PBL, 2020) electrification projection of road transport. While both options achieve the 27,1%

#### Main elements of the resolution regarding REDII implementation in the NL

By 2030, total renewable fuel obligation is set to 27,1%. This can be met according to below rules:

- 1G biofuels limited to 1.2%
- Biofuels from Annex IX, B limited to 4,2% (administratively 2x)
- Biofuels from Annex IX, A minimum share 3,5% (administratively 2x)
- Other renewable fuels
  - Renewable electricity (RE-E) share in road transport administratively 4x
  - Renewable fuels from non-biological origin (multiple counting to be determined).

renewable fuel target, in physical terms, option 1 contributes to 13% of the diesel and gasoline demand and option 2 contributes to 11%.

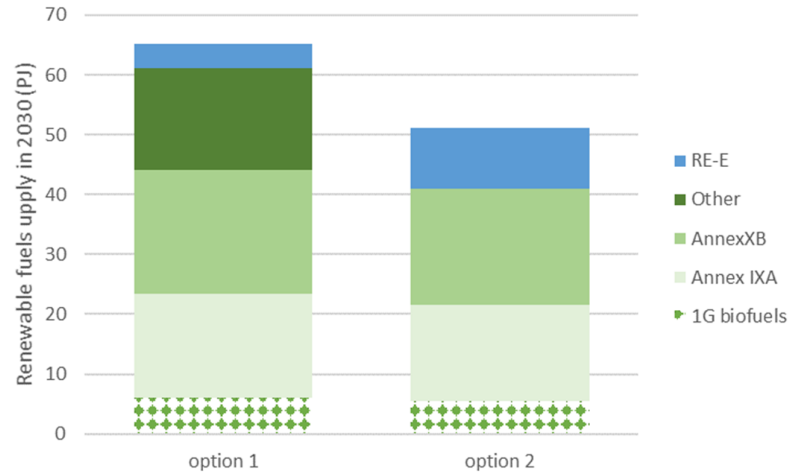


Figure 22 Renewable fuel supply options in 2030 according to REDII implementation (PJ).

In 2050, there should be no fossil fuels consumed in transport, excluding international maritime and aviation. This means that either all renewable hydrocarbons need to be drop-in, or the vehicle fleet will need to be adapted to use new types of renewable hydrocarbons like MeOH, DME, CNG/LNG, next to batter electric vehicles and fuel cell electric vehicles. Therefore, two different cases are studied:

- Case 1 considers a future where the car fleet and the current blending limitations stay as they are. This will mean that the renewable fuels will mostly need to be drop-in to be used in compressed ignition engines or spark ignition engines.
- Case 2 looks at a future where the low-cost production of renewable hydrocarbons leads the way, and the vehicle fleet adapts accordingly.
- For both cases, the limitations/caps introduced in national implementation of REDII up to 2030 are considered to be implemented also in 2050.

Figure 23 illustrates the two cases, where different renewable fuel mixes are considered. According to these two cases, when all renewable fuels are based on biomass, the total primary biomass demand will be in the range of 800-900 PJ in 2050. These correspond to roughly 2 times the total biomass potential in the Netherlands. Wet biomass suitable for biogas generation or hydrothermal liquefaction (HTL) appears to be sufficient to meet the demand for these types of biofuels. When it comes to woody and grassy feedstocks, the national potential appears to satisfy only 10% and 30% of the total supply, according to Case 1 and Case 2, respectively. It is necessary to highlight that woody biomass in the Netherlands is currently used for heat and electricity generation.

This study shows that around 90 TWh renewable electricity will be needed, if the total aviation demand in 2050 is assumed to be met via e-kerosene. When also direct electrification in road and rail transport is included, the total renewable electricity demand for the transport sector reaches to 140 TWh in 2050. For comparison, the renewable electricity generation in the Netherlands in 2019 was



around 22,5 TWh and it is projected to grow up to 92 TWh in 2030 according to the KEV 2020 (PBL, 2020). The amount of CO<sub>2</sub> that needs to be captured in 2050 to produce the total e-kerosene will be around 12 Mt. This amount is roughly 2 times the amount of CO<sub>2</sub> emissions that are allowed by the aviation sector in 2050 to meet the 50% GHG emission reduction target.

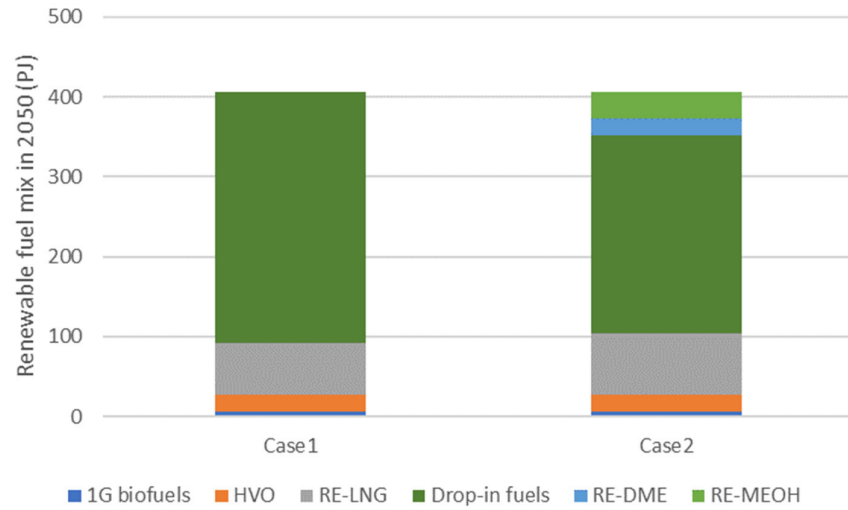


Figure 23 Renewable fuels mix in 2050 according to two illustrative cases (PJ).

## 3 Chemical industry

### 3.1 Introduction

The chemical industry uses about half of its fossil fuel demand as feedstock. These fossil resources are used as raw material for a variety of widely used products like plastics, fertilisers, solvents, detergents, or tyres in the chemical and plastics industries. According to Bazzanella and Ausfelder (2017) from 78,6 Mt of feedstocks in the EU chemical industry, 73% are based on mineral oil, 16% on natural gas, 1% on coal and 10% on renewable feedstocks (biomass).

To mitigate climate change and reach EU's goal of net-zero carbon emissions by 2050, large-scale use of fossil resources as raw materials should be substituted by the renewable options. The phase-out of fossil carbon use as raw material will prevent a further increase in CO<sub>2</sub> concentrations because a big part of the carbons incorporated in these chemicals are released to atmosphere at some point in their life cycle.

The chemical sector is complex and presents a vast variety of products. Eight primary chemicals are the key building blocks on which the bulk of the chemical industry is based. These include ammonia, methanol, ethylene, propylene, butadiene, benzene, toluene, and mixed xylenes. These primary chemicals are responsible for approximately two-thirds of the sector's total final energy (IEA, 2018).. Dimethyl-ether (DME) is expected to be relevant for the chemical sector in the future, mainly because of the possibility to convert DME into olefins. Due to their importance for the sector, this study focuses on methanol, DME, ethylene, propylene, butadiene, and aromatics (benzene, toluene, and xylenes). Products that do not require a carbon source, such as ammonia, urea, and chlorine, are excluded from this study. Figure 24 illustrates the building blocks, which are the focus of this study.

A brief introduction of these chemical building blocks and their production status and the trade flows can be found in appendix A-C.

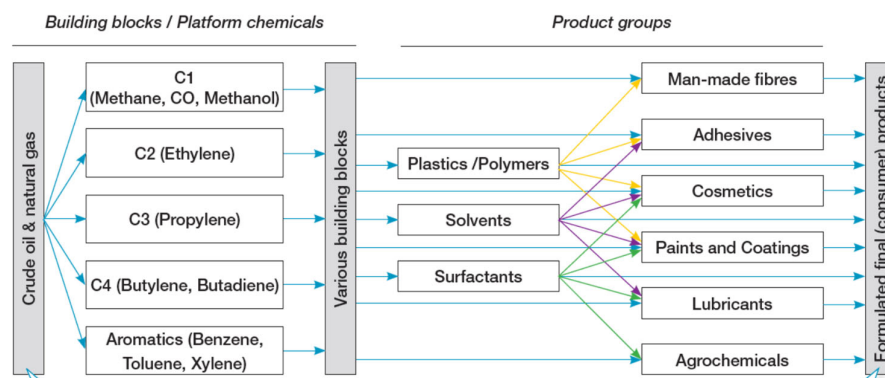


Figure 24 Building blocks chemicals and production routes (Rübberdt et al., 2018)

### 3.2 Scenario set-up for the chemical building blocks

The main goal of this baseline scenario is to reduce embedded fossil carbon in methanol, DME, ethylene, propylene, butadienes, benzene and xylenes by substituting the production of these chemicals with renewable carbon as feedstock.

In this study, the projections are conducted for the production volumes rather than the demand projections. This relates to the ambitions to reduce the fossil hydrocarbon demand of the chemical industry in European and the Netherlands. The main scenario assumptions are introduced in Table 7 and specified further in the following sections.

Table 7 Main scenario assumptions

Chemical industry	
European Union	
Demand/ production volumes	<ul style="list-style-type: none"> <li>- Ethylene, propylene, butadienes and aromatics: 13% volume shrink in 2030; and 25% in 2050 compared to 2017 volumes</li> <li>- Methanol: 30% volume increase in 2030 and 50% in 2050.</li> </ul>
Recycling polices	<ul style="list-style-type: none"> <li>- Development on recycling is not considered in the projections, i.e., the demand for the selected chemicals is not affected by recycling.</li> </ul>
Renewable substitution target	<ul style="list-style-type: none"> <li>- 15% of chemical building blocks to be based on renewable feedstocks in 2030, increasing to 30% in 2050</li> </ul>
Netherlands	
Demand/ production volumes	<ul style="list-style-type: none"> <li>- Methanol, ethylene, propylene, butadienes and aromatics: 4% volume growth in 2030; and 9% in 2050 compared to 2017 volumes</li> </ul>
RES target	<ul style="list-style-type: none"> <li>- RES target of 15% in 2030, increasing to 30% in 2050</li> </ul>

#### 3.2.1 Production of methanol, ethylene, propylene, and aromatics in the EU

The EU projections for petrochemicals production are based on the indications given by the Reference Technology Scenario presented by the IEA report *Future of Petrochemicals* (IEA, 2018). This scenario was grounded on cost-optimal decisions on the equipment and operation of the industry. These decisions were considered to be driven by commodity prices and chemical demand within the context of existing and announced policies. The scenario complies the petrochemicals market worldwide and includes a wide set of considerations; among those, the following aspects can be highlighted as relevant for this study:

- Demand for HVCs grows around 55% in 2030 and 60% in 2050 worldwide (compared to 2017).
- Asia Pacific is the leading producer region in both 2030 and 2050.

- Middle East and Africa are the fastest growing regions.
- American continent continuing growing in the sector, but in slower rates than the current.
- Europe HVCs production shrinks, compared to 2017 values, around 13% in 2030 and 25% in 2050 due to less competitiveness in the market in terms of feedstock and energy costs.
- Naphtha remains the main feedstocks for the HVCs processes in Europe.
- Plastics continues to be the main driver for the HVCs demand. Polyethylene and polypropylene accounts for 2/3 of the demand of their monomers.
- Benzene is still used in a broader set of application, but around 50% of its production is destined for plastic production.
- Production of methanol worldwide is the highest area of global growth among primary chemicals, with output increasing by more than 50% by 2030 and almost doubling by 2050. China remains the main producer of methanol, keeping responsible for more than 50% of the total production in 2050.
- North America is the region with the fastest growth rate; by 2050, its methanol production nearly triples.
- Methanol production in Europe grows around 30% in 2030 and 50% in 2050 (compared to 2017).

Due to cheaper feedstocks in other regions (US and Asia) and higher energy costs, the European HVC production is expected to become less competitive in the market. These are the main reasons for the volume shrink foreseen for 2030 and 2050.

For methanol, the scenario differs; production in Europe continues to grow as a reflection of the high growth rates projected for global demand. The main reasons for the demand increase relate to two applications: methanol use as a fuel additive and its use as an intermediate for producing olefins and aromatics. Fuel-related applications of methanol, which currently account for about 35-40% of demand, are motivated by their capacity to be blended directly with or substitute some conventional fuels, such as gasoline and bunker fuel (IEA, 2018).

No specific future projections were found to produce butadienes, xylenes and toluene in Europe. However, butadienes production is entangled with ethylene and propylene production and the same occurs between xylenes, toluene and benzene (see Appendix B). For this reason, it is assumed that the production levels will follow a similar pattern as ethylene, propylene, and benzene projections.

### 3.2.2 *Production of the selected chemical building blocks in the Netherlands*

The development of the Dutch petrochemicals is based on the Climate and Energy Outlook (PBL, 2019), which provides an integrated view of developments in energy supply and energy consumption in the Netherlands, as well as other activities that lead to GHG emissions. It includes a single reference scenario which incorporates external factors such as the economy, demographics, fuel and CO<sub>2</sub> prices, specific technological developments, assumptions about human behaviour until 2030.

The KEV 2019 scenario includes adopted and proposed policies in the Netherlands and, in addition to the reference scenario two variants with high/low energy and

CO<sub>2</sub> prices are available. The outlook also provides physical development index for several industrial sectors up to 2030. These values are used to estimate the projections of the petrochemicals production in the country. The progressions for methanol, olefins and aromatics production in the KEV present the same values.

Since the Energy Outlook has physical developments only until 2030, the 2050 growth rates were estimated based on extrapolation towards 2050 of the KEV projections (Figure 25, grey dots).

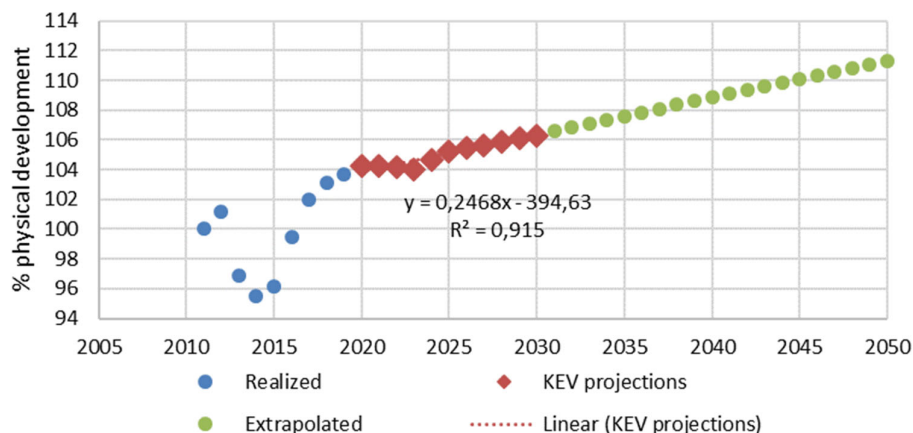


Figure 25 KEV 2019 projections and extrapolation of physical development of olefins, aromatics and methanol industries in the Netherlands.

The Netherlands is one of the most relevant traders of ethylene worldwide, therefore, the country plays a key role in the international chemicals market. This is one of the reasons why the Dutch production increases, while the European production decreases in the future. Other causes that result in different assumptions than the European ones are further explored in Appendix B.

### 3.2.3 Production volume projections 2030-2050

Considering the current production for the studied chemicals and assumptions for their future development, the production volumes for methanol, olefins and aromatics are estimated. Table 8 gives an overview of these estimations.

Table 8 Production volumes for ethylene, propylene, C4, methanol and aromatics for EU28 and the Netherlands for 2030 and 2050

<b>Chemicals – Netherlands (Kt/yr)</b>					
Year	Methanol	Ethylene	Propylene	Butadienes <sup>2)</sup>	Aromatics (BTX)
2017 <sup>1)</sup>	425 <sup>3)</sup>	2668	1797	333	1268
2030	443	2781	1873	347	1321
2050	464	2911	1961	363	1384
<b>Chemicals - EU28 (Kt/y)</b>					
Year	Methanol	Ethylene	Propylene	Butadienes <sup>2)</sup>	Aromatics (BTX)
2017 <sup>1)</sup>	1500	19010	13128	2954	8698
2030	1950	16634	11487	2585	7611
2050	2250	14257	9846	2215	6524

<sup>(1)</sup> Production volumes for 2017 based on data found in EUROSTAT (2020)

<sup>(2)</sup> It considers Buta-1,3-diene and isoprene

<sup>(3)</sup> Only nameplate capacity available. It was assumed a utilization factor of 85% to calculate the production volume for methanol in the Netherlands

## 4 Renewable hydrocarbon supply options

Renewable carbon is defined as “all carbon sources that avoid or substitute the use of any additional fossil carbon from geosphere” by Carus et al (2020). They indicate three sources of renewable carbon: from biomass resources, from direct CO<sub>2</sub> utilisation and from recycling of already existing plastics and other chemical products. This study limits its focus to the first two options. Thus, renewable carbon supply via:

- All types of biomass that respect the sustainability criteria, and
- CO<sub>2</sub> utilisation of fossil point sources (while they still exist) as well as from direct air capture.

### 4.1 Biomass supply potential

There is an extensive list of literature providing a wide range of biomass supply potential for Europe and the Netherlands. In a recent work, (PBL, 2020) indicates the total biomass potential in the EU to be in range of 17-31 EJ in 2050. (Ruiz et al., 2015b) highlights the range as 8-21 EJ. The same study estimates the solid biomass import potential to the EU from other world regions to be around 0,5-0,9 EJ in 2050. There are other dedicated studies that analyse the sustainable biomass potential for energy and biobased production such as Biomass Futures, Biomass Policies (both IEE projects) and S2Biom (FP7 project). The main data source for domestic biomass feedstock potential is derived from the two projects: Biomass Policies (2016) and S2BIOM (2017) projects. While Biomass Policies (Elbersen et al., 2016) has investigated all types of biomass resources, the S2BIOM project has focused on the lignocellulosic feedstock potentials. In this study we apply the FP7 S2Biom project dataset related to the supply of lignocellulosic feedstocks. Projections beyond 2030 are based on the relative change using the JEC-EU-TIMES project (Ruiz et al., 2015). The biomass supply potential in the Netherlands is based on the recent PBL study (PBL, 2020). Figure 26 and Figure 27 present the dataset used for the EU28 and for the Netherlands, respectively.

While there are established markets for traded biomass, such as wood chips and wood pellets, there are currently no established markets to define feedstock prices dedicated to advanced biofuels. Advanced biofuels refer to biofuels produced from lignocellulosic wastes and residues from agriculture and forestry. In this study, the EU average roadside costs of biomass feedstocks are used, instead of prices. These costs cover the production costs (in case of dedicated crops), in the field/forest pre-treatment (i.e., chipping, baling), and collection up to roadside/farm gate. Appendix C presents the biomass feedstock costs.

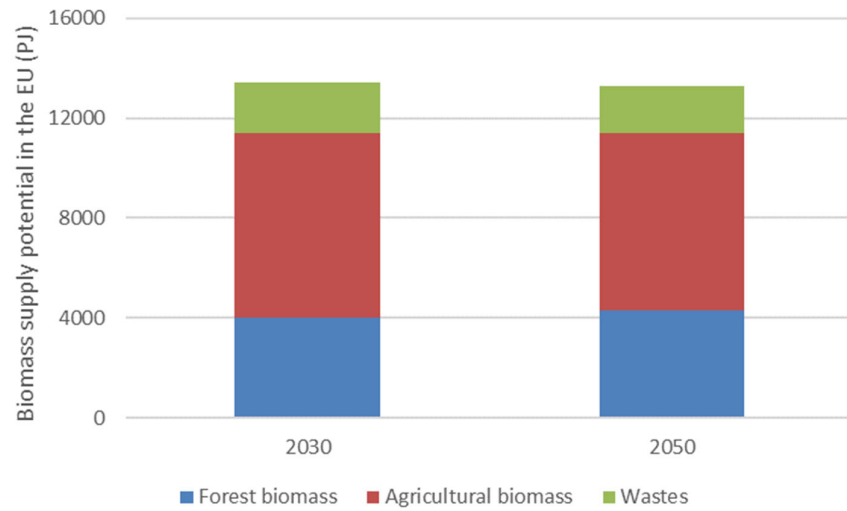


Figure 26 EU28 biomass supply potential (based on S2Biom & Biomass Policies)  
 \*Grassland cuttings and dedicated energy cropping are considered under agricultural feedstocks

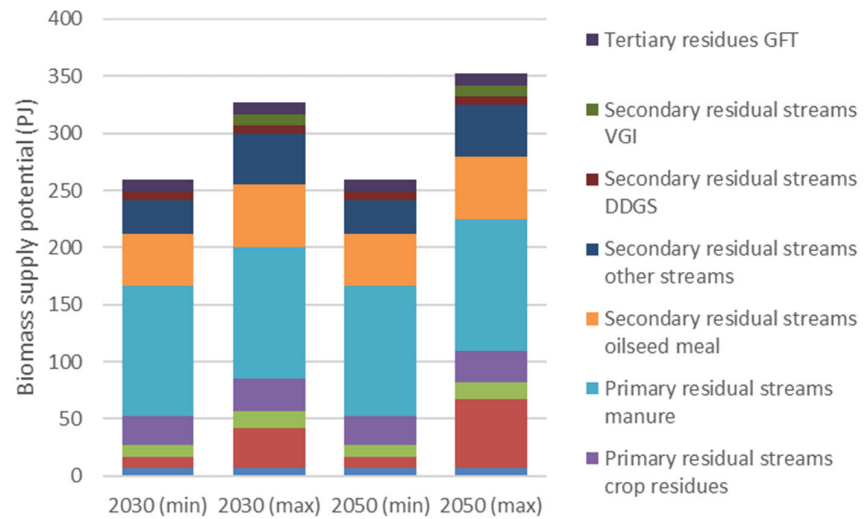


Figure 27 Domestic biomass supply potential in the Netherlands (based on PBL, 2020; CeDelft, 2019)

#### 4.2 CO<sub>2</sub> availability as feedstock

CO<sub>2</sub> can be captured and supplied from fossil point sources such as power or other industrial plants producing high concentration CO<sub>2</sub>, from biogenic point sources such as biochemical and thermochemical biomass processes, and directly from the air. The attractiveness of a point source depends on its volume, concentration, partial pressure, integrated system aspects and proximity to a suitable process industry that can utilise the CO<sub>2</sub> (CarbonNext, 2018). Cement, steel, ammonia and ethylene manufacturing, natural gas processing and steam-methane reforming for



hydrogen production are considered as the most interesting industrial processes for CO<sub>2</sub> capture due to high concentrations of CO<sub>2</sub> (CarbonNext, 2018). Table 8 provides information about the CO<sub>2</sub> concentrations of different sectors and also presents the CO<sub>2</sub> emission volumes from the most relevant point sources with the lowest capture costs for 2015. In the EU the total CO<sub>2</sub> emissions from these sources add up to 350 Mt CO<sub>2</sub> per year, with the capture cost of 30-768 €/t (CarbonNext, 2018).

As part of the sectoral transformation, industries will reduce their GHG emissions significantly up to 2050. According to the FORECAST projections (Fleiter et al., 2019), deep decarbonisation of industry may result in significant GHG emission reductions. This study constructs several scenarios for the future. All scenarios assume today's best available energy efficiency techniques as the starting point, as well as a certain level of recycling, material efficiency and substitution. Some of the key results of scenarios to reduce GHG emissions by 80% or more (compared to 1990) are introduced below:

- Scenario focusing on CCS: In 2050, with around 294 MtCO<sub>2</sub> capture per year (mainly from cement and lime production, the chemical and iron & steel industry) a 79% emission reduction compared to 2015 is possible.
- Scenario focusing on electrification: 66% GHG emission reduction by 2050, without CCS with significant electrification of industry is possible. The remaining emissions amount to 256 Mt.
- Mix 80% scenario assumes a balanced mix of technical options: this scenario projects the emissions to be around 221 Mt in 2050. This scenario, also, does not consider CCS technology.

Based on the above study we estimate the future CO<sub>2</sub> capture potential to be approximately 209<sup>13</sup>-294 Mt, although the FORECAST projections are not limited to the industries producing concentrated CO<sub>2</sub>, but all. Therefore, this is a very rough indication of the supply potential for 2050. For comparison, (Bazzanella and Ausfelder, 2017) indicates the availability of CO<sub>2</sub> to be 381 Mt, of which 313 Mt is from industry. This data is based on the IEA ETP2015 2 °C scenario projections. It is necessary to highlight that our estimate is based on a light literature research. A more comprehensive assessment of the future CO<sub>2</sub> supply potential will be necessary.

Table 9 Key sources of CO<sub>2</sub> in the EU (CarbonNext, 2018)

Sector	CO <sub>2</sub> source	CO <sub>2</sub> concentration in exhaust gas (vol%)	Current Emission (Mt CO <sub>2</sub> /y)
<b>Biomass processes</b>	Fermentation	15-100	
	Biogas upgrading	~100	
	Biogas	19-38	
	Bioethanol	100	
<b>Power generation</b>	Natural gas	3-10	4,47
	Petroleum	3-8	
	Coal (IGCC)	3-15	3,7
	Cement	14-33	119,4

<sup>13</sup> Assuming that 95% of the GHG emission relate to CO<sub>2</sub>.

Sector	CO <sub>2</sub> source	CO <sub>2</sub> concentration in exhaust gas (vol%)	Current Emission (Mt CO <sub>2</sub> /y)
<b>Industrial processes</b>	Iron and steel	15-35	151,3
	Ethylene oxide	30-100	17,7
	Oil refineries	3-13	
	Ammonia	~100	322,6
	Hydrogen production	70-90	5,3
	Natural gas production	5-100	5
	Pulp and paper	7-20	31,4
<b>Other</b>	Air	0,04	

### 4.3 Approach to defining the promising supply options

The approach followed to assess different supply options integrates data of the demand of chemicals for 2030 and 2050, data of feedstock potentials (i.e., biomass and CO<sub>2</sub>) and prices for 2030 and 2050, and data related to the conversion of those feedstocks into the valuable chemicals. The overall approach followed can be described in 9 steps (see Figure 28). The steps are described in detail in appendix H.

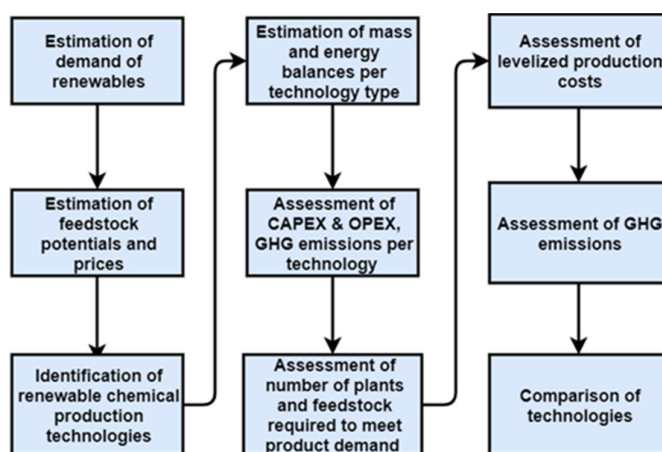


Figure 29 Approach followed to assess technologies options for producing renewable chemicals in 2030 and 2050

Table 38 in Appendix E presents a summary description of the renewable pathways considered in this study.

Table 10 presents the list of pathways considered in this study. It is important to mention that the renewable options are focused on bio-based and e-based (power-to-X) production pathways.

Table 10 Pathways included in this analysis for producing different *chemicals B* refers to biomass-based value chains, whereas *E* refers to *p-to-x* option

Methanol	DME	Olefins (standalone ethylene)	Olefins (mainly ethylene and propylene)	Olefins (mainly propylene)	Olefins (mainly butadiene)	Olefins & BTX (via pyrolysis) <sup>a</sup>
B1. via biogas	B3. via methanol from biogas	B7. via first generation (1G) ethanol	B11. via methanol to olefins. Methanol from biogas	B16. via methanol to propylene. Methanol from biogas	B18. via 1G ethanol	B22. downstream processing of WSBO and WIBO <sup>b</sup>
B2. via gasification	B4. via methanol from gasification	B8. via second generation (2G) ethanol. Dilute acid pre-treatment	B12. via methanol to olefins. Methanol from gasification	B17. via methanol to propylene. Methanol from gasification	B19. via 2G ethanol. Dilute acid pre-treatment	B23. downstream processing of WSBO and WIBO. One step hydrogenation
E1. via alkaline electrolysis	B5. via syngas from biogas	B9. via 2G ethanol. Steam explosion pre-treatment	E6. via methanol to olefins. Methanol via alkaline electrolysis	E9. via methanol to propylene. Methanol via alkaline electrolysis	B20. via 2G ethanol. Steam explosion pre-treatment	B24. downstream processing of WSBO
E2. via solid oxide electrolyser (SOE) cell co-electrolysis	B6. via syngas from gasification	B10. 2G ethanol. Dilute acid pre-treatment	E7. via methanol to olefins. Methanol via SOEC	E10. via methanol to propylene. Methanol via SOEC	B21. via 2G ethanol. Dilute acid pre-treatment	B25. downstream processing of WSBO. One step hydrogenation
	E3. via methanol. Alkaline electrolysis		B13. via DME. DME direct from biogas			B26. downstream processing of WSBO. Two step hydrogenation
	E4. via methanol. SOE co electrolysis		B14. via DME. DME direct via gasification			
	E5. via syngas. SOE co-electrolysis		E8. via DME. DME direct via SOE co-electrolysis			
			B15. via Fischer Tropsch. Biomass gasification			
			E9. via Fischer Tropsch. SOE co-electrolysis			

<sup>a</sup> Olefins and BTX are produced simultaneously from pyrolytic oil.

<sup>b</sup> WSBO: Water soluble bio-oil, WIBO: Water insoluble bio-oil.

## 5 Results of renewable hydrocarbon supply

This section focuses on presenting and discussing the results on levelized costs and GHG emissions for Europe and the Netherlands. The analysis was done for 2030 and 2050. Results in this report are focused on EU 2050 and the Netherlands in 2030 to illustrate the main aspects for each case. Nevertheless, main results regarding resources use are presented in section 5.2. For a better understanding of the reader, assumptions for estimating CAPEX, OPEX and GHG emissions are presented in detail in Appendix H. Details on assumptions such as carbon sources and biomass sources are also shown in Appendix H. Data for CAPEX estimation is presented in Appendix D. Results of sensitivity analysis are presented in Appendix F. This includes results for all routes. Some examples are presented in the body of the text in this section. Results of mass and energy flows of each technology option are represented in appendix G.

### 5.1 Assessment of renewable supply options

#### 5.1.1 EU 2050

This section focuses on presenting and discussing the results on levelized costs and GHG emissions for the different alternatives for EU in 2050. The results are presented and discussed in groups of chemicals below.

#### **Methanol**

Four processing routes were assessed for methanol production, two bio-based routes and two e-based routes. present the most relevant technical results such as number of plants required, capacity utilization, and feedstock required. In all cases feedstock projections for 2050 in Europe show that the consumption of biomass to meet the renewable demand of methanol by 2050 is 1-3% of the feedstock available in Europe (see section 4.1). The analysis was done by one alternative at the time, and thus competing uses for feedstock supply are not considered in this study. When the systems are assumed to operate continuously for a full year (assuming that all year renewable electricity supply is possible for e-based systems), the number of plants, each with a 100 kt/y installed capacity, is 7 in all cases. From the 700 kt/y installed capacity, 96% of that is operated to meet methanol production demand. In contrast, when the operating hours are reduced to 4000 h/y for the e-based systems, the number of installations required are doubled (fourteen 100 kt/y plants required) and can only operate 48% of their installed capacity. This is a relevant aspect as it influences levelized costs. We present results here of operating by 4,000 h per year to assess the impact of intermittency in case it cannot be solved by 2050. This will be discussed in upcoming sections. Something important to remark is that to run the power-to-x systems and meet the demand a renewable electricity supply of 869 and 690 MW is needed for E1 and E2 systems, respectively. Conversion efficiencies for all routes are presented in the appendix F.

Table 11 Relevant results of the routes producing methanol in EU 2050.

Feature	Units	B1. Methanol via biogas	B2. Methanol via gasification	E1. Methanol via alkaline electrolysis	E2. Methanol via SOE co- electrolysis
Total product demand	kt/y	2250	2250	2250	2250
Substitution by renewables	%	30%	30%	30%	30%
Renewable product demand	kt/y	675	675	675	675
Plant capacity	kt/y product	100	100	100	100
Yield	t/t feedstock	0,06	0,50	0,72	0,68
Operating hours per plant	h/y	8000	8000	8000 (4000)	8000 (4000)
Total number of plants required		7	7	7 (14)	7 (14)
Capacity utilization	%	96%	96%	96% (48%)	96% (48%)
Feedstock per plant	kt/y	1492	192	134 (67)	141 (71)
Total biomass feedstock required	kt/y	10441	1341	-	-
Total CO <sub>2</sub> requirement	Kt/y	-	-	940	990
Total renewable electricity	MW	-	-	869	690

Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y

Figure 30 shows levelized costs (assumptions can be found in appendix H) for all methanol production options and as can be seen there is a significant difference in cost between the bio-based processes with the e-based processes. E-based processes are factor 3-4 higher than the bio-based processes (assuming that the e-based processes can run full time during the year see Figure 30a). Given the uncertainty on future intermittency of renewable energy sources, we have here assessed the effect of reducing operating hours for the e-based processes from 8000 to 4000 per year (see Figure 30b). In this last case, levelized costs of the e-based processes were increased by 20-30% in comparison to full year operation. This has to do with the large effect of CAPEX on cost as the processes are installed for certain capacity, and those can only run for a fraction of it. In all cases, the process route with the lowest cost is methanol via biogas. This has to do with its low CAPEX requirements (compared to the other cases) as well as its low feedstock costs (here as 9 €/t). However, in case feedstock price increases for this route, cost can become quite high as it is the route with the lowest conversion yield (see Table 11). This has to do with the fact that biomass such as manure has low yields towards biogas production in comparison to other feedstocks. Nonetheless, feedstocks which can derive higher yields (lignocellulosic biomass) were not considered for anaerobic digestion given the uncertainties in the technical development of those concepts. In contrast, biogas from wet stream is a proven and commercial concept. It is important to mention that biomass potentials distinguish between the different type of biomasses and only wet biomass was considered for the biogas cases. Levelized cost of methanol via biogas falls within the fossil methanol price range for 2020 (250-350 €/t, Methanex). Methanol via gasification is higher than methanol via biogas by approx. 30%.

Although the contribution of feedstock cost is much lower than that of biogas (due to higher yield), the contribution of CAPEX is much larger, due to high cost of gasification. In the case of e-based systems, the major contributors to costs are CAPEX and energy costs. This is typical behaviour for e-based systems (Detz et al., 2018). At this point, it is important to highlight that all cost inputs are based on

2019 values (e.g., prices for energy, CAPEX). This therefore implies that future reductions in CAPEX and prices of renewable energy, were not included directly in this study. As the impact of CAPEX and energy costs is important on levelized costs, we have here carried out a sensitivity analysis of the effect of electricity price and CAPEX reduction/increases on levelized costs. These results are discussed in more detail below.

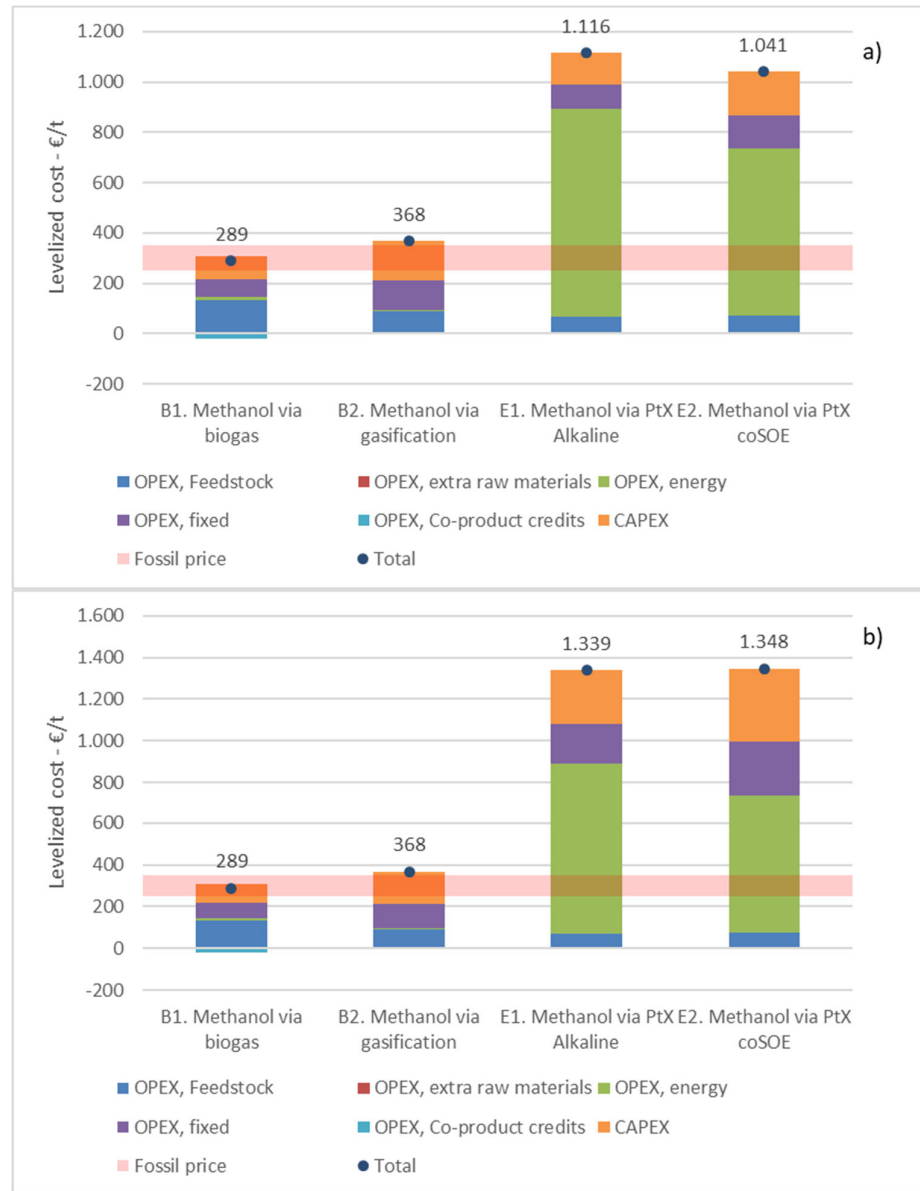


Figure 30 Levelized costs of renewable methanol production. a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

Figure 31 shows the results of sensitivity analysis of electricity prices and changes in CAPEX. In the case of electricity prices (Figure 31.a and b), the effect is highly noticeable for both e-based processes. If the e-based processes operate continuously across the year, the price of electricity needs to be around 0-10 €/MWh, so the systems start to be comparable to the bio-based routes. Nevertheless, when the number of hours is decreased by half (see Figure 31.b), even at 0 €/MWh of electricity price the e-based systems show much higher costs than the bio-based ones. In the case of CAPEX, the effect on levelized cost is not as noticeable as for the case of electricity, but its effect is still significant towards costs reduction in the future. If CAPEX of e-based routes is reduced up to 50%, for the cases in which the systems operate the whole year (see Figure 31c), costs can be reduced by 28%, 37%, 10% and 15% for systems B1, B2, E1 and E2, respectively. It is necessary to highlight possible cost reductions for the gasification technology is not included in this sensitivity.

According to a recent publication from IEA, 10-20% CAPEX and OPEX cost reduction are achievable (Brown et al, 2020). This figure changes slightly (see Figure 31) when considering operation of 4000 h/y for e-based processes, with reduction of levelized costs 17-23% for systems E1 and E2. The results presented here suggest that, to make power-to-x competitive and comparable with bio-based processes, efforts in both CAPEX and electricity prices reduction are needed. For example, in the case in which CAPEX is reduced by 50% and electricity price is 5 €/MWh levelized costs for systems E1 and E2 become 325 and 427 €/t, even when the systems operate for 4000 h per year. It is also important to mention that for all analyses presented for 2050, the contribution of CO<sub>2</sub> cost is low in comparison to CAPEX and electricity price. In this case 50 €/t was assumed as price for CO<sub>2</sub> in 2050 (based on (Detz et al., 2018)). Nevertheless, if CO<sub>2</sub> prices go higher, that can have a significant impact on production costs.

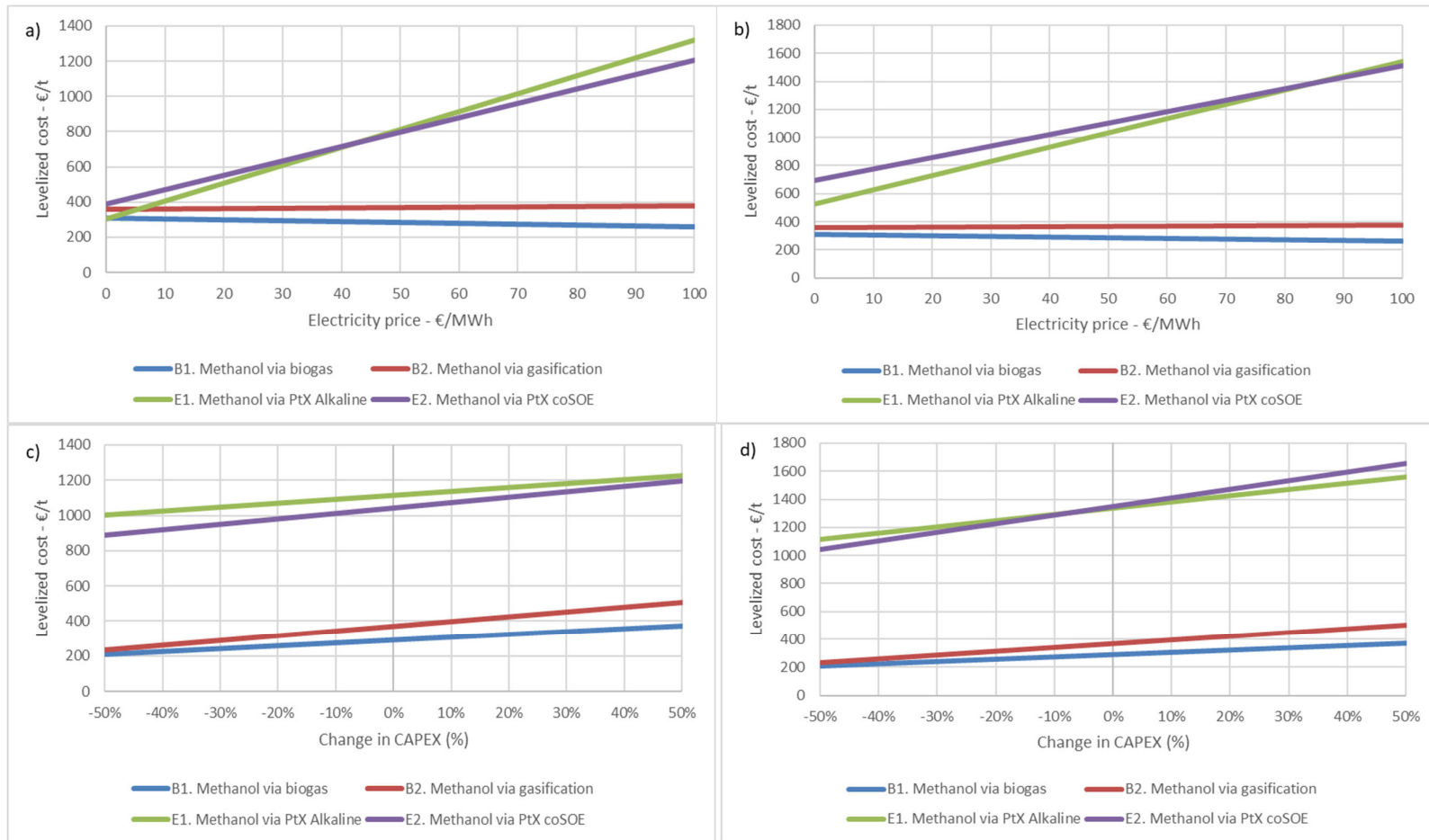


Figure 31 Sensitivity analysis of cost parameters on levelized cost. Electricity price: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year. Change in CAPEX: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.



Figure 32 presents GHG emissions estimation results following a cradle-to-gate approach (see Figure 32a) and a cradle-to-grave (see Figure 32b). The results of the cradle to gate analysis suggest that the system with the highest emissions is methanol from biogas. This has to do with the fact that energy requirements were assumed to be supplied by fossil sources and because its net energy consumption (steam in this case) is slightly higher than in the other systems (excluding renewable electricity for electrolysis). In case utilities for anaerobic digestion and methanol production can be covered by energy produced within the system, emissions are expected to go lower. It is important to mention that decarbonization of biorefineries is an important topic that needs to be analysed further. Today many biorefinery concepts still rely on fossil sources to provide energy to their processes, such as the use of natural gas for steam production or like in pyrolysis supply of hydrogen from natural gas. In the case of the biogas route the contribution of feedstock use into emissions is almost negligible, however, a small fraction of it is considered as negative as manure use avoids methane emissions into the atmosphere. The reader should be careful with these results as we have not included the effect of energy integration potentials (between syngas production and methanol process) and possible energy use of adjacent industries (as those were to be included in an industrial cluster). Therefore, this analysis considers the extreme cases in which supply of energy needs are in all cases supply by fossil sources. In the analysis, only few cases in which internal CHP systems are included within the system boundaries of the processes are considered and discussed.

In the case of gasification, feedstock use has an important contribution. However, the net emissions remain lower as the process is more energy efficient. In that case (process B2), energy requirements were also assumed to be supplied externally by fossil sources, and if energy consumption can be decreased by optimizing internal streams and using a fraction of the biomass for producing steam and power, the overall energy efficiency of the process can be improved and thus process related emissions be decreased significantly. In the case of e-based processes, the contribution of feedstock is 0 because of two aspects. The first one is related to the assumption that CO<sub>2</sub> supply is carbon free, however, that is only possible if the energy use for carbon capture is of renewable nature. In this case we assumed that carbon supply for 2050 will be done with direct air capture (DAC), but as it is now, this is an energy intensive process with a significant requirement of heat and power. If those are not of renewable nature, DAC might not be efficient in terms of net GHG emissions reductions. The second aspect is that emissions related to energy use for electrolysis are accounted as 0 as we here assumed that electricity supply for those operations is purely renewable. Thus, emissions for the e-based processes are related to grey energy requirements (steam and electricity) for the downstream systems. In case grey electricity is used for electrolysis emissions will easily overshoot emissions from the fossil reference due to the large requirements on electricity. In comparison to the petrochemical counterpart, cradle-to-gate emissions are 78-87% lower for renewable methanol production.

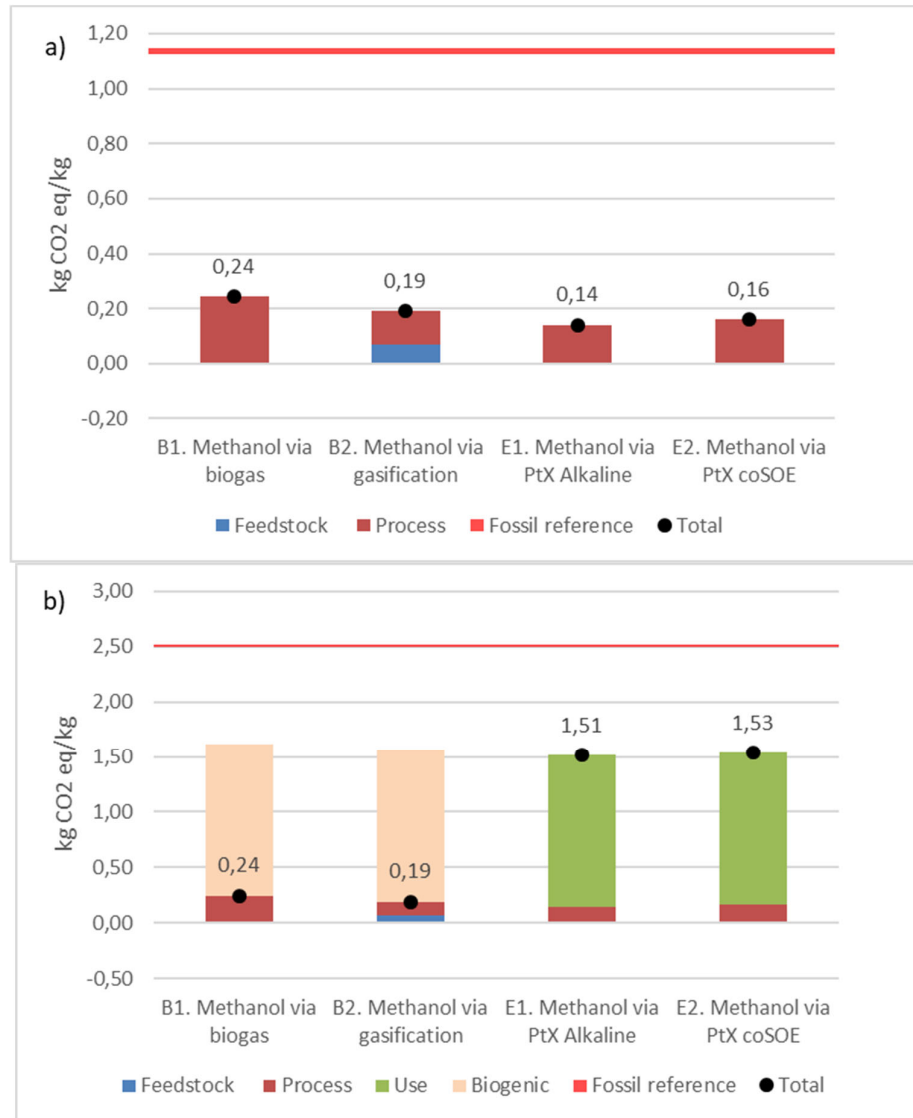


Figure 32 GHG emissions of renewable methanol production. a) cradle-to-gate approach, b) cradle-to gate + use.

As there is a long debate on how to account for carbon in power-to-x systems, it was considered that the carbon that is contained in the product is released to the atmosphere in the form of CO<sub>2</sub> at some point during its lifetime. Thus, on top of the cradle to gate emissions discussed in the analysis presented the emissions by use are added. Results show that emissions of the bio-based processes remain identical as emissions derived from bio-based products are considered biogenic and thus not accounted for. This is not the case of e-based systems as the carbon used for producing the product is not considered biogenic. This aspect is of great relevance when accounting for the benefits and challenges of power-to-x systems implementation. One can argue on the approach for accounting for emissions in power-to-x, and this is why we included both approaches in this study as emissions savings potentials of e-based systems are decreased significantly when carbon embedded in the product is released. In this case, saving potentials were decreased for the e-based processes (in comparison to fossil reference) to approx. 40%,

whereas in the case of bio-based processes the saving potentials increased up to 90%. It is important to mention that this in extreme case assuming that there are no recycling potentials. In case that is included, emissions in the use phase can be lower, but also emissions related to treatment and recycling need to be accounted for. This is, however, not part of the scope of this study.

### DME

Table 12 presents the most relevant technical results such as number of plants required, capacity utilization, and feedstock required. The analysis of number of plants required and capacity utilization is analogous to the one presented before for methanol. To meet the demand, renewable electricity supply of 976, 792 and 822 MW is required for systems E3, E4 and E5, respectively.

Table 12 Relevant results of the routes producing DME in EU 2050

Feature	Units	B3. DME indirect via biogas	B4. DME indirect via gasification	B5. DME direct via biogas	B6. DME direct via gasification	E3. DME indirect PtX Alkaline	E4. DME indirect PtX coSOE	E5. DME direct PtX coSOE
Total product demand	kt/y	1800	1800	1800	1800	1800	1800	1800
Substitution by renewables	%	30%	30%	30%	30%	30%	30%	30%
Renewable product demand	kt/y	540	540	540	540	540	540	540
Plant capacity	kt/y product	100	100	100	100	100	100	100
Yield	t/t feedstock	0,05	0,36	0,08	0,80	0,51	0,49	0,48
Operating hours per plant	h/y	8000	8000	8000	8000	8000 (4000)	8000 (4000)	8000 (4000)
Total number of plants required		6	6	6	6	6 (11)	6 (11)	6 (11)
Capacity utilization	%	90%	90%	90%	90%	90% (49%)	90% (49%)	90% (49%)
Feedstock per plant	kt/y	1955	251	1062	112	176 (96)	185 (101)	186 (101)
Total biomass feedstock required	kt/y	11732	1507	6373	675			
Total CO <sub>2</sub> requirement						1056	1113	1115
Total renewable electricity required (as main input)	MW					976	792	822

Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y.

Figure 33 shows levelized costs for all DME production options and similar to the methanol case there is a significant difference in cost between the bio-based processes with the e-based processes. E-based processes are factor 3-7 higher than the bio-based processes (assuming e-based processes can run full time during the

year see Figure 33a). When considering operation of 4000 h/y (see Figure 33b) levelized costs of the e-based processes were increased by 20-26% in comparison to full year operation. In all cases, the process route with the lowest cost is direct DME production via biogas (system B5). Something relevant to highlight here is that direct conversion routes of syngas to DME show better costs performances than those routes in which methanol is produced as intermediate. The indirect routes of bio-DME production shows higher costs than the reference DME fossil price (300-400 €/t). In the case of e-based systems, the major contributors to costs are CAPEX and energy costs, which follows a similar trend to the results presented for methanol.

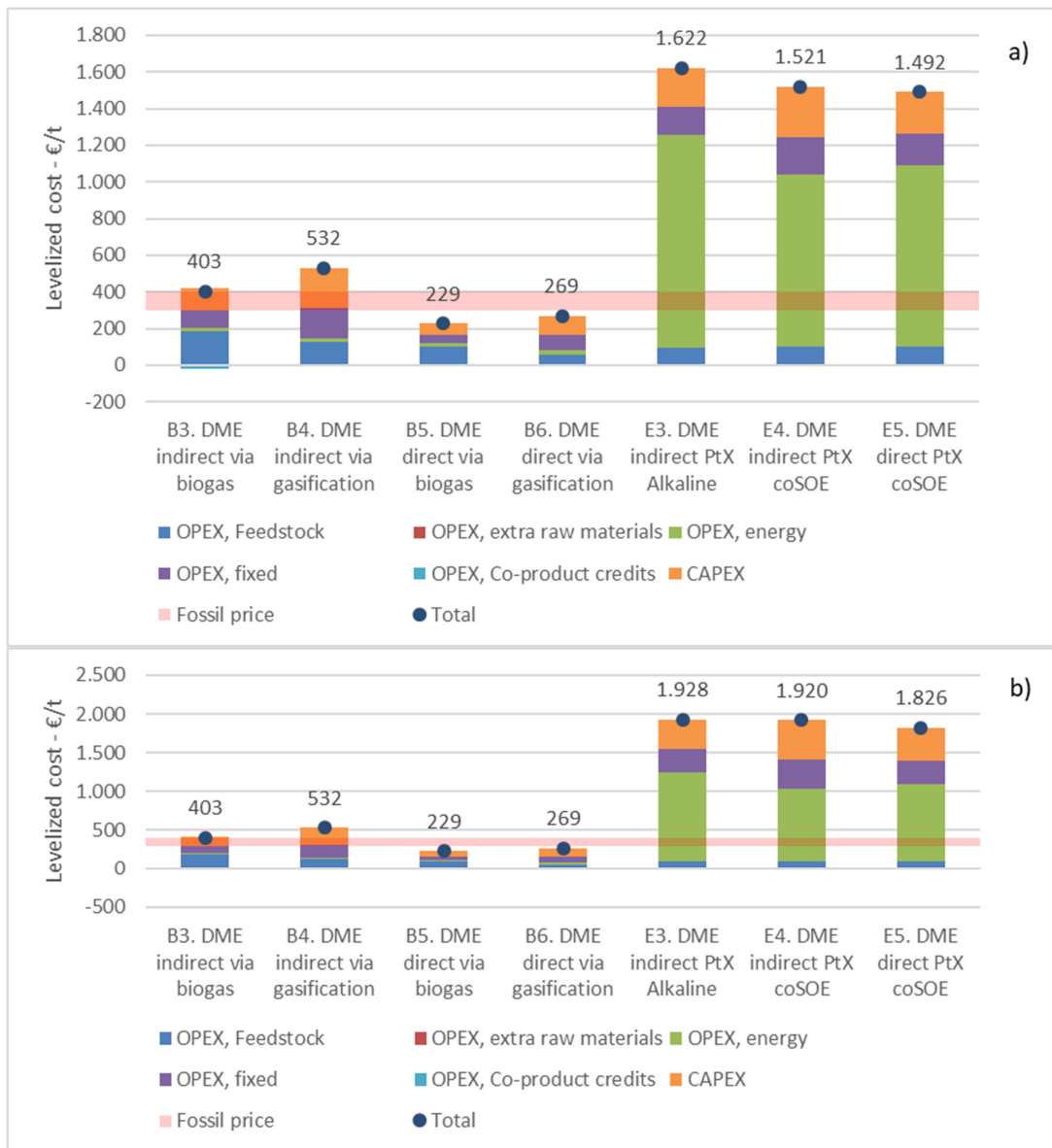
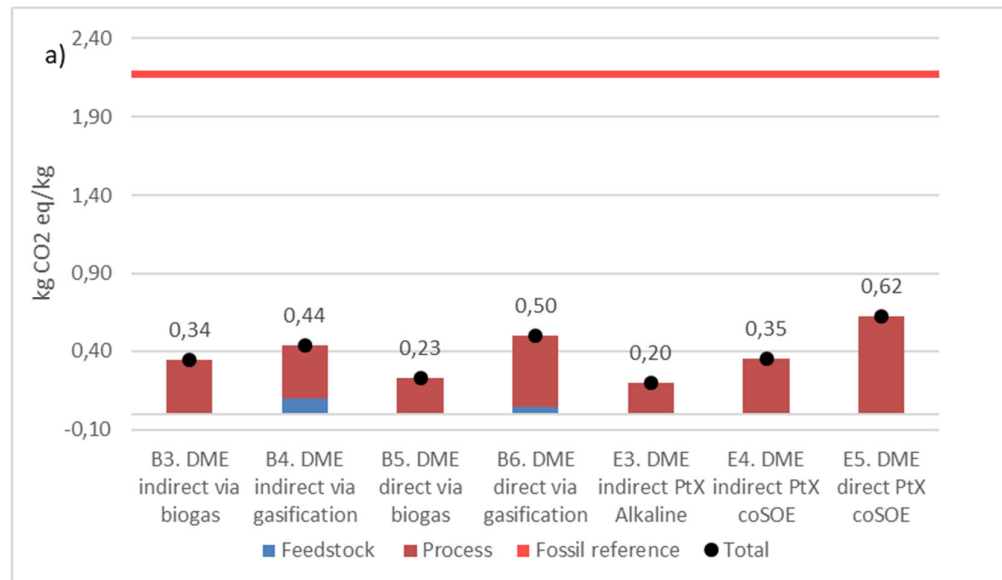


Figure 33 Levelized costs of renewable DME production. a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

Figure 34 presents GHG emissions estimation results following a cradle-to-gate approach (see Figure 34a) and a cradle-to-gate approach plus use (Figure 34b). The results of the cradle to gate analysis suggest that the system with the lowest emissions is indirect DME production via alkaline electrolysis. The contribution of emission due to feedstock production is analogous to that discussed for the methanol case. The emissions presented here, for the process, are basically due to energy consumption in the form of steam or electricity from the grid (not for electrolysers). SOE electrolysis routes show higher energy consumption levels due to the need to supply heat to the electrolysis section. In case energy efficiency for this process is improved, emissions are expected to go much lower. Although there are differences in emissions among the different process, those remain low (cradle to-gate) in comparison to the fossil reference (70-90% lower). When use phase is included), results show that emissions of the bio-based processes remain identical but much higher for e-based systems. In this case, saving potentials were decreased for the e-based processes (in comparison to fossil reference) to approx. 40-48%, whereas in the case of bio-based processes the saving potentials increased up to 90%.



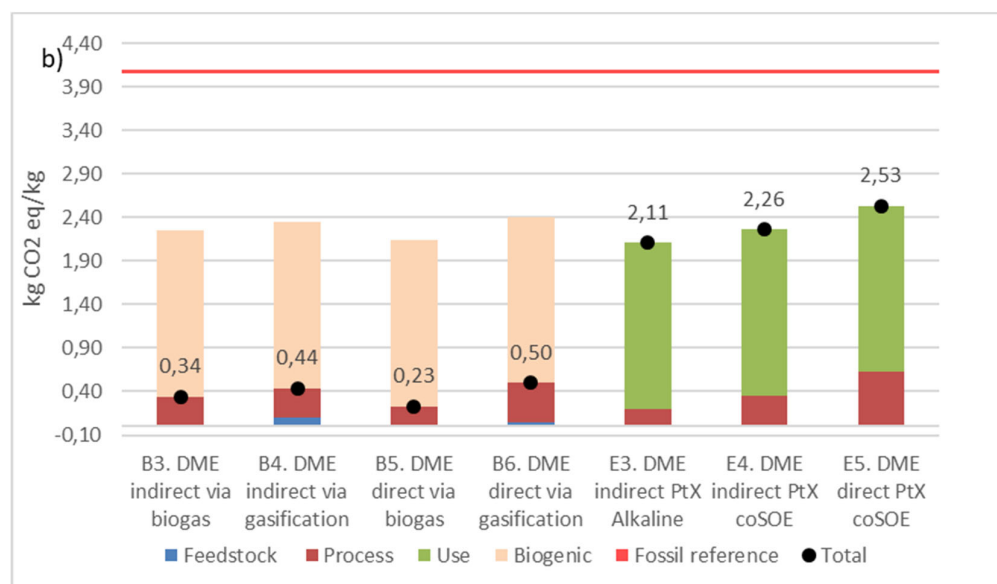


Figure 34 GHG emissions of renewable DME production. a) cradle-to-gate approach, b) cradle-to-gate + use.

### Ethylene (standalone)

Table 13 present the most relevant technical results such as number of plants required, capacity utilization, and feedstock required for ethylene production systems via ethanol. Different than the case of methanol and DME, the demand for ethylene is much higher, and thus a larger number of plants is required or larger plants.

Table 13 Relevant results of the routes producing ethylene via ethanol.

Feature	Units	B7. Ethylene via EtOH 1G S. Beets	B8. Ethylene via EtOH 2G dilute acid	B9. Ethylene via EtOH 2G SE	B10. Ethylene via EtOH 2G Org
Total product demand	kt/y	14257	14257	14257	14257
Substitution by renewables	%	30%	30%	30%	30%
Renewable product demand	kt/y	4277	4277	4277	4277
Plant capacity	kt/y product	100	100	100	100
Yield	t/t feedstock	0,03	0,09	0,08	0,09
Operating hours per plant	h/y	8000	8000	8000	8000
Total number of plants required		43	43	43	43
Capacity utilization	%	99%	99%	99%	99%
Feedstock per plant	kt/y	2937	1111	1176	1052
Total biomass feedstock required	kt/y	126303	47790	50560	45240

Figure 35 shows levelized costs for all ethylene production options. In this case, to the knowledge of the authors there are no e-based routes to directly produce ethylene via ethanol. In all cases, levelized costs are within the range of fossil ethylene price (900-1300 €/t), or slightly lower. Second generation (2G) conversion processes are more expensive than first generation (1G) process if electricity credits are not accounted for (electricity credits refer to sales of electricity produced on site), however, electricity cost credits have a considerable influence on cost reductions for 2G systems. Additionally, as 2G ethanol production systems can produce steam, this can cover substantial amounts of energy use, and thus energy efficiency is in this case a bit higher than 1G production route. In all cases, feedstock costs have an important contribution to production costs, this is mostly related to the fact that different conversion steps are required, and that an important amount of the carbon contained in the feedstock leaves the system in the form of carbon dioxide (biogenic) during the fermentation process to produce ethanol. Contribution of CAPEX for 2G systems is much larger than that of 1G. In general, dilute acid pre-treatment shows better performances than steam explosion and organosolv pre-treatment. However, the performances of those still within the order of magnitude, and given the uncertainties for 2050, it is difficult to provide a strong conclusion on which technology can be a potential winner and more in-depth analysis would be required to support that discussion.

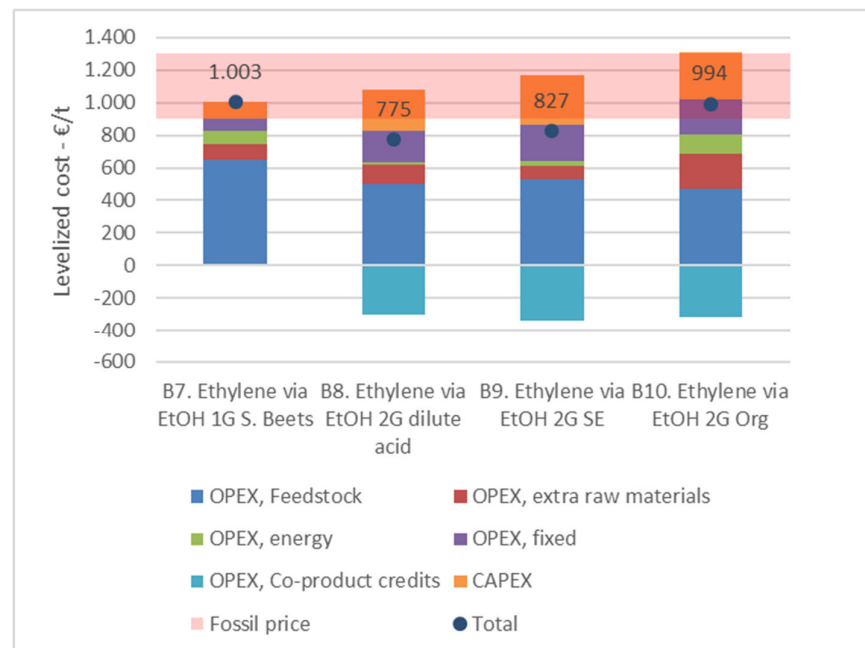


Figure 35 Levelized costs of renewable ethylene production.

Figure 36 presents GHG emissions estimation results following a cradle-to-gate approach (see Figure 36a) and a cradle-to-gate approach plus use (see Figure 36b). The results of the cradle to gate analysis suggest that the system with the lowest emissions is 2G ethylene production via dilute acid. Results show that when a cradle to gate approach is followed, emissions of 1G production overshoots the emissions of fossil ethylene production. This is related to production of 1G

feedstocks, which have higher GHG emissions than 2G feedstocks. Furthermore, 1G process suffers from low energy efficiency compared to 2G and thus emissions in the processing stage become higher. 2G processes show lower GHG emission than the fossil reference by 72-82%. As emissions related to use of bio-based systems are considered biogenic, in the use phase emissions for all system are lower than the reference fossil system being 1G ethylene 25% lower. However, the benefits are clearer for 2G systems in which emissions can be up to 91-94% lower than fossil ethylene including use phase.

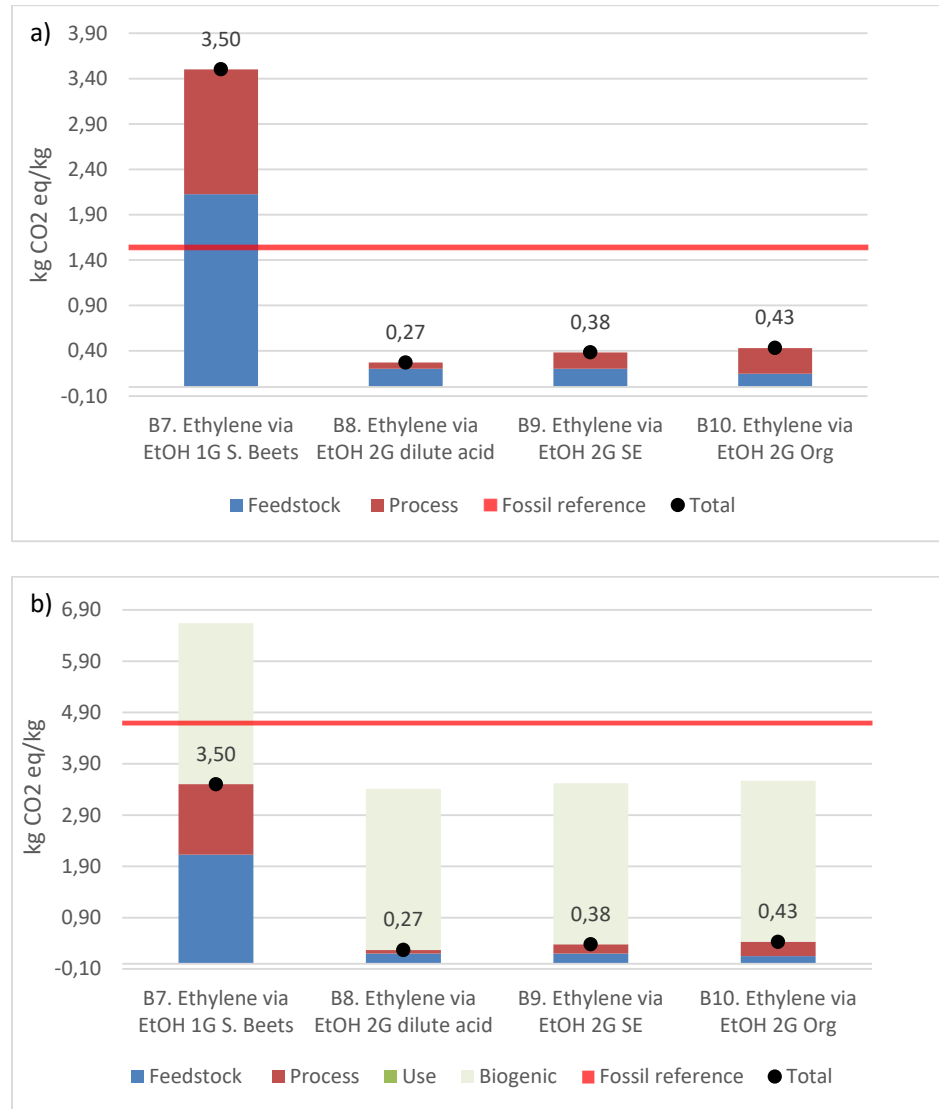


Figure 36 GHG emissions of renewable ethylene production. a) cradle-to-gate approach, b) cradle-to gate + use.



### Olefins (mainly ethylene and propylene)

Table 14 and Table 15 present the most relevant technical results for olefins production systems. Product demand was based on the projection of ethylene for 2050 (renewable 4358 kt/y) and completed with the mixture produced in each renewable option (see Table 16). This means that the number of plants required to reach ethylene production demand are equal to those presented for the standalone case from ethanol production. However, as the product is a mixture, the capacity is different for each process route, but ethylene capacity is kept as 100 kt/y as depicted in Table 16. The demand of ethylene is always met with these routes, however, the production of propylene in all cases exceeds the production needs for 2050 (2954 kt in 2050). For route B11, the estimated amount of wet biomass available for 2050 in Europe (351824 kt) is not enough to cover the feedstock required to produce 37069 kt/y of olefins mixture. Only 92% can be covered and the remaining fraction would need to be imported. This is a relevant result as it is only assessing one route and competing uses of that biomass are not included in this analysis. The results therefore suggest that biogas production routes might not be sufficient for covering the demand of olefins in Europe. Although for route B13, the amount of biomass is enough if only this production process is considered using biomass. , almost 90% of it is utilized for that specific route. To meet production requirements the e-based routes require 32, 25, 35 and 100 GW of electricity input, for systems E6, E7, E8 and E9, respectively.

Table 14. Relevant results of the routes producing olefins via methanol to olefins (MTO)

Feature	Units	B11. Olefins via MTO via biogas	B12. Olefins via MTO via gasification	E6. Olefins via MTO PtX Alkaline	E7. Olefins via MTO PtX coSOE
Total product mixture demand	kt/y	37069	37069	37069	37069
Substitution by renewables	%	30%	30%	30%	30%
Renewable product demand	kt/y	11121	11121	11121	11121
Plant capacity (of product mixture)	kt/y product	260	260	260	260
Yield	t/t feedstock	0,3	0,23	0,32	0,31
Operating hours per plant	h/y	8000	8000	8000 (4000)	8000 (4000)
Number of plants required		43	43	43(86)	43 (86)
Capacity utilization	%	99%	99%	99% (50%)	99% (50%)
Feedstock per plant	kt/y	8924	1146	803 (402)	846 (423)
Total feedstock required	kt/y	383717	49274	34541	36393

Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y

Table 15. Relevant results of the routes producing olefins via DME and Fischer Tropsch

Feature	Units	B13. Olefins via DME, biogas	B14. Olefins via DME, gasification	E8. Olefins via DME direct, SOE PtX	B15. Olefins, biomass gasification + Fischer Tropsch	E9. Olefins, SOE + Fischer Tropsch
Total product mixture demand	kt/y	31693	31693	31693	95807	95807
Substitution by renewables	%	30%	30%	30%	30%	30%
Renewable demand	kt/y	9508	9508	9508	28742	28742
Plant capacity	kt/y product	222	222	222	672	672
Yield	t/t feedstock	0,03	0,33	0,20	0,12	0,29
Operating hours per plant	h/y	8000	8000	8000	8000	8000
Number of plants required		43	43	43 (86)	43	43 (86)
Capacity utilization	%	99%	99%	99% (50%)	99%	99% (50%)
Feedstock per plant	kt/y	6365	674	1114 (557)	5639	2272 (1136)
Total feedstock required	kt/y	273693	28980	47900	242498	97682

Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y

Table 16 Production ratios of olefins production in the different olefins production routes

Product	Unit	Routes B11, B12, E6 and E7	Routes B13, B14, E8	Routes B15, E9
Ethylene	kt/y	100	100	100
Propylene	kt/y	100	86	158
C4 fraction	kt/y	40	-	75
LPG	kt/y	20	36	140
C5 fraction	kt/y	-	-	199

Figure 37 shows levelized costs for olefins production options and similar to methanol and DME cases there is a significant difference in cost between the bio-based processes with the e-based processes. Levelized costs of e-based processes are factor 4-6 higher than that of bio-based processes (assuming that the e-based processes can run full time during the year see Figure 37a). When considering operation of 4000 h/y (Figure 37b) levelized costs of the e-based processes increase by 20-30% in comparison to full year operation.

The process route with the lowest cost is olefins production via direct DME production from biogas (system B13). Something relevant to highlight here is that all bio-based routes present lower costs in comparison to the fossil price range by 30-55%. Similar to what has been discussed above for the other routes, CAPEX and energy costs are the major contributor for costs in the e-based processes.



Figure 37 Levelized costs of renewable olefins production. a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

Figure 38 presents GHG emissions estimation results following a cradle-to-gate approach (see Figure 38a) and a cradle-to-gate approach plus use (see Figure 38b). The results of the cradle to gate analysis suggest that the systems with the lowest emissions are olefins via biomass gasification and FT and olefins via SOE and FT. One of the reasons why these systems present low emissions compared to the other is because energy efficiency of the system is increased using onsite CHP plant

to use the gases that were not converted into olefins. Therefore, for the other cases the process emissions are high, as the systems were not optimized, and energy recovery was not considered. This means that there is large room for improvement on emissions related to processing as further energy savings can be achieved by following energy integration strategies and use of side streams with energy value (e.g., internal use of LPG for energy supply). When the use phase is included the e-based process become even at the same level of reference fossil emissions. This is therefore important to consider options for achieving net zero emissions after use of chemicals as suggested by (Gabrielli et al., 2020).



Figure 38 GHG emissions of renewable olefins production. a) cradle-to-gate approach, b) cradle-to-gate + use.

### Olefins (mainly propylene)

Table 17 presents the most relevant technical results for olefins production systems via methanol to propylene. Product demand was based on the projection of propylene for 2050 (renewable 2954 kt/y) and completed with the mixture produced in each renewable option (see Table 17 footnote). The demand of propylene is always met with these routes, however, the production of ethylene in all cases is lower than its production needs for 2050 (4277 kt in 2050). In all cases,

feedstock availability seems sufficient to meet production needs if only this process is used, and no competing uses are considered. Electricity supply is 13 and 10 GW for systems E10 and E11, respectively.

Table 17 Relevant results of the routes producing olefins via methanol to propylene (MTP)

Feature	Units	B16 Olefins via MTP via biogas	B17 Olefins via MTP via gasification	E10 Olefins via MTP PtX Alkaline	E11 Olefins via MTP PtX coSOE
Total product mixture demand	kt/y	14769	14769	14769	14769
Substitution by renewables	%	30%	30%	30%	30%
Renewable product demand	kt/y	4431	4431	4431	4431
Plant capacity <sup>b</sup>	kt/y product	150	150	150	150
Yield	t/t feedstock	0,03	0,22	0,32	0,30
Operating hours per plant <sup>a</sup>	h/y	8000	8000	8000 (4000)	8000 (4000)
Total number of plants required		30	30	30 (60)	30 (60)
Capacity utilization	%	98%	98%	98% (49%)	98% (49%)
Feedstock per plant	kt/y	5130	659	462	487
Total feedstock required	kt/y	153899	19762	13854	14596

<sup>a</sup> Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y

<sup>b</sup> Production ratios per plant Propylene: 100 kt/y, Ethylene 5,8 kt/y, LPG 7,4 kt/y, C5+ fraction 36,8 kt/y.

Figure 39 shows levelized costs of propylene production options, and similar to the cases discussed previously, there is a significant difference in cost between the bio-based processes with the e-based processes. e-based processes are factor 3-4 higher than those for bio-based processes (assuming e-based processes can run continuously Figure 39a). When 4000 hours per year are considered (see Figure 39b), levelized costs of the e-based processes were increased by 20-30% in comparison to full year operation. The process route with the lowest cost is methanol to propylene via biogas (system B16), which benefits from credits from electricity sales. Something relevant to highlight here is that the bio-based routes present lower costs in comparison to the fossil price range by 30%. Similar to what has been discussed above for the other routes, CAPEX and energy costs are the major contributor for costs in the e-based processes.



Figure 39 Levelized costs of renewable olefins (mainly propylene) production. a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

Figure 40 presents GHG emissions estimation results following a cradle-to-gate approach (see Figure 40a) and a cradle-to-gate approach plus use (see Figure 40b). The results of the cradle to gate analysis suggest that the systems with the lowest emissions are olefins via methanol to propylene using a SOE electrolyser for the methanol production stage (system E11). The carbon sources used for e-based processes are described in appendix H.

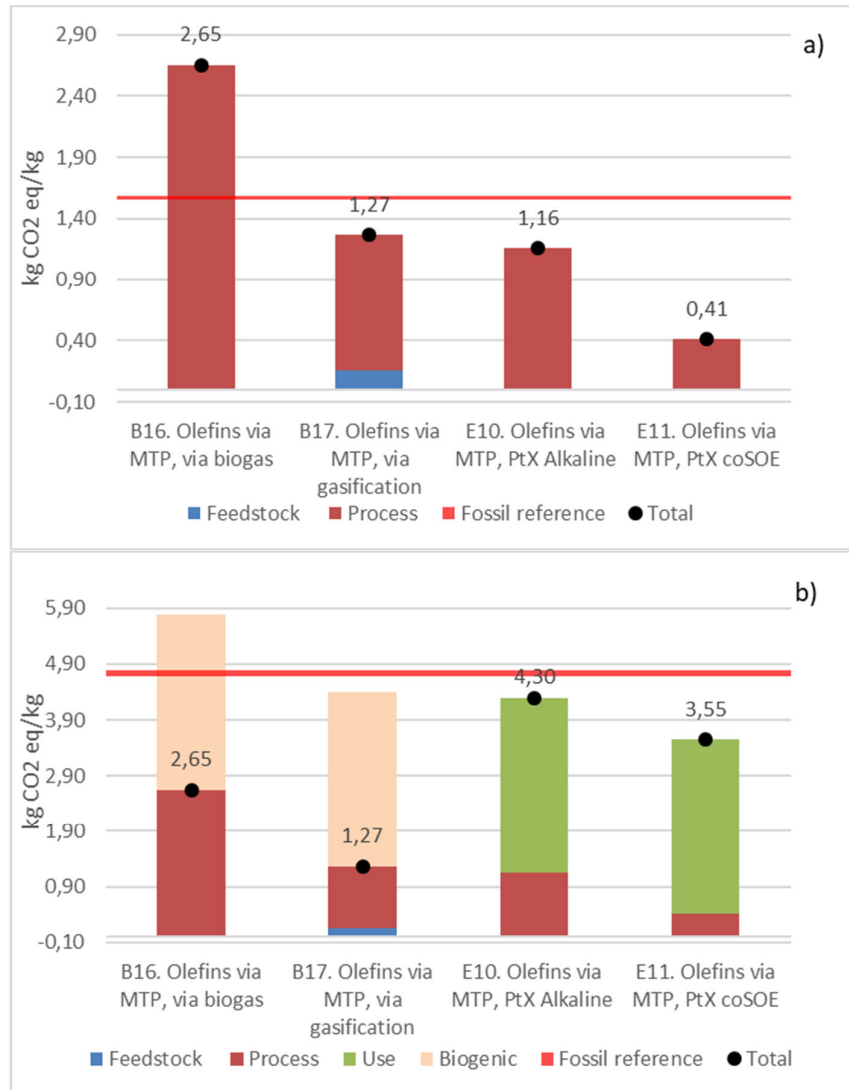


Figure 40 GHG emissions of renewable olefins production. a) cradle-to-gate approach, b) cradle-to gate + use.

**Olefins (butadiene mainly)**

Table 18 presents the most relevant technical results such as number of plants required, capacity utilization, and feedstock required for butadiene production systems via ethanol.

Table 18 Relevant results of the routes producing ethylene via ethanol.

Feature	Units	B18, Butadiene via EtOH 1G S, Beets	B19, Butadiene via EtOH 2G dilute acid	B20, Butadiene via EtOH 2G SE	B21, Butadiene via EtOH 2G Org
Total product demand <sup>a</sup>	kt/y	2997	2997	2997	2997
Substitution by renewables	%	30%	30%	30%	30%
Renewable product demand	kt/y	899	899	899	899
Plant capacity	kt/y product	135	135	135	135
Yield	t/t feedstock	0,04	0,11	0,10	0,11
Operating hours per plant	h/y	8000	8000	8000	8000
Total number of plants required		7	7	7	7
Capacity utilization	%	95%	95%	95%	95%
Feedstock per plant	kt/y	3154	1193	1262	1130
Total biomass feedstock required	kt/y	22077	8353	8837	7908

<sup>a</sup> Demand for mixture. Production capacity per plant butadiene 100 kt/y, Ethylene 26,7 kt/y, C4 3,1 kt/y, hydrogen 5,4 kt/y

Figure 41 shows levelized costs for all butadiene production options. In all cases, levelized costs are within the range of fossil butadiene price (900-1300 €/t), or slightly lower. Second generation (2G) conversion processes are more expensive than the first generation (1G) process if electricity credits are not accounted for, however, electricity cost credits have a considerable influence on cost reductions for 2G systems.

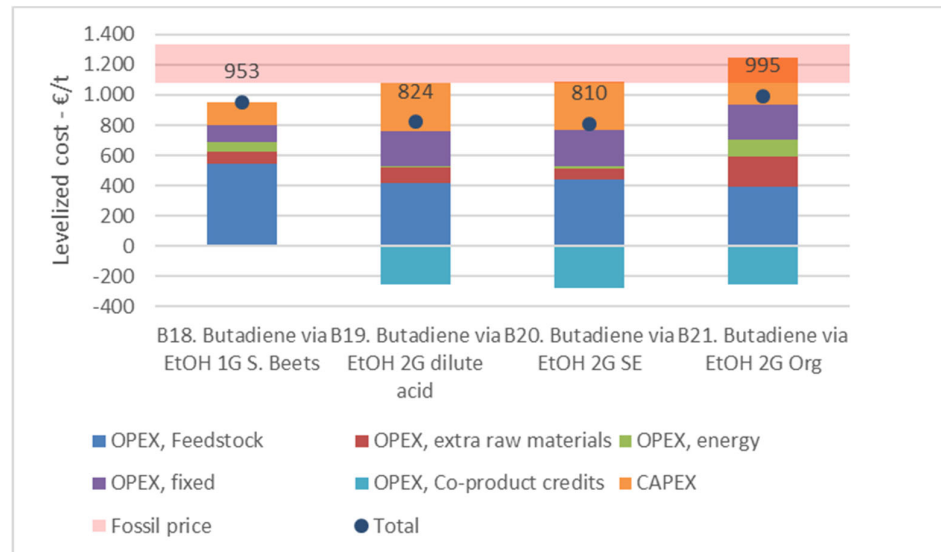


Figure 41 Levelized costs of renewable butadiene production EU 2050.



Figure 42 presents GHG emissions estimation results following a cradle-to-gate approach (see Figure 42a) and a cradle-to-gate approach plus use (see Figure 42b). The results of the cradle to gate analysis suggest that the system with the lowest emissions is 2G ethylene production via dilute acid. Results presented here shows that when a cradle to gate approach is followed, emissions of 1G production overshoots the emissions of fossil butadiene production. At the gate, emissions for systems B19, B20, B21 are 63, 41 and 6% lower than that of fossil butadiene. When used is included, emissions for systems B18, B19, B20 and B21 are 30%, 91%, 86% and 77% lower than fossil butadiene, respectively.

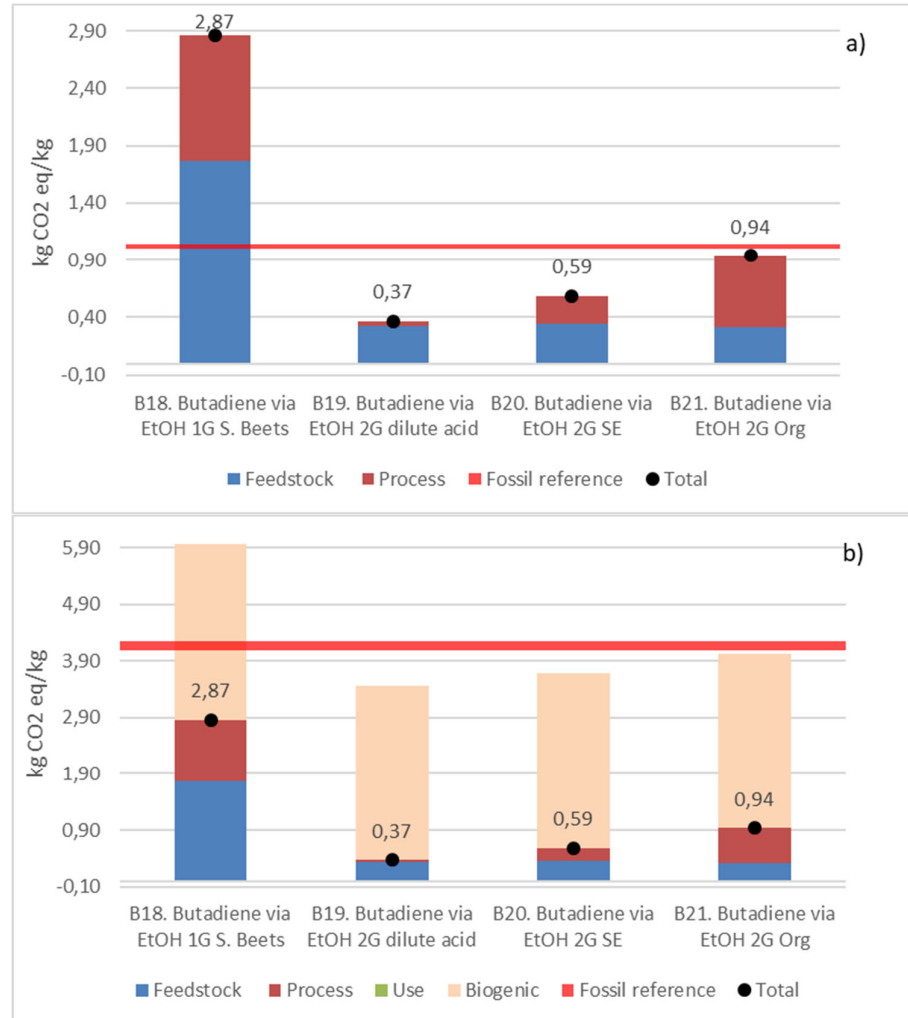


Figure 42 GHG emissions of renewable butadiene production. a) cradle-to-gate approach, b) cradle-to-gate + use.

### Olefins (from biomass pyrolysis)

Table 19 shows the most relevant technical results for olefins production systems from biomass pyrolysis. In all cases feedstock is sufficient to supply feedstock requirements. Product demand was based on the projection of ethylene for 2050 (renewable 4,358 kt/y) and completed with the mixture produced in each renewable option (see Table 20). This means that the number of plants required to reach ethylene production demand are equal to those presented for the standalone case from ethanol production, and olefins as discussed above. However, as the product is a mixture, the capacity is different for each process route, but ethylene capacity is kept as 100 kt/y as depicted in Table 20. The demand of ethylene is always met with these routes. Biomass is in all cases sufficient to supply the target of covering 30% of ethylene production by renewables in 2050, if only this process is considered.

Table 19 Relevant results of the routes producing olefins via methanol to olefins

Feature	Units	B22, Olefins pyrolysis WSBO + WI BO	B23, Olefins pyrolysis WSBO+WIBO hydrogenated	B24, Olefins pyrolysis WSBO	B25, Olefins pyrolysis WSBO hydrogenated	B26, Olefins pyrolysis WSBO two step hydrogenated
Total product mixture demand	kt/y	27522	27049	34278	44825	44566
Substitution by renewables	%	30%	30%	30%	30%	30%
Renewable product demand	kt/y	8257	8115	10283	13447	13370
Plant capacity (of product mixture)	kt/y product	193	190	240	314	313
Yield	t/t feedstock	0,07	0,11	0,06	0,12	0,19
Operating hours per plant	h/y	8000	8000	8000	8000	8000
Total number of plants required		43	43	43	43	43
Capacity utilization	%	99%	99%	99%	99%	99%
Feedstock per plant	kt/y	2817	1748	3786	2637	1678
Total feedstock required	kt/y	121151	75166	162780	113382	72135

WSBO: Water soluble bio-oil, WIBO: Water insoluble bio-oil.

Table 20 Production ratios of olefins and BTX production in pyrolysis.

Route		B22	B23	B24	B25	B26
Benzene	kt/y	27	23,6	26,4	36,6	33,3
Toluene	kt/y	64,8	52,5	46,6	95,9	61,6
Xylenes	kt/y	37,6	54,6	20,9	66,5	24,0
Ethylbenzene	kt/y	3,2	4,8	1,2	5,5	2,9
Ethylene	kt/y	100	100	100	100	100
Propylene	kt/y	70,7	68,1	110,4	174,2	168,2
Butylene	kt/y	22,4	21,6	30,1	40,2	44,4

Something relevant to mention for the pyrolysis routes is that both olefins and BTX are co-produced. When these routes are used to meet renewable ethylene production in 2050, the amount of BTX produced in all cases surpasses the demand of BTX for 2050. Results for BTX production will be discussed separately, but it is important to bear in mind that production ratios for aromatics remain intact as those presented in Table 20.

Figure 43 shows levelized costs for the olefins from pyrolysis. In all cases, levelized costs are lower than olefins price range (900-1300 €/t). It is important to mention that hydrotreatment processes increase the yield towards olefins production, specially towards propylene as depicted in Table 20. Nevertheless, the amount of electricity produced as co-product decreases as the gaseous hydrocarbons are lower. This is the reason the amount of electricity co-product is much higher in systems B22 and B24 than in the other cases. This processing route benefits from energy integration as residual gases can be used in situ for producing steam and electricity. In all cases, feedstock cost has an important contribution, this is mostly related to the fact that different conversion steps are required. Figure 82, in Appendix F, shows that in case electricity price is increased the systems are benefitted as it is assumed that electricity selling price would be equal to electricity buying price.

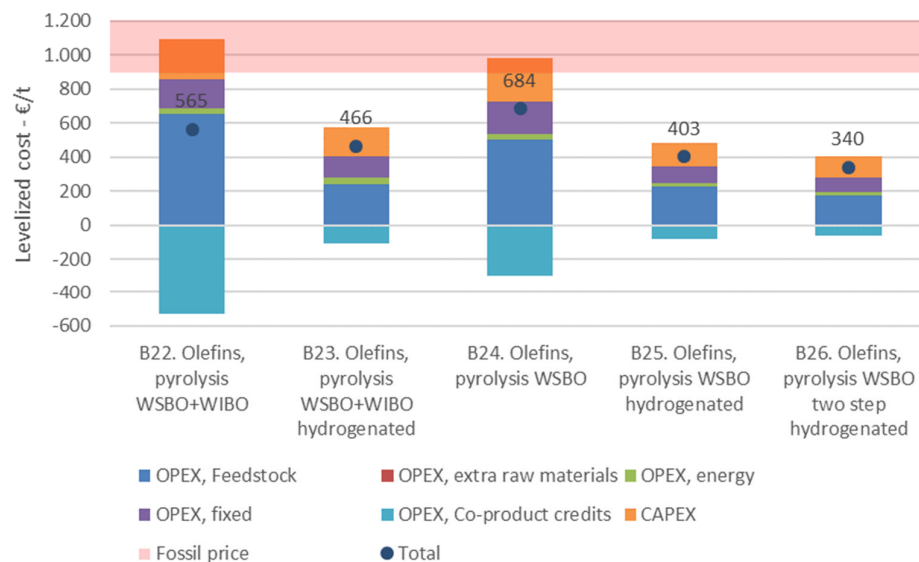


Figure 43 Levelized costs of renewable olefins production via pyrolysis.

Figure 44 presents GHG emissions following a cradle-to-gate approach (see Figure 44a) and a cradle-to-gate approach plus use (see Figure 44b). All cases present a clear benefit over the petrochemical reference, being lower by 80-90%. When use is included this difference is increased up to 97%.

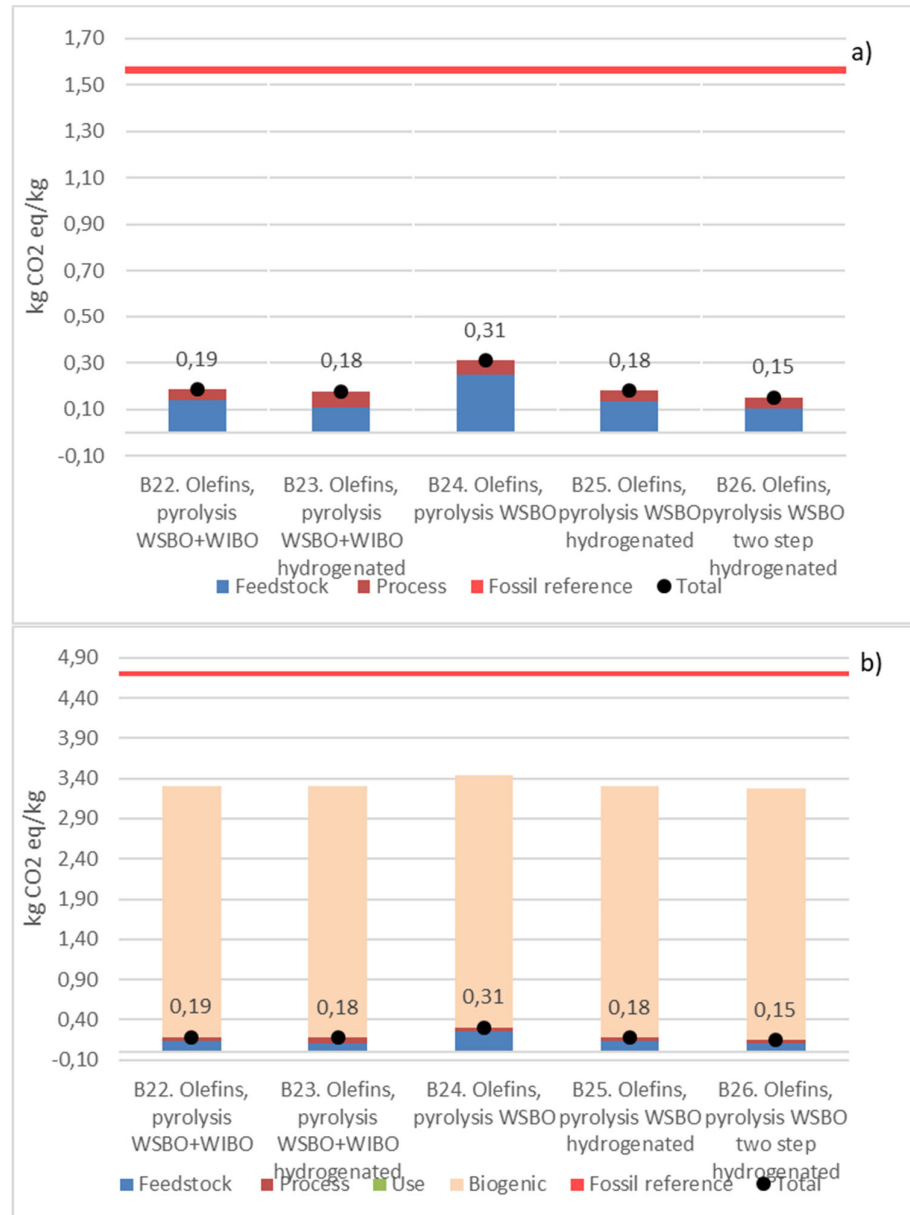


Figure 44 GHG emissions of renewable olefins production. a) cradle-to-gate approach, b) cradle-to-gate + use.

**BTX (from biomass pyrolysis)**

Table 21 shows the most relevant technical results for BTX production systems from biomass pyrolysis. In case the aim is to meet BTX demand, the number of plants (co-producing olefins) is lower. However, that would imply that the demand of ethylene cannot be met. In this case, it is needed to find a balance on the co-

existence of BTX and olefins and decide on which market to tackle if these are the only options to meet the production demand. It is important to mention that combination of options is not considered in this study and thus not optimized when for instance multiple routes can meet the demand of certain product. The capacity is different for each process route, but ethylene production volume is kept to 100 kt/y as depicted in Table 20.

Table 21 Relevant results of the routes producing BTX via pyrolysis

Feature	Units	B22, BTX pyrolysis WSBO+ WIBO	B23, BTX pyrolysis WSBO+WIBO hydrogenated	B24, BTX pyrolysis WSBO	B25, BTX pyrolysis WSBO hydrogenated	B26, BTX pyrolysis WSBO two step hydrogenated
Total product mixture demand	kt/y	6524	6524	6524	6524	6524
Substitution by renewables	%	30%	30%	30%	30%	30%
Renewable product demand	kt/y	1957	1957	1957	1957	1957
Plant capacity (of product mixture)	kt/y product	132	136	95	204	122
Yield	t/t feedstock	0,05	0,08	0,02	0,08	0,07
Operating hours per plant	h/y	8000	8000	8000	8000	8000
Total number of plants required		15	15	21	10	17
Capacity utilization	%	98%	96%	98%	96%	94%
Feedstock per plant	kt/y	2789	1692	3730	2537	1594
Total feedstock required	kt/y	41840	25379	78335	25369	27091

Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y

Figure 45 shows levelized costs for the BTX from pyrolysis. In all cases, levelized costs are lower than olefins price range (1000-1400 €/t). The analysis on cost for BTX is analogous to that presented for olefins from pyrolysis Figure 83. Appendix F shows that in case electricity price is increased the systems are benefitted as it is assumed that electricity selling price would be equal to electricity buying price. For these systems, reductions in CAPEX can further benefit levelized costs as pyrolysis systems are still not very well developed in comparison to other technologies and there is room for learning until full commercial implementation.

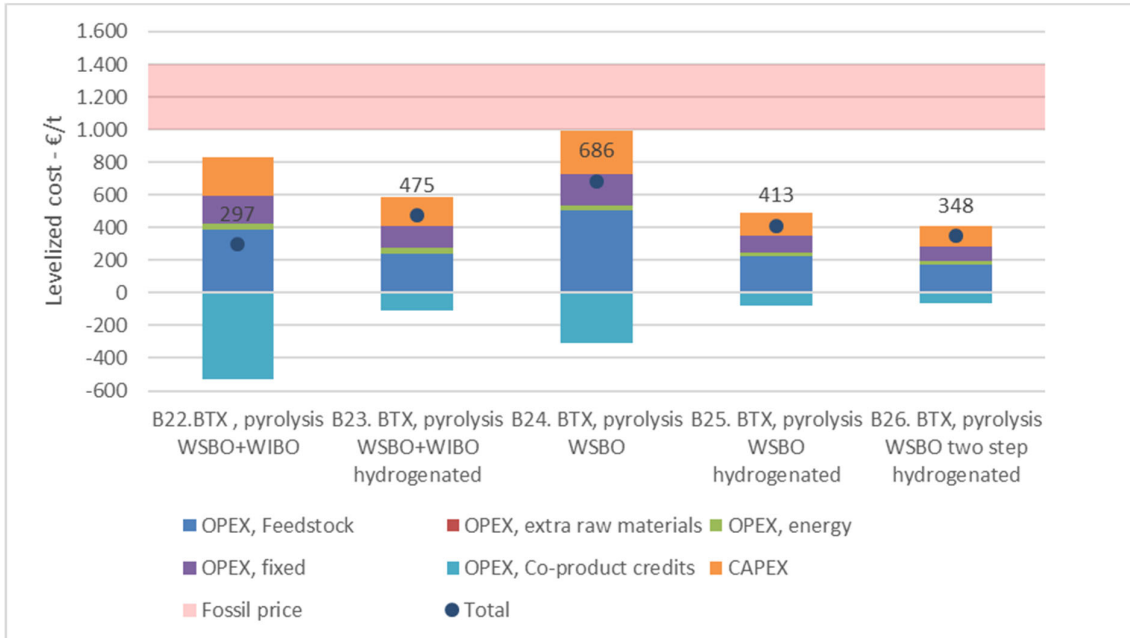
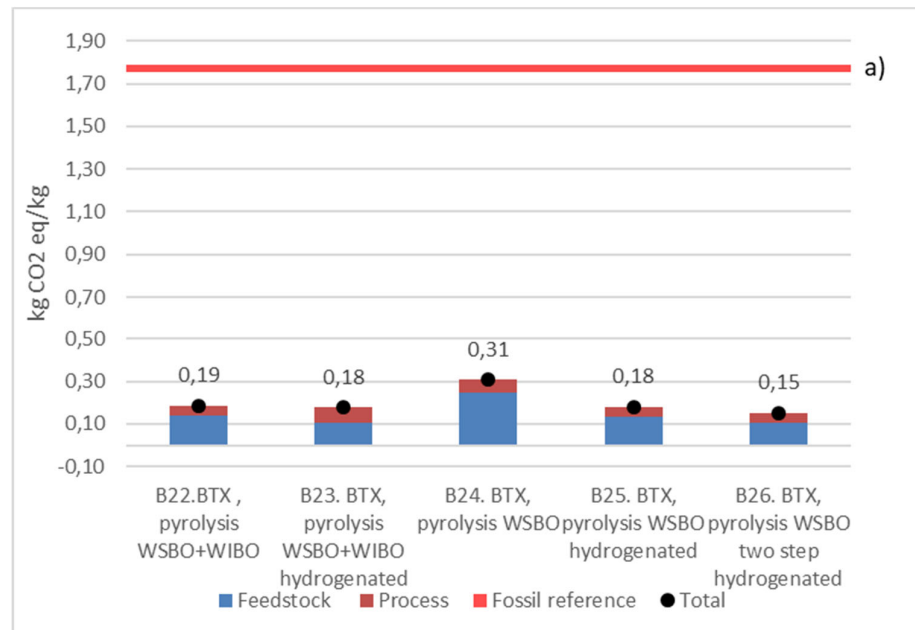


Figure 45 Levelized costs of renewable BTX production via pyrolysis in EU 2050

Figure 46 presents GHG emissions following a cradle-to-gate approach (see Figure 46a) and a cradle-to-gate approach plus use (see Figure 46b). All cases present a clear benefit over the petrochemical reference, being lower by 82-91%. When use is included this difference is increased up to 97%.



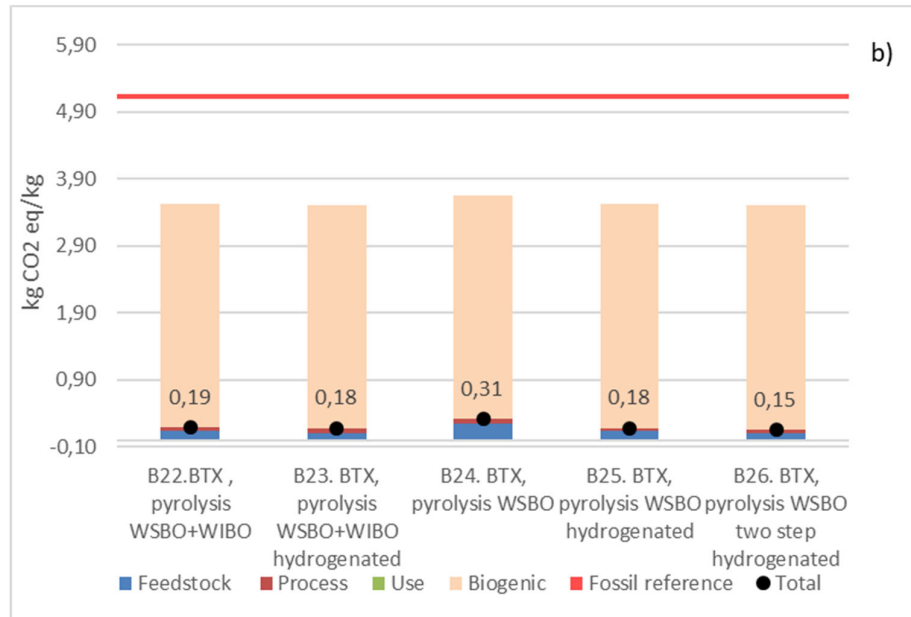


Figure 46 GHG emissions of renewable BTX production. a) cradle-to-gate approach, b) cradle-to-gate + use.

### 5.1.2 The Netherlands 2030

This section focuses on presenting and discussing the results on levelized costs and GHG emissions for the different alternatives for the Netherlands in 2030. The formatting of the results is kept similar to the case of EU 2050. Results on GHG emissions are completely analogous to those presented for EU2050. This happens as in the current study there is no analysis of efficiency improvements in terms of energy use and production flows. Thus, physical flows were kept identical for both 2030 and 2050 cases. Technical parameters on flows from the technologies are identical for both 2030 and 2050. The differences are in resource potentials and feedstock cost. CAPEX was assumed to remain identical for both 2030 and 2050 due to lack of data on learning. However, in all cases, sensitivity of the most important parameters was considered.

#### Methanol

Four processing routes were assessed for methanol production, two bio-based routes and two e-based routes. Table 22 presents technical results for methanol production in 2030 in the Netherlands.

Table 22 Relevant results of the routes producing methanol in NL 2030

Feature	Units	B1 Methanol via biogas	B2 Methanol via gasification	E1 Methanol via alkaline electrolysis	E2 Methanol via SOE co- electrolysis
Total product demand	kt/y	443	443	443	443
Substitution by renewables	%	15%	15%	15%	15%
Renewable product demand	kt/y	66	66	66	66
Plant capacity	kt/y product	100	100	100	100
Yield	t/t feedstock	0,06	05,0	0,72	0,68
Operating hours per plant	h/y	8000	8000	8000 (4000)	8000 (4000)
Total number of plants required		1	1	1 (2)	1 (2)
Capacity utilization	%	66%	66%	66% (33%)	66% (33%)
Feedstock per plant	kt/y	1028	132	93 (46)	97 (49)
Total biomass feedstock required	kt/y	1028	132	-	
Total CO <sub>2</sub> requirement	Kt/y	-	-	93	97
Total renewable electricity required (as main input)	MW	-	-	86	68
Share of feedstock requirements		2 % wet biomass	2% of solid biomass		

Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y

Figure 47 shows levelized costs for all methanol production options and similar to what was discussed for EU in 2050, there is a significant difference in cost between the bio-based processes with the e-based processes. When operating at 4000 h/y, levelized costs of the e-based processes were increased by 30-40% in comparison to full year operation. This has to do with the large effect of CAPEX on cost as the processes are installed for certain capacity, and those can only run for a fraction of it. In this case, base case capacity of 100 kt/y seems rather large for installations in the Netherlands, but in case the target coverage by renewables (15% by 2030) is increased, cost can also be slightly decreased. In all cases, the process route with the lowest cost is methanol via biogas. This has to do with its low CAPEX requirements (compared to the other cases) as well as its low feedstock costs (here as 15 €/t). However, in case feedstock price increases for this route, cost can become quite high as it is the route with the lowest conversion yield (see Table 22). In all cases costs are higher than the reference fossil price, due to the high influence of CAPEX that is not fully utilized across the year. In the case of e-based systems, the major contributors to costs are CAPEX and energy costs, as previously discussed for the results of Europe.



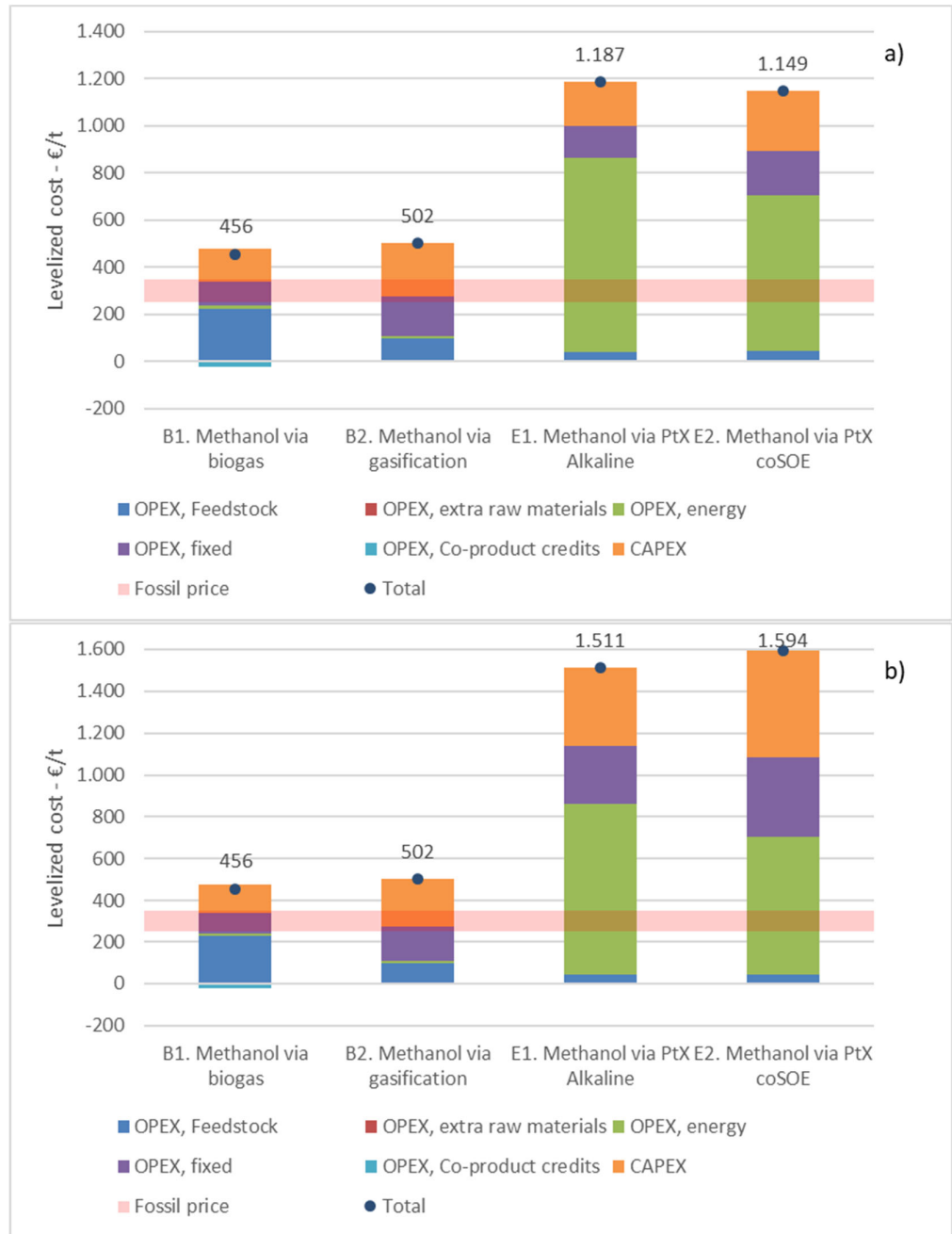


Figure 47 Levelized costs of renewable methanol production. a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

**DME**

Table 23 presents the most relevant technical results such as number of plants required, capacity utilization, and feedstock required. In all cases feedstock available can supply feedstock requirements if only 15% renewable DME is considered. The analysis of number of plants required and capacity utilization is analogous to the one presented before for methanol.

Table 23 Relevant results of the routes producing DME.

Feature	Units	B3, DME indirect via biogas	B4, DME indirect via gasification	B5, DME direct via biogas	B6, DME direct via gasification	E3, DME indirect PtX Alkaline	E4, DME indirect PtX coSOE	E5, DME direct PtX coSOE
Total product demand	kt/y	354	354	354	354	354	354	354
Substitution by renewables	%	15%	15%	15%	15%	15%	15%	15%
Renewable product demand	kt/y	53	53	53	53	53	53	53
Plant capacity	kt/y product	100	100	100	100	100	100	100
Yield	t/t feedstock	0,05	0,36	0,08	0,80	0,51	0,49	0,48
Operating hours per plant	h/y	8000	8000	8000	8000	8000 (4000)	8000 (4000)	8000 (4000)
Total number of plants required		1	1	1	1	1(2)	1 (2)	1 (2)
Capacity utilization	%	53%	53%	53%	53%	53% (27%)	53% (27%)	53% (27%)
Feedstock per plant	kt/y	1955	251	1062	112	104 (52)	110 (55)	110 (55)
Total biomass feedstock required	kt/y	1155	148	627	66	52	55	55
Total CO <sub>2</sub> requirement	kt/y					104	110	110
Total renewable electricity required (as main input)	MW					96	78	81

Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y

Figure 48 shows levelized costs for all DME production options and similar to the methanol case there is a significant difference in cost between the bio-based processes with the e-based processes. In all cases, the process route with the lowest cost is direct DME production via biogas (system B5), however, DME produced via gasification also shows quite similar costs. The main reason for this, different than for the EU case, is that wet biomass costs (15 €/t) in NL are higher than those of EU in 2050 (9 €/t). Something relevant to highlight here is that direct conversion routes of syngas to DME show better costs performances than those routes in which methanol is produced as intermediate. The indirect routes of bio-DME production showed higher costs than the reference DME fossil price (300-400 €/t). In the case of e-based systems, the major contributors to costs are CAPEX and energy costs, which follows a similar trend to the results presented for methanol. Figure 85 in Appendix F shows the results of sensitivity analysis of electricity prices and changes in CAPEX. In the case of electricity prices (Figure 85 a and b), the effect is highly noticeable for both e-based processes. The analysis is completely analogous to the one presented for EU 2050; however, absolute values are higher

for the case of NL in 2030 as the contribution of CAPEX is much larger than that for the European case.

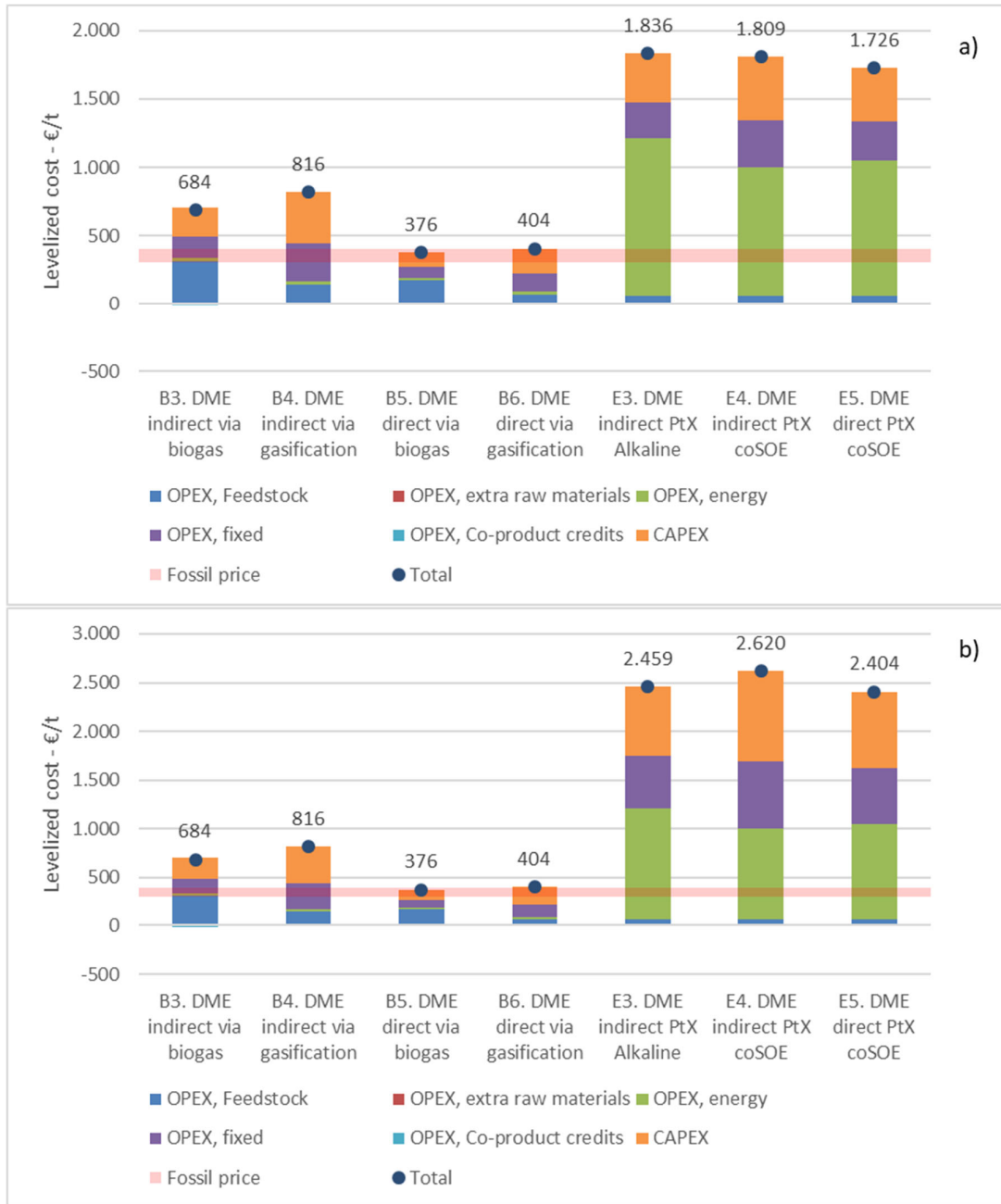


Figure 48 Levelized costs of renewable DME production. a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

**Ethylene (standalone)**

Table 24 shows the most relevant technical results such as number of plants required, capacity. Projections for 2030 on availability in NL show that biomass

requirements are enough to cover the production, if only 15% of fossil ethylene is substituted with renewable ethylene. The share of biomass required is 60-67% of the available in the Netherlands in 2030. This is a relevant aspect as this assessment do not consider competing uses of biomass, and if this is to be included, the amount of available biomass in the Netherlands may be very limited, and possibly imports would be required. This also depends on the substitution rate, if that goes higher, the amount of resources required will also be much higher

Table 24 Relevant results of the routes producing ethylene via ethanol.

Feature	Units	B7, Ethylene via EtOH 1G S, Beets	B8, Ethylene via EtOH 2G dilute acid	B9, Ethylene via EtOH 2G SE	B10, Ethylene via EtOH 2G Org
Total product demand	kt/y	2781	2781	2781	2781
Substitution by renewables	%	15%	15%	15%	15%
Renewable product demand	kt/y	417	417	417	417
Plant capacity	kt/y product	100	100	100	100
Yield	t/t feedstock	0,03	0,09	0,08	0,09
Operating hours per plant	h/y	8000	8000	8000	8000
Total number of plants required		5	5	5	5
Capacity utilization	%	83%	83%	83%	83%
Feedstock per plant	kt/y	2463	932	986	882
Total biomass feedstock required	kt/y	12317	4660	4931	4412

Figure 49 shows levelized costs for all ethylene production options. In all cases, levelized costs are within the range of fossil ethylene price (900-1300 €/t), or slightly lower. 2G conversion processes are more expensive than 1G process if electricity credits are not accounted for, however, electricity cost credits have a considerable influence on cost reductions for 2G systems.

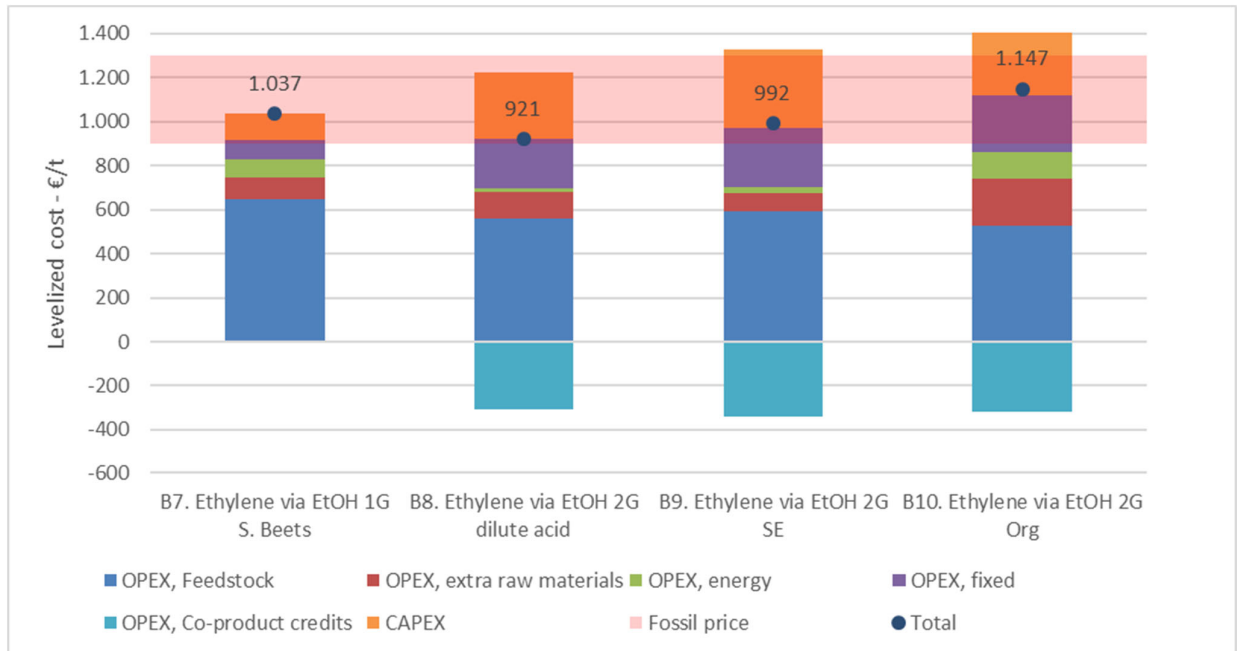


Figure 49 Levelized costs of renewable ethylene production in NL 2030

### Olefins (mainly ethylene and propylene)

Table 25 and Table 26 present the most relevant technical results for olefins production systems. For routes B13 and B14, from total biomass available a share of 43% of wet biomass for anaerobic digestion (AD), and 38% of solid biomass is required, respectively. This only happens if the 15% substitution is considered. Routes E6 and E7 needed to rely partly on direct air capture as CO<sub>2</sub> supply assumed in this study (high concentration and low concentration from industry, respectively) can only cover 92 and 87% of the requirements, respectively. In the case of routes B11 and B12, biomass available in the Netherlands is sufficient to meet production requirements with a share of 61% of wet biomass for AD, and 65% of solid biomass, respectively. For route B15, the amount of biomass required is large and the solid biomass available in the Netherlands in 2030 can only meet 31% of feedstock requirements, the remaining fraction should be imported. In this case it was assumed that imported solid biomass would be more expensive at 80€/t. For routes E8 and E9, available CO<sub>2</sub> from industry would not be sufficient and thus supply need to be complemented with direct air capture. It should be taken into account that a conservative approach was followed regarding CO<sub>2</sub> supply and only a limited amount was assumed to be available from industry for carbon utilization, while a large fraction assumed to be emitted or captured (an in-depth analysis is out of the scope of this study).

Table 25 Relevant results of the routes producing olefins via methanol to olefins (MTO)

Feature	Units	B11. Olefins via MTO, via biogas	B12. Olefins via MTO, via gasification	E6. Olefins via MTO, PtX, Alkaline	E7. Olefins via MTO, PtX coSOE
Total product mixture demand	kt/y	7230	7230	7230	7230
Substitution by renewables	%	15%	15%	15%	15%
Renewable demand	kt/y	1084	1084	1084	1084
Plant capacity (of product mixture)	kt/y product	260	260	260	260
Yield	t/t feedstock	0,03	0,23	0,32	0,31
Operating hours per plant	h/y	8000	8000	8000 (4000)	8000 (4000)
Total number of plants required		5	5	5(9)	5 (9)
Capacity utilization	%	83%	83%	46% (50%)	46% (50%)
Feedstock per plant	kt/y	8924	1146	674 (374)	710 (394)
Total feedstock required	kt/y	37420	4805	3368	3549

Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y

Table 26 Relevant results of the routes producing olefins via DME and Fischer Tropsch

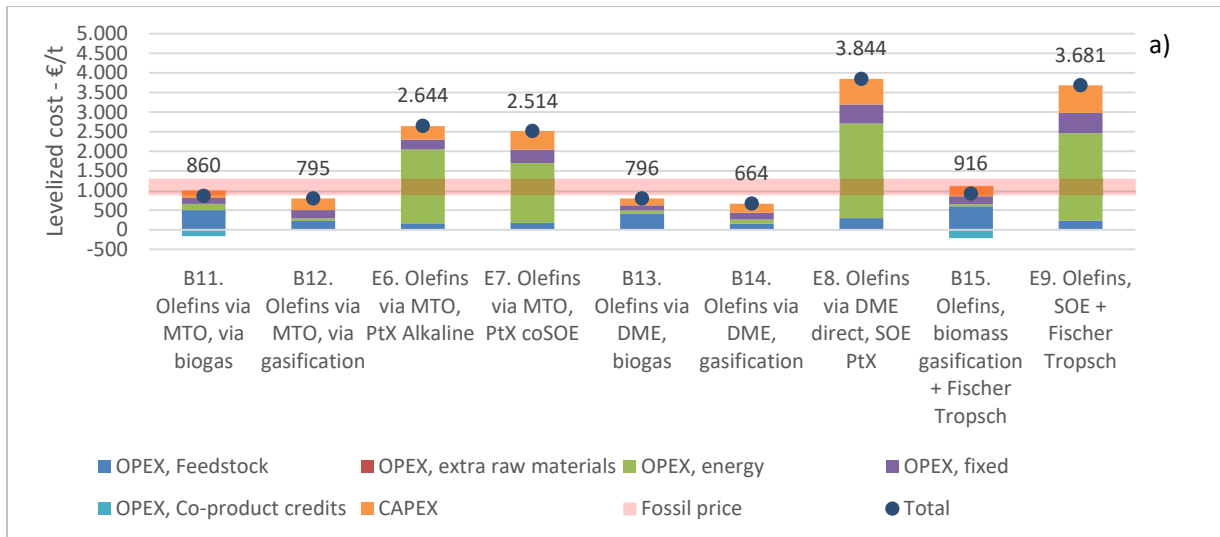
Feature	Units	B13, Olefins via DME biogas	B14, Olefins via DME gasification	E8, Olefins via DME direct SOE PtX	B15, Olefins biomass gasification + Fischer Tropsch	E9, Olefins SOE + Fischer Tropsch
Total product mixture demand	kt/y	6181	6181	6181	18686	18686
Substitution by renewables	%	15%	15%	15%	15%	15%
Renewable product demand	kt/y	927	927	927	2803	2803
Plant capacity	kt/y product	222	222	222	672	672
Yield	t/t feedstock	0,03	0,33	0,20	0,12	0,29
Operating hours per plant	h/y	8000	8000	8000 (4000)	8000	8000 (4000)
Total number of plants required		5	5	5(9)	43	5(9)
Capacity utilization	%	83%	83%	46% (50%)	83%	46% (50%)
Feedstock per plant	kt/y	5338	565	934 (510)	4730	1905 (1058)
Total feedstock required	kt/y	26690	2826	4671	23648	9526

Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y

Table 27 Production ratios of olefins production in the different olefins production routes

Product	Unit	Routes B11, B12, E6 and E7	Routes B13, B14, E8	Routes B15,E9
Ethylene	kt/y	100	100	100
Propylene	kt/y	100	86	158
C4 fraction	kt/y	40	-	75
LPG	kt/y	20	36	140
C5 fraction	kt/y	-	-	199

Figure 50 shows levelized costs for olefins production options and similar to methanol and DME cases there is a significant difference in cost between the bio-based processes with the e-based processes. The process route with the lowest cost olefins production via direct DME production gasification (system B14). Instead, the price of solid biomass is very similar in both EU and NL assessments. Similar to what has been discussed above for the other routes, CAPEX and energy costs are the major contributor for costs in the e-based processes. Figure 87 in Appendix F shows the results of sensitivity analysis of electricity prices and changes in CAPEX. In the case of electricity prices (Figure 87 a and b), the effect is highly noticeable for all e-based processes. The analysis is completely analogous to the one presented for methanol and DME.



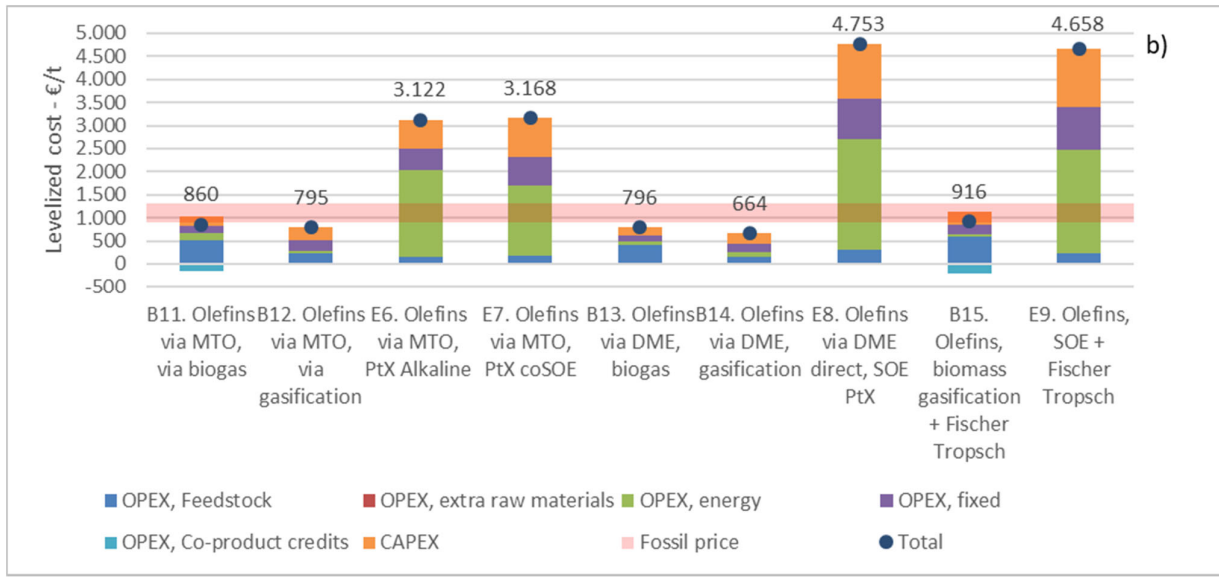


Figure 50 Levelized costs of renewable olefins production. a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

### Olefins (mainly propylene)

Table 28 presents the most relevant technical results for olefins production systems via methanol to propylene. In all cases feedstock is sufficient available to supply feedstock requirements considering the assumptions made. Electricity supply is 1226 and 976 MW for systems E10 and E11, respectively.

Table 28 Relevant results of the routes producing olefins via methanol to propylene (MTP)

Feature	Units	B16, Olefins via MTP via biogas	B17, Olefins via MTP via gasification	E10, Olefins via MTP PtX Alkaline	E11, Olefins via MTP PtX coSOE
Total product mixture demand	kt/y	2809	2809	2809	2809
Substitution by renewables	%	15%	15%	15%	15%
Renewable product demand	kt/y	421	421	421	421
Plant capacity <sup>b</sup>	kt/y	150	150	150	150
Yield	t/t	0,03	0,22	0,32	0,30
Operating hours per plant <sup>a</sup>	h/y	8000	8000	8000 (4000)	8000 (4000)
Total number of plants required		3	3	3 (6)	3 (6)
Capacity utilization	%	94%	94%	94% (47%)	98% (47%)
Feedstock per plant	kt/y	4878	626	439 (220)	463 (231)
Total feedstock required					

<sup>a</sup> Numbers in brackets illustrate main outputs when operations of e-based routes are assumed as 4000 h/y

<sup>b</sup> Production ratios per plant Propylene: 100 kt/y, Ethylene 5,8 kt/y, LPG 7,4 kt/y, C5+ fraction 3,8 kt/y.



Figure 51 shows levelized costs of propylene production options, and similar to the cases discussed previously, there is a significant difference in cost between the bio-based processes with the e-based processes. The process route with the lowest cost is methanol to propylene via gasification (system B17). The main reason applies to this case as discussed above for olefins in which feedstock costs for anaerobic digestion on the Netherlands, makes it less attractive. Similar to what has been discussed above for the other routes, CAPEX and energy costs are the major contributor for costs in the e-based processes. Figure 88 in Appendix F shows the results of sensitivity analysis of electricity prices and changes in CAPEX. In the case of electricity prices (Figure 88 a and b), the effect is highly noticeable for both e-based processes. The analysis is completely analogous to the one presented for methanol and DME, and olefins above.

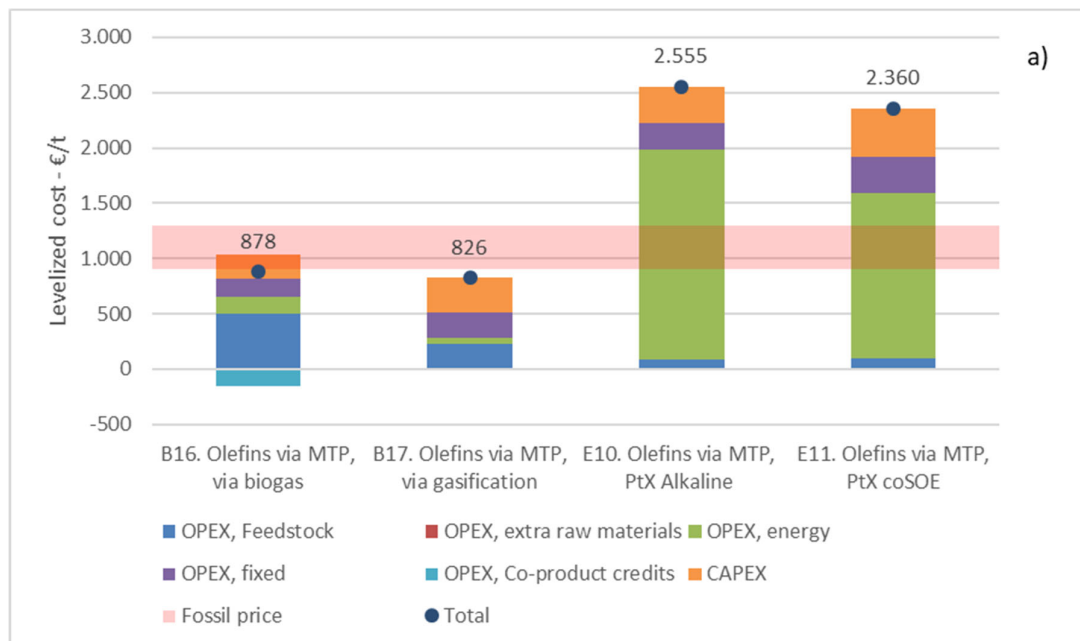


Figure 51 Levelized costs of renewable olefins (mainly propylene) production. a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

### Olefins (butadiene mainly)

Table 29 presents the most relevant technical results such as number of plants required, capacity utilization, and feedstock required for butadiene production systems via ethanol. The analysis here is similar to that presented for ethylene production from ethanol. However, the production requirements for butadiene are lower (52 kt for 2030) compared to the demand for ethylene and/or propylene. For all cases 1 plant is required. In all cases biomass is sufficient available to meet requirements with a share of 9%, considering the assumptions made.

Table 29 Relevant results of the routes producing butadiene via ethanol.

Feature	Units	B18.	B19.	B20.	B21.
		Butadiene via EtOH 1G S. Beets	Butadiene via EtOH 2G dilute acid	Butadiene via EtOH 2G SE	Butadiene via EtOH 2G Org
Total product demand <sup>a</sup>	kt/y	470	470	470	470
Substitution by renewables	%	15%	15%	15%	15%
Renewable demand	kt/y	70	70	70	70
Plant capacity	kt/y product	135	135	135	135
Yield	t/t feedstock	470	470	470	470
Operating hours per plant	h/y	8000	8000	8000	8000
Total number of plants required		1	1	1	1
Capacity utilization	%	52%	52%	52%	52%
Feedstock per plant	kt/y	1729	654	692	619
Total biomass feedstock required	kt/y	1729	654	692	619

<sup>a</sup> Demand for mixture. Production capacity per plant butadiene 100 kt/y, Ethylene 26,7 kt/y, C4 3,1 kt/y, hydrogen 5,4 kt/y.

Figure 52 shows levelized costs for all butadiene production options. In all cases, levelized costs are within the range of fossil butadiene price (900-1300 €/t), or slightly lower. Second generation (2G) conversion processes are more expensive than first generation (1G) process even if electricity credits are accounted for. This is a different result than that obtained for EU 2050, and it is because the plant size assumed here would be very large to meet the production requirements and thus a fraction of it is unutilized. In this study, 100 kt/y capacities were considered across all technologies, and smaller units than those have not been considered. This result highlights the fact that 2G systems are more sensitive to lower production rates than in the case of 1G. The result also means that the capacity selected can cover more than 15% of butadiene production target in 2030 in NL. Figure 89 in Appendix F shows that in case electricity price is increased, 2G systems are benefitted as here we assumed that electricity selling price would be equal to electricity buying price.

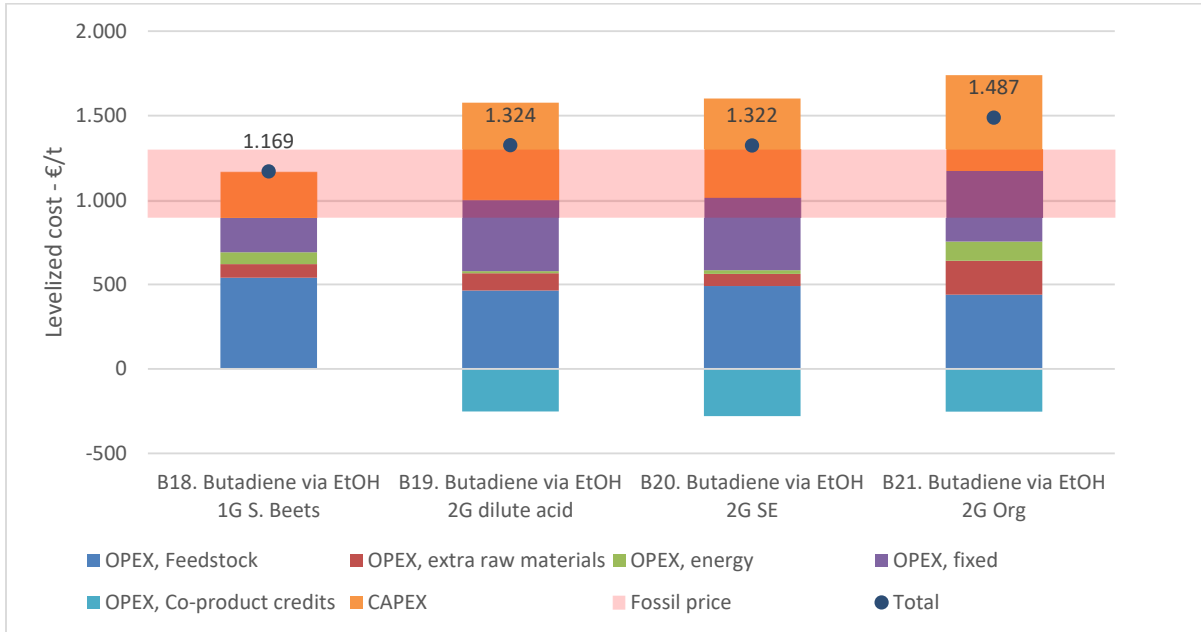


Figure 52 Levelized costs of renewable butadiene production.

**Olefins (from biomass pyrolysis)**

Table 30 shows the most relevant technical results for olefins production systems from biomass pyrolysis. Product demand was based on the projection of ethylene for 2030 (renewable 417 kt/y) and completed with the mixture produced in each renewable option (see Table 31). The demand of ethylene is always met with these routes. In this case, only in routes B23 and B26, solid biomass in the Netherlands is sufficiently available to meet requirements, however, almost all biomass would be required. For routes B22, B24 and B25, biomass would not be enough and domestic availability can only cover 62, 46 and 67%, respectively. The remaining biomass fractions need to be imported.

Table 30 Relevant results of the routes producing olefins via biomass pyrolysis

Feature	Units	B22. Olefins, pyrolysis WSBO+WI BO	B23. Olefins, pyrolysis WSBO+ WIBO hydro- genated	B24. Olefins, pyrolysis WSBO	B25. Olefins, pyrolysis WSBO hydro- genated	B26. Olefins, pyrolysis WSBO two step hydro- genated
Total product mixture demand	kt/y	5368	5276	6686	8743	8692
Substitution by renewables	%	15%	15%	15%	15%	15%
Renewable product demand	kt/y	805	791	1003	1311	1304
Plant capacity (of product mixture)	kt/y product	193	190	240	314	313
Yield	t/t feedstock	0.07	0.11	0.06	0.12	0.19
Operating hours per plant	h/y	8000	8000	8000	8000	8000
Total number of plants required		5	5	5	5	5
Capacity utilization	%	83%	83%	83%	83%	83%
Feedstock per plant	kt/y	2363	1466	3175	2211	1407
Total feedstock required	kt/y	11815	7330	15874	11057	7035

WSBO: Water soluble bio-oil, WIBO: Water insoluble bio-oil.

Table 31 Production ratios of olefins and BTX production in pyrolysis.

	Route	B22	B23	B24	B25	B26
Benzene	kt/y	27,0	23,6	26,4	36,6	33,3
Toluene	kt/y	64,8	52,5	46,6	95,9	61,6
Xylenes	kt/y	37,6	54,6	20,9	66,5	24,0
Ethylbenzene	kt/y	3,2	4,8	1,2	5,5	2,9
Ethylene	kt/y	100,0	100,0	100,0	100,0	100,0
Propylene	kt/y	70,7	68,1	110,4	174,2	168,2
Butylene	kt/y	22,4	21,6	30,1	40,2	44,4

Something relevant to mention for the pyrolysis routes is that both olefins and BTX are co-produced. When these routes are used to meet renewable ethylene production in 2030, the amount of BTX produced in all cases do not meet the demand of BTX for 2030 in the Netherlands. This result is contrary to the one presented for EU 2050. Results for BTX will be discussed separately, but it is important to bear in mind that production ratios for aromatics remain intact as those presented in Table 31.

Figure 53 shows levelized costs for the olefins from pyrolysis. In all cases, levelized costs are lower than olefins price range (900-1300 €/t). It is important to mention that hydrotreatment processes increase the yield towards olefins production, specially towards propylene. Nevertheless, the amount of electricity produced as co-product decreases as the gaseous hydrocarbons are lower. This is why in systems B22 and B24 the amount of electricity co-product is higher than in the other cases. These processing routes highly benefits from energy integration as residual gases can be used in situ for producing steam and electricity. Figure 90 in Appendix F shows that in case electricity price is increased the systems are benefitted as it is assumed that electricity selling price would be equal to electricity buying price.

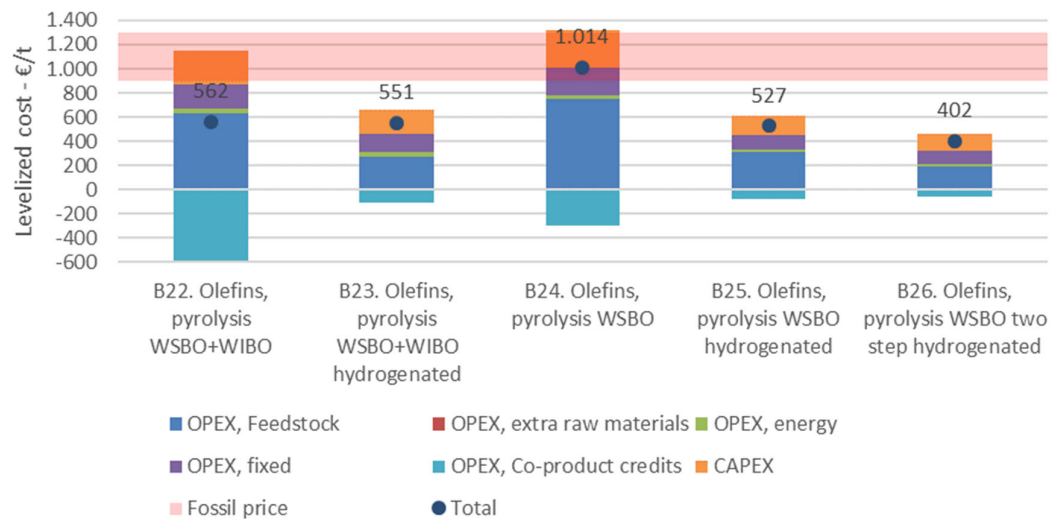


Figure 53 Levelized costs of renewable olefins production via pyrolysis.

### BTX (from biomass pyrolysis)

Table 32 shows the most relevant technical results for BTX production systems from biomass pyrolysis. In case the aim is to meet BTX demand, the number of plants (co-producing olefins) is larger. To meet the demand of BTX, solid biomass is in all cases not enough in NL in 2030. Biomass available covers 26-74% of the requirements in systems B22 to B26.

Table 32 Relevant results of the routes producing olefins via pyrolysis

Feature	Units	B22.BTX , pyrolysis WSBO+W IBO	B23. BTX, pyrolysis WSBO+ WIBO hydro- genated	B24. BTX, pyrolysis WSBO	B25. BTX, pyrolysis WSBO hydro- genated	B26. BTX, pyrolysis WSBO two step hydro- genated
Total product mixture demand	kt/y	6483	7578	4766	7377	4830
Substitution by renewables	%	15%	15%	15%	15%	15%
Renewable product demand	kt/y	973	1137	715	1107	724
Plant capacity (of product mixture)	kt/y product	132	136	95	204	122
Yield	t/t feedstock	0.05	0.08	0.02	0.08	0.07
Operating hours per plant	h/y	8000	8000	8000	8000	8000
Total number of plants required		8	9	8	6	6
Capacity utilization	%	92%	93%	94%	90%	99%
Feedstock per plant	kt/y	2599	1638	3577	2391	1672
Total feedstock required	kt/y	20791	14741	28616	14344	10029

WSBO: Water soluble bio-oil, WIBO: Water insoluble bio-oil.

Figure 54 shows levelized costs for the BTX from pyrolysis. In all cases, levelized costs are lower than BTX price range (1000-1400 €/t). The analysis on cost for BTX is analogous to that presented for olefins from pyrolysis. Figure 91 in Appendix F shows that in case electricity price is increased the systems are benefitted as it is assumed that electricity selling price would be equal to electricity buying price. For these systems, reductions in CAPEX can further benefit levelized costs as pyrolysis systems are still not very well developed in comparison to other technologies and there is room for learning until full commercial implementation.

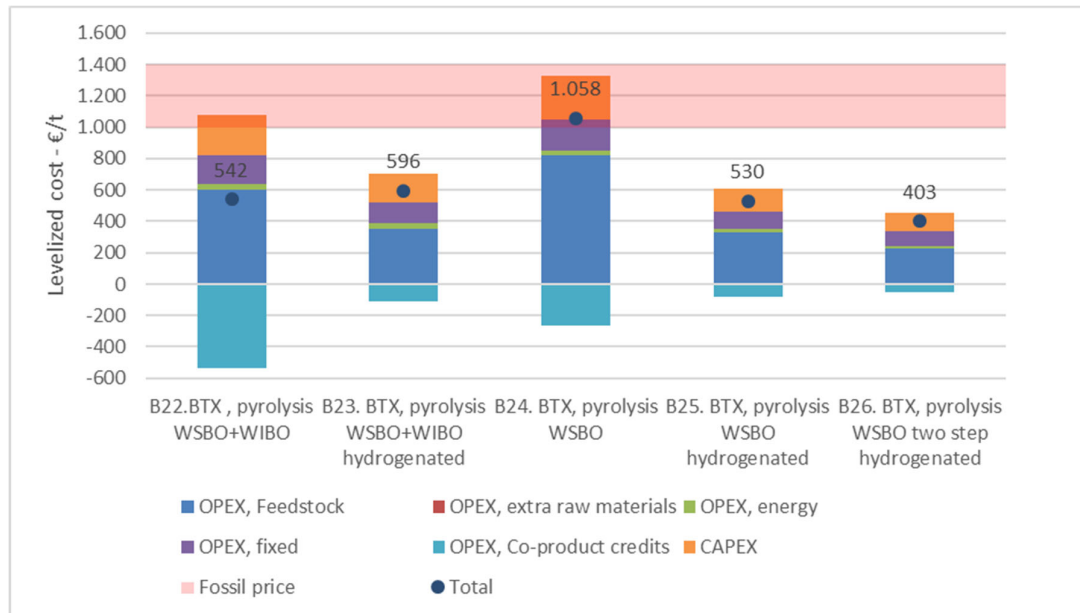


Figure 54 Levelized costs of renewable olefins production via pyrolysis.

## 5.2 Demand for renewable resources

### 5.2.1 EU 2030 and 2050

Table 33 presents a summary of feedstock and renewable electricity requirements for the different set of chemicals for EU in 2030 and 2050. Results presented here give a sense on how much biomass, CO<sub>2</sub> and renewable electricity would be required to meet the target of replacing 15% of chemicals production by renewables in 2030, and 30% by 2050. In the case of biomass, results suggest that biomass would be available to cover the requirements to meet these targets. In terms of renewable electricity supply, the capacity to cover 15% of the chemicals considered in this study, it can go up to 35 GW and up to 61 GW to cover 30% of the demand of chemical. This picture can, however, drastically change if the ambition to replacing chemicals by renewables is larger. Figure 55 shows the projected biomass and renewable electricity requirements in case the ambition to replace chemicals by renewables is much larger than 15% and 30% assessed in this study.

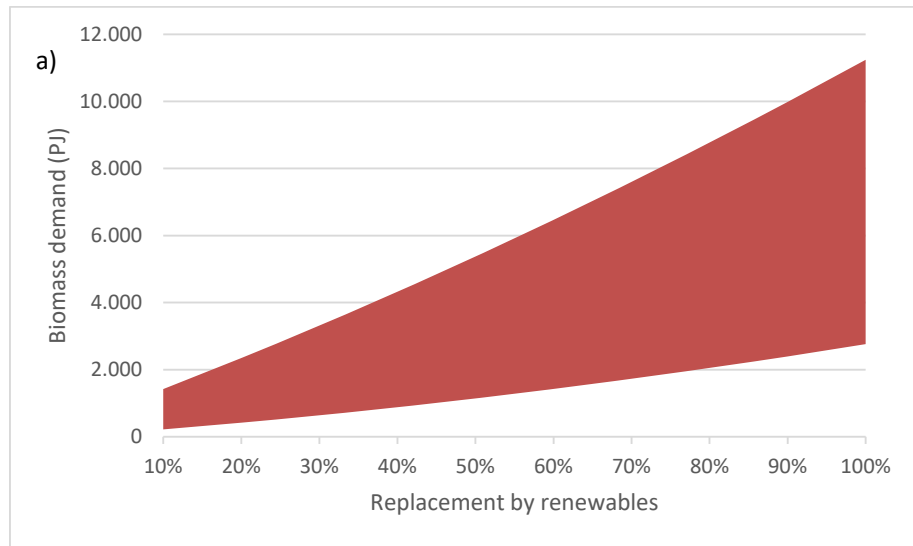
In case base chemicals are aimed to be replaced by renewables up to 100% in 2050, feedstock demand can go up to 11,000 PJ (high end, Figure 55b) which is slightly below the potential presented in Figure 26. That would therefore suggest that if other uses are considered, biomass available would not be sufficient to cover such demand. Additionally, it should be taken into account that biomass potential does not necessarily indicate that it would be easily accessible at low cost, and thus, it is likely that high rates of biomass imports would be required. In terms of renewable electricity, worst case scenario would require up to 200 GW of electricity supply to cover 100% of chemicals in EU in 2050. That does not include electricity use for other purposes. The range of electricity needs for chemicals production is presented in Figure 55b. According to Tennet and Gasunie (TenneT and Gasunie, 2019), Europe can generate renewable electricity in 2050 up to 875 GW. This would mean that in worst case scenario to replace the chemical industry by power-to-x, up to 23% of that supply needs to be allocated to this sector. According to PRIMES the renewable power generation in 2050 would be around 1200 GW, that would mean that around 17% (worst case) of it needs to be destined to chemicals production if all are produced from power-to-x technologies.

Table 33 Feedstock requirements to meet demand of chemicals in EU in 2030 and 2050

EU -2030	Unit	Methanol	DME	Ethylene	Propylene	Butadiene	BTX
Product demand	kt	1950	1560	16634	11487	2585	7611
Renewable coverage	%	15%	15%	15%	15%	15%	15%
Renewable product demand	kt	293	234	2495	1723	388	1142
Biomass (dry)	kt	452-581	276-653	2726-52339	668-35909	322-1289	12960-104715
Biomass	PJ	10-15	5-17	103-934	107-641	12-23	81-249
Total Biomass	kt	<b>12960-104715</b>					
Total Biomass	PJ	<b>319-1879</b>					
CO <sub>2</sub>	kt	407-429	458-483	7,495-21,083	4,202-12,933		

EU -2030	Unit	Methanol	DME	Ethylene	Propylene	Butadiene	BTX
Electricity	GW	0,30-0,38	0,34-0,42	5-21	3-13		
Total CO <sub>2</sub>	GW	<b>12522-34929</b>					
Total Electricity	GW	<b>9-35</b>					

EU -2050	Unit	Methanol	DME	Ethylene	Propylene	Butadiene	BTX
Product demand	kt	2250	1800	14257	9846	2215	6524
Renewable coverage	%	30%	30%	30%	30%	30%	30%
Renewable product demand	kt	675	540	4277	2954	665	1957
Biomass	kt	1044-1341	637-1507	4673-83365	8003-61559	2208-8837	9031-27887
Biomass	PJ	24-35	12-40	177-1487	183-1098	84-158	161-498
Total Biomass	kt	<b>2596-184495</b>					
Total Biomass	PJ	<b>641-3316</b>					
CO <sub>2</sub>	kt	940-990	1056-1115	12780-36142	7204-22171		
Electricity	GW	0,69-0,87	0,79-0,98	9-37	5-23		
Total CO <sub>2</sub>	kt	21980-60419					
Total Electricity	GW	16-61					





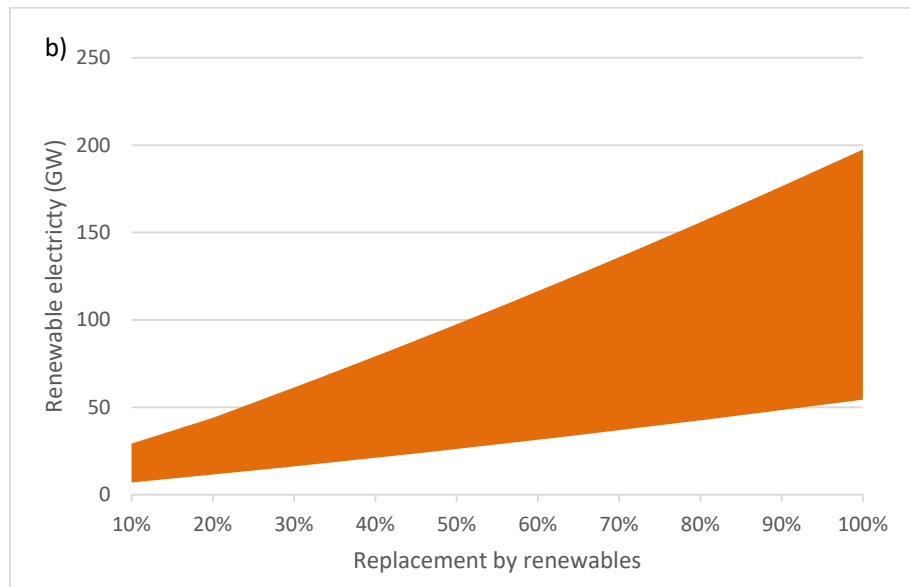


Figure 55 Resources requirements as function of percentage of coverage of chemicals demand by renewables. a) biomass requirements, b) renewable electricity supply requirements

### 5.2.2 The Netherlands 2030 and 2050

Table 34 presents resources requirements for the Netherlands in 2030 and 2050, to meet 15% and 30% of chemicals by renewables, respectively. Nevertheless, it should be taken into account that biomass quality is also important and possibly the distribution of biomass available in the Netherlands would suit all processes presented in this study, thus biomass imports would be needed. In case the high end is the case, both in 2030 and 2050, biomass would not be sufficient to cover the demand and this biomass imports would be required. In terms of electricity needs dedicated to the chemical industry in the Netherlands up to 3-12GW would be required to cover a 30% of the demand by renewables. According to the Tennet and Gasunie (Fennema and van Beek, 2019), the projected scenarios for 2050 in the Netherlands would include a capacity production of renewable energy between 27-126 GW in 2050, thus it would mean that 3-46% of the capacity production in the Netherlands need to be destined to chemicals production.

Table 34 Feedstock requirements to meet demand of chemicals in NL in 2030 and 2050

NL-2030	Unit	Methanol	DME	Ethylene	Propylene	Butadiene	Benzene
Product demand	kt	443	354	2,781	1,873	347	1,321
Renewable coverage	%	15%	15%	15%	15%	15%	15%
Renewable product demand	kt	66	53	417	281	52	198
Biomass (dry)	kt	103-132	63-148	456-8,750	761-5,854	173-692	2407-6868
Biomass	PJ	2,4-3,5	1,2-3,9	17-156	17-104	7-12	43-123
Total Biomass	kt	<b>3962-22444</b>					
Total Biomass	PJ	<b>88-403</b>					
CO <sub>2</sub>	kt	93-97	104-110	1246-3525	685-2108		
Electricity	GW	0,07-0,09	0,08-0,1	0,9-3,6	0,5-2,1		
Total CO <sub>2</sub>	kt	<b>2168-5840</b>					
Total Electricity	GW	<b>1,6-5,9</b>					
NL -2050	Unit	Methanol	DME	Ethylene	Propylene	Butadiene	Benzene
Demand	kt	464	371	2911	1961	363	1384
Renewable coverage	%	30%	30%	30%	30%	30%	30%
Renewable demand	kt	139	111	873	588	109	415
Biomass	kt	215-276	131-311	954-18322	1522-12257	346-1385	5040-14381
Biomass	PJ	5-7	2-8	36-27	35-219	13-25	90-257
Total Biomass	kt	<b>8209-46931</b>					
Total Biomass	PJ	<b>181-842</b>					
CO <sub>2</sub>	kt	194-204	218-230	2610-7380	1370-4415		
Electricity	GW	0,14-0,18	0,16-0,20	1,9-7,5	1,0-4,5		
Total CO <sub>2</sub>	kt	<b>4391-12229</b>					
Total Electricity	GW	<b>3,2-12,4</b>					

## 6 Discussion points

This section focuses on discussing main limitations and important aspects that were not included in the assessment and that may influence the findings. These aspects are here discussed per main section of the study.

### ***EU-wide transport sector***

Demand analysis for renewable hydrocarbons is sensitive to the assumptions on the direct electrification of road transport. The direct electrification assumption for the EU appears to be remarkably high. When compared with the PRIMES projections for 2050, our figure is higher than the scenario where electricity use was prioritised. As such the renewable hydrocarbon demand in our assessment may be considered as low.

### ***Chemical sector***

The current production analysis of chemicals does not include the potential of some base chemicals to become relevant building blocks in the industry, such as the case of methanol. Methanol can be an important precursor for olefins (via methanol to olefins, and methanol to propylene) and the demand presented here is somehow low if additional applications for methanol are included. This therefore implies that in case methanol becomes a leading building block for renewables, its demand can rapidly grow in upcoming years.

The techno-economic data used to assess the different pathways is quite heterogeneous. Although the data was harmonized to match production requirements, the variety of sources used bring uncertainties as in many cases assumptions are different, system boundaries differ, and sometimes the data is model derived (such as the case of process modelling exercises). This therefore leads to difficulties as suboptimal energy requirements, and over/sub estimation of CAPEX. To overcome this, a more in-depth analysis of energy flows and CAPEX components would be needed. The results showed that energy use still is important aspect that contributes to GHG emissions of both bio and e-based processes. This confirms the need to understand in more depth energy flows across a value chain and the need of decarbonization of renewable systems as those to great extent rely on fossil energy (for heat purposes for instance).

It is worth mentioning that this study does not focus on assessing potential combinations and/or multiple combinations of technologies to meet demand targets. The study presented here focuses on identifying potential standalone value chains that can meet demand targets. However, integrated configurations of biorefineries can enhance the overall performance of systems and provide a more efficient solution to resource utilization. Additionally, configurations including the integration of bio-based systems together with power-to-x systems may improve resource efficiency and power-to-x can benefit from integration with bio-based processes.

***CO<sub>2</sub> accounting in the p-to-x value chains***

One of the aspects that is causing a lot of debate on the use of CO<sub>2</sub> both for chemicals production and transport fuel production how to account for it. CO<sub>2</sub> can be captured and supplied from fossil point sources such as power plants or process industries like steel or ammonia production. It can be sourced from biogenic point sources like bioenergy plants. They can also be captured directly from air. In this study, CO<sub>2</sub> supply is considered as zero emission to simplify the calculations. No upstream emissions (CO<sub>2</sub> capture, purification, compression) or credits due to avoided GHG emissions are included. This may appear inconsistent as the system boundaries for biomass value chains also cover the biomass production related emissions. It is, however, worthwhile to mention that negative emissions resulting from the removal of atmospheric CO<sub>2</sub> during the growth of the biomass is also not included in the biomass value chain analysis.

A central part of the carbon capture and supply of CO<sub>2</sub> relates to the source of CO<sub>2</sub> and to the concentration for CO<sub>2</sub>. Lower CO<sub>2</sub> concentrations will increase the energy demand to capture CO<sub>2</sub>. Literature provides a wide range for the GHG emission footprint of CO<sub>2</sub> as feedstock. Some studies (Kim et al., 2011; Kongpanna et al., 2015; Luu et al., 2015; Souza et al., 2014; Van Der Giesen et al., 2014; Wu et al., 2014) show negative emissions in which the concentrated CO<sub>2</sub> flows are considered available and their consumption would lead to negative emissions. Other studies take into account the sources of CO<sub>2</sub> and provide positive carbon footprint, which means that CO<sub>2</sub> capture results in more emissions to the atmosphere. (Müller et al., 2020) indicates that assuming a concentrated CO<sub>2</sub> flow as available, leading to -1 kg CO<sub>2</sub> eq. emission per CO<sub>2</sub> capture, neglects the main principals of LCA.

Within a power-to-x value chain CO<sub>2</sub> is one of the main feedstocks whereas CO<sub>2</sub> is typically not the main product but rather an undesired by-product that needs to be gotten rid of. How to allocate the CO<sub>2</sub> emission reduction credits among the main-products and the by-products is an important aspect, also referred to as dealing with the multi-functionality of CCU systems. This negative footprint indicates that the CO<sub>2</sub> emissions are reduced in comparison to a process without capture. It does not mean that CO<sub>2</sub> capture removes GHG from the atmosphere. Negative LCA results do not necessarily imply that the CCU product is carbon neutral or even has negative emissions over its life cycle

According to the recast renewable energy directive (REDII), the European Commission will adopt a delegated act by 31 December 2021. This act will specify the methodology for assessing GHG emissions savings from renewable liquid and gaseous transport fuels of non-biological origin, which shall ensure that credit for avoided emissions is not given for CO<sub>2</sub> the capture of which has already received an emission credit under other provisions of law. As such, clear legislative rules for calculating the GHG of these fuels do not yet exist yet but are underway.

## 7 Conclusions

### 7.1 EU-wide transport sector conclusions

**The renewable hydrocarbon deployment will need to be increased by a factor of 10 in 2050 even with significant electrification of road transport.** This will be needed to achieve carbon neutrality in road, rail, and inland shipping and to reduce CO<sub>2</sub> emissions from international aviation and maritime sectors. The existing policy framework results in around 12% increase of renewable hydrocarbons in 2030 in Europe. Reducing GHG emissions in transport (excluding international maritime and aviation) to zero and reducing the GHG emissions in international aviation and maritime by 50% will require an increase of renewable hydrocarbons with a factor of 10 compared to 2030 in Europe. Even with high electrification the demand for renewable hydrocarbon in road transport stays high, almost half of the total renewable hydrocarbon demand. The other half of the renewable hydrocarbons will be used in international aviation and maritime in 2050.

**Meeting these high demands in 2050 will be challenging as there will be no fossil hydrocarbons in road transport.** All fuels consumed in road transport will need to be based on renewable hydrocarbons. This will require either high demand for drop-in renewable fuels, mainly diesel substitute suitable for the existing internal combustion engines, or a drastic transformation of vehicle fleet to run on other types of renewable fuels like methanol, DME and LNG. The high demand for drop-in diesel substitute and the renewable value chains producing a mixture of diesel, gasoline and naphtha makes it challenging. A share of the vehicle fleet will need to be shifted from compression ignition engine to spark ignition engine to use gasoline. This may be more difficult in marine sector as the lifetime of the ships are much longer (up to 40 year) and most ships are based on diesel engine. This problem can be address with ships built with multifuel engines.

**All renewable hydrocarbon options and demand side management will be needed to meet this high demand in 2050.** Results show that around 12 EJ primary biomass will be needed if these targets are to be met with only biobased hydrocarbons. This amount corresponds to approximately 90% of the sustainable biomass supply potential considered in this study or around 40% of the biomass potential highlighted by some other literature. In case the renewable kerosene is to be met via power-to-jet fuel options, this requires around 1010 TWh renewable electricity and 143Mt CO<sub>2</sub> as feedstock in 2050. It should be noted that when also direct electrification is included the total renewable electricity demand by 2050 increases up to 1731 TWh.

### 7.2 Chemical industry conclusions

**The production of the European high value chemicals (HVCs) is expected to become less competitive in the market compared to US and Asian markets and therefore shrink up to 2050.** *For methanol, however, the production in Europe is assumed to grow.* The main reasons for the increase in the demand relate to two applications: methanol use as a fuel additive and its use as an intermediate

for producing olefins and aromatics. However, the demand numbers presented in this study for the case of methanol may be significantly lower as the requirements for olefins might be larger.

CO<sub>2</sub> emissions related to production and supply of building blocks can be reduced by substituting a fraction of these with the renewable hydrocarbon options.

**Results on costs show that there is a tendency that favours the deployment of bio-based systems in comparison to e-based systems. E-based processes are factor 2-5 higher than the bio-based processes.** Among the value chains, methanol and DME production via biogas routes appear the most favourable ones, however, highly dependent on feedstock price. The levelized production costs of these routes are comparable to the market prices of fossil references. Figure 57 recaps the calculated ranges for different renewable-based hydrocarbon value chains.

**E-based routes can become comparable to the biomass value chains when supplied by cheap electricity, reduced CAPEX and continues operation across the year.** For instance, results show that the production cost of e-methanol production becomes comparable to biobased routes when the renewable electricity price is very low (0-10€/MWh) and a 50% CAPEX reduction is implemented. Improvements can be further reached if renewable electricity supply is maintained through the year. E-based systems highly suffer from costs associated to CAPEX when the systems are not running.

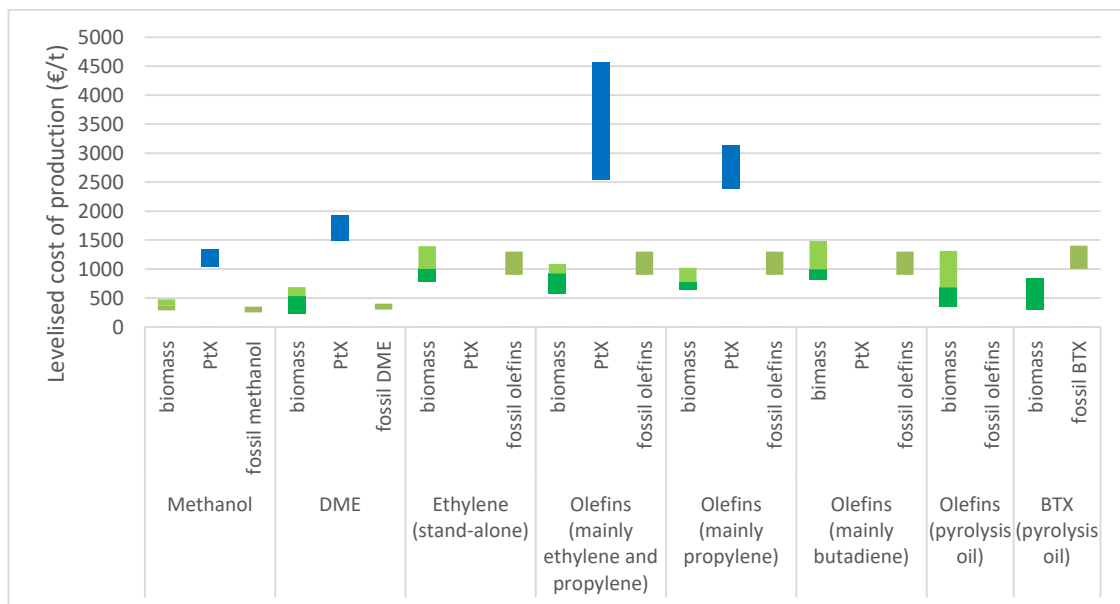


Figure 56 Levelised production cost range of selected chemical building blocks (€/t). Dark green refers to cost range with biomass price of 38-45 €/t for solid biomass and 9 €/t for wet biomass. Light green illustrates the high range with biomass price of 100 €/t. Mostly low costs relate to biogas-based value chains. In PtX options (blue bars), low costs relate to continues operation (8000 hr) and high costs refer to 4000 hr operation.

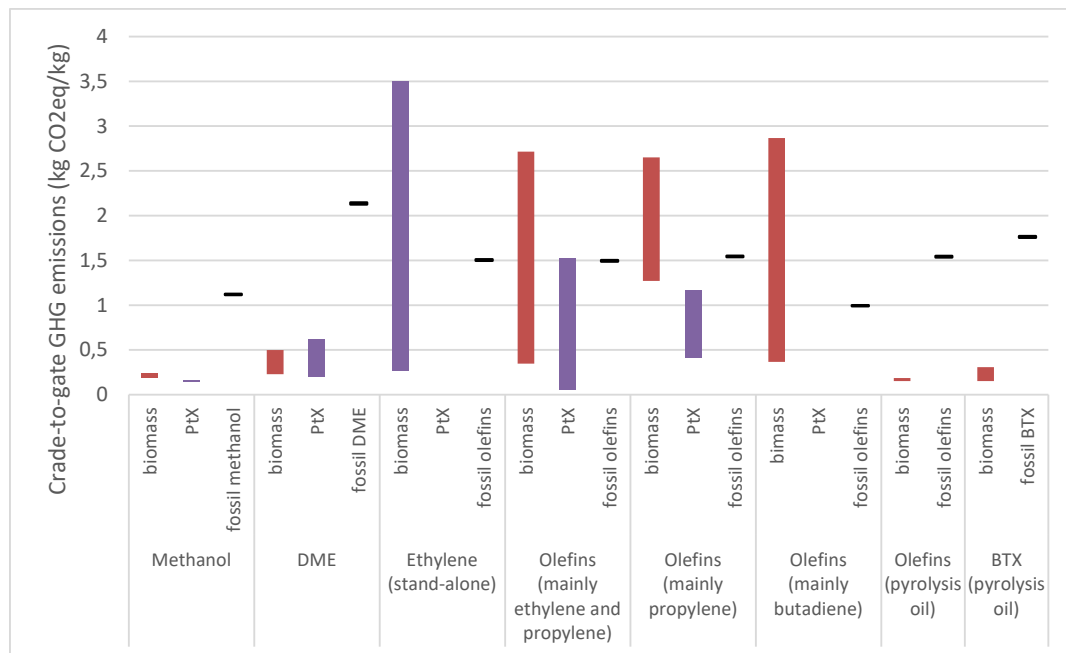


Figure 57 Cradle-to-gate GHG emission ranges of different value chains (kg CO<sub>2</sub>eq/kg)

**Renewable based value chains result in 78-87% GHG emission reductions when compared with the fossil counterparts according to a cradle-to-gate analysis.**

The results suggest that the system with the highest emission reduction potential are e-based routes. These value chains result in more than 85% emission reduction. In this study e-based routes are assumed to use renewable electricity; therefore, related CO<sub>2</sub> emissions are counted as zero. Also, the CO<sub>2</sub> as feedstock is considered to have zero emission in a cradle-to-gate assessment. There are many discussions about what methodology to use and how to define the GHG emission factor for different CO<sub>2</sub> resources. The allocation of GHG emissions to the use face is also important. When emitted to the atmosphere biomass embedded CO<sub>2</sub> is considered as carbon neutral and accounted zero. How the accounting will be done when the e-based routes are based on CO<sub>2</sub> feedstock that is fossil based remains to be decided. The Commission is expected to clarify this point by December 2021 with an amending act at least for the transport sector.

**To cover the demand for chemicals in 2030 and 2050, with a coverage of 15% and 30% with renewables, biomass potential in Europe, seems sufficient.**

Nevertheless, in case the share of renewables is increased to 100%, up to 11,000 PJ of biomass would be required in the worst case. That value is high in comparison to EU potential, which might imply that in case other uses for biomass are considered, imports might be required. Also, it should be taken into account that this does not include competing uses for instance with fuels production.

**Total requirements of electricity to have 30% coverage by renewables of chemicals demand is around 16-61 GW by 2050.** This can however be much larger if the amount of chemicals to be replaced by renewables is larger. **In case 100% of fossils are envisioned, 50-200 GW of renewable electricity supply is required.** This may represent up to 23% of the projected renewable power generation in the Europe in 2050.

### 7.3 Conclusions for the Netherlands

#### *Transport sector*

The renewable hydrocarbon demand in 2030 is around 3 times the consumption in 2019. **To achieve a zero-emission road and rail transport and a reduction of CO<sub>2</sub> emissions from the international aviation and maritime sectors by 50% in 2050, the total renewable hydrocarbon demand will need to be more than 21 times the current renewable fuel supply in the transport sector.** In 2050, the international aviation and maritime sectors account for 70% of the total renewable hydrocarbon demand. This depicts a notable change compared to 2019, where the renewable hydrocarbons, in the form of biofuels, were used completely in road transport.

The adoption of REDII in the Netherlands will set the framework for the renewable fuel supply up to 2030. The recently issued (December 2020) consultation document on the decision to adopt REDII introduces the main elements of this framework. The renewable fuel obligation is introduced as 27,1% in 2030. Translation of this, using the KEV 2020 projections, shows that the renewable hydrocarbon demand will be in the range of 40-61 PJ in 2030. In physical terms, these values correspond to 11-13% of the diesel and gasoline demand, respectively. The electrification of road transport and related energy savings play a key role in determining these values.

**In 2050, there should be no fossil fuels consumed in transport, excluding international maritime and aviation. This means that either all renewable hydrocarbons need to be drop-in, or the vehicle fleet will need to be adapted to use new types of renewable hydrocarbons like MeOH, DME, CNG/LNG.**

When all renewable hydrocarbons are supplied via biomass, the total primary biomass demand will be in the range of 800-900 PJ in 2050. These correspond to approximately 2 times the total biomass potential in the Netherlands. However, the national potential appears to satisfy only 10-30% of the total demand of woody and grassy feedstocks. The rest is to be imported from the EU and/or outside.

When the total aviation demand in 2050 is to be met via e-kerosene, this will require around 87 TWh renewable electricity. When also direct electrification is included the renewable electricity demand for transport sector reaches to 143 TWh in 2050. For comparison, the renewable electricity generation in the Netherlands in 2019 was around 22,5 TWh and it is projected to grow up to 92 TWh in 2030 according to KEV (2020). The amount of CO<sub>2</sub> that needs to be captured in 2050 to produce the total e-kerosene will be around 14 Mt CO<sub>2</sub>. This CO<sub>2</sub> amount is 2 times the amount of CO<sub>2</sub> that is allowed by the aviation sector in 2050 to meet the 50% GHG emission reduction target.



### *Chemical industry*

Conclusion for the chemical industry in the Netherlands are almost identical to those presented for Europe above. The main differences rely on resources use. In **this case, biomass potential in the Netherlands seems not to be sufficient to cover renewable chemicals production**. The results suggest that there would be requirements for biomass imports.

**Green electricity requirements in the Netherlands to cover 30% of the projected demand for chemicals in 2050 is 3-12 GW**. This would be 3-46% of the projected renewable energy generation in the Netherlands (TenneT & Gasunie, 27-126GW).

## 7.4 Further research

Many of technologies assessed in this study are still at early development stages (e.g., pyrolysis, methanol to olefins, Fischer Tropsch to olefins) which inherently brings uncertainties on their techno-economic and environmental performances. Thus, **the assessment of uncertainties** of emerging technologies needs to be accounted for reporting risks associated to transitions from early development concepts to commercial technologies. **Uncertainties in CAPEX**, should be closely monitored, and if required assessments should be revisited.

Challenges remain to assess and understand the **end-of-life greenhouse gas emissions of renewable chemicals**. The development of scenarios in the use phase are required to further understand whether there are long term mitigation potentials compared to traditional fossil products.

**The methodological implications of carbon accounting of e-based systems as well as the use of allocation** needs to be further investigated. The insights provided in this study shows that there is still vast confusion and debate on how to account for carbon use in power-to-x systems. Using the appropriate approach for carbon accounting in power-to-x systems can avoid bringing unclear messages on the potential use of carbon recycling and storage in chemical bonds. This is also highly related to the need to further understand end-of-life scenarios for chemicals.

Insights presented in this study rely on high level analysis of resource availability (*i.e.*, CO<sub>2</sub> supply, green electricity supply, biomass supply), nevertheless, additional work is still **needed to understand the synergies, competition and impacts of resource** supply on the techno-economic and GHG emissions performances of the different value chains. Resource supply can represent an important bottleneck on the deployment of low carbon technologies due to technical, economic, and environmental constraints. For instance, development of CO<sub>2</sub> supply infrastructures can impact on generating additional costs, increase in energy use which can hinder the deployment of power-to-x systems in the future. Thus, analysing in more detail resource supply challenges would allow contextualizing low carbon technologies to regions/countries with unique resource supply constraints.

Additional work on **the assessment of technology combinations** to reach optimal targets (e.g., lowest cost, minimum GHG emissions) is still needed. In reality, demand targets are not met with one technology but with multiple technology options. Further research on identifying potential configurations of technology options can allow identifying trade-off and bottlenecks between environmental and economic objectives. This is also related to the integration of power-to-x systems together with bio-based systems, as it could trigger better environmental and economic performances than standalone systems.

**The effects of a future circular economy** are not included in this study. However, circularity and recycling of raw materials become increasingly important. Resource and material efficiency, recycling and re-use, product and process innovations, cascading use of materials are some of the important aspects that should be part of another study on this topic.

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## A Introduction to the chemical building blocks

**Methanol** (MeOH) is a liquid chemical represented by the formula CH<sub>3</sub>OH. While it can be made from a variety of sources (including coal and oil), natural gas is most often used. It is commonly used in the production process of other chemicals. Around 40% of the methanol worldwide is converted to formaldehyde, which is further processed into plastics, plywood, paints, explosives and textiles (IEA, 2018). Methanol can be used also to produce antifreeze chemicals and solvents, such as methyl methacrylate (MMA). For the transport sector, methanol is a primary feedstock for the manufacturing of MTBE (methyl-tert-butyl-ether), which an important fuel additive to increase octane number. (Petrochemicals Europe, 2020a). Methanol can also be feedstock for the production of ethylene and propylene via the process called methanol to olefins (MTO). The global methanol production is approximately 100 Mtonnes/yr (IEA, 2018).

**Ethylene** is one of the basic organic chemicals (molecular formula: CH<sub>2</sub>=CH<sub>2</sub>) and the largest bulk chemical used for the production of around half of the plastics (Rübberdt et al., 2018). It is used for direct or indirect production of most important synthetic polymers, including high- and low-density polyethylene (HDPE and LDPE), polyvinyl chloride (PVC), polystyrene (PS) and polyethylene terephthalate (PET). Almost all ethylene is produced from petroleum derivatives, including naphtha, gas condensate (mostly Europe and Asia), ethane and, to a lesser extent, propane and butane in the Middle East and North America. As mentioned previously, methanol is also a precursor for the production of ethylene via MTO process, which takes place mostly in China.

**Propylene (C<sub>3</sub>H<sub>6</sub>)** is another largest volume petrochemical. The industry is somewhat unique considering that most propylene is manufactured as a by-product from either steam cracking or refining operations. Propylene was produced almost exclusively as a by-product for around 15 years ago, however fluidized catalytic cracking (FCC), a common process unit in refineries, propane dehydrogenation (PDH) and metathesis are alternatives to produce only propylene. The supply landscape has changed considerably since then, with on-purpose propylene production technologies now responsible for roughly 20% of global supply. Both growing propylene demand and slower growth in supply from the steam cracking motivate the current focus on-purpose propylene capacity (Kelly, 2016).

Ethylene together with propylene form the group named light olefins. The most common process for producing them is steam cracking, which can be briefly defined by thermal conversion of saturated hydrocarbons into smaller, often unsaturated, hydrocarbons. This process occurs under high temperature (>800°C) and, therefore, it is energy intensive. A higher cracking severity favours ethylene production whereas lower severity yields higher amounts of propylene (Bazzanella and Ausfelder, 2017). Also, depending on the feedstock used in the steam cracking process, the shares of ethylene and propylene can differ. Combined global ethylene and propylene production is approximately 255 Mtonnes/yr (IEA, 2018).

**Butadienes (1,3 – butadiene and isoprene)**

For the butadienes group, 1,3-butadiene ( $C_4H_6$ ) and isoprene ( $C_5H_8$ ) were chosen for this study due to their relevance in the market. 1,3-butadiene is used mainly as a monomer for the production of synthetic rubbers – its largest single use is in the production of styrene butadiene rubber (SBR), which is the main material for the manufacture of automobile tyres. Other examples of synthetic rubbers are: polybutadiene rubber (PBR), acrylonitrile butadiene styrene (ABS), polychloroprene (neoprene) and nitrile rubber (NR) (ICIS, 2017). Isoprene is also called 2-methyl-1,3-butadiene and is normally used for synthetic rubber production. Polyisoprene resembles natural rubber and has a vast application, including medical equipment, baby bottles, toys, shoe soles, tyres, and elastic films and threads for golf balls or textiles. It can also be used in the adhesives, paints and coatings manufacturing (Shell, 2017).

**Benzene, Toluene and Xylene** (also called BTX) are major aromatic compounds used to produce synthetic fibres, resins, detergent, and polymers, including, for instance, (poly)styrene, polyurethane, and polyesters. In Europe, BTX production mainly follows the same pathway as the olefins, i.e. steam cracking of Naphtha. BTX is extracted from pyrolysis gasoline, one of the by-products from the steam cracking process. An alternative process, commonly present in refineries, is catalytic reforming of Naphtha (also known as Platforming) yielding high-octane gasoline and BTX rich aromatics, which are further extracted (Bazzanella and Ausfelder, 2017). These aromatics are normally used in health and hygiene, food production and processing, transportation, and information technology sectors. Global production of BTX aromatics is approximately 110 Mtonnes/yr (IEA, 2018).

Light olefins and aromatics are usually grouped in the so called high value chemicals (HVCs).

## B Current status of bulk chemical building blocks

### Current status of bulk chemical building blocks

In this section, the historic and the current production volumes of the bulk chemical building blocks are introduced. Also the import and export volumes are presented to provide some indications in regard to how far the production volumes correspond to the demand in the EU and the Dutch chemical industry.

#### *EU chemical industry*

##### **Methanol**

Methanol production capacity in the EU28 sums more than 3,2 Mt/yr (Table 35), which represents around 2% of the total global capacity in 2019 (148 Mt/yr). Germany represents more than half of the Union's production capacity. According to Eurostat, methanol production was around 1,6 Mt in 2018, increasing to 2,4 Mt in 2019. Figure 58 provides the historical methanol production volumes in the EU. These figures indicate that around 49% of the installed capacity was used in 2018, increasing to 73% in 2019. Figure 59 illustrates the methanol trades volumes. This figure shows that large part of the methanol produced in the EU is consumed within the member states.

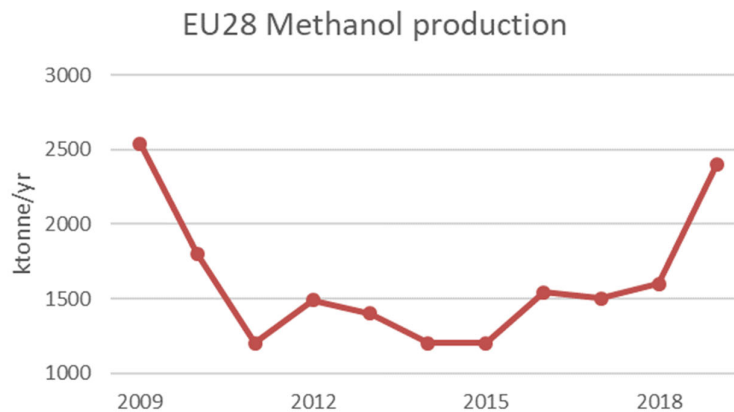


Figure 58 EU28 Methanol production 2009-2019 (Eurostat, 2020)  
Source: (EUROSTAT, 2020)(PRCCODE 20122210 Methanol)



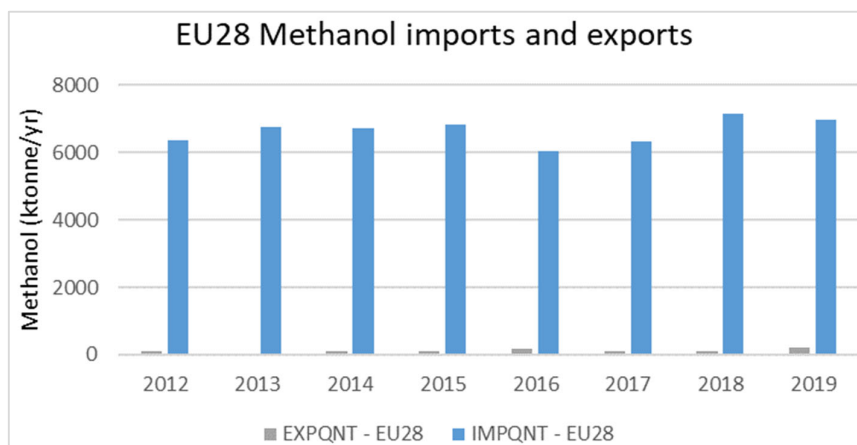


Figure 59 Methanol trade volumes for the EU28 2012-2019 (EUROSTAT, 2020)

Table 35 Nameplate capacity for Methanol manufacturing sites in Europe EU28 (ICIS, 2018)

Company	Location	Nameplate capacity [kt/yr]
BioMCN	Delfzijl, Netherlands	1000
Milder-Helm Methanol	Leuna, Germany	660
BASF	Ludwigshafen, Germany	480
Shell & DEA Oil	Wesseling, Germany	400
BP Refining & Petrochemicals	Gelsenkirchen, Germany	300
Vitromet	Victoria, Romania	225
Achema	Jonava, Lithuania	130
Silekol	Chorzow, Poland	100
	<b>TOTAL</b>	<b>3295</b>

Methanol is an important feedstock for the production of several chemicals. The majority of the methanol is used in formaldehyde production. The second largest use is the production of MTBE, of which more than 95% is used as an octane booster and as an oxygenate in gasoline (ICIS, 2018).

### **Olefins (ethylene and propylene) and Aromatics (benzene, toluene, and xylenes)**

The feedstock processing capacity for high value chemicals (HVCs) production in the EU28 was approximately 66,7 million tonnes, which represented about 16% of the global capacity (IEA, 2018). The nameplate capacity for petrochemicals production via steam cracking in 2019 can be found in Table 36 in Appendix B.

Despite the significant relevance of the European petrochemical sector worldwide, the production capacity of HVCs in Europe in the past 10 years was either constant or declining, especially for ethylene. This decline can be observed in Figure 60, which presents the nameplate capacity figures since 2009 for EU15 and Norway. Other regions of the world such as North America, Middle East and Pacific Asia present the opposite tendency to produce these products (IEA, 2018).

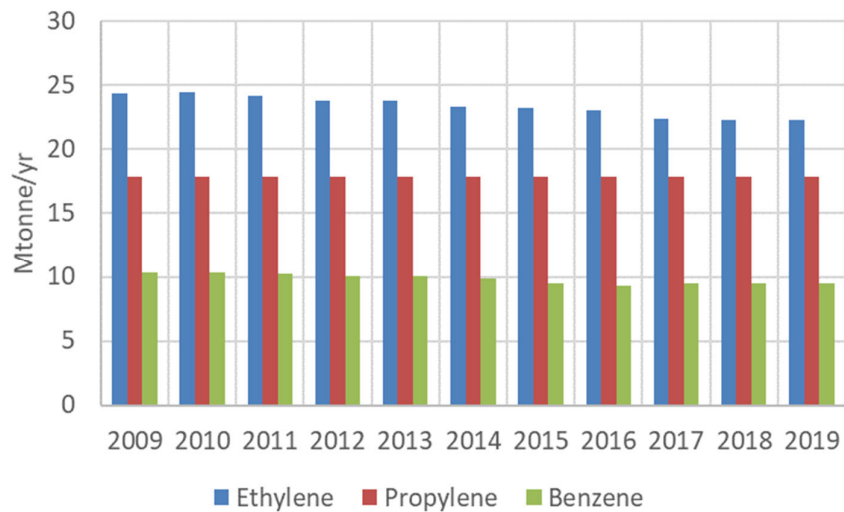


Figure 60 Nameplate capacity progression for ethylene, propylene and benzene in EU15 + Norway from 2009 until 2019 (Petrochemicals Europe, 2020b)

### *Ethylene*

Ethylene is mainly used as a monomer in polymerization processes. In 2019, polyethylene polymers accounted for approximately 60% of the ethylene usage in the EU15+Norway (Petrochemicals Europe, 2020b). Data from Petrochemicals Europe (2020b) indicates that both supply and demand comprise around 90% of the production capacity for the EU15+Norway group. Also, for the past 5 years, the supply was slightly higher than the demand, but both present remarkably similar fluctuation. Figure 61 shows the production volumes for the past 8 years for ethylene in the EU. This figure also presents the export<sup>14</sup> and import volumes of ethylene. An estimation of consumption, also known as apparent consumption (EUROSTAT, 2008), can be made by calculating production + imports – exports. The EU consumption of ethylene appears to be more or less equal to the production levels, around 0,5% to 3% of the ethylene production volumes correspond to exports and import of ethylene corresponds to around 25% to 60% of the production volume in the past 8 years.

<sup>14</sup> The exported figures may include goods that were produced or manufactured in the Netherlands, but also goods that were initially imported.

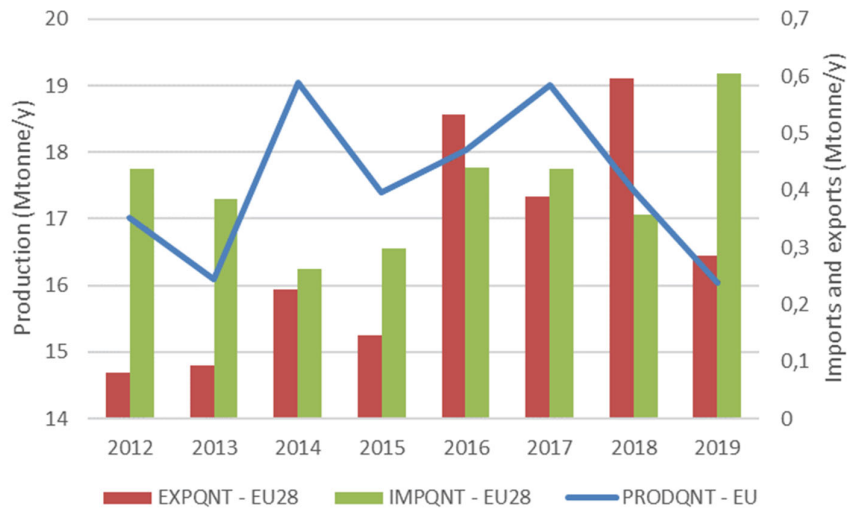


Figure 61 EU28 Ethylene production, import and export 2009-2019 (EUROSTAT, 2020)  
Source: (EUROSTAT, 2020), PRODCOM (PRCCODE 20141130 - Ethylene)

The ethylene production in the EU becomes less competitive due to both cheaper feedstock and energy costs offered by other regions. Feedstock costs can represent between 15% and 85% of the levelized production costs of HVCs, depending on the feedstock used (Figure 62). For instance, ethane became an attractive feedstock option due to the shale gas revolution in the United States. However, ethane crackers yield more ethylene, leading to low volumes of propylene and almost no aromatics. This fact gives an advantage to the steam cracker and methanol-to-olefins (MTO) processes. The European steam crackers use mainly naphtha as feedstock (around 70% in 2019), followed by LPG (27% in 2019) and ethane (6% in 2019) (Petrochemicals Europe, 2020b). In China, the MTO process plays an important role and its costs are lower than the HVC production in Europe. For the Middle East, both naphtha and energy costs are much lower than the European values. Since the levelized costs for ethylene are highly affected by the feedstock costs, the more competitive prices for naphtha in the Middle East and the expansion of ethane crackers in the US would influence the increase of the production of HVCs in these regions.

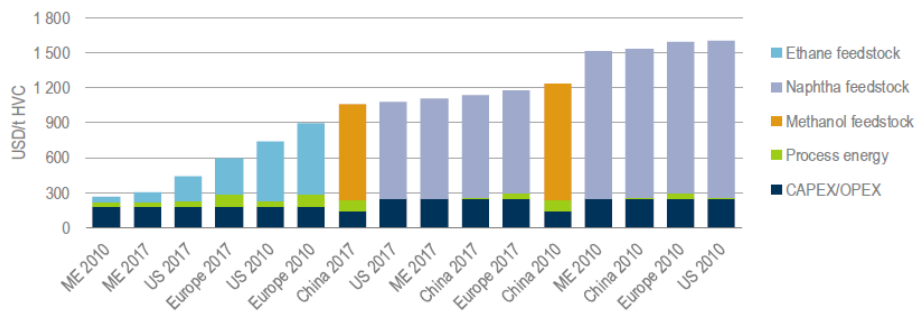


Figure 62 Levelized costs cost of HVCs for selected feedstocks and regions (IEA, 2018)

*Propylene*

Propylene can originate several products, such as polypropylene, acrylonitrile, propylene oxide and cumene. The plastic polypropylene is most relevant derivate product because it is responsible for around 58% of the total propylene demand in the EU15+Norway (Petrochemicals Europe, 2020b).

Similarly to ethylene, propylene supply is close to the demand in Europe, the demand was around 2% higher than the supply in the last 3 years. However, the nameplate capacity is constant already for 15 years (Petrochemicals Europe 2020b). The distinction between the nameplate capacity of propylene and ethylene could be explained by the fact that the shale gas availability and low cost in the US affected the European propylene market less. Steam crackers with gas feedstock present lower production yield to produce propylene when compared to naphtha steam crackers, therefore, the effect of the shale gas in the US was lower than to ethylene production. Besides, the diversity of processes to produce this chemical is higher in Europe. Around 30% of the total propylene produced in the continent is prevented from sources other than steam crackers. This aspect allows more flexibility at the European propylene market, which could, for instance, minimize the effects from the naphtha price fluctuation.

Figure 63 shows the propylene production, import and export volumes for the EU28 between 2009 and 2019. The yearly production figures range from 12 to 14 Mt/yr and both 2018 and 2019 presented the lowest values in the presented timeframe. The drop could be explained by similar reasons already explored in the ethylene section; however, the reduction rate is less intensive for propylene (3% yearly) when compared to ethylene (8% yearly).

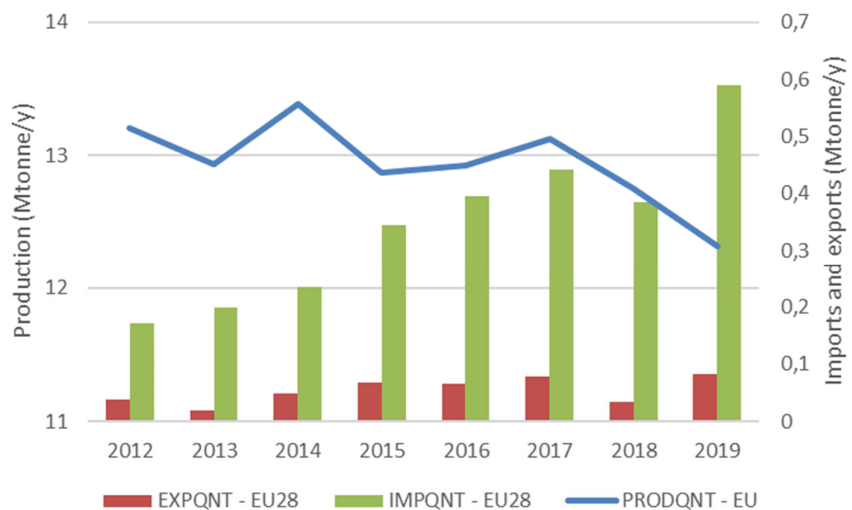


Figure 63 EU28 Propylene production, import and export 2009-2019 (EUROSTAT, 2020)  
 Source:(EUROSTAT, 2020) (PRCCODE 20141140 - Propene [propylene])

### *Benzene, toluene and xylenes (BTX)*

Benzene is one of the main aromatics products in the chemical industry. It is commercialized not only as a final product, but also as an intermediary for the production of other relevant chemicals, such as ethylbenzene, cyclohexane, nitrobenzene and cumene.

Aromatics processes use three main feedstocks: refinery reformates, steam cracker pyrolysis gasoline (pygas) and benzene from coal tar processing. For benzene production in the EU15+Norway, around 50% is via pygas, 40% from reformat and the remaining 10% via coal (Petrochemicals Europe, 2020). Both steam crackers and refineries can choose whether to produce or not aromatics depending on its market price. For instance, for steam crackers, the aromatic fraction can be kept in the pyrolysis gasoline.

Figure 64 shows the production volumes of aromatics in the EU28 and, as expected, benzene presents the highest values when compared to xylene and toluene. The supply varies between 6-7 Mt/yr for benzene, 1-2 Mt/yr for toluene and 0,2-1 Mt/yr for xylene in the timeframe presented.

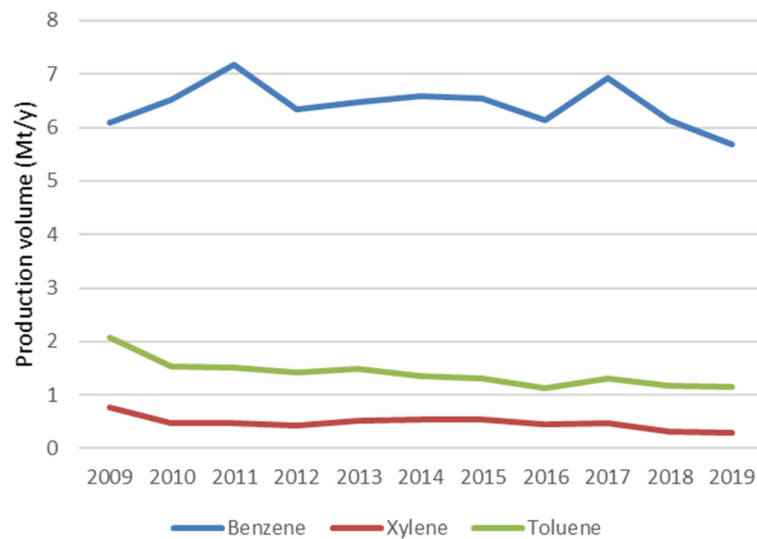


Figure 64 EU28 Benzene, toluene and xylene production 2009-2019 (EUROSTAT, 2020)  
Source: (EUROSTAT, 2020), PRODCOM (PRCCODE 20141223 Benzene, 20141225 Toluene, 20141243/45/47 Xylenes combined)

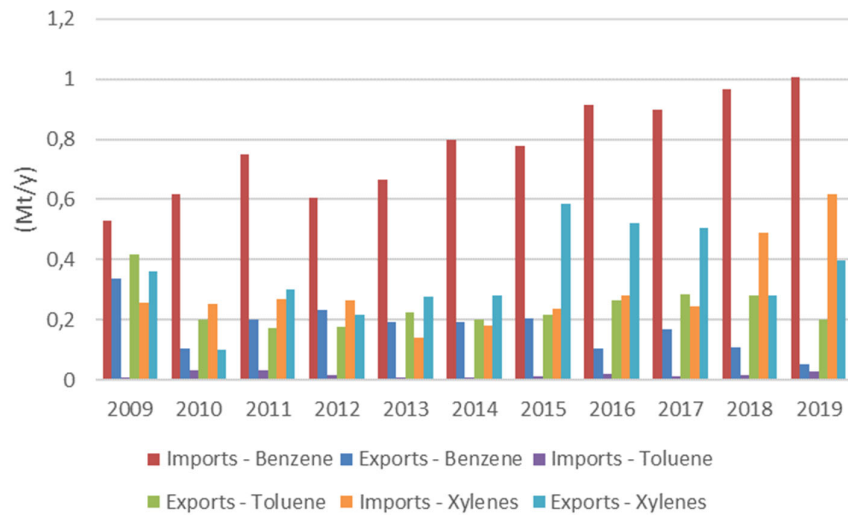


Figure 65 EU28 Aromatics trade volumes 2009-2019 (EUROSTAT 2020)  
 Source: (EUROSTAT, 2020), PRODCOM (PRCCODE 20141223 Benzene, 20141225 Toluene, 20141243/45/47 Xylenes combined)

### Butadienes (2-methyl-1,3-butadiene and buta-1,3-diene)

Butadiene production in the EU28 is kept between 2,5-3 Mt/yr and decreased 6% in 2019, compared to 2018 value (Figure 66). The ethylene market influences the butadiene production directly because butadienes are mainly obtained as a by-product from steam crackers. Therefore, when the demand for ethylene reduces, the butadienes production decreases as well.

The demand for butadiene is reducing at the moment because of the depression of the automotive industry, which is causing lower demand for the derivative synthetic rubber (SBR) and there is an expectation that there might be an oversupply of butadiene in the European market<sup>15</sup> (S&P Global Platts, 2020).

<sup>15</sup> Around 90% of the butadiene transactions in Europe are handled via contracts and butadiene buyers are willing to reduce contractual volumes in 2020. However, sellers are pushing for long term deals to minimize the volumes reduction in contract deals.

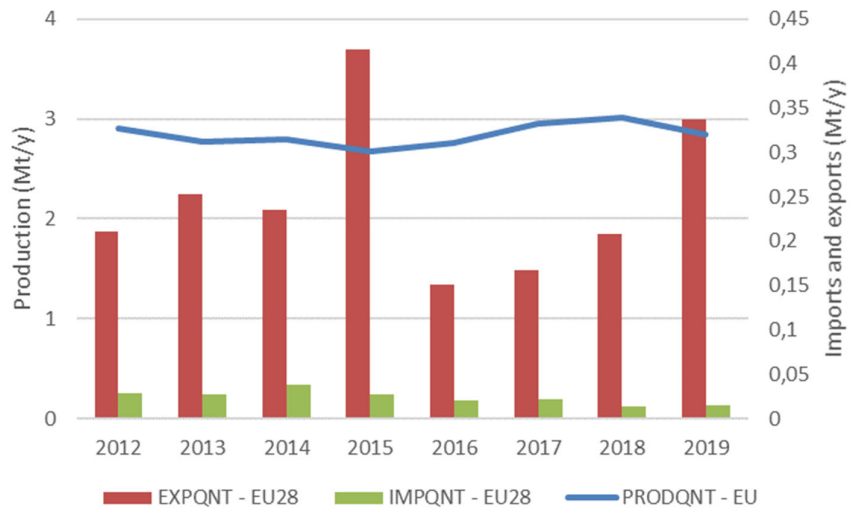


Figure 66 EU28 Butadienes production and trade volumes 2009-2019 (EUROSTAT 2020 Source: (EUROSTAT 2020), PRODCOM (PRCCODE 20141160 Buta-1,3-diene and isoprene)

*Production of ethylene, propylene, butadiene, and aromatics in the Netherlands*

The petrochemical sector in the Netherlands is defined by three industrial sites: Shell Moerdijk, located nearby the Rotterdam port; Dow Terneuzen, close to the Zeeland Refinery and SABIC Geleen, the closest to both Germany and Belgium borders. The Netherlands steam cracking capacity accounts for approximately 3% globally and for 18% of the total EU28 capacity.

The intake of feedstocks (in mass) for the petrochemical sector in 2019 corresponded to 49% for naphtha, 24% for LPG and 25% for aromatics feedstocks. The remaining 2% related to other fossil feedstocks, such as heavy oil (CBS, 2020a).



Figure 67 Steam crackers locations in the Netherlands (Google maps, 2020)

Figure 68, Figure 69 and Figure 70 present the production, import and export volumes for ethylene, propylene, butadienes and benzene in the Netherlands for the past years. No specific information for xylenes and toluene Dutch production was available. The variation in the production volumes for the olefins products in the past 2 years was higher for the Netherlands when compared to the total EU28 region (7-20% compared to 3-8%). For benzene, the production shows slightly lower variation than the EU28 numbers (1-9% facing 7-11%). The Netherlands is known for being a relevant ethylene trader, being in the top 3 ethylene exporter worldwide in 2016 (IEA, 2018). The ethylene export from Netherlands represented in 2018 around 16% (1.44 BillionUSD) of the total trading value related to this chemical (OEC, 2020). The main destination of ethylene, propylene and butadienes are to other EU countries, (see Figure 72, Figure 73, Figure 74 ). The imports volumes also come mainly from EU countries. Ethylene is an intermediary product and its transport is done primarily via pipelines, therefore, it is reasonable that the trade destinations from and to the Netherlands are located in the EU.

Similarly to the olefins case, the butadienes trading flows for the Netherlands are higher than the ones from the EU28 (Figure 70). The butadienes trading flows from and to the Netherlands show similar behaviour to those regarding the olefins. Both Dutch imports and exports of butadienes are mainly originated/destinated to EU countries. The Dutch exports are around 7 times higher than the imports of this chemical for the observed period, compoment that is in line with the oversupply tendency observed for this chemical.

The Dutch trade market for benzene shows a different behaviour than the EU's. The imported volumes to the Netherlands have been reducing since 2017 and the exports were around 23% higher than the imports for the observed period.

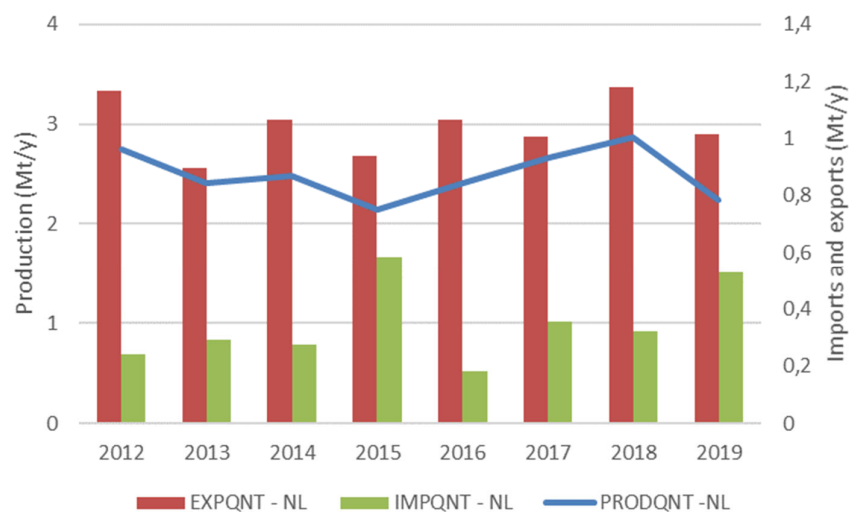


Figure 68 Production, import and export volumes in the Netherlands between 2012-2019 for ethylene (EUROSTAT 2020)



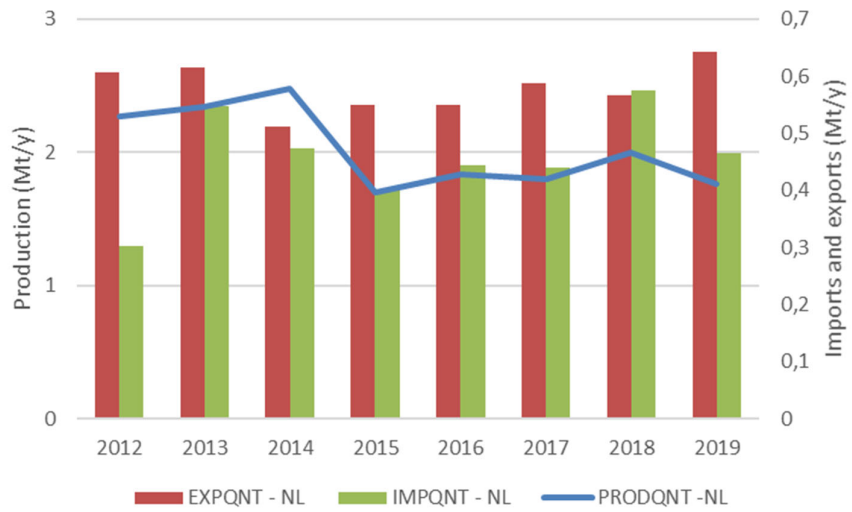


Figure 69 Production, import and export volumes in the Netherlands between 2012-2019 for propylene (EUROSTAT 2020)

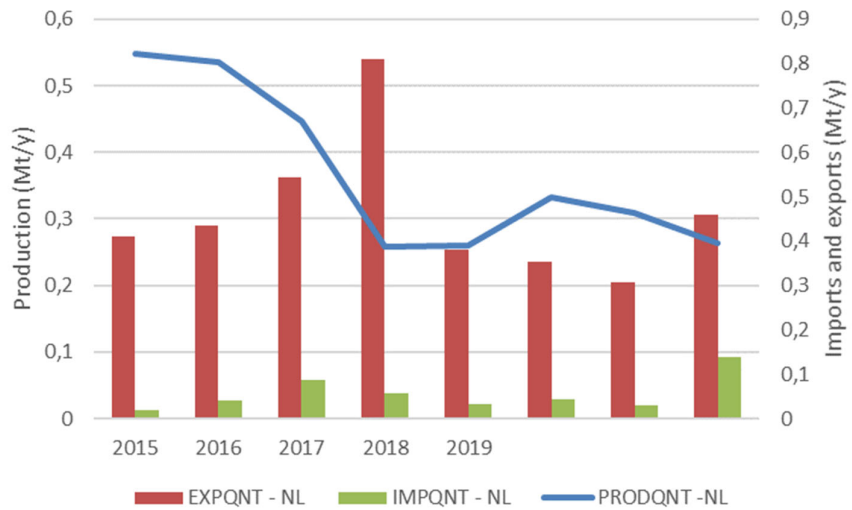


Figure 70 Production volumes in the Netherlands between 2012-2019 for butadienes (EUROSTAT 2020)

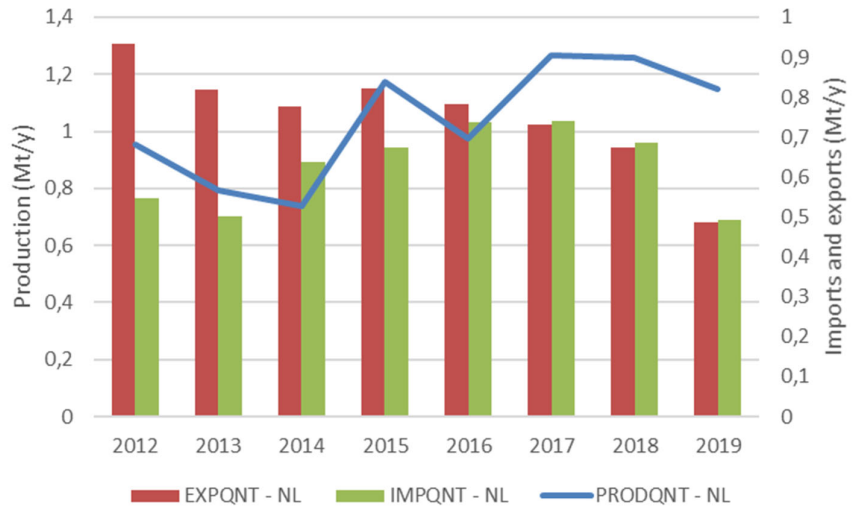


Figure 71 Production volumes in the Netherlands between 2012-2019 for benzene (EUROSTAT 2020)

*Ethylene, propylene and butadiene's trade volumes for the Netherlands*

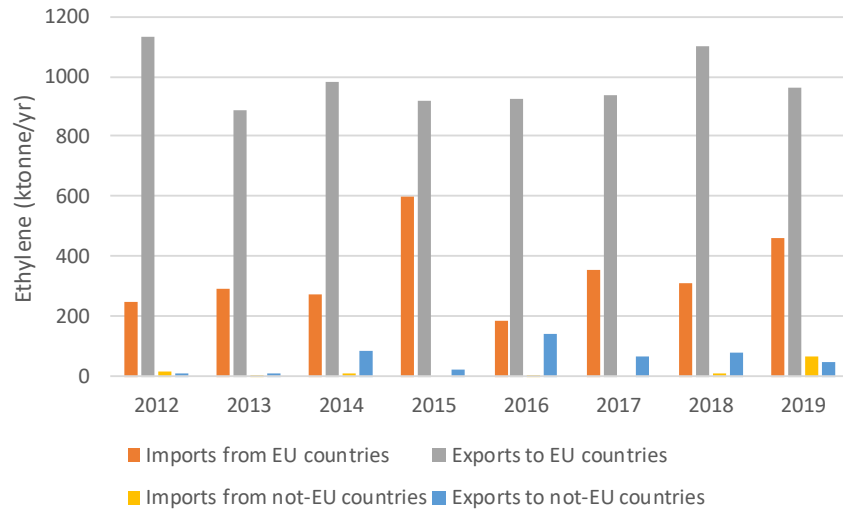


Figure 72 Detailed ethylene trade volumes for the Netherlands 2012-2019 (CBS, 2020)

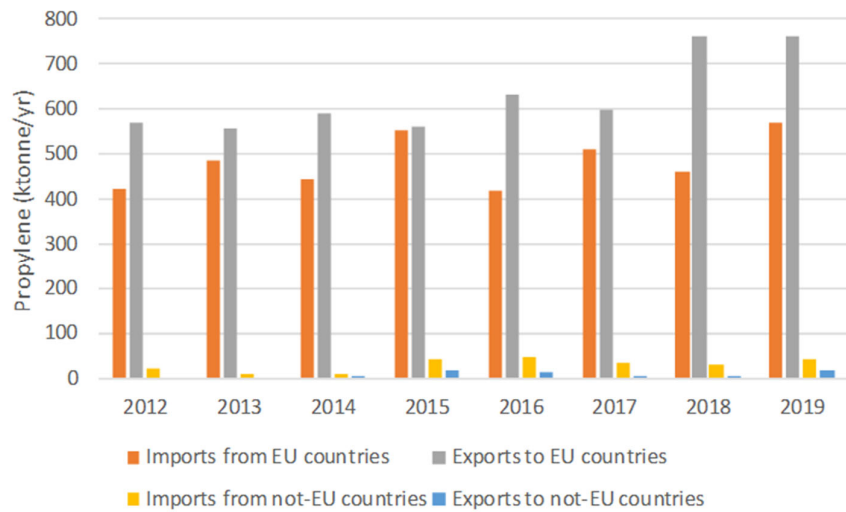


Figure 73 Detailed propylene trade volumes for the Netherlands 2012-2019 (CBS, 2020)

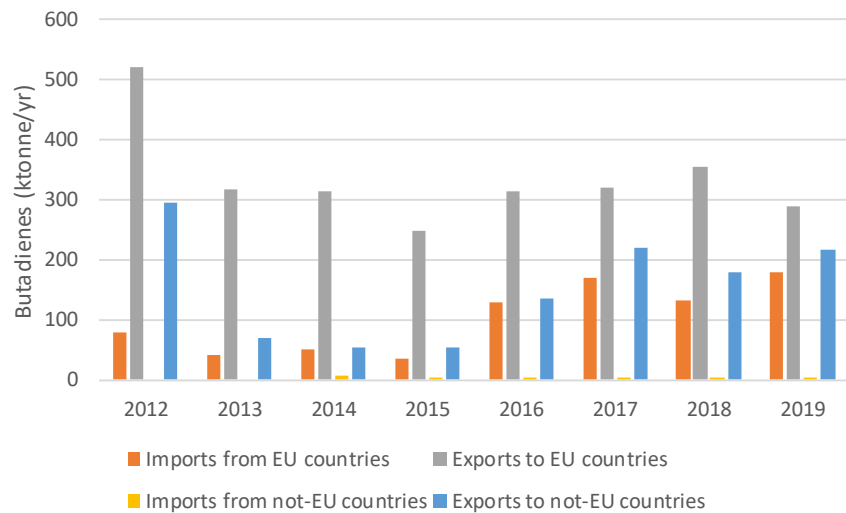


Figure 74 Detailed butadienes trade volumes for the Netherlands 2012-2019 (CBS, 2020)

*Methanol sector in the Netherlands*

In the Netherlands, there is only one methanol production site, BioMCN, which is located in Delfzijl industrial park. Currently, the site uses both fossil and bio-feedstock for the production of methanol, being the fossil share larger. There is no information on production volumes in the statistics database, however, literature indicates that the nameplate capacity of this site is around 425 kt/yr. The company has plans to expand its bio-methanol production for the next years.

A consortium of companies composed by Air Liquide, AkzoNobel Specialty Chemicals, Enerkem and the Port of Rotterdam has signed a project development agreement to start the development of an advanced waste-to-chemistry facility in Rotterdam. The goal of this new facility is to convert non-recyclable waste into valuable chemicals, being methanol one of the targeted products. The methanol production would occur via gasification of waste (AkzoNobel, 2018)

Figure 75 shows the import and export volumes of methanol for the Netherlands. Furthermore, Figure 76 presents the detailed trade flows from Netherlands to the EU and outside. It is noticeable that the majority of the export is within the EU, showing the significant role of the Netherlands in meeting the demand within the EU.



Figure 75 Methanol trade volumes for the Netherlands and EU28 2012-2019 (EUROSTAT 2020)

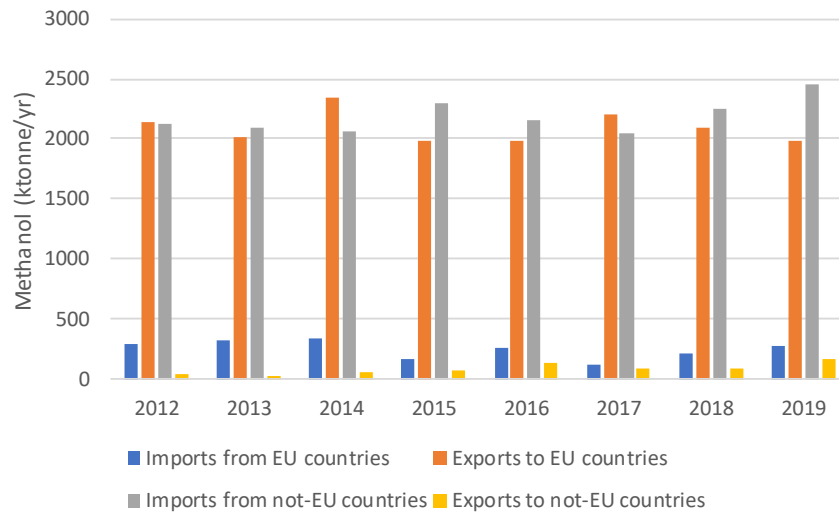


Figure 76 Detailed methanol trade volumes for the Netherlands 2012-2019 (CBS, 2020b)

## C EU name plate capacity

Table 36 EU28 nameplate capacity in 2017 (Petrochemicals Europe, 2020)

Location	Operator	Capacity ethylene kta (2017)	Capacity feedstock kta (2017) <sup>1)</sup> Calculated	Capacity propylene kta (2017) <sup>1)</sup> Calculated	Capacity benzene kta (2017) <sup>1)</sup> calculated	Capacity butadiene kta (2017) <sup>1)</sup> Calculated
AUSTRIA						
Schwechat	OMV	500	1539	229	120	55
BENELUX						
Antwerp	TOA	550	1693	252	131	61
Antwerp	TOA	610	1877	279	146	67
Antwerp	BASF	1080	3324	494	258	119
Geleen	Sabic Europe	1310	4031	599	313	144
Moerdijk	Shell	910	2800	416	218	100
Terneuzen	Dow	565	1739	258	135	62
Terneuzen	Dow	580	1785	265	139	64
Terneuzen	Dow	680	2093	311	163	75
FINLAND						
Porvoo	Borealis	400	1231	183	96	44
FRANCE						
Berre (Aubette)	LyondellBasell	470	1446	215	112	52
Dunkerque	Versalis	380	1169	174	91	42
Feyzin	A.P. Feyzin	250	769	114	60	28
Gonfreville	Total	525	1616	240	126	58
Lavera	Naphtachimie	740	2277	338	177	81
NDG	ExxonMobil	425	1308	194	102	47
GERMANY						
Boehlen	Dow	565	1739	258	135	62
Burghausen	OMV	450	1385	206	108	50
Gelsenkirchen	BP	1073	3302	491	257	118
Heide	Klesch	110	339	50	26	12
K-Worringen	Ineos Olefins	946	2911	433	226	104
Ludwigshafen	BASF	220	677	101	53	24
Ludwigshafen	BASF	400	1231	183	96	44
Munchmunster	LyondellBasell	400	1231	183	96	44
Wesseling	LyondellBasell	305	939	139	73	34
Wesseling	LyondellBasell	735	2262	336	176	81
Wesseling	Shell	310	954	142	74	34

Location	Operator	Capacity ethylene kta (2017)	Capacity feedstock kta (2017) <sup>1)</sup> Calculated	Capacity propylene kta (2017) <sup>1)</sup> Calculated	Capacity benzene kta (2017) <sup>1)</sup> calculated	Capacity butadiene kta (2017) <sup>1)</sup> Calculated
ITALY						
Brindisi	Versalis	440	1354	201	105	48
Priolo	Versalis	490	1508	224	117	54
Porto Marghera	Versalis	490	1508	224	117	54
PORTUGAL						
Sines	Repsol	410	1262	188	98	45
SPAIN						
Puertollano	Repsol	102	314	47	24	11
Tarragona	Repsol	702	2160	321	168	77
Tarragona	Dow	675	2077	309	161	74
SWEDEN						
Stenungsund	Borealis	625	1923	286	149	69
UK						
Grangemouth	Ineos Olefins	700	2154	320	167	77
Fife	ExxonMobil / Shell	770	2370	352	184	85
Wilton	Sabir UK	865	2662	396	207	95
	TOTAL EU28	21758	66956	9951	5201	2394

<sup>(1)</sup> Calculation based on the average feed distribution in Europe between LPG, Naphtha and ethane (Petrochemicals Europe, 2020) and product yields from conventional steam cracker process (JRC, 2017)

## D Biomass cost/price estimates

Table 37 EU average road-side cost estimates for the different feedstock supply options

<b>Miscanthus</b>	Price (€/GJ)	3	6	13.5
	Share (% of total potential)	70%	24%	16%
<b>Switchgrass</b>	Price (€/GJ)	3.8	7.8	12.5
	Share (% of total potential)	85%	13%	2%
<b>Reed canary</b>	Price (€/GJ)	3	4.5	10
	Share (% of total potential)	86%	9%	5%
<b>SRC Willow</b>	Price (€/GJ)	3	4	6.5
	Share (% of total potential)	85%	10%	5%
<b>SRC poplar</b>		2.5		
		100%		
<b>Sugarbeet leaves and beet</b>	Price (€/GJ)	27%	71%	3%
	Share (% of total potential)	2.2	4.4	7.8
<b>Primary forest residues</b>	Price (€/GJ)	1.8	3.1	4.8
	Share (% of total potential)	80%	19%	1%
<b>wood chips from stemwood</b>	Price (€/GJ)	3	6	4
	Share (% of total potential)	70%	13%	23%
<b>Straw</b>	Price (€/GJ)	7.5	3	
	Share (% of total potential)	5%	40%	55%1.8
<b>Verge grass</b>	Price (€/GJ)	2.5	4.4	
	Share (% of total potential)	40%	60%	
<b>Other biomass feedstocks</b>				
<b>Manure(solid)</b>	Price (€/GJ)	2		
<b>Manure liquid</b>	Price (€/GJ)	0		
<b>1G crops</b>	Price (€/GJ)	16		
<b>Forage maize</b>	Price (€/GJ)	2		

## E Description of processing routes and data for CAPEX estimations

Table 38 Pathways description and references used to build mass and energy balances

Building block	Pathway type	Pathway name	Description – Steps involved	References Mass & Energy balances calculations
Methanol	Bio-based	B1. Methanol via biogas	Biogas production from biomass Syngas production from biogas Conversion of syngas into methanol	Biomass to biogas production (Moncada et al., 2018b) Biogas to methanol (Sheets and Shah, 2018)(Ghosh et al., 2019)
	Bio-based	B2. Methanol via gasification	Gasification of biomass into syngas Syngas conversion into methanol	Biomass to methanol (Carvalho et al., 2017; Yang et al., 2018)
	e-based	E1. Methanol via alkaline electrolysis	Water electrolysis (using green electricity) into hydrogen Hydrogen and CO <sub>2</sub> conversion into methanol	Hydrogen production step (Detz et al., 2018) Methanol production step (Nyári et al., 2020)
	e-based	E2. Methanol via solid oxide electrolyser (SOE) cell co-electrolysis	Water and CO <sub>2</sub> co-electrolysis into syngas (using green electricity) Syngas conversion into methanol	CO <sub>2</sub> to Methanol (including electrolysis)(Zhang and Desideri, 2020)
DME	bio-based	B3. DME indirect production via methanol from biogas	Biogas production from biomass Syngas production from biogas Conversion of syngas into methanol Conversion of methanol into DME	Biomass to biogas production (Moncada et al., 2018b) Biogas to methanol (Sheets and Shah, 2018)(Ghosh et al., 2019) Methanol to DME (Tunã and Hulteberg, 2014)
	bio-based	B4. DME indirect production via methanol from gasification	Gasification of biomass into syngas Syngas conversion into methanol Conversion of methanol into DME	Biomass to methanol (Carvalho et al., 2017; Yang et al., 2018) Methanol to DME (Tunã and Hulteberg, 2014)
	bio-based	B5. DME direct production via syngas from biogas	Biogas production from biomass Syngas production from biogas Conversion of syngas into DME	Biomass to biogas production (Moncada et al., 2018b) Biogas to syngas (de França Lopes et al., 2020) Syngas to DME (de França Lopes et al., 2020)



Building block	Pathway type	Pathway name	Description – Steps involved	References Mass & Energy balances calculations
	bio-based	B6. DME direct production via syngas from gasification	Gasification of biomass into syngas Syngas conversion into DME	Biomass to syngas (Wan et al., 2013) Syngas to DME (de França Lopes et al., 2020)
	e-based	E3. DME indirect production via methanol. Alkaline electrolysis	Water electrolysis (using green electricity) into hydrogen Hydrogen and CO <sub>2</sub> conversion into methanol Conversion of methanol into DME	Hydrogen production step (Detz et al., 2018) Methanol production step (Nyári et al., 2020) Methanol to DME (Tunã and Hulteberg, 2014)
	e-based	E4. DME indirect production via methanol. SOE co electrolysis	Water and CO <sub>2</sub> co-electrolysis into syngas (using green electricity) Syngas conversion into methanol Conversion of methanol into DME	CO <sub>2</sub> to Methanol (including electrolysis)(Zhang and Desideri, 2020) Methanol to DME (Tunã and Hulteberg, 2014)
	e-based	E5. DME direct production via syngas. SOE co-electrolysis	Water and CO <sub>2</sub> co-electrolysis into syngas (using green electricity) Syngas conversion into DME	Co-electrolysis of water and CO <sub>2</sub> to syngas (Zhang and Desideri, 2020) Syngas to DME (de França Lopes et al., 2020)
Olefins (standalone ethylene)	bio-based	B7. Ethylene production via 1G ethanol	1G ethanol production from sugar beets Conversion of ethanol into ethylene	Sugar beets to ethanol (Edwards, R.; O'Connell, A.; Padella, M.; Giuntoli, J.; Koeble, R.; Bulgheroni, C.; Marelli, L. Lonza, 2019) Ethanol to ethylene (Nitzsche et al., 2016)
	bio-based	B8. Ethylene production via 2G ethanol. Dilute acid pre-treatment	2G ethanol production using dilute acid pre-treatment Conversion of ethanol into ethylene	Lignocellulosic biomass to ethanol (FAO, 2020a) Ethanol to ethylene (Nitzsche et al., 2016)
	bio-based	B9. Ethylene production via 2G ethanol. Steam explosion pre-treatment	2G ethanol production using steam explosion pre-treatment Conversion of ethanol into ethylene	Lignocellulosic biomass to ethanol (FAO, 2020a) Ethanol to ethylene (Nitzsche et al., 2016)
	bio-based	B10. Ethylene production via 2G ethanol. Dilute acid pre-treatment	2G ethanol production using organosolv pre-treatment Conversion of ethanol into ethylene	Lignocellulosic biomass to ethylene (Nitzsche et al., 2016)
Olefins (mainly ethylene and propylene)	bio-based	B11. Olefins production via methanol to olefins. Methanol produced from biogas	Biogas production from biomass Syngas production from biogas Conversion of syngas into methanol Conversion of methanol into olefins	Biomass to biogas production (Moncada et al., 2018b) Biogas to methanol (Sheets and Shah, 2018)(Ghosh et al., 2019)

Building block	Pathway type	Pathway name	Description – Steps involved	References Mass & Energy balances calculations
				Methanol to olefins (Zhao et al., 2021)
	bio-based	B12. Olefins production via methanol to olefins. Methanol produced from gasification	Gasification of biomass into syngas Syngas conversion into methanol Conversion of methanol into olefins	Biomass to methanol (Carvalho et al., 2017; Yang et al., 2018) Methanol to olefins (Zhao et al., 2021)
	e-based	E6. Olefins production via methanol to olefins. Methanol produced via alkaline electrolysis	Water electrolysis (using green electricity) into hydrogen Hydrogen and CO <sub>2</sub> conversion into methanol Conversion of methanol into olefins	Hydrogen production step (Detz et al., 2018) Methanol production step (Nyári et al., 2020) Methanol to olefins (Zhao et al., 2021)
	e-based	E7. Olefins production via methanol to olefins. Methanol produced via SOEC	Water and CO <sub>2</sub> co-electrolysis into syngas (using green electricity) Syngas conversion into methanol conversion of methanol into olefins	CO <sub>2</sub> to Methanol (including electrolysis)(Zhang and Desideri, 2020) Methanol to olefins (Zhao et al., 2021)
	bio-based	B13. Olefins production via DME. DME direct production from biogas	Biogas production from biomass Syngas production from biogas Conversion of syngas into DME DME conversion into olefins	Biomass to biogas production (Moncada et al., 2018b) Biogas to syngas (de França Lopes et al., 2020) Syngas to DME (de França Lopes et al., 2020) DME to olefins (Haro et al., 2013)
	bio-based	B14. Olefins production via DME. DME direct production via gasification	Gasification of biomass into syngas Syngas conversion into DME DME conversion into olefins	Biomass to syngas (Wan et al., 2013) Syngas to DME (de França Lopes et al., 2020) DME to olefins (Haro et al., 2013)
	e-based	E8. Olefins production via DME. DME direct production via SOE co-electrolysis	Water and CO <sub>2</sub> co-electrolysis into syngas (using green electricity) Syngas conversion into DME DME conversion into olefins	Co-electrolysis of water and CO <sub>2</sub> to syngas (Zhang and Desideri, 2020) Syngas to DME (de França Lopes et al., 2020) DME to olefins (Haro et al., 2013)
	Bio-based	B15. Olefins production via Fischer Tropsch. Biomass gasification	Gasification of biomass into syngas Syngas conversion into olefins	Biomass to syngas (Wan et al., 2013) Syngas to olefins (Zhao et al., 2021),(Liu et al., 2020)

Building block	Pathway type	Pathway name	Description – Steps involved	References Mass & Energy balances calculations
	e-based	E9. Olefins production via Fischer Tropsch. SOE co-electrolysis	Water and CO <sub>2</sub> co-electrolysis into syngas (using green electricity) Syngas conversion into olefins	Co-electrolysis of water and CO <sub>2</sub> to syngas (Zhang and Desideri, 2020) Syngas to olefins (Zhao et al., 2021),(Liu et al., 2020)
Olefins (mainly propylene)	bio-based	B16. Propylene via methanol to propylene. Methanol produced from biogas	Biogas production from biomass Syngas production from biogas Conversion of syngas into methanol Conversion of methanol into propylene	Biomass to biogas production (Moncada et al., 2018b) Biogas to methanol (Sheets and Shah, 2018)(Ghosh et al., 2019) Methanol to propylene (Zhao et al., 2021)
	bio-based	B17. Propylene via methanol to propylene. Methanol produced from gasification	Gasification of biomass into syngas Syngas conversion into methanol Conversion of methanol into propylene	Biomass to methanol (Carvalho et al., 2017; Yang et al., 2018) Methanol to propylene (Zhao et al., 2021)
	e-based	E9. Propylene via methanol to propylene. Methanol produced via alkaline electrolysis	Water electrolysis (using green electricity) into hydrogen Hydrogen and CO <sub>2</sub> conversion into methanol Conversion of methanol into propylene	Hydrogen production step (Detz et al., 2018) Methanol production step (Nyári et al., 2020) Methanol to propylene (Zhao et al., 2021)
	e-based	E10. Propylene via methanol to propylene. Methanol produced via SOEC	Water and CO <sub>2</sub> co-electrolysis into syngas (using green electricity) Syngas conversion into methanol conversion of methanol into propylene	CO <sub>2</sub> to Methanol (including electrolysis)(Zhang and Desideri, 2020) Methanol to propylene (Zhao et al., 2021)
Olefins (mainly butadiene)	bio-based	B18. Butadiene production via 1G ethanol	1G ethanol production from sugar beets Conversion of ethanol into butadiene	Sugar beets to ethanol (Edwards, R.; O'Connell, A.; Padella, M.; Giuntoli, J.; Koeble, R.; Bulgheroni, C.; Marelli, L. Lonza, 2019) Ethanol to butadiene (Moncada et al., 2018a)
	bio-based	B19. Butadiene production via 2G ethanol. Dilute acid pre-treatment	2G ethanol production using dilute acid pre-treatment Conversion of ethanol into butadiene	Lignocellulosic biomass to ethanol (FAO, 2020a) Ethanol to butadiene (Moncada et al., 2018a)
	bio-based	B20. Butadiene production via 2G ethanol. Steam explosion pre-treatment	2G ethanol production using steam explosion pre-treatment Conversion of ethanol into butadiene	Lignocellulosic biomass to ethanol (FAO, 2020a) Ethanol to butadiene (Moncada et al., 2018a)

Building block	Pathway type	Pathway name	Description – Steps involved	References Mass & Energy balances calculations
	bio-based	B21. Butadiene production via 2G ethanol. Dilute acid pre-treatment	2G ethanol production using organosolv pre-treatment Conversion of ethanol into butadiene	Lignocellulosic biomass to ethanol (Nitzsche et al., 2016) Ethanol to butadiene (Moncada et al., 2018a)
Olefins & BTX (via pyrolysis) <sup>a</sup>	bio-based	B22. Olefins & BTX production, biomass pyrolysis and downstream processing of WSBO and WIBO <sup>b</sup>	Pyrolysis of biomass Olefins and BTX recovery from bio-oil mixture	Biomass to BTX and Olefins (Sharifzadeh et al., 2015)
	bio-based	B23. Olefins & BTX production, biomass pyrolysis and downstream processing of WSBO and WIBO. One step hydrogenation	Pyrolysis of biomass One step hydrogenation of WSBO & WIBO mixture Olefins and BTX recovery from hydrogenated bio-oil	Biomass to BTX and Olefins (Sharifzadeh et al., 2015)
	bio-based	B24. Olefins & BTX production, biomass pyrolysis and downstream processing of WSBO	Pyrolysis of biomass Olefins and BTX recovery from WSBO fraction	Biomass to BTX and Olefins (Sharifzadeh et al., 2015)
	bio-based	B25. Olefins & BTX production, biomass pyrolysis and downstream processing of WSBO. One step hydrogenation	Pyrolysis of biomass One step hydrogenation of WSBO fraction Olefins and BTX recovery from hydrogenated WSBO	Biomass to BTX and Olefins (Sharifzadeh et al., 2015)
	bio-based	B26. Olefins & BTX production, biomass pyrolysis and downstream processing of WSBO. Two step hydrogenation	Pyrolysis of biomass Two step hydrogenation of WSBO fraction Olefins and BTX recovery from hydrogenated WSBO	Biomass to BTX and Olefins (Sharifzadeh et al., 2015)

<sup>a</sup> Olefins and BTX are produced simultaneously from pyrolytic oil.

<sup>b</sup> WSBO: Water soluble bio-oil, WIBO: Water insoluble bio-oil.

Table 39 Capital cost reference costs and sources broken down by process sections.

Pathway	Element of capex/ process section	Base Cost, M€	Base year	Capacity parameter	Base case capacity value	Reference
B1.	Biomass to biogas (Anaerobic digestion)	54	2012	Biomass input	200 kt/y	(Rajendran and Murthy, 2019)
	Biogas to syngas (SMR)	110	2006	Gas input	1187 kt/y	(NREL; Nexant, 2006)
	Syngas to methanol (conversion and separation)	80	2010	Methanol output	200 kt/y	(NREL; Nexant, 2006)
B2.	Biomass to syngas (gasification)	250	2010	Methanol output	200 kt/y	(NREL; Nexant, 2006)
	Syngas to methanol (conversion and separation)	80	2010	Methanol output	200 kt/y	(NREL; Nexant, 2006)
E1.	Water electrolysis	10	2019	Electricity input	10 MW	(Detz et al., 2018)
	Methanol production (including conversion and separation)	382	2017	Methanol output	1670 kt/y	(Nyári et al., 2020)
E2.	CO <sub>2</sub> and water co-electrolysis	19.4	2019	Electricity input	10 MW	(Detz et al., 2018)
	Syngas to methanol (conversion and separation)	80	2010	Methanol output	200 kt/y	(NREL; Nexant, 2006)
B3.	Biomass to Methanol	Same elements described for B1 pathway				
	Methanol to DME (including separation)	22	2011	DME output	212 kt/y	(Tunå and Hulteberg, 2014)
B4.	Biomass to Methanol	Same elements described for B2 pathway				
	Methanol to DME (including separation)	22	2011	DME output	212 kt/y	(Tunå and Hulteberg, 2014)
B5.	Biomass to biogas (Anaerobic digestion)	54	2012	Biomass input	200 kt/y	(Rajendran and Murthy, 2019)
	Biogas to syngas (SMR)	110	2006	Gas input	1187 kt/y	(NREL; Nexant, 2006)
	Syngas to DME (including separation)	42	2017	DME output	333 kt/y	(de França Lopes et al., 2020)

Pathway	Element of capex/ process section	Base Cost, M€	Base year	Capacity parameter	Base case capacity value	Reference
B6.	Biomass to syngas (gasification)	250	2010	Methanol output	200 kt/y	(NREL; Nexant, 2006)
	Syngas to DME (including separation)	42	2017	DME output	333 kt/y	(de França Lopes et al., 2020)
E3.	CO <sub>2</sub> to Methanol	Same elements described for E1 pathway				
	Methanol to DME (including separation)	22	2011	DME output	212 kt/y	(Tunã and Hulteberg, 2014)
E4.	CO <sub>2</sub> to Methanol	Same elements described for E2 pathway				
	Methanol to DME (including separation)	22	2011	DME output	212 kt/y	(Tunã and Hulteberg, 2014)
E5.	CO <sub>2</sub> and water co-electrolysis	19.4	2019	Electricity input	10 MW	(Detz et al., 2018)
	Syngas to DME (including separation)	42	2017	DME output	333 kt/y	(de França Lopes et al., 2020)
B7.	Biomass to ethanol (including separation)	38	2014	Ethanol output	78.9 kt/y	(FAO, 2020b)
	Ethanol to ethylene (including separation)	28	2014	Ethylene output	41.6 kt/y	(Nitzsche et al., 2016)
B8.	Biomass to ethanol (including separation and CHP plant)	159	2014	Ethanol output	78.9 kt/y	(FAO, 2020a)
	Ethanol to ethylene (including separation)	28	2014	Ethylene output	41.6 kt/y	(Nitzsche et al., 2016)
B9.	Biomass to ethanol (including separation and CHP plant)	163	2014	Ethanol output	78.9 kt/y	(FAO, 2020a)
	Ethanol to ethylene (including separation)	28	2014	Ethylene output	41.6 kt/y	(Nitzsche et al., 2016)
B10.	Biomass to ethylene (including separation, and CHP plant)	206	2014	Ethylene output	41.6 kt/y	(Nitzsche et al., 2016)
B11.	Biomass to Methanol	Same elements described for B1 pathway				
	Methanol to Olefins (including separation)	55	2013	Ethylene output	19.7 kt/y	(Mariano et al., 2013)
B12.	Biomass to Methanol	Same elements described for B2 pathway				
	Methanol to Olefins (including separation)	55	2013	Ethylene output	19.7 kt/y	(Mariano et al., 2013)
E6.	CO <sub>2</sub> to Methanol	Same elements described for E1 pathway				
	Methanol to Olefins (including separation)	55	2013	Ethylene output	19.7 kt/y	(Mariano et al., 2013)

Pathway	Element of capex/ process section	Base Cost, M€	Base year	Capacity parameter	Base case capacity value	Reference
E7.	CO <sub>2</sub> to Methanol			Same elements described for E2 pathway		
	Methanol to Olefins (including separation)	55	2013	Ethylene output	19.7 kt/y	(Mariano et al., 2013)
B13.	Biomass to DME			Same elements described for B5 pathway		
	DME to olefins (including separation)	192	2010	Ethylene output	132.8 kt/y	(Haro et al., 2013)
B14.	Biomass to DME			Same elements described for B6 pathway		
	DME to olefins (including separation)	192	2010	Ethylene output	132.8 kt/y	(Haro et al., 2013)
E8.	CO <sub>2</sub> to DME			Same elements described for E5 pathway		
	DME to olefins (including separation)	192	2010	Ethylene output	132.8 kt/y	(Haro et al., 2013)
B15.	Biomass to syngas (gasification)	250	2010	Biomass input	397 kt/y	(NREL; Nexant, 2006)
	Syngas to olefins (including separation)	77	2015	Ethylene output	132.8 kt/y	(Liu et al., 2020)
E9.	CO <sub>2</sub> and water co-electrolysis	19.4	2019	Electricity input	10 MW	(Detz et al., 2018)
	Syngas to olefins (including separation)	77	2015	Ethylene output	132.8 kt/y	(Liu et al., 2020)
B16.	Biomass to Methanol			Same elements described for B1 pathway		
	Methanol to propylene (including separation)	59	2013	Propylene output	35 kt/y	(Mariano et al., 2013)
B17.	Biomass to Methanol			Same elements described for B2 pathway		
	Methanol to propylene (including separation)	59	2013	Propylene output	35 kt/y	(Mariano et al., 2013)
E10.	CO <sub>2</sub> to Methanol			Same elements described for E1 pathway		
	Methanol to propylene (including separation)	59	2013	Propylene output	35 kt/y	(Mariano et al., 2013)
E11.	CO <sub>2</sub> to Methanol			Same elements described for E1 pathway		
	Methanol to propylene (including separation)	59	2013	Propylene output	35 kt/y	(Mariano et al., 2013)
B18	Biomass to ethanol (including separation)	38	2014	Ethanol output	78.9 kt/y	(FAO, 2020b)
	Ethanol to butadiene (including separation)	80	2014	butadiene output	34 kt/y	(Moncada et al., 2018a)
B19.	Biomass to ethanol (including separation and CHP plant)	159	2014	Ethanol output	78.9 kt/y	(FAO, 2020a)
	Ethanol to butadiene (including separation)	80	2014	butadiene output	34 kt/y	(Moncada et al., 2018a)
B20.	Biomass to ethanol (including separation and CHP plant)	163	2014	Ethanol output	78.9 kt/y	(FAO, 2020a)
	Ethanol to butadiene (including separation)	80	2014	butadiene output	34 kt/y	(Moncada et al., 2018a)

Pathway	Element of capex/ process section	Base Cost, M€	Base year	Capacity parameter	Base case capacity value	Reference
B21.	Biomass to ethanol (including separation, and CHP plant)	170	2014	Biomass input	440 kt/y	(Nitzsche et al., 2016)
	Ethanol to butadiene (including separation)	80	2014	butadiene output	34 kt/y	(Moncada et al., 2018a)
B22.	Biomass pyrolysis	330	2010	Biomass input	733 kt/y	(Sa et al., 2011)
	Reaction	20	2012	Biomass input	630 kt/y	(Sharifzadeh et al., 2015)
	Separation	20	2012	Biomass input	630 kt/y	(Sharifzadeh et al., 2015)
	CHP Plant	15	2014	Fuel input to CHP	190 kt/y	(FAO, 2020a)
B23.	Biomass pyrolysis	330	2010	Biomass input	733 kt/y	(Sa et al., 2011)
	Reaction	28	2012	Biomass input	630 kt/y	(Sharifzadeh et al., 2015)
	Separation	23	2012	Biomass input	630 kt/y	(Sharifzadeh et al., 2015)
	CHP Plant	15	2014	Fuel input to CHP	190 kt/y	(FAO, 2020a)
B24.	Biomass pyrolysis	330	2010	Biomass input	733 kt/y	(Sa et al., 2011)
	Reaction	7	2012	Biomass input	630 kt/y	(Sharifzadeh et al., 2015)
	Separation	15	2012	Biomass input	630 kt/y	(Sharifzadeh et al., 2015)
	CHP Plant	15	2014	Fuel input to CHP	190 kt/y	(FAO, 2020a)
B25.	Biomass pyrolysis	330	2010	Biomass input	733 kt/y	(Sa et al., 2011)
	Reaction	20	2012	Biomass input	630 kt/y	(Sharifzadeh et al., 2015)
	Separation	22	2012	Biomass input	630 kt/y	(Sharifzadeh et al., 2015)
	CHP Plant	15	2014	Fuel input to CHP	190 kt/y	(FAO, 2020a)
B26.	Biomass pyrolysis	330	2010	Biomass input	733 kt/y	(Sa et al., 2011)
	Reaction	25	2012	Biomass input	630 kt/y	(Sharifzadeh et al., 2015)
	Separation	22	2012	Biomass input	630 kt/y	(Sharifzadeh et al., 2015)
	CHP Plant	15	2014	Fuel input to CHP	190 kt/y	(FAO, 2020a)

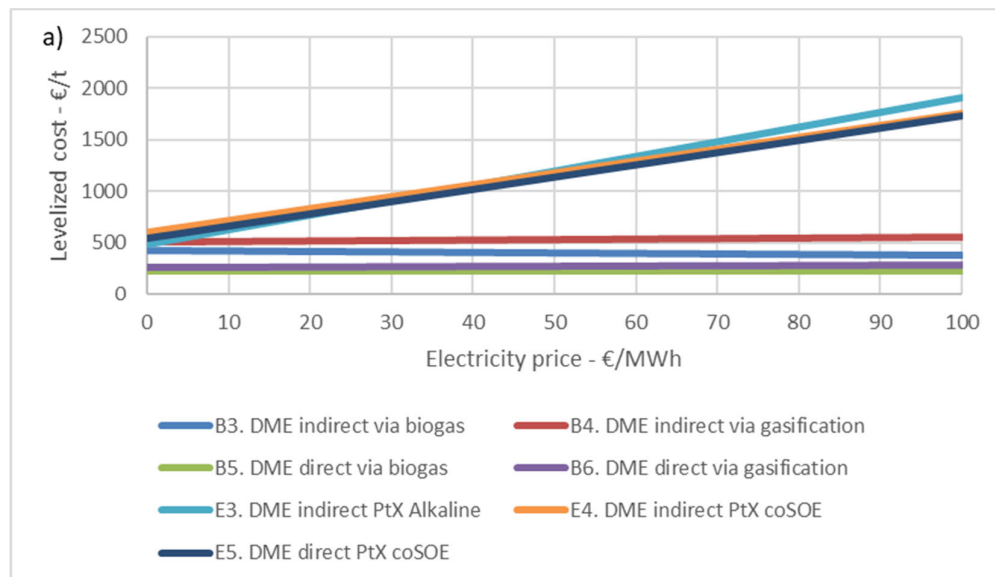


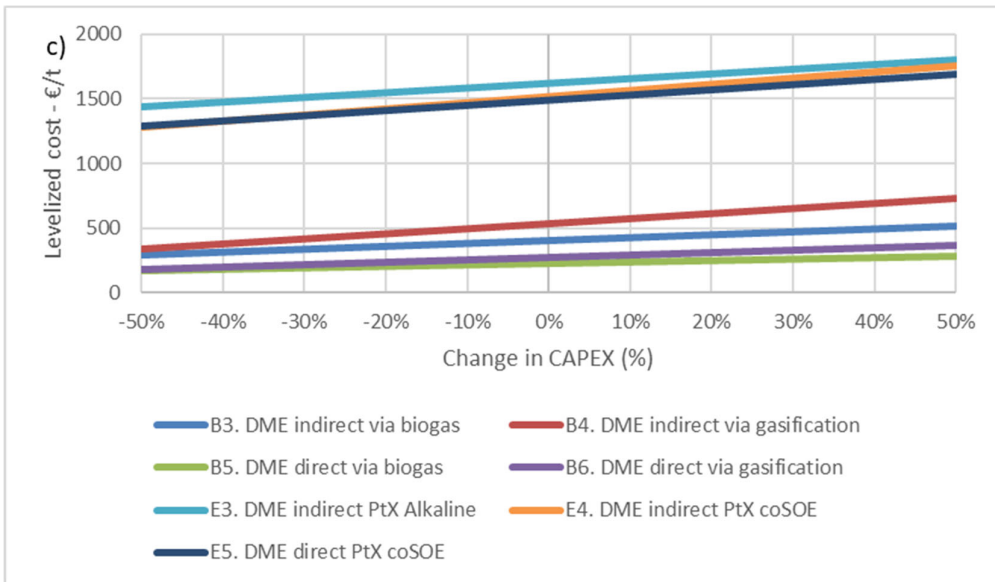
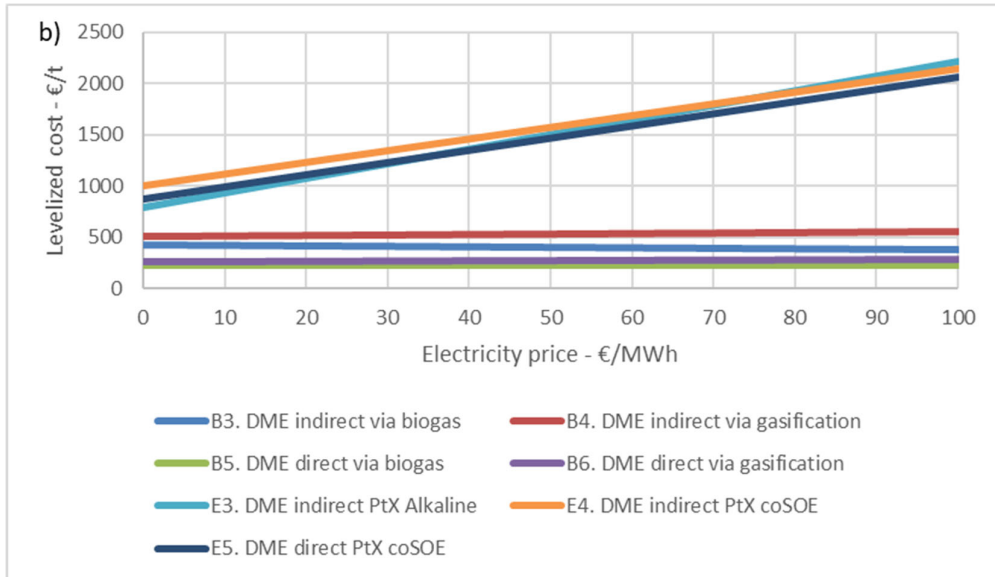
## F Sensitivity analysis

### F.1 Europe 2050

#### DME

Figure 77 shows the results of sensitivity analysis of electricity prices and changes in CAPEX. In the case of electricity prices (Figure 77a and b), the effect is highly noticeable for both e-based processes. The analysis is completely analogous to the one presented for methanol. In order to make DME competitive both, reductions in CAPEX and electricity prices are needed. When CAPEX is reduced by 50% and electricity price is 5 €/MWh, DME costs for systems E3, E4 and E5 become 525, 619 and 566 €/t, respectively. Although the costs still quite high in comparison to the bio-based alternatives, they become a bit more realistic, however, it should be taken into account that possibly reductions of electricity price to such levels might not be realistic in the future and thus more robust strategies should be looked at for further reducing costs. Possibly, further optimization of CAPEX and further energy efficiency.





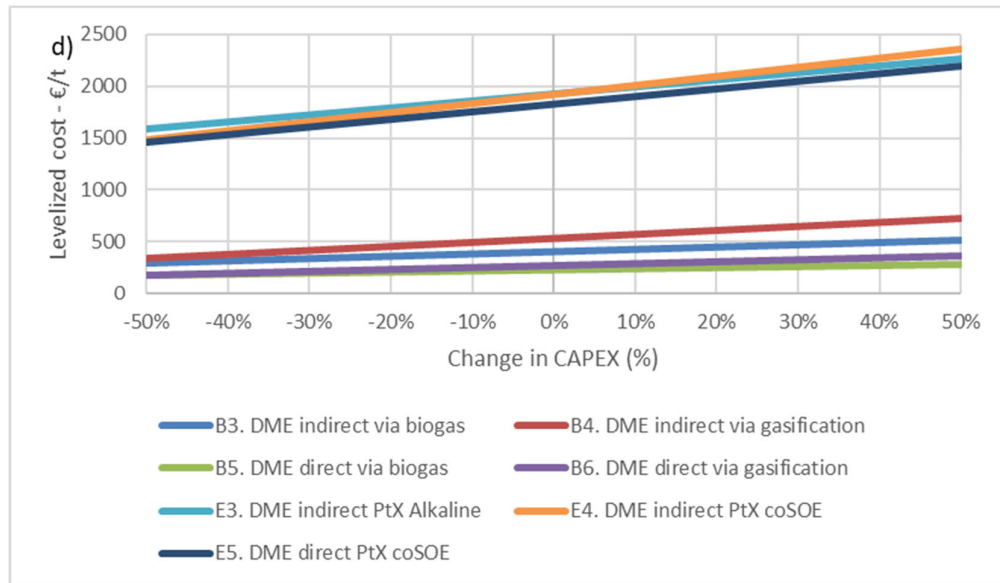


Figure 77 Sensitivity analysis of cost parameters on levelized cost. Electricity price: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year. Change in CAPEX: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

**Ethylene**

Figure 78 shows that in case electricity price is increased, 2G systems are benefitted as here we assumed that electricity selling price would be equal to electricity buying price. This can show that in the case that there are any incentives that favour electricity producers, ethylene costs might become lower. In terms of CAPEX it can be seen that ethylene costs can be further decreased if CAPEX is further reduced. It should be noted that 2G ethanol plants are currently near to commercialization and developers indicate that there is significant potential for reducing plant capital costs (IEA, 2020).

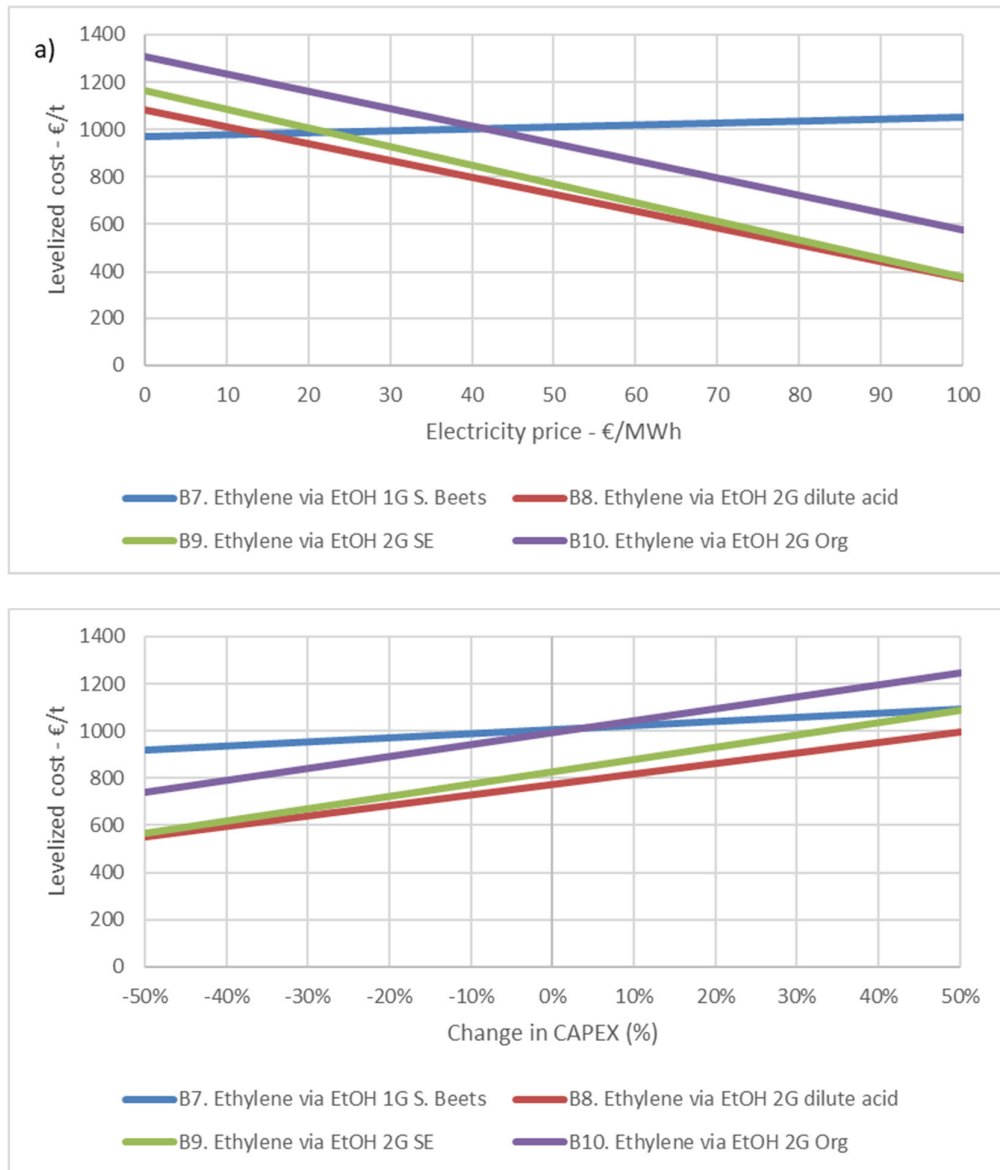
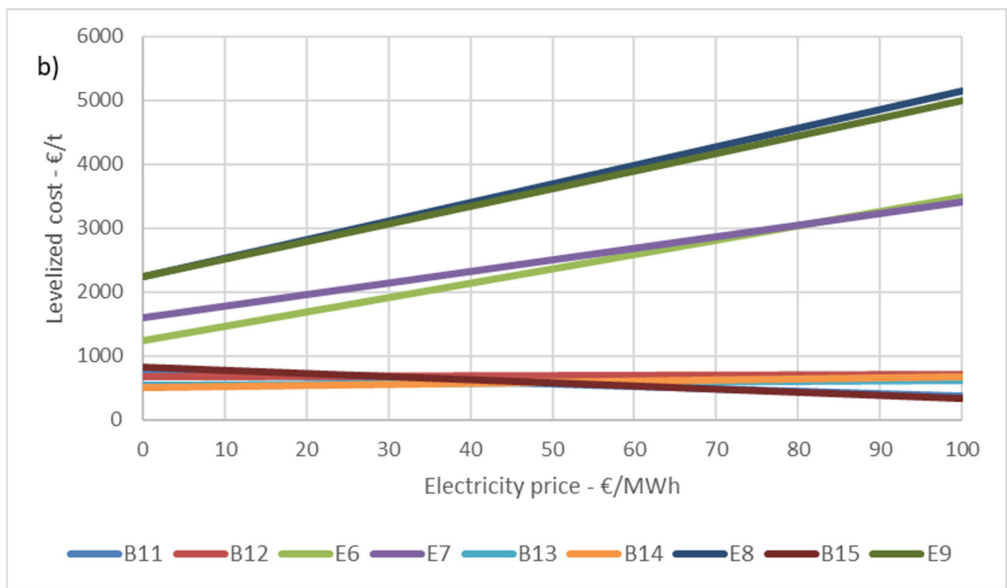
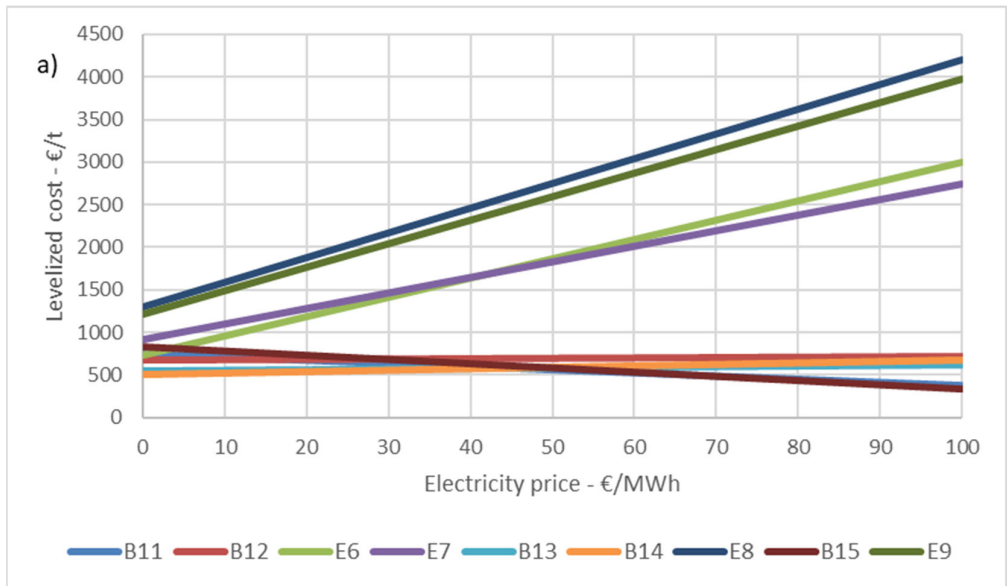


Figure 78 Sensitivity analysis of cost parameters on levelized cost. Electricity price, CAPEX

**Olefins (mainly ethylene and propylene)**

Figure 79 shows the results of sensitivity analysis of electricity prices and changes in CAPEX. In the case of electricity prices (Figure 79 a and b), the effect is highly noticeable for both e-based processes. The analysis is completely analogous to the one presented for methanol and DME. In order to make DME competitive both, reductions in CAPEX and electricity prices are needed.



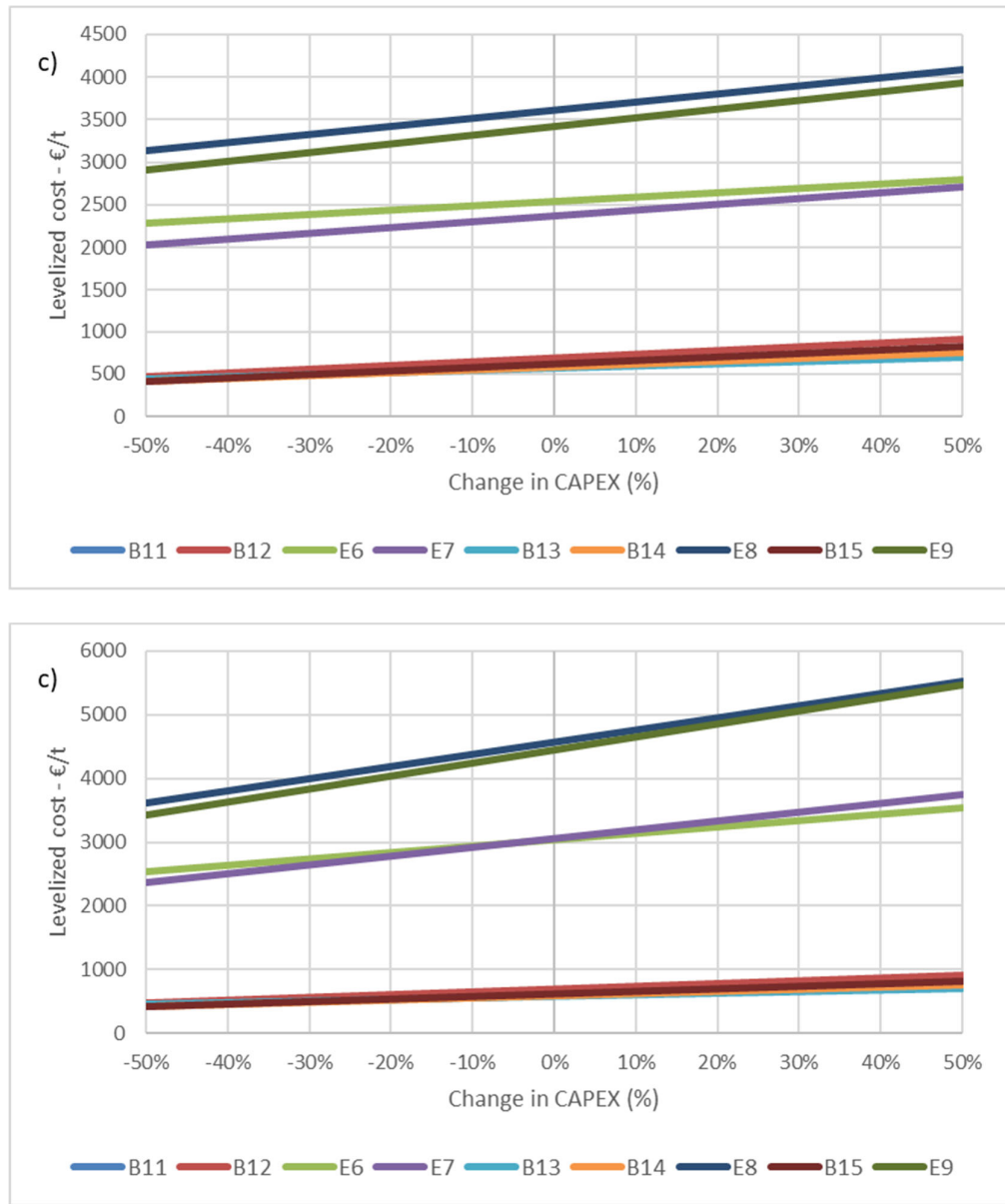
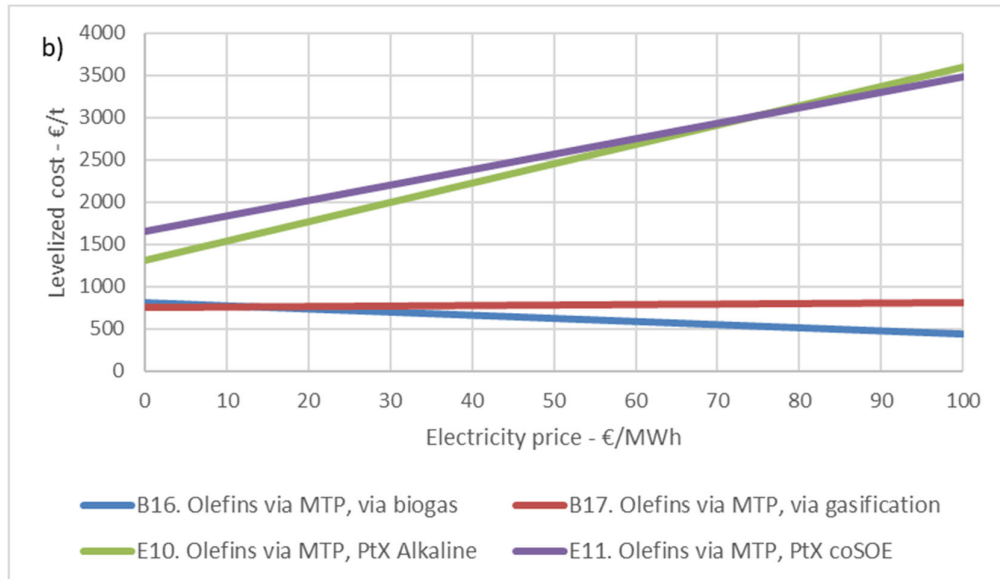
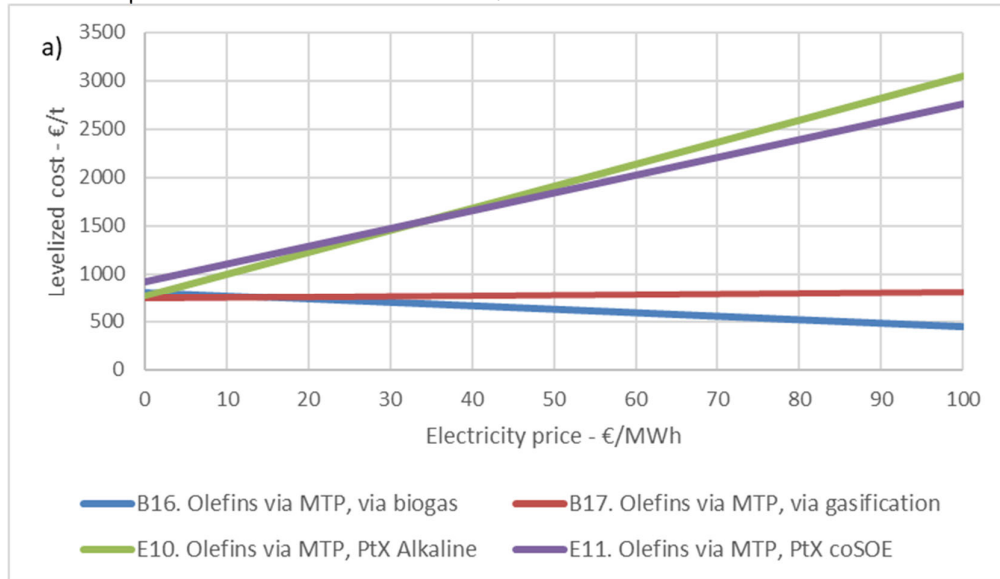


Figure 79 Hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year. Change in CAPEX: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

**Olefins (mainly propylene)**

Figure 80 shows the results of sensitivity analysis of electricity prices and changes in CAPEX. In the case of electricity prices (Figure 80a and b), the effect is highly noticeable for both e-based processes. The analysis is completely analogous to the one presented for methanol and DME, and olefins above.



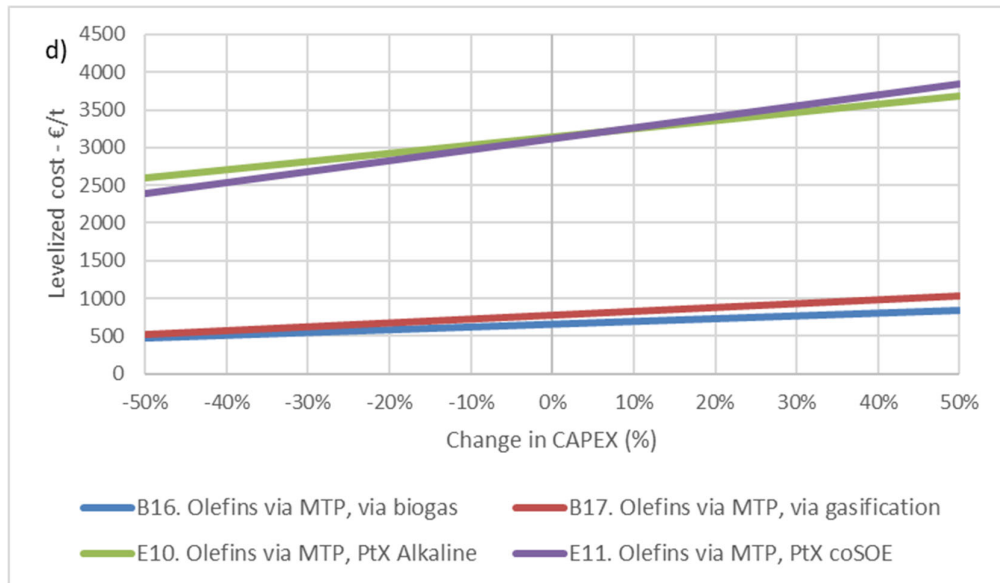
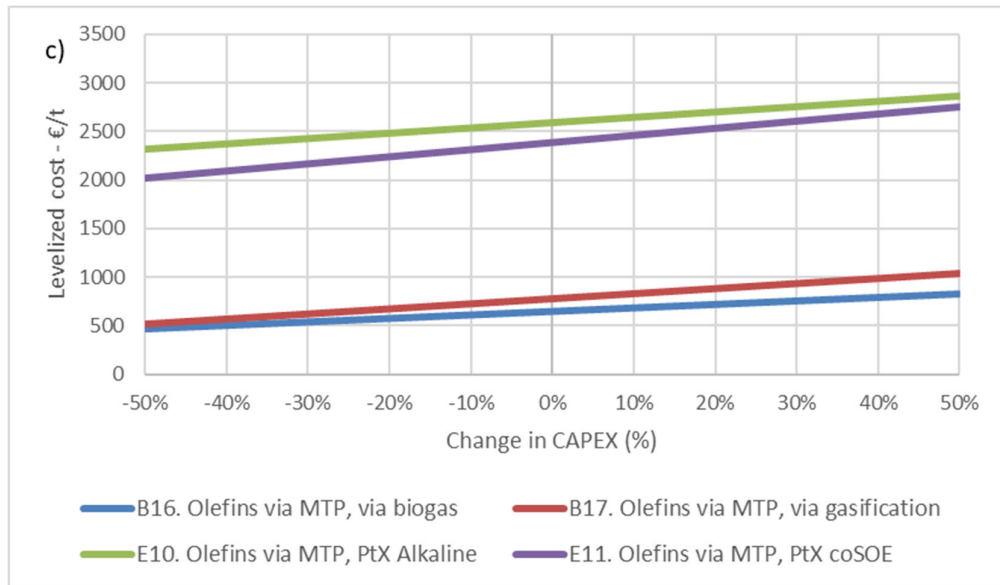


Figure 80 Sensitivity analysis of cost parameters on levelized cost. Electricity price: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year. Change in CAPEX: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.



**Olefins (butadiene mainly)**

Figure 81, that in case electricity price is increased, 2G systems are benefitted as here we assumed that electricity selling price would be equal to electricity buying price.

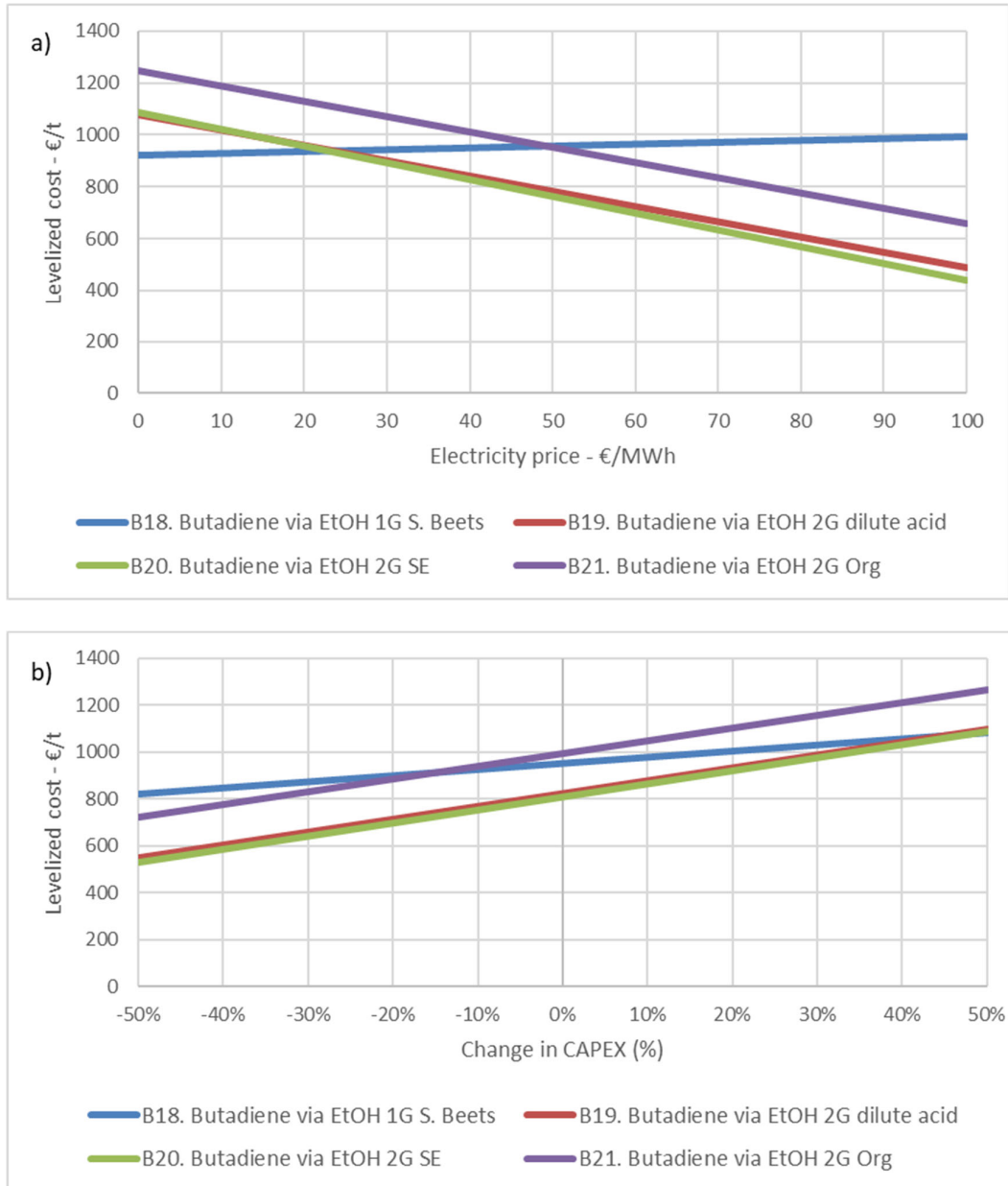


Figure 81 Sensitivity analysis of cost parameters on levelized cost. Electricity price, CAPEX

**Olefins (from biomass pyrolysis)**

Figure 82 shows that in case electricity price is increased the systems are benefitted as it is assumed that electricity selling price would be equal to electricity buying price.

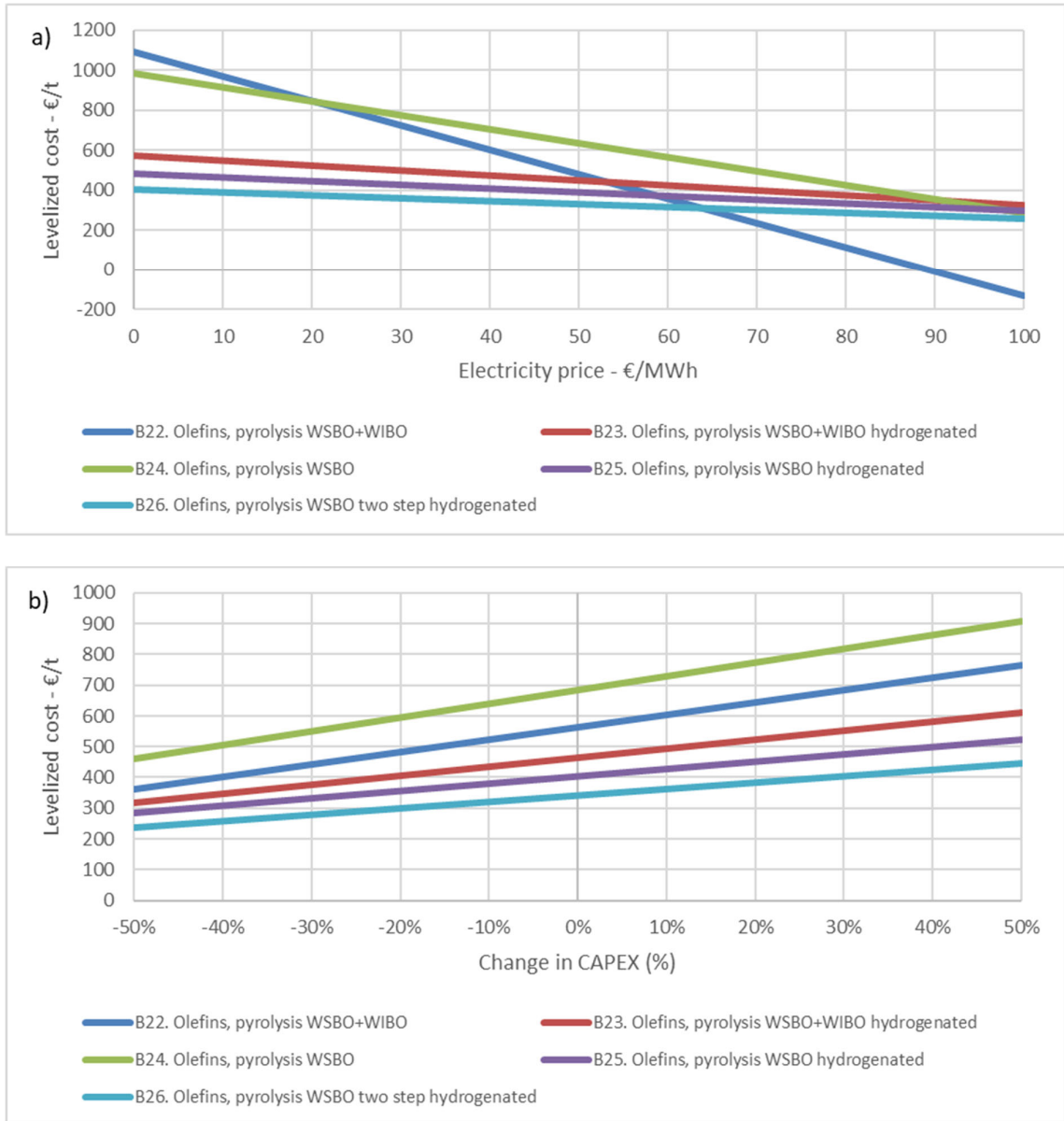


Figure 82 Sensitivity analysis of cost parameters on levelized cost. Electricity price, CAPEX

**BTX (from biomass pyrolysis)**

Figure 83 shows that in case electricity price is increased the systems are benefitted as it is assumed that electricity selling price would be equal to electricity buying price. For these systems, reductions in CAPEX can further benefit levelized costs as pyrolysis systems are still not very well developed in comparison to other technologies and there is room for learning until full commercial implementation.

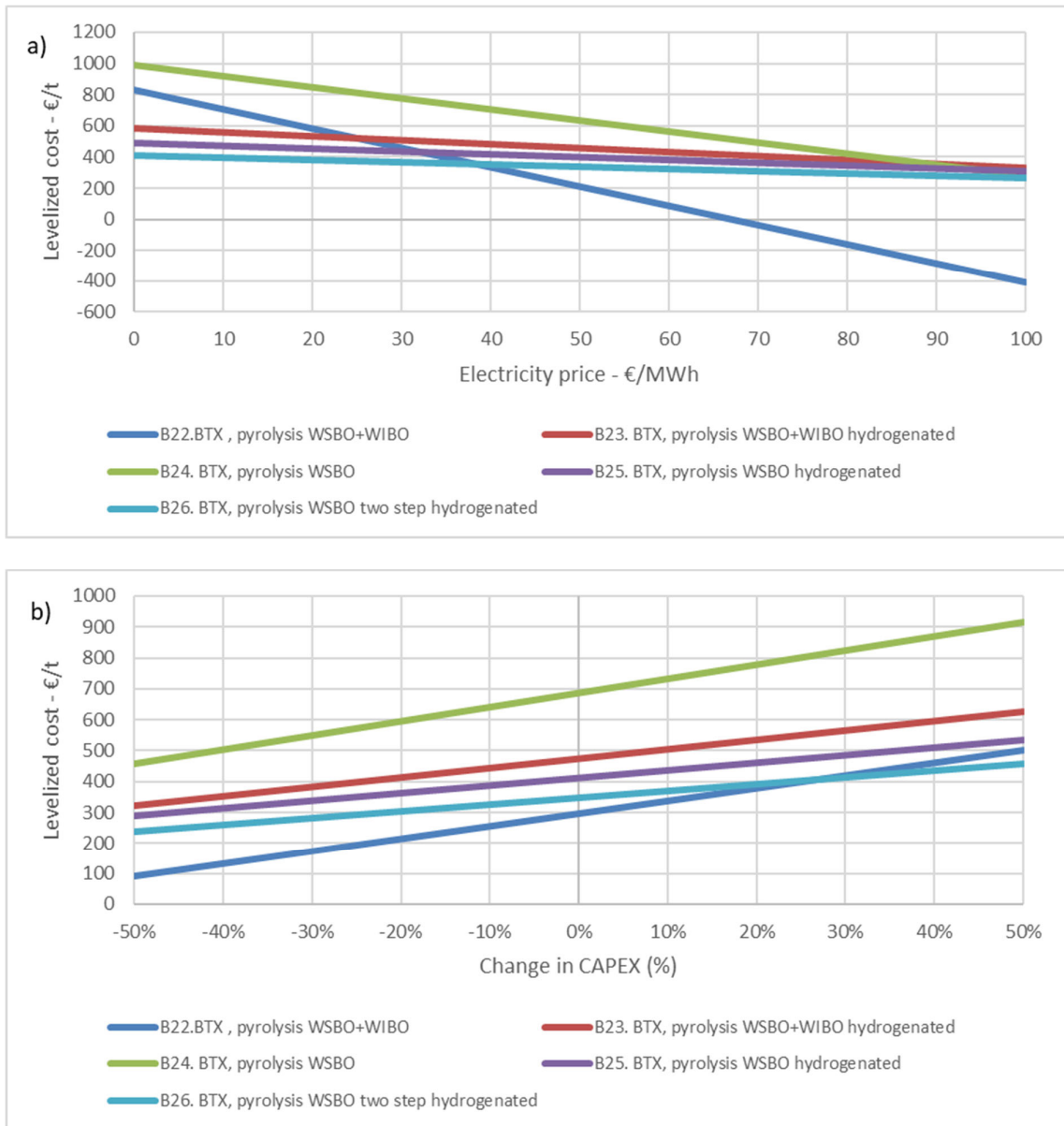


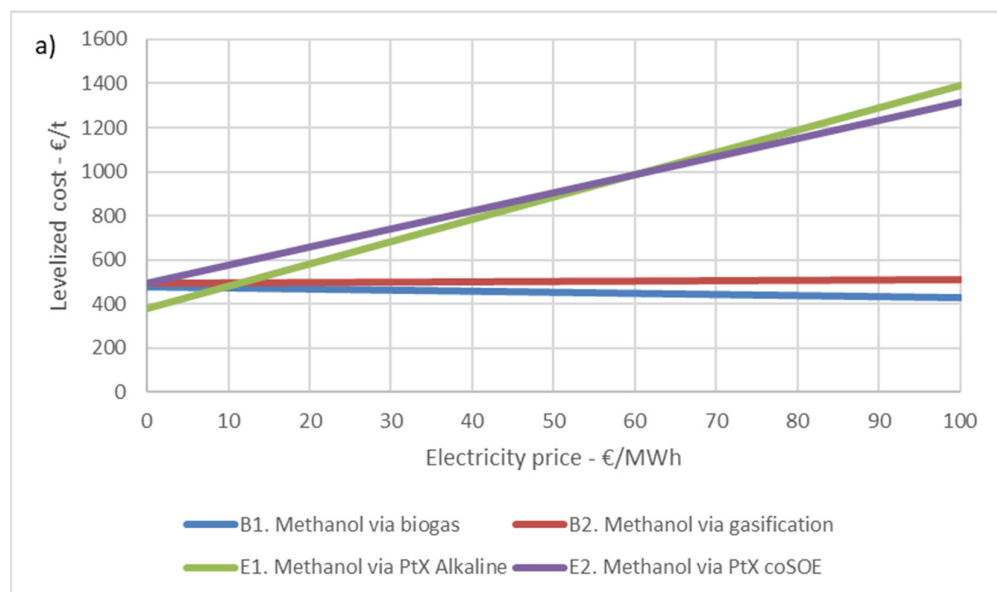
Figure 83 Sensitivity analysis of cost parameters on levelized cost. Electricity price, CAPEX

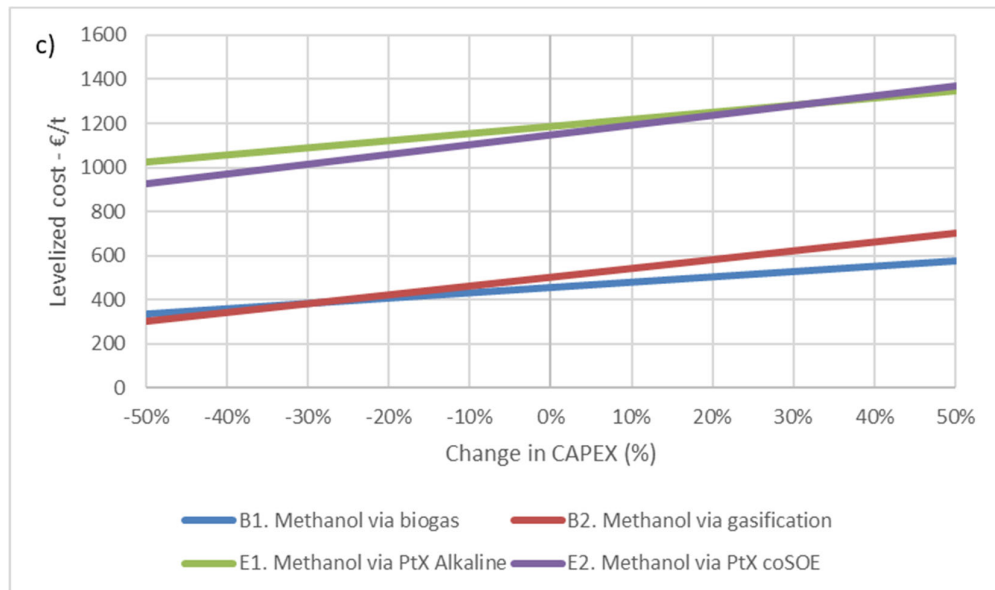
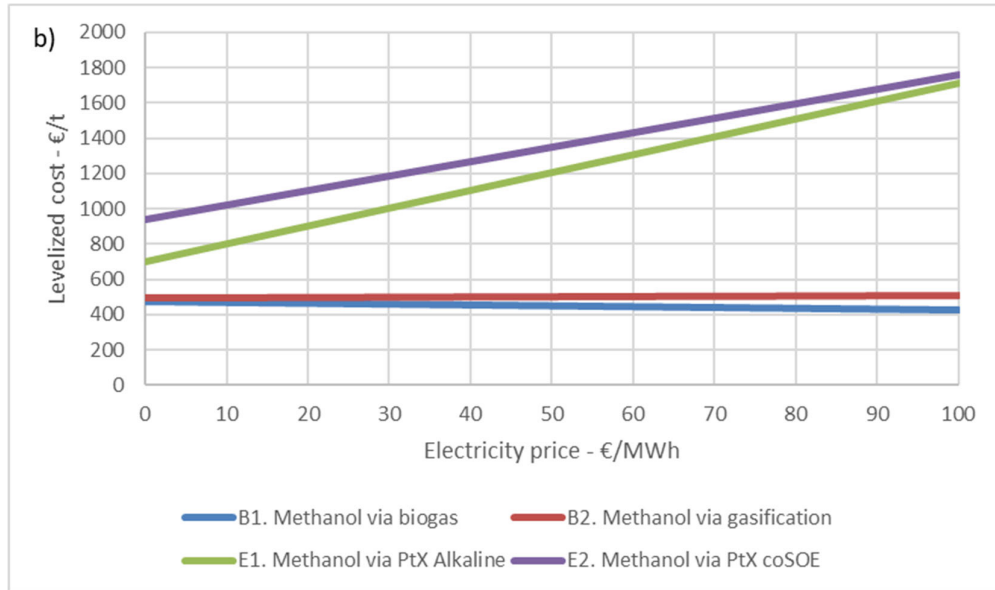
## F.2 Netherlands 2030

### Methanol

Figure 84 shows the results of sensitivity analysis of electricity prices and changes in CAPEX. In the case of electricity prices (Figure 84 a and b), the effect is highly noticeable for both e-based processes. If the e-based processes operate continuously across the year, the price of electricity needs to be around 0-10 €/MWh so the systems start to be comparable to the bio-based routes.

Nevertheless, when the number of hours is decreased by half (see Figure 84b), even at 0 €/MWh of electricity price the e-based systems show much higher costs than the bio-based ones. In the case of CAPEX, the effect on levelized cost is not as noticeable as for the case of electricity, but its effect is still significant towards costs reduction in the future. It is also important to mention that for all analyses presented for 2030, the contribution of CO<sub>2</sub> cost is rather low in comparison to CAPEX and Electricity price. In this case three different levels of CO<sub>2</sub> costs were considered. The first one assuming CO<sub>2</sub> from concentrated sources from industry (like ammonia, with a limited potential of 1,346 kt/y) at 29 €/t. The second correspond to diluted CO<sub>2</sub> streams from industry (like steel, potential of 1,751 kt/y) at 67 €/t. Both costs of these options were gathered from IEA descriptions on CCSU (IEA, 2020). The third option is direct air capture with a cost of 75 €/t (assumed 50% higher than that costs of CO<sub>2</sub> assumed for the cases on 2050). For the case of methanol, all CO<sub>2</sub> is able to be supplied by the cheapest option and therefore its contribution on costs is rather low. However, it should be noted that in case CO<sub>2</sub> costs become higher, costs of e-based processes can be significantly impacted.





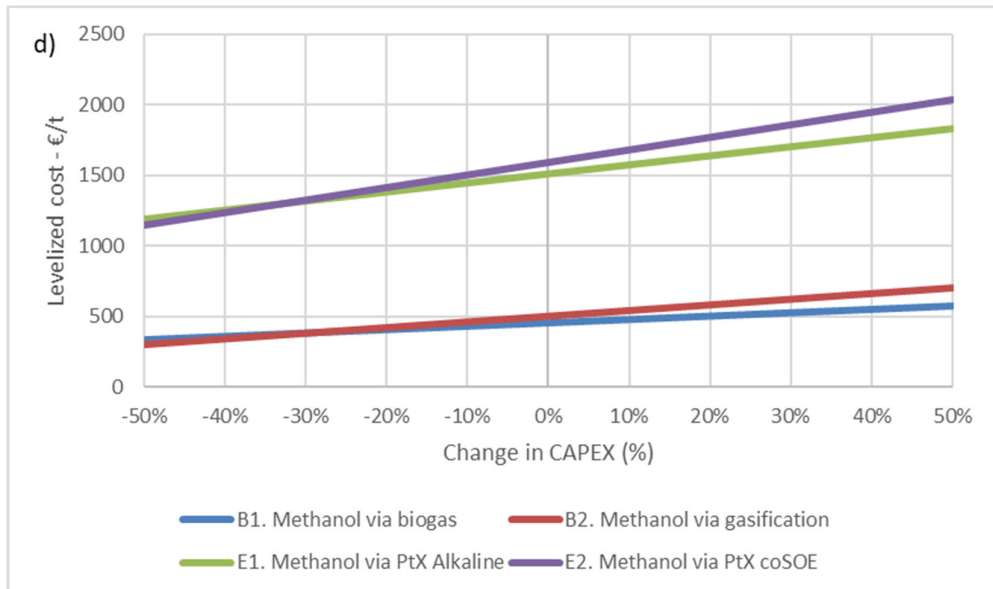
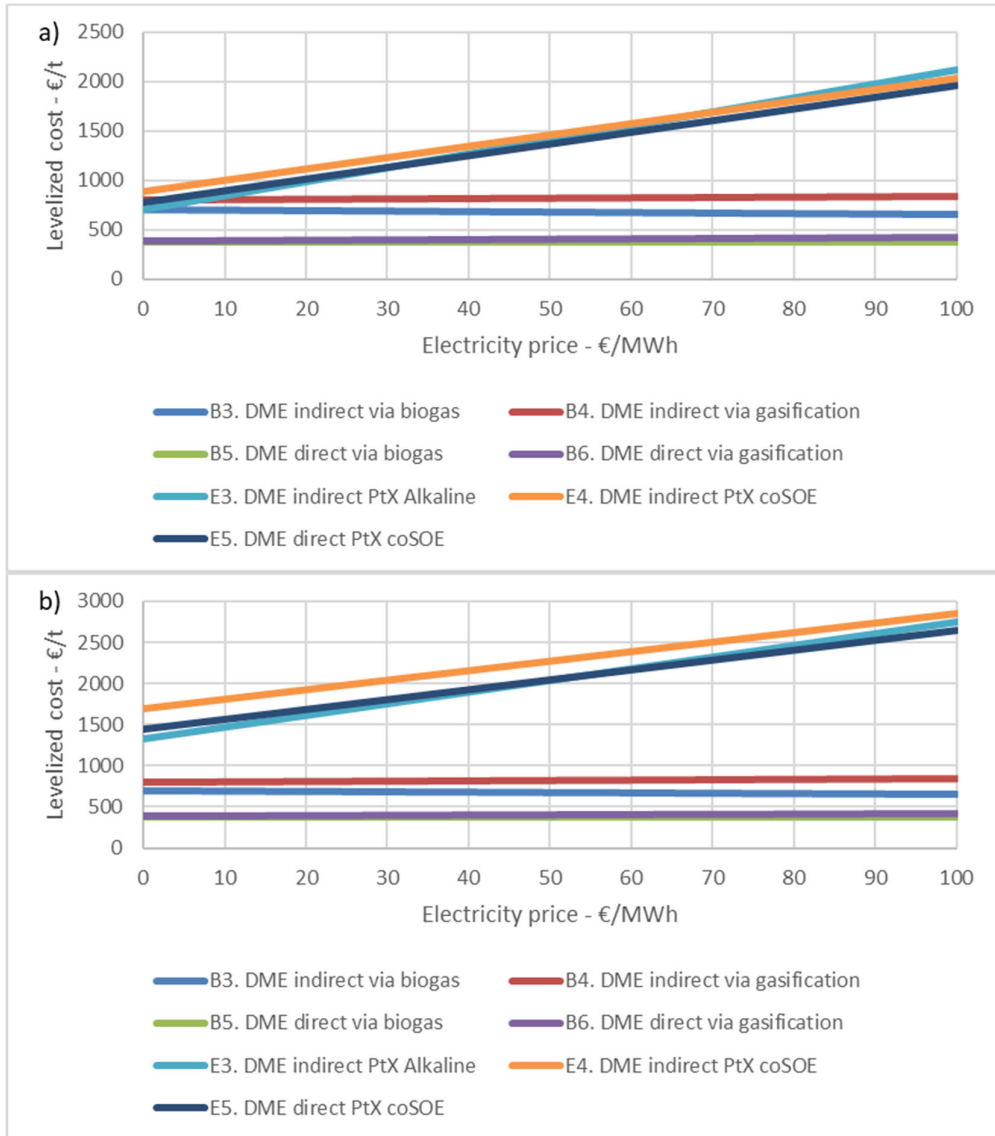


Figure 84 Sensitivity analysis of cost parameters on levelized cost. Electricity price: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year. Change in CAPEX: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

**DME**



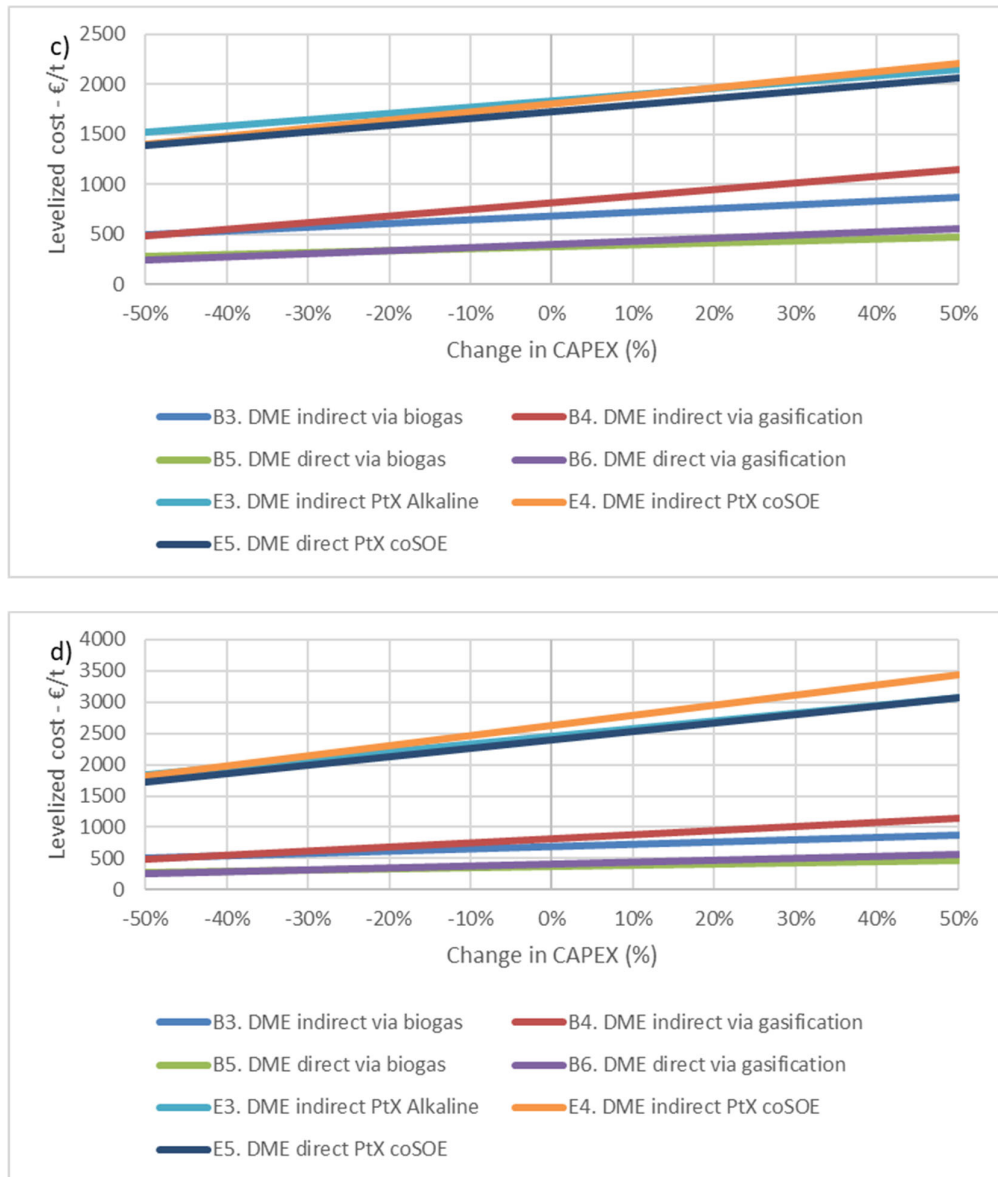


Figure 85 Sensitivity analysis of cost parameters on levelized cost. Electricity price: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year. Change in CAPEX: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.



**Ethylene (standalone)**

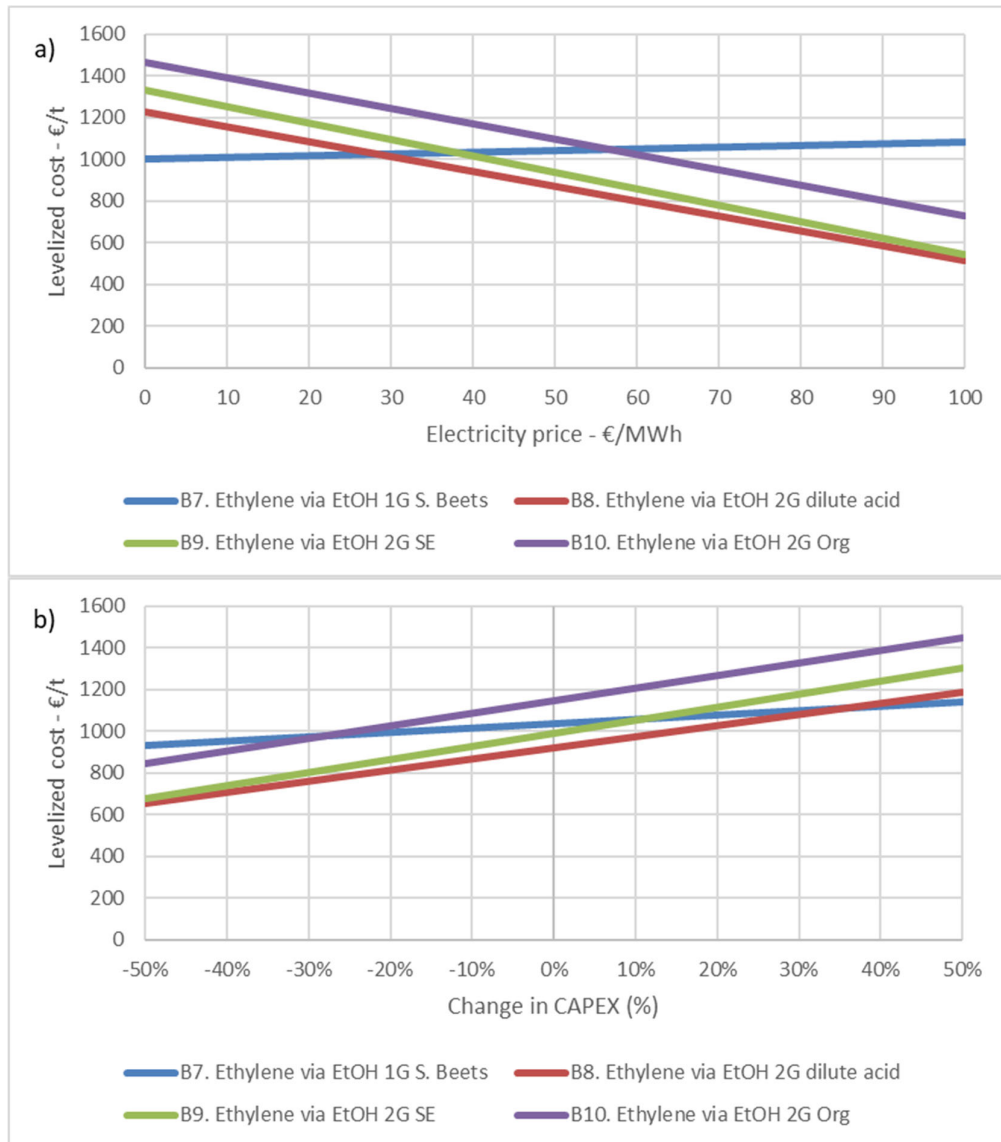
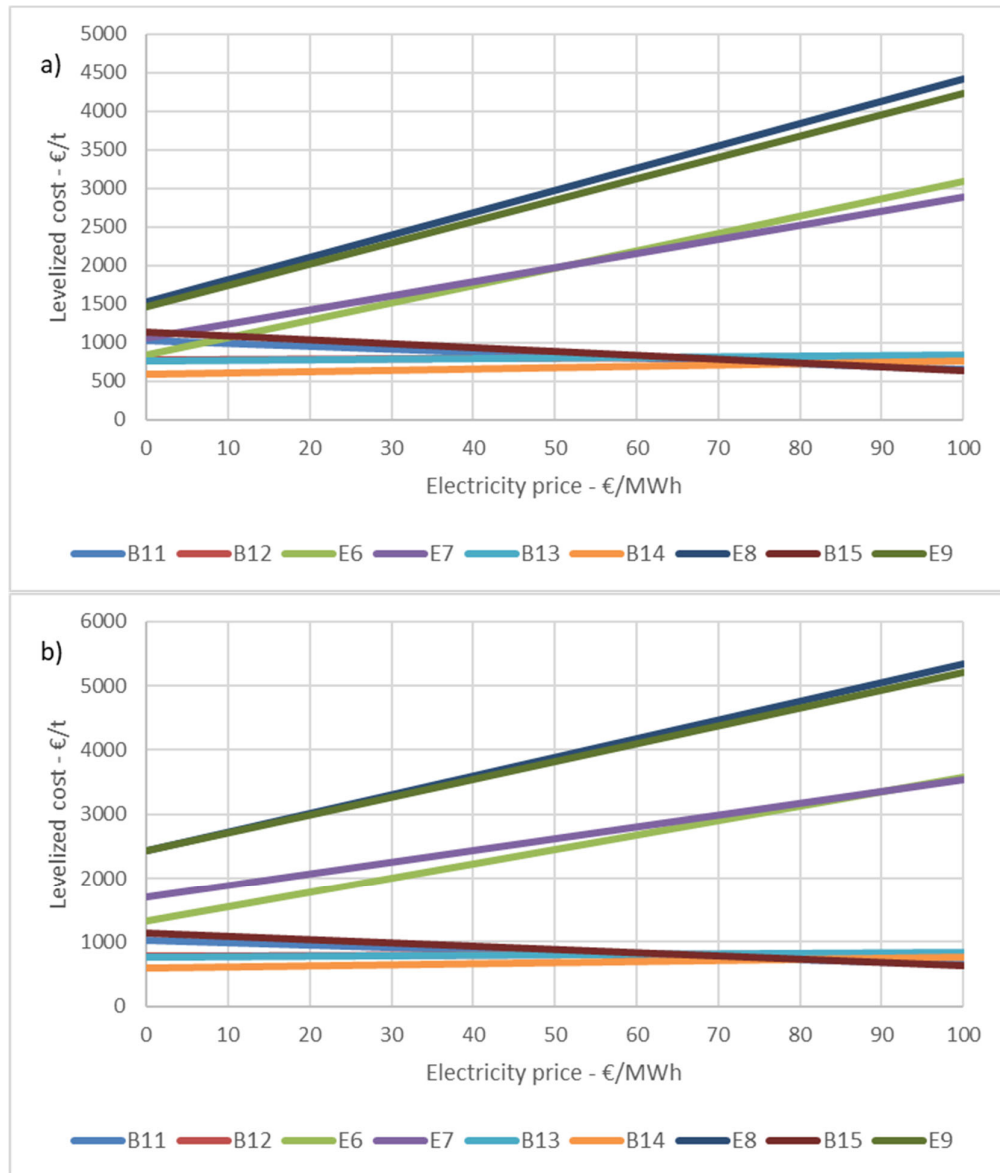


Figure 86 Sensitivity analysis of cost parameters on levelized cost. Electricity price, CAPEX

**Olefins (mainly ethylene and propylene)**



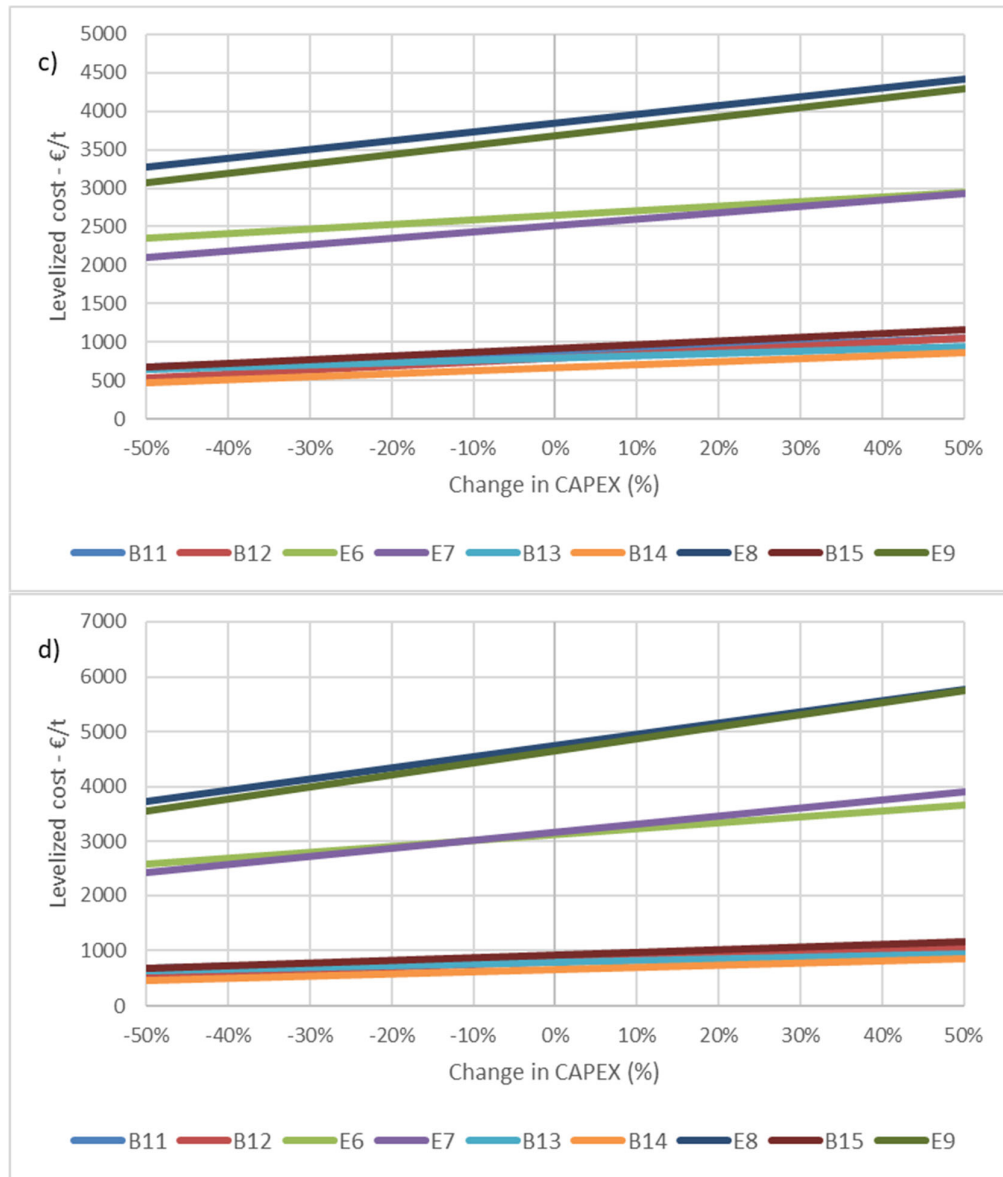
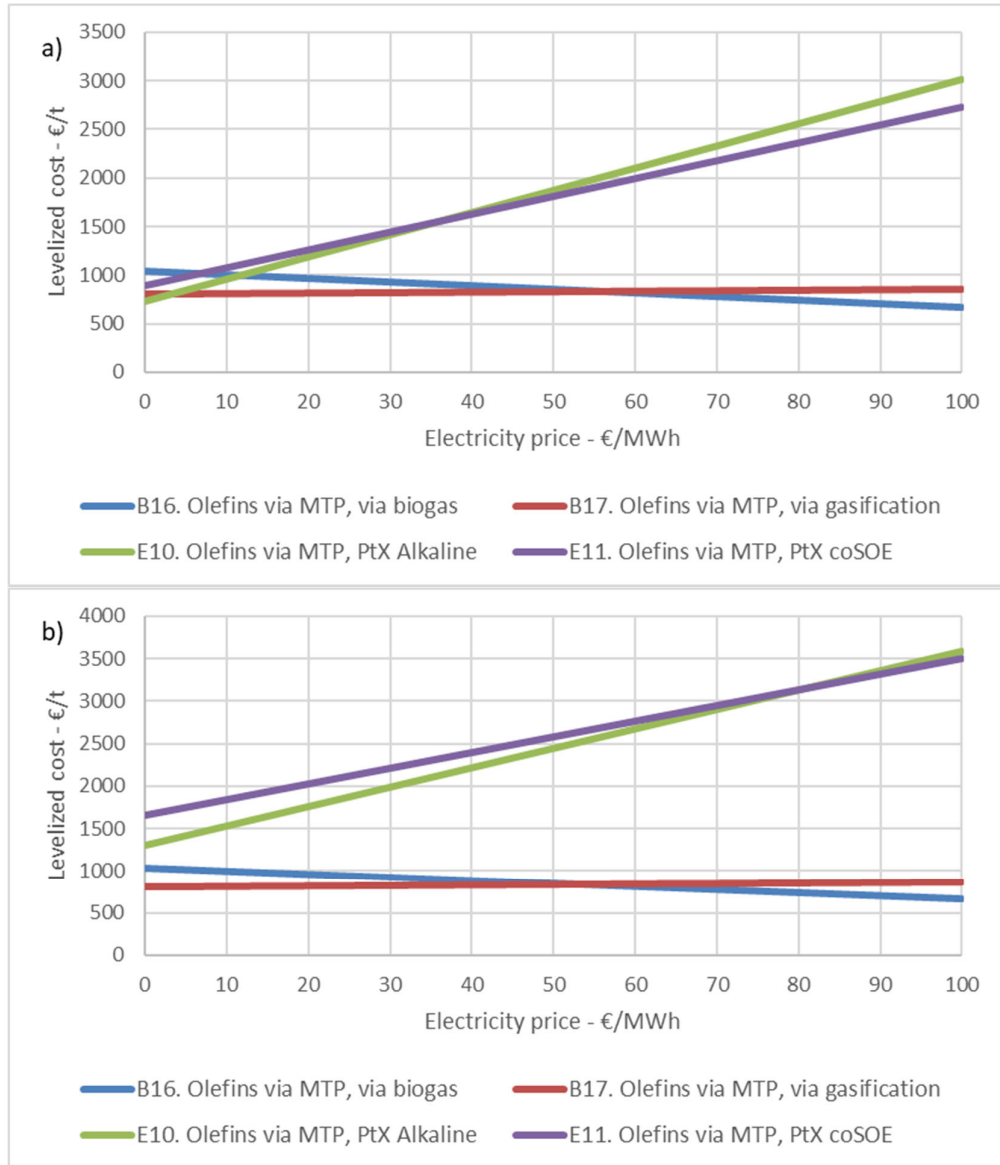


Figure 87 Sensitivity analysis of cost parameters on levelized cost. Electricity price: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year. Change in CAPEX: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

**Olefins (mainly propylene)**



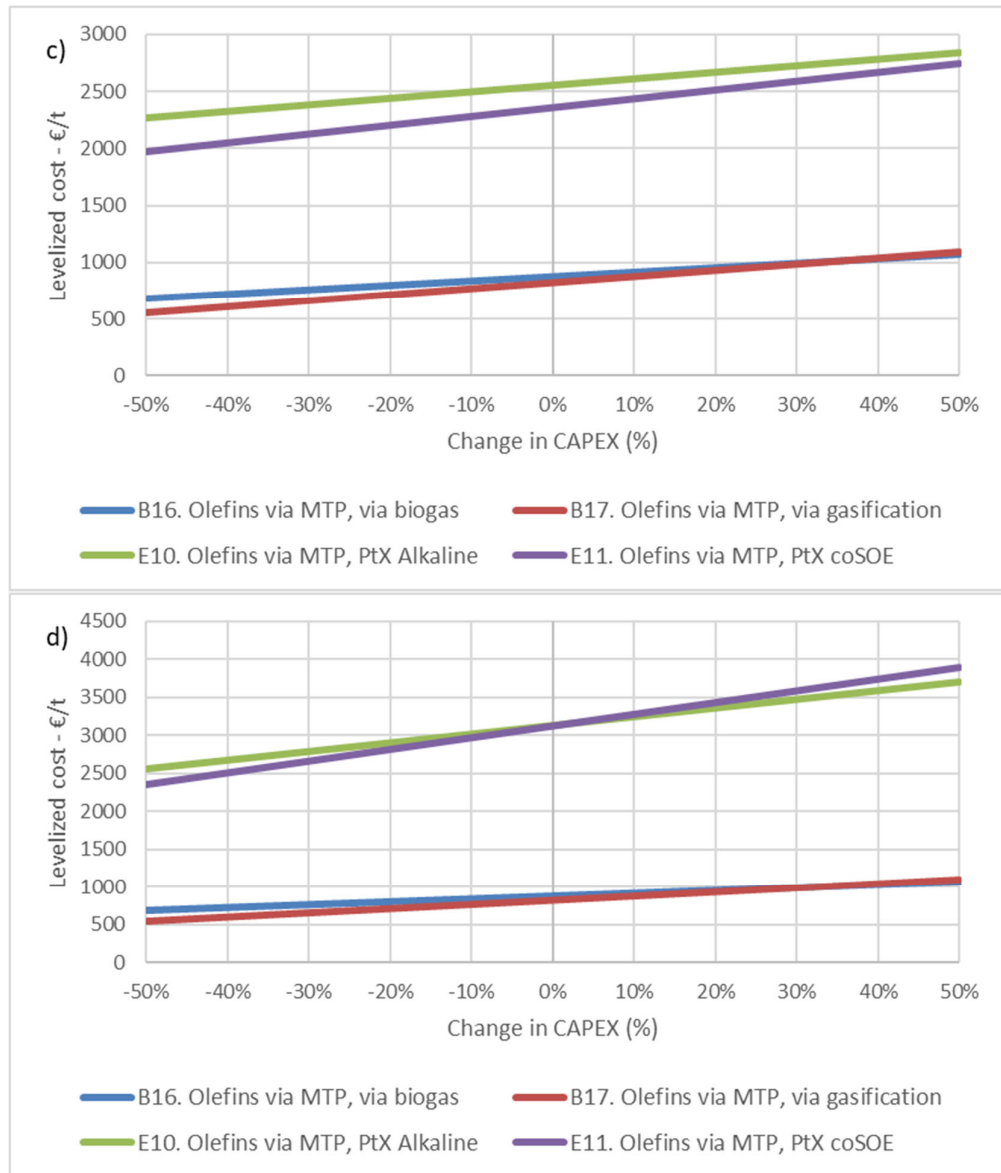


Figure 88 Sensitivity analysis of cost parameters on levelized cost. Electricity price: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year. Change in CAPEX: a) operating hours per year 8000 for all cases, b) bio-based operating hours: 8000 per year, e-based operating hours: 4000 per year.

**Olefins (butadiene mainly)**

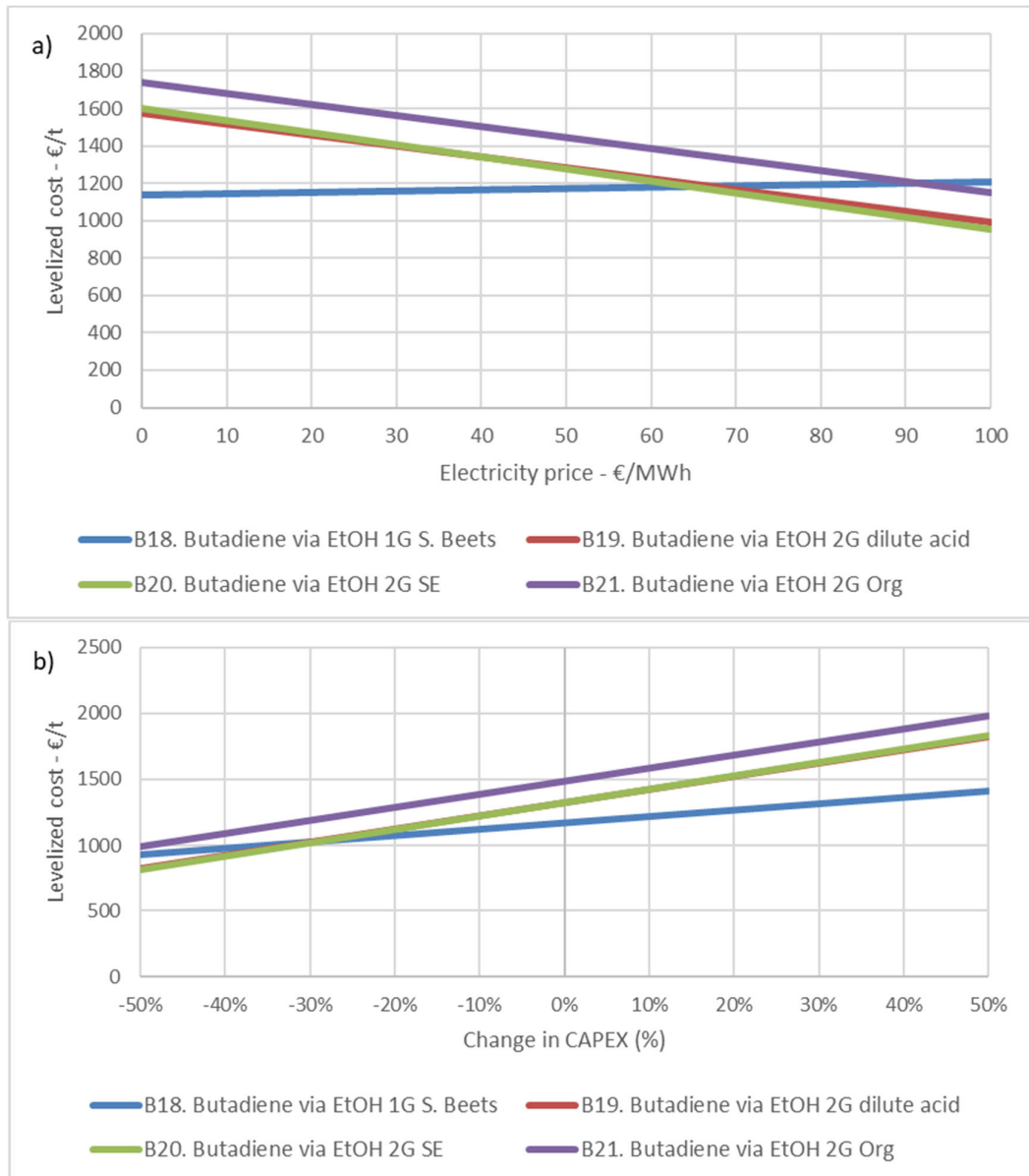


Figure 89 Sensitivity analysis of cost parameters on levelized cost. Electricity price, CAPEX

**Olefins (from biomass pyrolysis)**

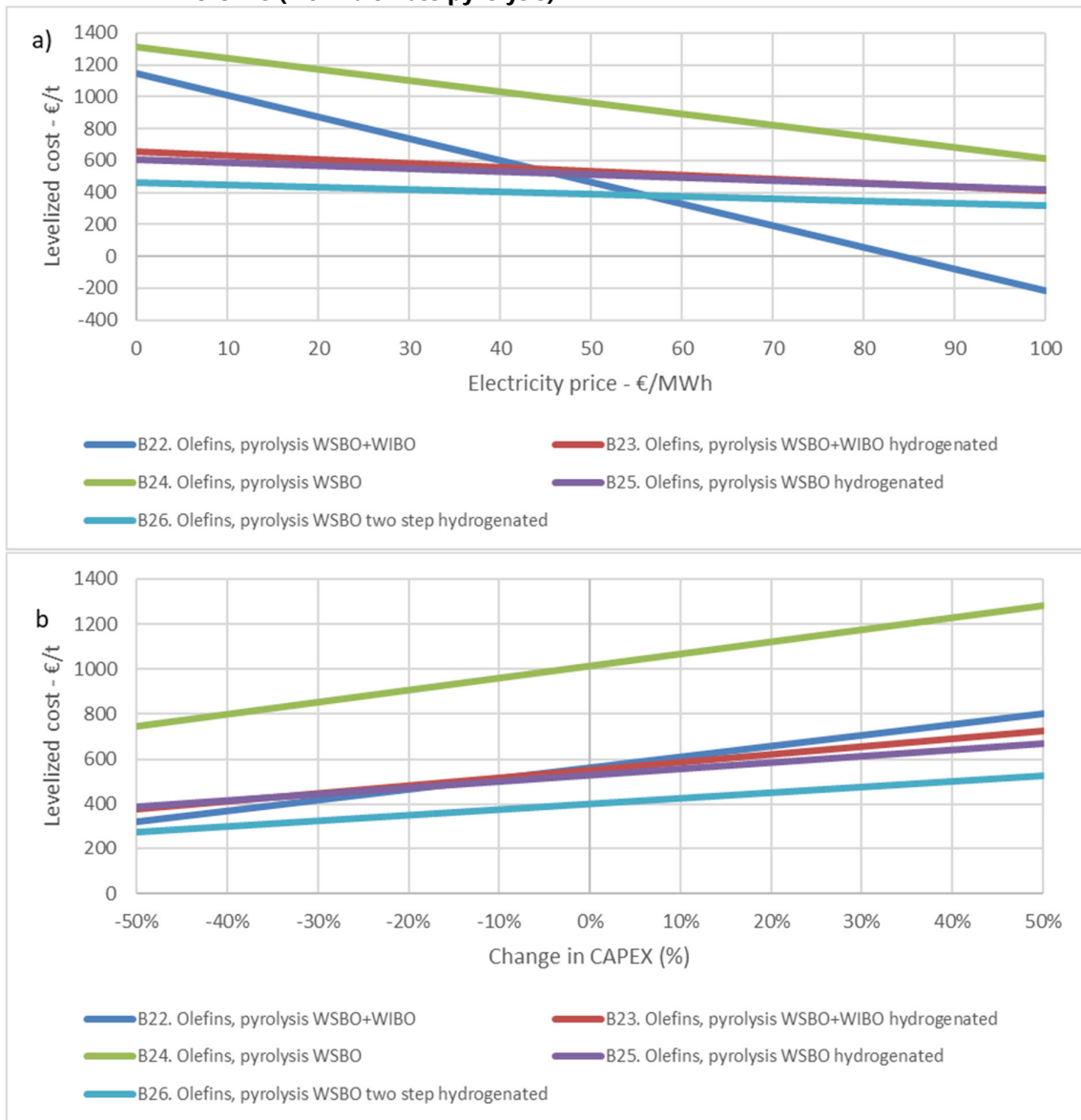


Figure 90 Sensitivity analysis of cost parameters on levelized cost. Electricity price, CAPEX

**BTX (from biomass pyrolysis)**

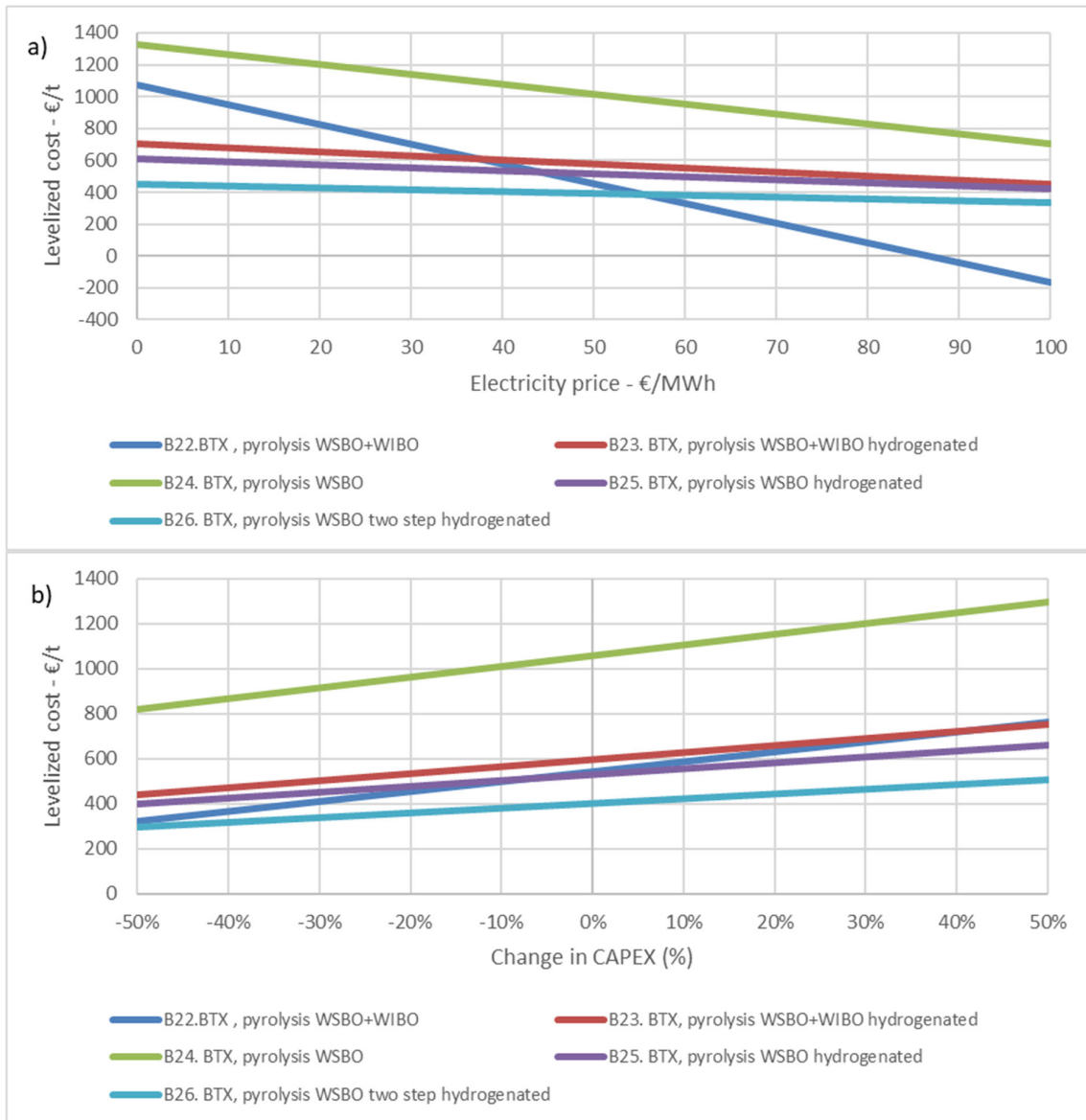


Figure 91 Sensitivity analysis of cost parameters on levelized cost. Electricity price, CAPEX



## G Summary of inputs and outputs of the conversion routes

This section presents a summary of mass inputs and outputs, as well as a summary of energy needs of the different conversion routes considered in this study.

### G.1 Methanol production

#### B1. Methanol via biogas

Table 40 Summary of inputs and outputs of route B1

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	1,547	Methanol	100	Electricity	-174
Water	13,921	Waste water	13,934	Refrigerant	0
		Flue gases	13	Cooling water	147
		Digestate	1,420	Steam	224
<b>Total</b>	<b>15,468</b>	<b>Total</b>	<b>15,468</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

#### B2. Methanol via gasification

Table 41 Summary of inputs and outputs of route B2

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	199	Methanol	100	Electricity	61
Water	586	waste water	604		
Air	262	Flue gases	333		
		Ash	10		
<b>Total</b>	<b>1,047</b>	<b>Total</b>	<b>1,047</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

#### E1. Methanol via alkaline electrolysis

Table 42 Summary of inputs and outputs of route E1

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	171	Methanol	100	Electricity	3,644
Air	15	Waste water	56	Electricity grid	63
CO <sub>2</sub>	139	Flue gases	17	Cooling water	289
		Oxygen	152		
<b>Total</b>	<b>325</b>	<b>Total</b>	<b>325</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

## E2. Methanol via solid oxide electrolyser (SOE) cell co-electrolysis

Table 43 Summary of inputs and outputs of route E2

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	163	Methanol	100	Electricity	2946
CO <sub>2</sub>	147	Water	51	Steam	125
Air	56	Flue gases	43		
		CO <sub>2</sub>	9		
		Oxygen	163		
<b>Total</b>	<b>366</b>	<b>Total</b>	<b>366</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

## G.2 DME

### B3. DME indirect production via methanol from biogas

Table 44 Summary of inputs and outputs of route B3

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	163	Methanol	100	Electricity	2946
CO <sub>2</sub>	147	Water	51	Steam	125
Air	56	Flue gases	43		
		CO <sub>2</sub>	9		
		Oxygen	163		
<b>Total</b>	<b>366</b>	<b>Total</b>	<b>366</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

### B4. DME indirect production via methanol from gasification

Table 45 Summary of inputs and outputs of route B4

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	279	DME	100	Electricity	172
Water	823	Waste water	888		
Air	368	Flue gases	467		
		Ash	14		
<b>Total</b>	<b>1470</b>	<b>Total</b>	<b>1470</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

### B5. DME direct production via syngas from biogas

Table 46 Summary of inputs and outputs of route B5

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	1180	DME	100	Electricity	-19
Water	10851	waste water	10848	Cooling water	285
Air	144	Flue gases	144	Steam	236
		Digestate	1084		
<b>Total</b>	<b>12175</b>	<b>Total</b>	<b>12175</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

### B6. DME direct production via syngas from gasification

Table 47 Summary of inputs and outputs of route B6

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	125	DME	100	Electricity	109
Air	212	Waste water	59	Cooling water	206
		Flue gases	173	Steam	219
		Char	5		
<b>Total</b>	<b>337</b>	<b>Total</b>	<b>337</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

### E3. DME indirect production via methanol. Alkaline electrolysis

Table 48 Summary of inputs and outputs of route E3

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	240	DME	100	Electricity	5118
Air	21	waste water	120	Electricity grid	88
CO <sub>2</sub>	196	Flue gases	24	Cooling water	406
		Oxygen	213		
<b>Total</b>	<b>457</b>	<b>Total</b>	<b>457</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

#### E4. DME indirect production via methanol. SOE co electrolysis

Table 49 Summary of inputs and outputs of route E4

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	229	DME	100	Electricity renewable	4138
CO <sub>2</sub>	206	Water	112	Electricity grid	87
Air	78	Flue gases	60	Steam	176
		CO <sub>2</sub>	13		
		Oxygen	229		
<b>Total</b>	<b>514</b>	<b>Total</b>	<b>514</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

#### E5.DME direct production via syngas. SOE co-electrolysis

Table 50 Summary of inputs and outputs of route E5

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	230	DME	100	Electricity renewable	4285
CO <sub>2</sub>	207	Water	107	Electricity grid	101
		Flue gases	0	Cooling water	206
		CO <sub>2</sub>	0	Steam	395
		Oxygen	229		
<b>Total</b>	<b>436</b>	<b>Total</b>	<b>436</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

### G.3 Olefins (standalone ethylene)

#### B7. Ethylene production via 1G ethanol

Table 51 Summary of inputs and outputs of route B7

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	2953	Ethylene	100	Electricity	294
Lime	25	Water	2228	Cooling water	277
Sulfuric acid	31	Cell biomass	52	Steam	639
Water	2114	Solids	2493	Fired heat	173
Ammonia	4	CO <sub>2</sub>	252		
Yeast	1	Ash	2		
<b>Total</b>	<b>5128</b>	<b>Total</b>	<b>5128</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

## B8. Ethylene production via 2G ethanol. Dilute acid pre-treatment

Table 52 Summary of inputs and outputs of route B8

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	1117	Ethylene	100	Electricity	-2559
Sulfuric Acid	25	Water	129	Cooling water	277
Ammonia	6	Steam	2026	Fired heat	173
Enzyme	3	Flue gas	1370		
Yeast	1	CO <sub>2</sub>	252		
Water	2026	Ash	2		
Air	914	Sludge	211		
<b>Total</b>	<b>4091</b>	<b>Total</b>	<b>4091</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

## B9. Ethylene production via 2G ethanol. Steam explosion pre-treatment

Table 53 Summary of inputs and outputs of route B9

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	1182	Ethylene	100	Electricity	-2830
Steam	1064	Water	129	Cooling water	277
Ammonia	6	Steam	2237	Steam	230
Enzyme	3	Flue gas	1536	Fired heat	173
Yeast	1	CO <sub>2</sub>	252		
Water	2237	Ash	2		
Air	1024	Sludge	1260		
<b>Total</b>	<b>5516</b>	<b>Total</b>	<b>5516</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

### B10. Ethylene production via 2G ethanol. Dilute acid pre-treatment

Table 54 Summary of inputs and outputs of route B10

Mass flows		Energy requirements			
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
<b>Biomass</b>	1058	<b>Ethylene</b>	100	<b>Electricity</b>	-2649
<b>Catalyst</b>	9	<b>Waste water</b>	382	<b>Refrigerant</b>	111
<b>Water</b>	7000	<b>CO<sub>2</sub></b>	177	<b>Cooling water</b>	1461
<b>Enzymes</b>	3	<b>Fusel oil</b>	6	<b>Fired heat</b>	173
<b>Nutrients</b>	5	<b>Digestate</b>	6658		
<b>Yeast</b>	6	<b>Exhaust gas</b>	300		
<b>NaOH</b>	1	<b>Flue gas</b>	1376		
<b>Air</b>	917	<b>Steam</b>	16974		
<b>Water</b>	16974				
<b>Total</b>	25973	<b>Total</b>	25973		

<sup>a</sup> Negative values denote that energy is an output of the system.

## G.4 Olefins (mainly ethylene and propylene)

### B11. Olefins production via methanol to olefins. Methanol produced from biogas

Table 55 Summary of inputs and outputs of route B11

Mass flows		Energy requirements			
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
<b>biomass</b>	8971	<b>Ethylene</b>	100	<b>Electricity</b>	-3515
<b>Water</b>	80740	<b>Propylene</b>	100	<b>Cooling water</b>	3919
		<b>C4 fraction</b>	40	<b>Steam</b>	6502
		<b>LPG</b>	20		
		<b>Digestate</b>	8239		
		<b>Flue gas</b>	74		
		<b>Water</b>	81139		
<b>Total</b>	89712	<b>Total</b>	89712		

<sup>a</sup> Negative values denote that energy is an output of the system.

## B12. Olefins production via methanol to olefins. Methanol produced from gasification

Table 56 Summary of inputs and outputs of route B12

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
biomass	1152	Ethylene	100	Electricity	390
Water	3400	Propylene	100	Cooling water	933
Air	1519	C4 fraction	40	Steam	1944
		LPG	20		
		Ash	59		
		Flue gas	1930		
		Water	3822		
<b>Total</b>	6071	<b>Total</b>	6071		

<sup>a</sup> Negative values denote that energy is an output of the system.

## E6. Olefins production via methanol to olefins. Methanol produced via alkaline electrolysis

Table 57 Summary of inputs and outputs of route E6

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	992	Ethylene	100	Electricity renewable	21134
Air	87	Propylene	100	Electricity grid	402
CO <sub>2</sub>	808	C4 fraction	40	Cooling water	2611
		LPG	20	Steam	1944
		Water	647		
		Flue gases	98		
		Oxygen	881		
<b>Total</b>	1886	<b>Total</b>	1886		

<sup>a</sup> Negative values denote that energy is an output of the system.

### E7. Olefins production via methanol to olefins. Methanol produced via SOEC

Table 58 Summary of inputs and outputs of route E7

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	947	Ethylene	100	Electricity renewable	17087
CO <sub>2</sub>	851	Propylene	100	Electricity grid	36
Air	324	C4 fraction	40	Cooling water	933
		LPG	20	Steam	2669
		Water	614		
		Oxygen	945		
		Flue gases	248		
		CO <sub>2</sub>	54		
<b>Total</b>	2121	<b>Total</b>	2121		

<sup>a</sup> Negative values denote that energy is an output of the system.

### B13. Olefins production via DME. DME direct production from biogas

Table 59 Summary of inputs and outputs of route B13

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	6399	Ethylene	100	Electricity	636
Water	58832	Propylene	86	Cooling water	1544
Air	779	LPG	36	Mid Pressure steam	1280
		CO <sub>2</sub>	200		
		waste water	58932		
		Flue gases	779		
		Digestate	5876		
<b>Total</b>	66010	<b>Total</b>	66010		

<sup>a</sup> Negative values denote that energy is an output of the system.



### B14. Olefins production via DME. DME direct production via gasification

Table 60 Summary of inputs and outputs of route B14

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	678	Ethylene	100	Electricity	1327
Water	0	Propylene	86	Cooling water	1119
Air	1147	LPG	36	Steam	1187
		CO <sub>2</sub>	200		
		waste water	438		
		Flue gases	938		
		Char	27		
<b>Total</b>	1825	<b>Total</b>	1825		

<sup>a</sup> Negative values denote that energy is an output of the system.

### E8. Olefins production via DME. DME direct production via SOE co-electrolysis

Table 61 Summary of inputs and outputs of route E8

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	1246	Ethylene	100	Electricity renewable	23230
CO <sub>2</sub>	1120	Propylene	86	Electricity grid	548
		LPG	36	Cooling water	1119
		CO <sub>2</sub>	200	Steam	2141
		Water	700		
		Oxygen	1244		
<b>Total</b>	2366	<b>Total</b>	2366		

<sup>a</sup> Negative values denote that energy is an output of the system.

### B15. Olefins production via Fischer Tropsch. Biomass gasification

Table 62 Summary of inputs and outputs of route B15

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	5670	Ethylene	100	Electricity	-11912
Air	11934	Propylene	158	Cooling water	5240
Water	1413	Butylene	75		
		LPG	140		
		C5	199		
		Flue gas	11348		
		CO <sub>2</sub>	4822		
		Water	540		
		Char	222		
		Steam	1413		
<b>Total</b>	19016	<b>Total</b>	19016		

<sup>a</sup> Negative values denote that energy is an output of the system.

### E9. Olefins production via Fischer Tropsch. SOE co-electrolysis

Table 63 Summary of inputs and outputs of route E9

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	2446	Ethylene	100	Electricity Renewable	67048
CO <sub>2</sub>	2284	Propylene	158	Cooling water	5240
Air	2335	Butylene	75		
Water	1413	LPG	140		
		C5	199		
		Flue gas	1798		
		Steam	1413		
		Water	768		
		Oxygen	3827		
<b>Total</b>	8478	<b>Total</b>	8478		

<sup>a</sup> Negative values denote that energy is an output of the system.

## G.5 Olefins (mainly propylene)

**B16. Propylene via methanol to propylene. Methanol produced from biogas**

Table 64 Summary of inputs and outputs of route B16

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	5210	Propylene	100	Electricity	-1974
Water	46891	Ethylene	6	Cooling water	1739
		LPG	7	Steam	3693
		C5 fraction	37		
		Digestate	4785		
		Flue gas	43		
		Water	47124		
<b>Total</b>	52101	<b>Total</b>	52101		

<sup>a</sup> Negative values denote that energy is an output of the system.

**B17. Propylene via methanol to propylene. Methanol produced from gasification**

Table 65 Summary of inputs and outputs of route B17

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	669	Propylene	100	Electricity	294
Water	1975	Ethylene	6	Cooling water	5
Air	882	LPG	7	Steam	1046
		C5 fraction	37		
		Ash	34		
		Flue gas	1121		
		Water	2221		
<b>Total</b>	3526	<b>Total</b>	3526		

<sup>a</sup> Negative values denote that energy is an output of the system.

### E10. Propylene via methanol to propylene. Methanol produced via alkaline electrolysis

Table 66 Summary of inputs and outputs of route E10

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	576	Propylene	100	Electricity renewable	12274
Air	50	Ethylene	6	Electricity grid	301
CO <sub>2</sub>	469	LPG	7	Cooling water	979
		C5 fraction	37	Steam	1046
		Water	377		
		Flue gases	57		
		Oxygen	511		
<b>Total</b>	1095	<b>Total</b>	1095		

<sup>a</sup> Negative values denote that energy is an output of the system.

### E11. Propylene via methanol to propylene. Methanol produced via SOEC

Table 67 Summary of inputs and outputs of route E11

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Water	550	Propylene	100	Electricity, Renewable	9923
CO <sub>2</sub>	494	Ethylene	6	Electricity grid	89
Air	188	LPG	7	Cooling water	5
		C5 fraction	37	Steam	421
		Water	358		
		Oxygen	549		
		Flue gases	144		
		CO <sub>2</sub>	31		
<b>Total</b>	1232	<b>Total</b>	1232		

<sup>a</sup> Negative values denote that energy is an output of the system.

## G.6 Olefins (mainly butadiene)

**B18. Butadiene production via 1G ethanol**

Table 68 Summary of inputs and outputs of route B18

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	3322	Butadiene	100	Electricity	352
Lime	28	C4s	3	Cooling water	828
Sulfuric acid	35	Ethylene	27	Steam	719
Water	2453	H <sub>2</sub>	5		
Ammonia	5	Steam	75		
Yeast	1	Ash	2865		
Air	290	Flue gas	327		
	0	CO <sub>2</sub>	284		
		Waste water	2447		
<b>Total</b>	<b>6133</b>	<b>Total</b>	<b>6133</b>		

<sup>a</sup> Negative values denote that energy is an output of the system

**B19. Butadiene production via 2G ethanol. Dilute acid pre-treatment**

Table 69 Summary of inputs and outputs of route B19

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	1257	Butadiene	100	Electricity	-2858
Sulfuric Acid	28	C4s	3	Cooling water	828
Ammonia	6	Ethylene	27		
Enzyme	3	H <sub>2</sub>	5		
Yeast	1	Steam	2354		
Water	2354	Flue gas	1868		
Air	1318	CO <sub>2</sub>	284		
		Ash	2		
		Sludge	323		
<b>Total</b>	<b>4967</b>	<b>Total</b>	<b>4967</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

## B20. Butadiene production via 2G ethanol. Steam explosion pre-treatment

Table 70 Summary of inputs and outputs of route B20

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	1330	<b>Butadiene</b>	100	<b>Electricity</b>	-3163
Steam	1197	<b>C4s</b>	3	<b>Cooling water</b>	828
Ammonia	6	<b>Ethylene</b>	27	<b>Steam</b>	258
Enzyme	3	<b>H<sub>2</sub></b>	5		
Yeast	1	<b>Steam</b>	2591		
Water	2591	<b>Flue gas</b>	2055		
Air	1442	<b>CO<sub>2</sub></b>	284		
	0	<b>Ash</b>	2		
		<b>Sludge</b>	1503		
<b>Total</b>	<b>6569</b>	<b>Total</b>	<b>6569</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

## B21. Butadiene production via 2G ethanol. Organosolv pre-treatment

Table 71 Summary of inputs and outputs of route B21

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	1190	<b>Butadiene</b>	100	<b>Electricity</b>	-2866
Catalyst	10	<b>C4s</b>	3	<b>Refrigerant</b>	125
Water	7874	<b>Ethylene</b>	27	<b>Cooling water</b>	2471
Enzymes	3	<b>H<sub>2</sub></b>	5		
Nutrients	6	<b>Fusel oil</b>	7		
Yeast	6	<b>Digestate</b>	7489		
NaOH	1	<b>CO<sub>2</sub></b>	199		
Air	1322	<b>Flue gas</b>	2212		
Water	19169	<b>Steam</b>	19169		
		<b>Waste water</b>	369		
<b>Total</b>	<b>29580</b>	<b>Total</b>	<b>29580</b>		

<sup>a</sup> Negative values denote that energy is an output of the system.

## G.7 Olefins and BTX (via pyrolysis)

**B22. Olefins & BTX production, biomass pyrolysis and downstream processing of WSBO and WIBO**

Table 72 Summary of inputs and outputs of route B22

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
<b>Biomass</b>	2832	<b>Benzene</b>	27	<b>Electricity</b>	-14513
<b>Air</b>	4249	<b>Toluene</b>	65	<b>Cooling water</b>	5475
<b>Natural gas</b>	0	<b>Xylenes</b>	38		
<b>Water</b>	16991	<b>Ethylbenzene</b>	3		
<b>Air</b>	1700	<b>Ethylene</b>	100		
		<b>Propylene</b>	71		
		<b>Butylene</b>	22		
		<b>CO<sub>2</sub></b>	762		
		<b>Steam</b>	16991		
		<b>Flue gas</b>	7694		
<b>Total</b>	25772	<b>Total</b>	25772		

<sup>a</sup> Negative values denote that energy is an output of the system.

**B23. Olefins & BTX production, biomass pyrolysis and downstream processing of WSBO and WIBO. One step hydrogenation**

Table 73 Summary of inputs and outputs of route B22

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
<b>Biomass</b>	1757	<b>Benzene</b>	24	<b>Electricity</b>	-2936
<b>Air</b>	2636	<b>Toluene</b>	52	<b>Cooling water</b>	6309
<b>Natural gas</b>	55	<b>Xylenes</b>	55		
<b>Water</b>	7046	<b>Ethylbenzene</b>	5		
<b>Air</b>	670	<b>Ethylene</b>	100		
		<b>Propylene</b>	68		
		<b>Butylene</b>	22		
		<b>CO<sub>2</sub></b>	784		
		<b>Steam</b>	6923		
		<b>Flue gas</b>	4132		
<b>Total</b>	12164	<b>Total</b>	12164		

<sup>a</sup> Negative values denote that energy is an output of the system.

**B24. Olefins & BTX production, biomass pyrolysis and downstream processing of WSBO**

Table 74 Summary of inputs and outputs of route B22

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	3806	Benzene	26	Electricity	-8452
Air	5709	Toluene	47	Cooling water	5027
Water	11928	Xylenes	21		
Air	1164	Ethylbenzene	1		
		Ethylene	100		
		Propylene	110		
		Butylene	30		
		CO <sub>2</sub>	738		
		Steam	11928		
		Flue gas	8471		
		WIBO	1134		
<b>Total</b>	22607	<b>Total</b>	22607		

<sup>a</sup> Negative values denote that energy is an output of the system.

**B25. Olefins & BTX production, biomass pyrolysis and downstream processing of WSBO. One step hydrogenation**

Table 75 Summary of inputs and outputs of route B22

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	2651	Benzene	37	Electricity	-3503
Air	3976	Toluene	96	Cooling water	4842
Natural gas	128	Xylenes	66		
Water	8285	Ethylbenzene	6		
Air	673	Ethylene	100		
		Propylene	174		
		Butylene	40		
		CO <sub>2</sub>	737		
		Steam	7997		
		Flue gas	5670		
		WIBO	790		
<b>Total</b>	15713	<b>Total</b>	15713		

<sup>a</sup> Negative values denote that energy is an output of the system.



**B26. Olefins & BTX production, biomass pyrolysis and downstream processing of WSBO. Two step hydrogenation**

Table 76 Summary of inputs and outputs of route B22

Mass flows				Energy requirements	
Inputs	kt/y	Outputs	kt/y	Utility type <sup>a</sup>	TJ/y
Biomass	1687	Benzene	33	Electricity	-2223
Air	2530	Toluene	62	Cooling water	4305
Natural gas	114	Xylenes	24		
Water	5272	Ethylbenzene	3		
Air	355	Ethylene	100		
		Propylene	168		
		Butylene	44		
		CO <sub>2</sub>	519		
		Steam	5016		
		Flue gas	3485		
		WIBO	502		
<b>Total</b>	9958	<b>Total</b>	9958		

<sup>a</sup> Negative values denote that energy is an output of the system.

## H Approach to defining promising chemical supply options

The approach followed to assess different supply options integrates data of the demand of chemicals for 2030 and 2050, data of feedstock potentials (i.e., biomass and CO<sub>2</sub>) and prices for 2030 and 2050, and data related to the conversion of those feedstocks into the valuable chemicals. The overall approach followed can be described in 9 steps (see Figure 92).

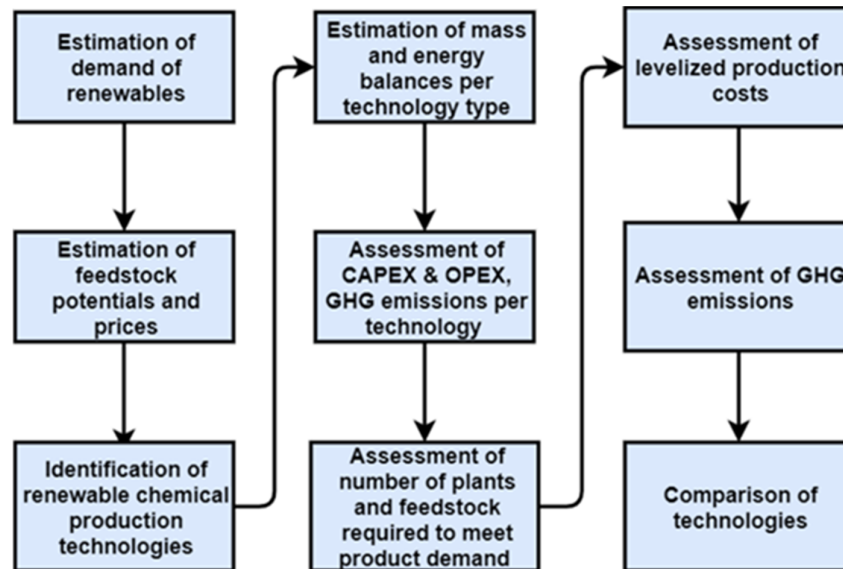


Figure 93 Approach followed to assess technologies options for producing renewable chemicals in 2030 and 2050

In total 37 different pathways are identified. Table 38 in Appendix presents a summary description of the renewable pathways considered in this study.

### ***Estimation of demand of renewables***

The information presented in section 3 section shows what are the projections of chemicals demand in 2030 and 2050. This information is key to the assessment of technologies as it allows to estimate the amounts of renewable chemicals that need to be produced in 2030 and 2050, respectively. We have assumed (according to the description of scenarios) that 15% of the demand of chemicals in 2030 and 30% in 2050 would be covered with production by alternative processes (i.e., bio-based and e-based) in comparison to their conventional production. The assessment is oriented to assess what are the impacts in leveled costs and GHG emissions when using renewable pathways to cover the required demand in 2030 and 2050.

### ***Estimation of feedstock potential and prices***

The information presented in section 5.1 relates the potential availability of feedstocks per type and their distribution of prices. This information is used as input to determine whether the feedstock available, technically feasible and at certain price is able to cover the feedstock required to meet the demand of the chemical. In case the cheapest technical feasible option is not sufficient to meet the demand, a second feasible feedstock is considered at a higher price. The latter is repeated until three level of feedstock availability and prices. In summary, up to three levels of feedstock availability and prices can be included in the assessment.

### ***Identification of renewable chemical technologies***

The identification of technologies came together with a thorough literature review on possible renewable production pathways of chemical building blocks. The identification and selection of technologies is focused on Methanol, DME, Ethylene, Propylene, Butadiene and BTX (Benzene, toluene, xylene).

### ***Estimation of mass and energy balances***

Mass and energy balances were estimated based on studies assessing the techno-economic performance of different conversion steps of the value chains described above. As there are value chains with multiple conversion steps, it was necessary to combine data reported in literature to be able to complete the mass and energy inputs and outputs. An example of this can be observed in the case of ethylene production, in which the conversion of biomass into ethanol was gathered from one source, but the conversion of ethanol into ethylene was gathered from a different source. This implied that harmonizing the data was necessary to be able to describe the conversion routes correctly. Due to this, linear escalation of mass and energy flows was adopted in this study. Table 38 provides an overview you of the studies used to illustrate the mass and energy flows of each value chain.

### ***Assessment of CAPEX, OPEX and GHG emissions per technology***

The energy flows estimated in the previous step are the basis for the assessment of cost and GHG emissions related to each technology option. An explanation of the assumptions and main input data is presented as follows.

#### **CAPEX**

The capital expenditure of each value chain was estimated by aggregating the capital cost of the different steps. Similar to the case of estimating mass and energy balances, capital costs also need to be harmonized, as different sources were required to illustrate the capital cost of the value chain. In this case, it was assumed that capital costs of each compression step were evaluated using the six tenth rule of thumb, using an escalation factor of 0.7 (in exception of electrolysis). Table 39 in Appendix provides an overview of the base CAPEX and sources used in each conversion step of the different value chains considered.

#### **OPEX**

The operational expenditure (OPEX) of each technology option is composed by the costs of main feedstock, additional materials, energy inputs, fixed and co-products credits. Feedstock costs are accounted for by relating its price with the mass. In case

there is any extra material its cost is estimated analogously. Energy costs relate to the cost of electricity, steam and cooling utilities required to run the process, and are estimated by relating the energy flows with input prices. Fixed costs are estimated as 5% of CAPEX in all cases. Electricity is accounted as the only co-product to be credited, its revenue are accounted for as a credit of OPEX. In the case of multioutput processes such as olefins production, a basket of products is selected as output (mixture). Table 77 shows main price inputs included in the analysis. It is important to mention that the prices presented below were selected as base inputs and fixed through the analysis. Only the most relevant parameters affecting cost the most will be assessed in more detail.

Table 77 Prices used to estimate OPEX. Prices assumed to be applicable for 2019. Projections on prices were not considered and thus left fixed for 2050.

Feature	Price <sup>a</sup>	Unit	Reference
Natural gas	6	€/GJ	(Rajendran and Murthy, 2019)
Electricity, grid	0.043	€/kWh	(Rajendran and Murthy, 2019)
Electricity, green	0.080	€/kWh	Assumed, to be assessed its effect
Steam	11	€/tonne	(Rajendran and Murthy, 2019)
Water	0.1	€/m <sup>3</sup>	(Moncada et al., 2018b)
Lime	100	€/t	(Nitzsche et al., 2016)
Yeast	1000	€/t	(Nitzsche et al., 2016)
Sulfuric acid	150	€/t	(Nitzsche et al., 2016)
Ammonia	400	€/t	(Nitzsche et al., 2016)
Enzymes	2000	€/t	(Nitzsche et al., 2016)

<sup>a</sup> All prices were assumed to be applicable to 2019.

### GHG Emissions

GHG emissions were estimated using two approaches. The first approach considers a cradle to gate greenhouse gas emissions accounting in which emissions for the production of feedstock, production of utilities and emissions produced during processing are considered (if those are not biogenic). The second approach considers the accounting of emissions as cradle to gate plus the emissions if the carbon embedded in the product is released in the form of CO<sub>2</sub> at any time in its lifetime. This was done to assess the effect of different approaches for GHG emission accounting for those systems which uses CO<sub>2</sub> as feedstock (i.e., power to x). In the case of bio-based systems emissions related to product use were considered as biogenic.

GHG emissions accounting do not consider emissions related to transport distribution, logistics, infrastructure given the coarse characteristic of the analysis. Emissions were compared to the petrochemical counterparts. Emission factors related to biomass production were gathered from the JRC Science for policy report on solid and gaseous bioenergy pathways (Rajendran and Murthy, 2019) (see Table 78) and assumed to be applicable for 2050. The main bio feedstocks used in this study are woody biomass, agricultural residues, wet biomass (for anaerobic digestion), and sugar beet (for 1G ethanol production). In the case of woody

biomass, as well as for the case of wet biomass, the average emission factor of those presented in Table 78 were used. Emission factor for sugar beets was gathered from Ecoinvent databases (Wernet et al., 2016). Carbon dioxide inputs were assumed to be carbon free, as for 2050 it is expected that energy use for capture is done with renewable energy.

Table 78 Emission factors used for biomass.

Emission factors	gCO <sub>2</sub> eq/MJ biomass
	Value
Wood chips from	
Forest residues	1.90
SRC (poplar with no fertiliser)	2.20
SRC (poplar with fertiliser)	3.90
Stem wood	1.50
Wood industry residues	0.40
Average	2.00
Agricultural feedstocks	
Agricultural residues	1.10
Biowastes for AD	
Manure	-0.023
Maize	0.063
Vegetable waste	0.00
Sludge	0.00
Animal & mixed food waste	0.00
Weighted average	-0.00486

In the case of processes having electricity as co-product, mass allocation was adopted by using the carbon mass that is used for electricity production and the main product(s), as previously done in (Moncada et al., 2018b). Only in the case of pyrolysis, where both BTX and olefins are produced mass allocation was used to distribute the impacts between basket of products with olefins applications and basket of products with BTX applications.

#### ***Assessment of number of plants and feedstock required to meet demand***

To estimate the number of processing plants to meet product demand, it was necessary to establish a base case process capacity for the renewable routes. We here assumed that the base capacity is 100 kt/y of renewable product output. With this information and the total product demand, one can estimate the number of plants required, at 100 kt/y each (installed capacity), to meet the demand. To make the estimation realistic the relation of plant capacity and product demand was rounded up as plants can only be counted as natural numbers. That means that in some the plants are not necessarily running at full capacity to meet the demand, but at a lower rate that installed.

The number of plants required also account for the impact of operating hours per year, especially for power to x systems or to those systems where seasonality is

important. For instance, an e-based system is built to run at its maximum utilization capacity (100 kt/y) assuming that it can be operated for 8000 h/y. However if the system can only run for 4000 h/y, it means that it can only deliver half of its production capacity and thus double number of installations would be required to meet the demand. In this study, we have assumed that both bio-based and e-based systems would run for 8000 h/y. Nevertheless, as for e-based systems this could be a very relevant factor, we have analysed the cases where those run for 4000 h/y. Feedstock required was estimated by relating the conversion yield of each technology option with total product demand.

### Assessment of levelized production costs and GHG emissions

Levelized costs were estimated by adding up annualized CAPEX and OPEX. Annualized CAPEX was estimated using Equation 1 where plant life time ( $t$ ) and interest rate ( $i$ ) are input parameters. A plant lifetime of 20 years and interest rate of 3% was assumed for all cases .

$$\text{Annualized CAPEX} \left( \frac{\text{€}}{\text{year}} \right) = \text{CAPEX} (\text{€}) \cdot \frac{i}{1 - \frac{1}{(1+i)^t}} \quad \text{Equation 1}$$

OPEX was estimated using the categories mentioned above. Nevertheless, it should be mentioned that we considered three levels of feedstock supply and costs. The assessment considers that the most technical feasible and as well as the cheapest is the preferred feedstock supply alternative. Nevertheless, if the feedstock is not enough to supply the systems to meet the product demand, the second level (second cheapest) is used. The same was done for the third level. In case feedstock is not sufficient, it is complemented with external feedstock and is discussed in the results in case it happens. The prices used for biomass and CO<sub>2</sub> are explained in detailed in section 4.1. Sensitivity analysis on main parameters such as renewable electricity price, CAPEX, is considered within the analysis.

It is important to mention here that the analysis do not follow an optimization procedure and we have assessed each technology option individually as one can meet the production demand required. If best combinations of technologies is aimed to be established (under certain constraints) an in depth modelling exercise might be required and it is out of the scope of this study.

GHG emissions are compared between technologies and as well with emissions of their counterparts following the approaches mentioned above.