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Technical assistance to assess the potential of renewable liquid and gaseous transport fuels of non-biological origin (RFNBOs) as well as recycled carbon fuels (RCFs), to establish a methodology to determine the share of renewable energy from RFNBOs as well as to develop a framework on additionality in the transport sector

Final report | Task 1

Assessment of the potential of RFNBOs and RCFs over the period

2020 to 2050 in the EU transport sector

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ABSTRACT

This report is a summary of the work conducted in Task 1 of the technical assistance to assess the potential of renewable fuels of non-biological origin (RFNBOs) and recycled carbon fuels (RCFs) to establish a methodology to determine the share of renewable energy from RFNBOs as well as to develop a framework on additionality in the transport sector. The goal of Task 1 within the entire project was the assessment of the deployment potential of RFNBOs and RCFs over the period from 2020 to 2050 in the EU transport sector. All relevant transport sub-sectors and modalities are considered: road transport, maritime and inland shipping, aviation, and railway. Furthermore, the competition for RFNBOs and RCFs between the transport sectors and other sectors and applications of RFNBOs is considered. A central result is the potential gross final consumption of RFNBOs and RCFs that would count towards the RES target in the transport sector. In addition, the needed resources and the arising costs for this deployment as well as the impacts on greenhouse gas emissions and local environments are analyzed. Finally, barriers to the deployment and options to overcome these are outlined.

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LIST OF ABBREVIATIONS

AEL	alkaline electrolysis
CAPEX	capital expenditures
CCUS	carbon capture utilisation and storage
CLC	chemical looping combustion
CH_4	methane
CO_2	carbon dioxide
CSP	concentrated solar power
DAC	direct air capture
FEC	final energy consumption
FTS	Fischer-Tropsch synthesis
GHG	greenhouse gas
HHV	higher heating value
HT	high temperature
KIT	Karlsruhe Institute of Technology
KOH	potassium hydroxide
kWh	kilowatt-hour
LCA	life-cycle assessment
LCOE	levelized costs of electricity
LHV	lower heating value
LNG	liquefied natural gas
LSM	lanthanum strontium manganese
LT	low temperature
MEA	membrane electrode assembly
MEA	monoethanolamine
MOF	metal-organic frameworks
MeOH	methanol
MSW	municipal solid waste
MTG	methanol to gasoline
Ni	nickel
Ni-Co	nickel-cobalt
Ni-Mo	nickel-molybdenum
NH_3	ammoniac
Nm^3	normal cubic meter
OPEX	operating expenditures
PEMEL	polymer electrolyte/proton exchange membrane electrolysis
Pt-Pd	platinum-palladium
PtG	power-to-gas
PtL	power-to-liquid
PtX	power-to-x
PV	photovoltaic
PVC	polyvinyl chloride
RCF	recycled carbon fuel
RES	renewable energy source
RFNBO	renewable liquid and gaseous transport fuel of non-biological origin
rWGS	reverse water-gas shift
SNG	synthetic natural gas
SOEL	solid oxide electrolysis
TCO	total cost of ownership

TRL	technology readiness level
TWh	terawatt-hour
V	volt
wt%	mass fraction
YSZ	yttria-stabilised zirconia

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EXECUTIVE SUMMARY

This is a summary of the work conducted in Task 1 of the technical assistance to assess the potential of **renewable fuels of non-biological origin (RFNBOs) and recycled carbon fuels (RCFs)** to establish a methodology to determine the share of renewable energy from RFNBOs as well as to develop a framework on additionality in the transport sector. The goal of Task 1 within the entire project is the assessment of the potential of RFNBOs and RCFs over the period from 2020 to 2050 in the EU transport sector.

As a technical basis for the scenarios developed, a detailed **technical description of potential pathways to produce RFNBOs and RCFs** from different feedstock is provided (Section 2). To this end, the processing routes are divided into major processing steps, which are described step by step including the state-of-the-art processing technologies and technology readiness levels (TRL) of alternative technologies that are currently under development. The RFNBO processing steps include electrolysis, carbon capture, syngas formation as well as different synthesis processes and the subsequent fuel separation and refining. As clearly shown in the technical analysis, chemical synthesis in order to produce fuels from syngas are well-established, state-of-the-art industrial processes that have been put into practice for processing fossil fuels in various existing production facilities. However, upstream processing steps of RFNBOs such as syngas formation from CO_2 and H_2 or electrolysis to produce H_2 in large quantities are partly still in the development stage and show comparatively low TRLs. The same is true regarding processes to produce high-grade transport fuels (RCFs) from waste streams such as e.g. mixed plastic waste through catalytic pyrolysis or gasification. Here, the provision of tailored high-quality syngas or pyrolysis oil are challenging from a technical point of view, due to inhomogeneous waste fractions with various impurities. Relevant sources of RCFs are plastic waste that is not suitable for recycling, industrial exhaust gases and further liquid waste streams.

Following the technical description of the different production pathways, the **potentials for integrating RFNBOs and RCFs into the European energy system by 2050** are evaluated based on techno-economic and environmental factors in Section 3. To this end, three RFNBO demand scenarios and three RFNBO production scenarios are developed, which are subsequently combined with each other. The scenario development and the analyses are mainly based on existing long-term scenarios in published studies and additional data available in the literature, which are supplemented by own assumptions where necessary. The field of RCFs is not or not separately considered in existing long-term studies. For this reason, RCFs are considered in separate scenarios. For the development of RFNBO scenarios, 14 long-term scenarios from existing studies were selected for closer examination based on the criteria "reduction of CO_2 emissions" (> 90% by 2050 compared to 1990), broad range of "technical options and behaviour", and "data availability and harmonisation". The literature review reveals a wide range of projections for relevant parameters in the EU (EU-27 + UK), depending on the chosen assumptions (see Section 3.1.1).

Based on the literature review, the **three RFNBO demand scenarios MUST, CAN and COULD** are synthesised, which estimate a possible range of future RFNBO deployment in the EU in 2050 (see Section 3.1.2):

- The scenario **MUST** with in total 935 terawatt-hours (TWh) per year represents the lower bound of RFNBO use. To this end, a very low expected final energy consumption is combined with a low RFNBO coverage share that results mainly (but not exclusively) from energy applications in which the use of power-to-x (PtX) technologies is without alternatives. The latter include in particular aviation and international navigation with 236 TWh demand of RFNBOs (thereof 66% power-to-liquid (PtL)) as well as 460 TWh hydrogen as feedstock for industry. These demand

volumes are assumed as a constant baseline consumption in all three RFNBO demand scenarios. The remaining RFNBO demand is divided into 172 TWh (55% thereof hydrogen) for the domestic transport sector (land-based transport and inland navigation) and 67 TWh synthetic natural gas (SNG) for the industrial sector.

- The scenario **CAN** represents a possible medium demand for RFNBOs with applications in which the use of PtX technologies competes among others with direct electrification processes and where the respective use is subject e.g. to the evaluation of economic factors. In total, a final RFNBO consumption of 1,350 TWh (incl. hydrogen feedstock) per year is assumed. The final RFNBO consumption in the domestic transport sector rises moderately to 232 TWh (81% thereof hydrogen). In addition to the hydrogen feedstock, the industrial sector accounts for 88 TWh hydrogen and 124 TWh SNG for energy applications. Furthermore, 187 TWh SNG will be used in the building sector.
- The third scenario **COULD** represents the expected upper bound for RFNBO demand which also considers applications for which the use of RFNBOs is possible in principle but not the most likely option according to today's knowledge (e.g. small and medium passenger cars, light-duty vehicles, etc.). The RFNBO demand across all sectors reaches a level of about 2,270 TWh per year (incl. hydrogen feedstock). 754 TWh thereof are accounted for by the domestic transport sector (369 TWh hydrogen, 142 TWh SNG and 243 TWh PtL) in addition to the 236 TWh RFNBOs for aviation and international navigation. In the industrial sector, besides the 460 TWh hydrogen feedstock, 338 TWh hydrogen and 124 TWh SNG are used energetically. In the building sector, the demand for SNG increases to 254 TWh. Additionally, 80 TWh of hydrogen are used in buildings.

For the **three RFNBO supply scenarios (optimistic, medium, pessimistic)**, the assumptions regarding the availability and cost of feedstocks (renewable electricity and CO_2) and of electrolysis and synthesis plants for the production of RFNBOs in the EU are derived from the previously selected studies and further literature. Based on these assumptions, RFNBO cost potential curves are calculated and compared to the cost of imported RFNBOs. The results presented in Section 3.1.3 show that there is a significant potential for the production of green hydrogen and derived fuels in the EU (1,200 to 2,400 TWh_{H2} in 2050). Under the chosen assumptions, this potential is rather more limited by the assumed maximum capacity and usage of the electrolysers than by the available amount of renewable electricity. However, the RFNBO potential in the EU being cost-competitive with imports is limited by the available potentials of cheap renewable electricity. The results of the combined RFNBO demand and supply scenarios presented in Section 3.1.4 show that there is a substantial potential for RFNBO production in the EU at costs competitive with imports (at least 550 and up to 1,000 TWh in 2050). Under optimistic supply assumptions, a low RFNBO demand could be covered cost-effectively with only minor imports. However, under less optimistic supply assumptions and/or with demand for RFNBOs in further sectors and end uses, a considerable amount of RFNBOs (up to 1,700 TWh in 2050) would probably be imported due to lower supply costs. The feedstock demand for RFNBO production in the EU could be up to 1,400 TWh of renewable electricity and up to 75 $MtCO_2$ in the year 2050, which would require building up considerable renewable sources of electricity (RES-E) generation capacities and probably also capacities for direct air capture of CO_2.

Regarding the **potential production of RCFs**, the scenarios developed in Section 3.2 build upon the availability of relevant waste streams under consideration of alternative utilisation pathways because feedstock availability is the major limitation for all processing routes. The most relevant waste flows for the potential production of RCFs, which were identified in the analysis, are mixed plastic waste fractions from municipal solid waste (MSW) that can be processed through pyrolysis or gasification, exhaust gases from steel furnaces that can be transformed into ethanol through biotechnological fermentation, landfill gases with a high content of methane that could serve as a transport fuel and shipping slops as the most important source of liquid waste streams. Three scenarios regarding an optimistic, a medium and a pessimistic development of RCF production were developed. All scenarios are limited by feedstock availability, also against the backdrop of competing utilisation pathways of relevant waste streams, which are mainly used for energy provision through combined heat and power generation. However, improvements in chemical recycling and waste separation are also expected to further decrease feedstock availability for RCF production in future, particularly regarding solid waste streams. Subsequently, a strong limitation of landfilled waste and a replacement of oxygen steel furnaces through direct reduction technology with hydrogen are expected to strongly limit the availability of gaseous waste streams in future. Considering these developments, the optimistic scenario shows an overall production potential of 80 TWh of RCFs until 2040, the medium scenario reaches 60 TWh in 2040 with slightly declining production until 2050 while the pessimistic scenario only reaches a volume of around 30 TWh until 2040. Keeping in mind that the waste used for RCF production is fossil-based and that feedstock availability will decline in future, RCF production seems mainly suitable as an interim solution for the provision of alternative fuels.

Based on the scenarios for demand for and supply with RFNBOs and RCFs, **the impacts of the potential large-scale diffusion of RFNBOs and RCFs** are assesed as follows in this report (Section 4):

- According to the analysis, RFNBOs can substantially contribute to the **share of renewable energy sources (RES)** in energy consumption (Section 4.1). This applies to the transport sector already in 2030 with a share of up to 4%, while it is relevant for the overall RES share only in the longer term. However, the amount of RFNBOs produced will also have a dampening impact on the overall RES share due to the high electricity input required. In turn, RCFs can play a role as a bridging fuel in the transport sector in 2030 of 1 to 2%, but have a limited potential compared to RFNBOs in the long term until 2050.
- The strictness of requirements with respect to the **sourcing of renewable electricity (RES-E)** inputs can have substantial impacts on the competitiveness of domestic production of RFNBOs within the EU (Section 4.2). In particular, this applies in the shorter term until 2030 due to the constraints stemming from limited production capacities, but there are also relevant impacts in the longer term. However, the benefits from less strict requirements for competitiveness need to be seen in light of the lower stringency of the achieved GHG emission avoidance. Moreover, the loss of competitiveness in case of stricter requirements for RES-E sourcing can be reduced, if these requirements are applied to imports of RFNBOs in an equally strict manner.
- With respect to **wholesale prices** (Section 4.3.1), there is a large gap between the expected prices for fossil fuels and all kinds of RFNBOs not only in the shorter term until 2030 but also in the longer term, if external costs are not internalised in some way. Compared to hydrogen, the price gap is substantially larger for methane and liquid RFNBOs due to the higher conversion losses and the necessary carbon input. Accordingly, the required carbon price to close the gap for hydrogen could be reached in the longer term, while this seems questionable for methane and liquid RFNBOs. However, when total costs of ownership (TCO) is considered instead of fuels only, this would partially be compensated for vehicles running on standard combustion engines due to higher costs of fuel cells. For gaseous and liquid RFNBOs, blending quotas for sectors with a particular need such as the maritime and aviation sectors could provide a more promising option to support market uptake. For RCFs, the situation is similar to that for hydrogen with the exception of RCFs based on shipping slops, which might become cost-competitive by 2030.

- Based on the objective of GHG neutrality, there is a large potential **market volume** for RFNBOs in the long term, which corresponds to large investment requirements, in particular with respect to the building up of electrolyser capacities (Section 4.3.2). In order to foster the necessary scale up of **investments**, there already are substantial investment requirements of 8 to 22 billion €$_{2019}$ until 2030. If RCFs are meant to play a major role as a bridging fuel, there are also similar investment requirements of 5.5 to 13 billion €$_{2019}$ into RCF plants until 2030. However, these bear the risk of becoming stranded investments to a certain extent due to the non-renewability of waste carbon streams. The market potential for imported RFNBOs is substantial, especially if the demand for RFNBOs becomes widespread across different sectors.
- Considering **greenhouse gas emissions (GHG)** (Section 4.4), it can be stated that RFNBOs are only associated with emissions if the sourced electricity is not fully renewable, whereby potential GHG emissions from the construction of the plants are neglected here. This is true for the default case in the Renewable Energy Directive of sourcing grid electricity, the grid emission factor (along with the production efficiency) then determining the emission burden of the RFNBO. In the case of RCFs, the scope of the accounting determines the emissions as aspects of a life cycle analysis are considered to a varying degree. Emissions range between 78 and 90 gCO$_2$/MJ, depending on the source of the electricity and the accounting and use of by-products.
- **Local environmental impacts** from the production and use of RFNBOs are generally assumed to be much smaller than those from conventional crop-based biofuels (Section 4.5). However, there are impacts, mainly on land and water use. Renewable electricity generation for RFNBO production requires space and it must be examined whether land is occupied that could be used for agriculture or other purposes. Hydrogen production through electrolysis and some direct air capture (DAC) technologies consume large amounts of water, which could exacerbate water scarcity problems in countries with hot and dry climates. Given the limited information available on environmental impacts of RCFs, no clear assessment can be made yet.

Multiple barriers determine the overall potential of RFNBOs / RCFs and may slow down their deployment (see Section 5.1). Today and in the mid to long term, without funding or a corresponding legal framework, no type of synthetic fuel is competitive compared to its fossil or biogenic competitors. There are also critical limitations regarding the availability of infrastructure, energy and feedstocks that can further delay their ramp-up. On the regulatory side, the lack of a comprehensive framework for RFNBOs and RCFs providing long-term certainty, inhibits investments in the production and use of these fuels. Regarding the technological maturity, some promising technologies for RFNBOs and RCFs are not yet available on an industrial scale. Lastly, the uncertainty concerning novel technologies and their impact can lead to opposition from the civil society. **Options to address these barriers** (see Section 5.2) could include investment support and reduced taxes and levies for electricity to bring down production costs, while a quota for synthetic fuels in sectors with a particular need such as aviation and navigation can create long-term certainty for investors by creating a market for RFNBOs / RCFs. Equally important is establishing a comprehensive and coherent regulatory framework that addresses the uncertainty surrounding additionality criteria, standards, certification, and accounting rules for utilised process emissions.

Key takeaways:

ASSESSMENT OF POTENTIAL PATHWAYS FOR RFNBOS AND RCFS

- The **overall value chain of** most production pathways for **renewable fuels of non-biological origin (RFNBOs)** is not yet at a commercial development stage (TRL 9).
- **Downstream processing** regarding the conversion of syngas into liquid and gaseous fuels and their subsequent refining is well-established on an industrial scale based on the conversion of fossil natural gas into liquid fuels (mainly through Fischer-Tropsch synthesis (FTS)).
- **Upstream processing**, particularly the formation of syngas from hydrogen and carbon dioxide remains challenging and is not yet realised at a commercial level in large-scale industrial plants.
- The development of **direct air capture** (DAC) as a carbon source is a key factor for the implementation of large-scale industrial plants in regions where renewable electricity (solar, wind) is abundant.
- New technologies such as the **high temperature solid oxide co-electrolysis** (HT SOEC) are promising solutions to significantly increase the overall efficiency of RFNBO production. However, their current TRL is not sufficient for commercialisation.
- Regarding the production of **recycled carbon fuels (RCFs)**, especially the provision of high-grade transport fuels, there is often a competition between thermal use of waste streams, chemical recycling and fuel production, making RCFs from fossil-based mixed waste fractions questionable as a sustainable transport fuel.

ASSESSMENT OF DEMAND AND SUPPLY SCENARIOS FOR RFNBOS

- Projections of **final energy demand of all sectors in the EU** in existing studies show significant reductions from 1,060 Mtoe (today) to levels ranging from 740 Mtoe (-30 %) to 420 Mtoe (-60 %) in 2050. Fossil fuels will be replaced primarily by (renewable) electricity. Coverage shares by RFNBOs range from <1% up to 20%.

- Total **RFNBO demand across all sectors** in the scenarios developed in this study ranges from 935 TWh to 2,268 TWh and includes international transport as well as 460 TWh hydrogen feedstock demand for industry.

- The **RFNBO demand for domestic transport** (land-based and inland navigation) varies between 172 TWh and 754 TWh. For aviation (EU-internal and internationally) and for international navigation, a demand of 155 TWh power-to-liquid (PtL), 59 TWh synthetic natural gas (SNG) and 22 TWh hydrogen is expected in all developed RFNBO demand scenarios.

- The **green hydrogen generation potential** in the EU in 2050 varies between 1,200 and 2,400 TWh_{H2} in the scenarios developed in this study, but only a part of this potential would be cost-competitive with imports.

- The corresponding **hydrogen generation costs** in the EU in 2050 vary between 50 and more than 200 EUR/MWh.

- The **amount of RFNBOs from EU production being cost-competitive with imports** varies between 16 and 120 TWh in 2030 and between 550 and 1,000 TWh in 2050. The **RFNBO imports required to cover the demand in the EU** vary between 64 and 1,000 TWh in 2050.

ASSESSMENT OF SUPPLY SCENARIOS FOR RCFS

- Potential production volumes of RCFs are restricted by feedstock availability. A further limitation is the **competition with alternative utilisation** pathways of waste streams, most of which are expected to decline in future.
- Municipal solid waste fractions that are not suitable for recycling, mainly containing mixed plastic waste, are the most **important feedstock for RCF production** in terms of mass potentials, followed by shipping slops, landfill gas and blast furnace gas.
- The potential **production volume** peaks in 2040 and slightly decreases afterwards. The peak reaches 80 TWh in the optimistic scenario, 60 TWh in the medium scenario and 30 TWh in the pessimistic scenario.
- Due to the limited feedstock and the fact that fossil-based waste is not of renewable origin, which strongly reduces GHG mitigation potentials, RCFs mainly seem useful as an **interim source of alternative fuels** in the mid-term future.

IMPACTS OF A POTENTIAL LARGE-SCALE DIFFUSION OF RNFBOS AND RCFS

- RFNBOs can substantially contribute to the **RES share in energy consumption**, with a share of up to 4% in the transport sector as early as 2030. In turn, RCFs can play a role as a bridging fuel in the transport sector in 2030 of 1 to 2%, but have a limited potential compared to RFNBOs in the long term until 2050.
- The strictness of requirements with respect to the **sourcing of RES-E** inputs can have substantial impacts on the competitiveness of production of RFNBOs within the EU, particularly in the shorter term until 2030.
- There is a large **price gap** between the expected prices for fossil fuels and RFNBOs also in the long term until 2050, if external costs are not internalised in some way. Compared to hydrogen, the price gap is substantially larger for methane and liquid RFNBOs due to the higher conversion losses and the necessary carbon input. Certain types of RCFs might become cost-competitive by 2030, while other face price gaps similar to that for hydrogen.
- In order to foster the necessary **scale up of investments**, there are already substantial investment requirements of 8 to 22 billion €$_{2019}$ until 2030. For RCFs, similar investment of 5.5 to 13 billion €$_{2019}$ are required until 2030.
- Considering **GHG emissions**, RFNBOs are only associated with emissions if the sourced electricity is not fully renewable, in particular if grid electricity is used. In the case of RCFs, specific emissions range from 78 to 90 gCO_2/MJ.
- **Local environmental impacts** from RFNBOs are smaller than those from conventional crop-based biofuels, but electrolysis and certain DAC technologies consume large amounts of water, which could exacerbate water scarcity in countries with dry climates. Given the limited information available on RCFs, no clear assessment can be made yet.

BARRIERS TO A LARGE-SCALE DIFFUSION OF RNFBOS AND RCFS

- **Multiple barriers** regarding cost competitiveness, but also the availability of infrastructure, energy and feedstocks may slow down the deployment of RFNBOs and RCFs. Regarding the technological maturity, some promising technologies are not yet available on an industrial scale.
- The lack of a comprehensive regulatory framework and **uncertainty** surrounding novel technologies inhibit investments in the production and use of RFNBOs and RCFs.
- **Options to address these barriers** include financial support of RFNBO production and a quota for synthetic fuels in sectors with a particular need, such as aviation and navigation.
- Equally important is a comprehensive and coherent **regulatory framework**.

1 INTRODUCTION

1.1 Objectives and structure of the report for Task 1

This project is structured in three tasks which are covered by separate reports. This report deals with Task 1 which is concerned with assessing the potential of RFNBOs and RCFs in the EU's transport sector from today until 2050[1].

Details on the other tasks can be found in the respective separate reports. They are concerned with the following topics:

- Task 2: Developing detailed rules by which producers of RFNBOs can provide evidence that they are using fully renewable electricity in the production of their fuel in order to establish the methodology under Article 27, paragraph 3, subparagraph 7 of RED II.

- Task 3: Developing a framework on additionality in the transport sector and develop different options with a view to determining the baseline of Member States and measuring additionality, in accordance with Article 27, paragraph 3, subparagraph 3 of RED II.

In Task 1 we analyse the deployment potential of RFNBOs and RCFs in the EU's transport sector from today until 2050, the resources needed for this deployment as well as the environmental impacts, e.g. on greenhouse gas emissions. Another central result is the gross final consumption of RFNBOs and RCFs that counts towards the renewable energy target in the transport sector. All relevant transport sub-sectors and modalities are considered: road transport (with many submodalities), maritime and inland shipping, aviation, and railway. We also study the competition for RFNBOs and RCFs between the transport sectors and other sectors and applications of RFNBOs.

This task is divided into two major subtasks. In Subtask 1.1, we identify all potential pathways to produce and deliver RFNBOs and RCFs. We include a detailed description of relevant processing steps, basic material and energy balances, potential feedstocks targeted by each technology, the current technology readiness levels (TRLs) of the respective technologies and how TRLs could develop towards 2030 and 2050. Also, we map the organisations that are (currently) driving the development as these should be consulted elsewhere in this project.

In Subtask 1.2 we then assess the development potential of the identified RFNBO/RCF pathways towards 2050 in more detail. This analysis starts with a literature review of scenario and potential studies in Subtask 1.2.1. In Subtask 1.2.2 we then deduce the total realisable deployment of RFNBOs and RCFs for all sectors, taking into account relevant barriers, and in Subtask 1.2.3 we create (sensitivity) scenarios of how much of the total potential will be used in the transport sector. We differentiate by type of fuel, production pathways and the transport modes using the fuels. In Subtask 1.2.4 we then analyse the relevant aspects of the scenarios, especially the gross final consumption of RFNBOs and RCFs counting towards the renewable energy sources (RES) target in the transport sector. We perform a techno-economic evaluation of relevant processing steps regarding current investment and processing costs as well as potentials for technological improvements in the

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[1] Within this report, with "EU" we refer to the EU-27 member states and the United Kingdom (i.e. the former EU-28), if not otherwise stated.

coming years. Other aspects such as land use and local impacts are analysed systematically. The task concludes with Subtask 1.2.5, which is a discussion of barriers to the deployment of RFNBOs and RCFs, and how to overcome them.

As the assessment of development potentials of RFNBOs and RCFs is linked to high uncertainty particularly when regarding a far-off future, Subtask 1.2 also includes a comprehensive sensitivity analysis with the goal to both identify major drivers for the development potentials as well as to quantify potential ranges for relevant factors such as production quantities, cost and price developments or environmental impacts and greenhouse gas emissions.

In September 2020, the first interim report was provided, focusing on Subtask 1.1 and preliminary considerations for Subtask 1.2. This report updates the findings of Subtask 1 in Section 2, in particular by paying attention to additional kinds of RCFs. Furthermore, it presents the draft results for all elements of Subtask 1.2 in the Sections 3 to 5, including the findings of the first interim report in Section 3.1.1. The final report to be submitted in March 2021 will update the draft results based on the guidance to be provided by the European Commission.

1.2 Definitions of RFNBOs and RCFs according to RED II

A definition of RFNBOs and RCFs is provided in Article 2 of RED II. RFNBOs are defined as follows: *"renewable liquid and gaseous transport fuels of non-biological origin' means liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass".*

This definition does not include the origin of the carbon source (CO_2) for chemical synthesis but opens a broad spectrum of potential CO_2 sources ranging from industrial exhaust gases to bio-based carbon dioxide e.g. from biogas plants or biomass combustion to direct air capture of CO_2. We discuss the implications resulting from the respective carbon sources in the respective conclusions sections.

Besides RFNBOs, RED II particularly includes RCFs as alternative fuels of non-biological origin. RCFs are defined as follows: *"recycled carbon fuels' means liquid and gaseous fuels that are produced from liquid or solid waste streams of non-renewable origin which are not suitable for material recovery in accordance with Article 4 of Directive 2008/98/EC, or from waste processing gas and exhaust gas of non-renewable origin which are produced as an unavoidable and unintentional consequence of the production process in industrial installations".*

The main source of RCFs regarding quantity potentials are solid waste flows such as mixed plastic waste, however, also exhaust gases from industries or liquids containing hydrocarbons can be used for RCF production (see discussion of RCF feedstock in section 2.2.). As the use of waste feedstock for fuel production might compete with material recycling, RED II directly references the EU waste directive (*Article 4 of Directive 2008/98/EC*) that clearly declares material-based recycling as favourable compared to energetic use. Hence, only waste flows that are not suitable for recycling can be considered for the production of RCFs. As material recovery depends on individual processes and most waste flows that could be used for fuel production are also applicable for chemical recycling, this criterion is debatable. In this context, RED II leaves the decision whether or not to include RCFs in the fuel supplier obligation to the Member States and further elaborates: *"The promotion of recycled carbon fuels can contribute towards the policy objectives of* *energy diversification and decarbonisation of the transport sector where they fulfil the appropriate minimum greenhouse gas emissions savings threshold. It is therefore appropriate to include those fuels in the obligation on [the] fuel supplier, whilst giving Member States the option not to consider those fuels in the obligation if they do not wish to do so. Since those fuels are not renewable, they should not be counted towards the overall Union target for energy from renewable sources.*"

As far as exhaust processing gas as feedstock for RCFs is concerned, it is important that the energy content mainly stems from the waste flows. This is e.g. the case for blast furnace gas from steel production or coke oven gas, which contain certain amounts of CO and H_2 that could be used for chemical synthesis. The use of exhaust gases only containing CO_2 for chemical synthesis with green H_2 would be considered an RFNBO and not an RCF.

1.3 Methodology

As already mentioned above, Task 1 of this project is divided into two subtasks, for which the general methodology is described in the following sections.

1.3.1 Assessment of all potential pathways for RFNBOs and RCFs (Subtask 1.1)

In order to tackle the goals mentioned above, in Subtask 1.1 we follow a systematic approach consisting of the steps listed below which are described in more detail hereafter:

- Identification of relevant production pathways in a systematic literature screening.
- Development and provision of overview charts for all relevant processing routes including main products.
- Detailed flow charts of relevant processes with all necessary process steps and applied technologies as well as necessary feedstock.
- Assigning technology readiness levels (TRLs) to the respective process steps.

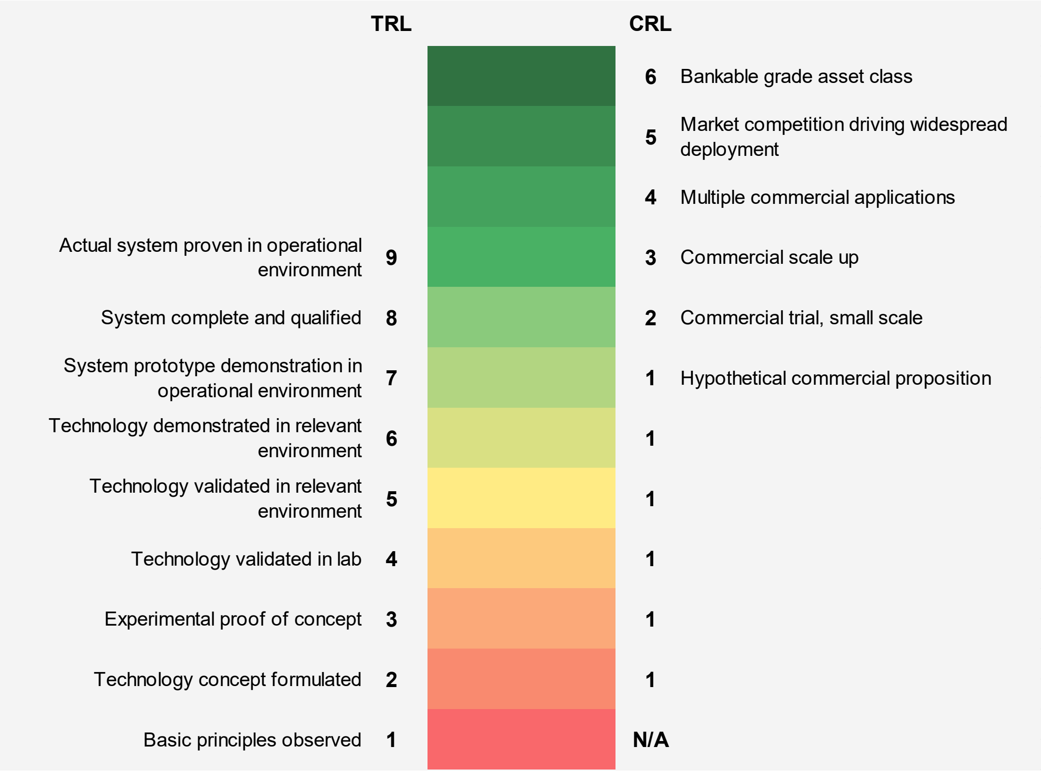
The identification of potential production pathways mainly builds upon a comprehensive literature review including scientific and technical sources, patents, and reports. While several synthesis routes for transport fuels are common standard and are already commercialised based on fossil feedstock (such as the Fischer-Tropsch synthesis) other processing routes only exist at pilot scale. When looking at entire value chains for alternative fuel production, the technology readiness levels of different processing steps have to be considered. This leads to technical conceptions and value chains for which several processing steps are common standard while others have not been realised at industrial scales, yet.

Besides the identification of entire processing routes and value chains, for each process step, related alternative technologies as well as their technology readiness levels (TRLs) are evaluated. Where applicable, we also take the commercial readiness level (CRL) into account.

With regard to the production of RFNBO and RCF, there is a plethora of different processing routes available. These possible configurations show highly diverse levels of maturity from the status of 'basic principles of the technology observed' to levels of 'commercial upscaling'. This report at hand limits its scope of analysis to those technologies that show the potential for a rather fast market run-up and market penetration for sustainable fuels.

Consequently, production pathways on the level of technology research are mentioned but not further assessed due to high levels of uncertainty of their functionality and little relevance for current regulation. The main focus lies on product demonstration and product manufacturing which can be converted to technology readiness levels (TRLs) of 5 or higher i.e. to technologies that are used in practice or are expected to be realised on the industrial scale in the coming decades. This seems to be an appropriate balance between the technological readiness of specific processes and their relevance for this study. However, especially in the timeframe beyond 2030 the assumed technological development is accompanied by higher levels of uncertainty.

For the classification of the level of maturity, this report uses the taxonomy that was adapted for H2020: DG RTD WP2014-15.[2] For technologies showing very high TRLs this method is amended by commercial readiness levels (CRLs) to allow for more detailed assessments (see Figure 1).[3]



	TRL	CRL	
		6	Bankable grade asset class
		5	Market competition driving widespread deployment
		4	Multiple commercial applications
Actual system proven in operational environment	9	3	Commercial scale up
System complete and qualified	8	2	Commercial trial, small scale
System prototype demonstration in operational environment	7	1	Hypothetical commercial proposition
Technology demonstrated in relevant environment	6	1	
Technology validated in relevant environment	5	1	
Technology validated in lab	4	1	
Experimental proof of concept	3	1	
Technology concept formulated	2	1	
Basic principles observed	1	N/A	

Figure 1: Definitions of TRL and CRL based on DG MOVE 2020

In order to enable a transparent depiction of all relevant processes, we provide basic flow sheets for each processing route. These flow sheets are then aggregated to an overview diagram of all relevant processing routes, while a detailed evaluation of alternative technologies including a qualitative description of their strengths and weaknesses as well as an assignment to different TRLs is provided at a processing step level based on the different flow sheets. Also, the pre-treatment of feedstock, which is particularly relevant for RCFs (flue gas scrubbing and waste treatment for pyrolysis) is included in the technical assessment.

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[2] https://ec.europa.eu/research/participants/data/ref/h2020/wp/2014_2015/annexes/h2020-wp1415-annex-g-trl_en.pdf

[3] https://arena.gov.au/assets/2014/02/Commercial-Readiness-Index.pdf

The outcome of Subtask 1.1 is a transparent depiction of all relevant processing routes for RFNBOs and RCFs including the respective feedstock. Each value chain is described in detail through basic flow sheets including the different processing steps, alternative technologies as well as their TRLs and how these could develop. This forms the basis for the selection of relevant technologies in relation to the RED II, which is then assessed in detail in Subtask 1.2.

1.3.2 Assessment of development potentials of identified technologies including techno-economic and ecological factors (Subtask 1.2)

Subtask 1.1 creates a systematic overview of the relevant technologies and production pathways. Building on that, Subtask 1.2 delivers a detailed assessment of the development potential for each of the production pathways regarding their integration into the energy supply structures until 2050. Therefore, the goal is to derive and analyse different plausible development pathways according to their impacts on the energy system. This includes the identification and assessment of important factors influencing the development potential of the different RFNBO and RCF production technologies, as well as their numerous interdependencies with the energy system as a whole. A central aspect in this context is determining the share of gross final energy consumption of RFNBOs/RCFs that can be counted towards the share of renewable energy in the transport sector included in RED II Article 25.

This task is challenging since many of the relevant aspects linked to RFNBO/RCF potential and possible diffusion pathways are both input for and output from RFNBO/RCF development scenarios. For example, lower production costs are likely to facilitate a faster and more wide-ranging diffusion of such fuels; however, a higher market penetration can also be expected to facilitate technological learning, thus reducing the costs of RFNBOs/RCFs. It is important to note that RFNBOs will most likely remain uncompetitive compared to fossil fuels on a production cost basis, at least in the medium term. The cost structure of RCFs strongly depends on the feedstock and further site specific aspects and is difficult to generalize. Therefore, central, if not even the most important factors for determining the future role of RFNBOs/RCFs are the market developments and policy mechanisms supporting the deployment of these fuels. As a consequence of this, the diffusion of RFNBOs/RCFs cannot be simulated bottom-up from fundamental data but is largely driven by political decisions.

Therefore, we have chosen the following five-step approach to generate the data needed to analyse the potential and impact of RFNBOs/RCFs:

- Evaluation of existing scenarios and data (Subtask 1.2.1)
  First, we analyse and categorise relevant, existing long-term scenario studies on a European, but also national and international level to deduct a range of possible developments for important factors affecting the potential of RFNBOs/RCFs. These are, for example, the demand for fuels (in general) in the transport sector and other sectors (which depends on the extent of direct electrification of the transport sector), the overall energy and electricity demand, the RES-E potential, and costs in the EU and abroad, the availability and costs of other feedstocks required for RFNBOs/ RCFs, and the costs of competing fuels and technologies (such as electric vehicles).

- Derivation of potential diffusion of RFNBO/RCF production (Subtask 1.2.2)
  We create three scenarios for the total RFNBO/RCF availability for all sectors, considering maximum deployment speeds and barriers (e.g. feedstock availability

such as RES-E-potential). Thereby we differentiate between "only EU" and "with imports".

- Different scenarios for the use of RFNBOs/RCFs in the transport sector (Subtask 1.2.3)
  We then define up to nine scenarios for how much of the total potential is used in the transport sector, i.e. the gross final consumption of energy. This includes a differentiation by the different kinds of RFNBOs/RCFs (considering different costs, GHG emissions, ...).

- Assessment of the development and impacts of RFNBOs/RCFs (Subtask 1.2.4)
  For each of the calculated scenarios in Subtask 1.2.3, we then assess the relevant aspects and impacts, such as the share of final consumption of renewable energy, which can be counted towards the share of renewable energy in the transport sector, specific and total costs, wholesale prices, greenhouse gas emissions, and local environmental impacts.

- Identification of barriers and options how to overcome them (Subtask 1.2.5)
  Concurrently to the other tasks, we assess the technical, distributional, or other, non-economic barriers to RFNBO/RCF development. These are taken into consideration in the potential assessments in the subtasks above. We furthermore discuss regulatory barriers, though these are not evaluated in the potential calculation. In this subtask, we then evaluate the relative importance of these barriers and discuss ways to deal with them.

This approach allows us to generate distinctive, plausible scenarios for the development of the RFNBO/RCF potential and usage in the transport sector with the required level of detail for the further analysis.

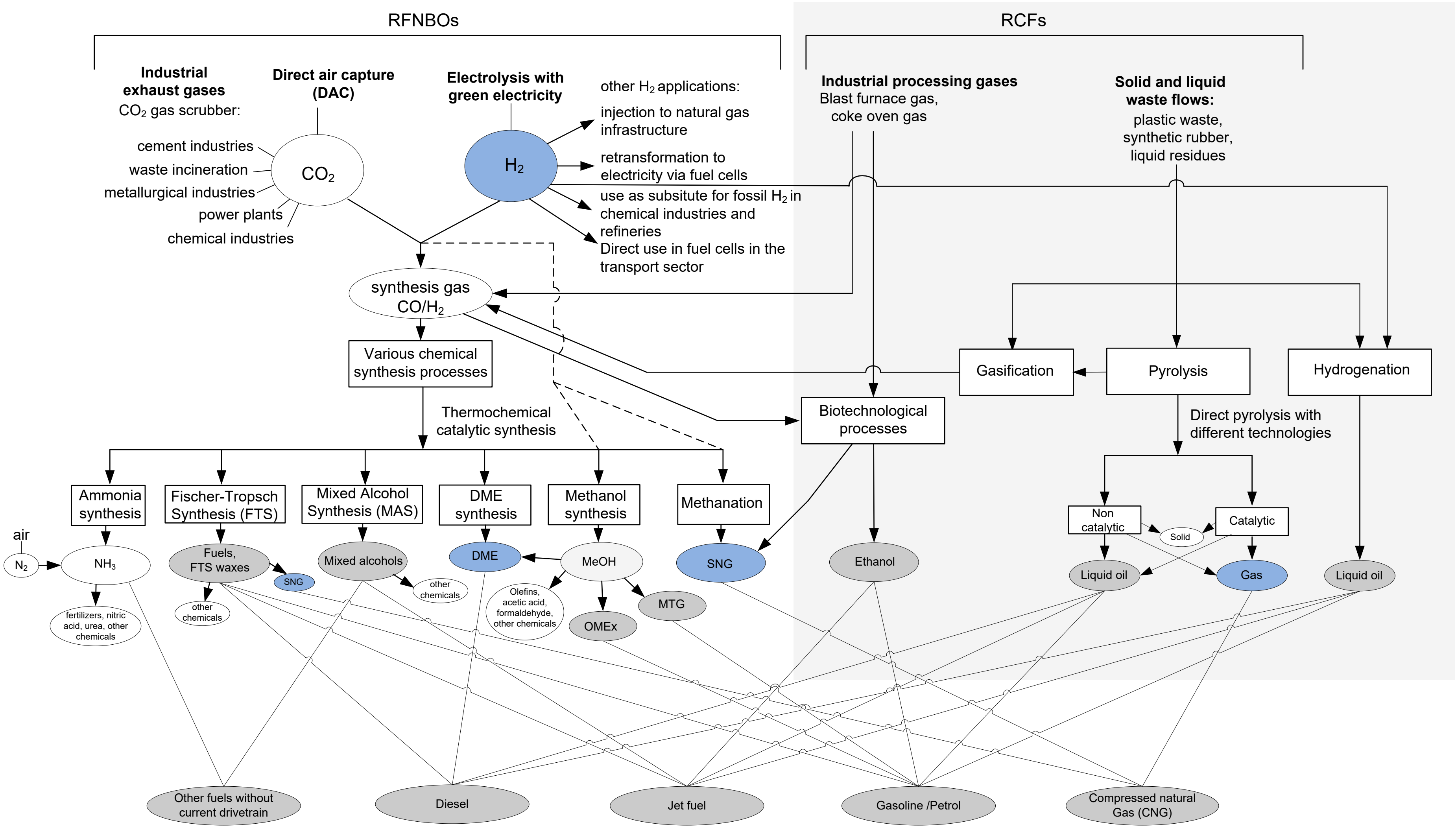
The result of the analysis is an assessment of the likelihood and influencing factors for different scenarios for the development of RFNBOs and RCFs as well as recommendations for eliminating non-economic barriers, an assessment of claimed greenhouse gas emissions and local environmental impacts of the fuel production.

2 ASSESSMENT OF ALL POTENTIAL PATHWAYS FOR RFNBOS AND RCFS

The following section provides a broad overview of different processing routes for the production of RFNBOs and RCFs including the technology readiness levels (TRL) of alternative technologies. As previously indicated in the introduction part, there are various carbon sources for RFNBOs and alternative processing and synthesis routes. The same is true for RCFs. While Figure 2 gives a general overview of alternative processing pathways and the corresponding product spectrum, we provide detailed technical information along the entire value chain in the following section.

The production process of RFNBOs begins with a carbon capture processing step to separate CO_2 from various sources such as exhaust gases from industrial processes or direct air capture (DAC). Besides CO_2, green hydrogen, which is gained from renewable electricity through different electrolysis technologies, is necessary to form so called syngas (a mixture of CO and H_2). This syngas can then be converted into various fuels and chemicals through respective catalytic thermochemical conversion. In the following, green hydrogen is considered to be exclusively produced from renewable electricity (excluding biomass power generation) through electrolysis. This distinction is important to meet the definition of RFNBOs to be of non-biological origin.

Unlike for RFNBOs, the energy content of RFCs is not of renewable origin but results from the processing of mainly fossil-based solid, liquid or gaseous waste. The main processing routes are pyrolysis (thermochemical decomposition under low-oxygen conditions) or gasification. Syngas, which can be processed in the same manner as described for RFNBOs, is also a product of gasification. Pyrolysis results in gaseous, liquid, and solid products, while the liquid pyrolysis oil in particular can be further processed to gain mainly diesel and jet fuel. However, due to the inhomogeneity of most waste flows, the production of high-grade transport fuels from solid or liquid waste remains challenging. Furthermore, it needs to be kept in mind that the energy content of RCFs is mainly based on fossil waste sources (see definition of RCFs in the introduction part and conclusions concerning RCFs in the conclusions section of Chapter 2). Therefore, as also indicated in RED II, RCFs cannot be counted towards the overall Union target for energy from renewable sources.


RFNBOs
RCFs
Industrial exhaust gases
CO_2 gas scrubber:
cement industries
waste incineration
metallurgical industries
power plants
chemical industries
Direct air capture (DAC)
CO_2
Electrolysis with green electricity
H_2
other H_2 applications:
injection to natural gas infrastructure
retransformation to electricity via fuel cells
use as subsitute for fossil H_2 in chemical industries and refineries
Direct use in fuel cells in the transport sector
Industrial processing gases
Blast furnace gas, coke oven gas
Solid and liquid waste flows:
plastic waste, synthetic rubber, liquid residues
synthesis gas CO/H_2
Various chemical synthesis processes
Thermochemical catalytic synthesis
Gasification
Pyrolysis
Hydrogenation
Biotechnological processes
Direct pyrolysis with different technologies
Ammonia synthesis
Fischer-Tropsch Synthesis (FTS)
Mixed Alcohol Synthesis (MAS)
DME synthesis
Methanol synthesis
Methanation
Non catalytic
Catalytic
Solid
air
N_2
NH_3
fertilizers, nitric acid, urea, other chemicals
Fuels, FTS waxes
SNG
other chemicals
Mixed alcohols
other chemicals
DME
MeOH
Olefins, acetic acid, formaldehyde, other chemicals
OMEx
MTG
SNG
Ethanol
Liquid oil
Gas
Liquid oil
Other fuels without current drivetrain
Diesel
Jet fuel
Gasoline /Petrol
Compressed natural Gas (CNG)

2.1 Potential production pathways for RFNBOs

As illustrated in Figure 2, numerous alternative pathways for the production of RFNBOs exist. Additionally, each pathway might also provide technical alternatives that need to be considered for the provision of relevant process information. Despite the versatility of process alternatives, there is a general structure to all value chains that produce hydrocarbons and, hence, depend on a carbon source. As indicated in Figure 2, also the direct use of H_2 as a fuel or the conversion to ammonia (NH_3) via the Haber-Bosch synthesis (see details in the following section) are also considered RFNBOs.

The general processing steps for the production of RFNBOs based on a CO_2 source are illustrated in Figure 3.

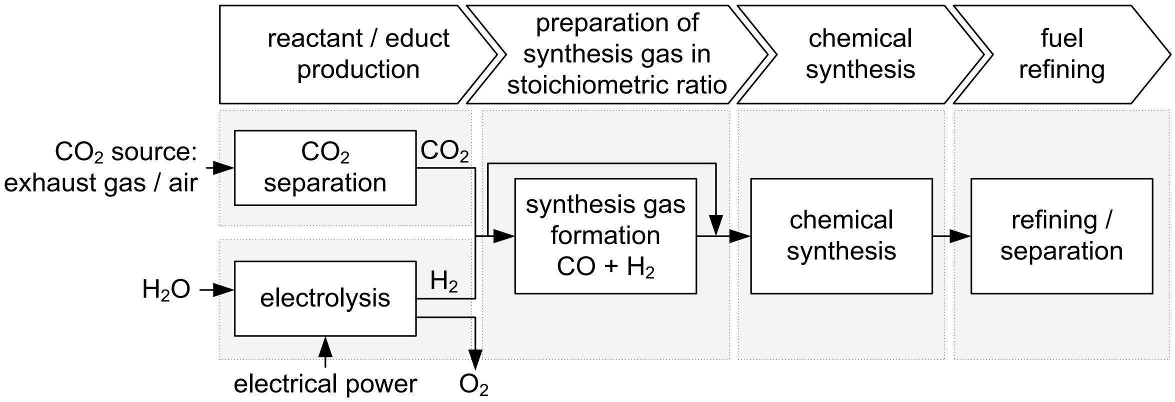


Figure 3: Basic processing steps for the production of RFNBOs

In the following sections, each processing step and its respective alternative technologies are described in detail. We start with electrolysis technologies, which are the source of green hydrogen. This green hydrogen already counts as a RFNBO because it can be used in fuel cells or combustion engines[4] in the transport sector without further processing. In this context, it should also be mentioned that for conventional combustion engines, chemical synthesis to synthetic natural gas (SNG through methanation), to diesel and jet fuel (mainly Fischer-Tropsch synthesis (FTS)) or to gasoline (methanol synthesis with subsequent methanol-to-gasoline process (MTG)) is necessary. The carbon source for the formation of synthesis gas is generally CO_2 from various sources. Here, we describe alternative scrubbing technologies from exhaust gases and direct air capture (DAC) approaches. For the optional generation of synthesis gas (depending on the applied synthesis process and its requirements), alternative technologies are also described in the following section. Regarding respective technology readiness levels (TRLs), it can be generally stated that downstream processing such as chemical synthesis and subsequent refining of respective fuels are in most cases well-established and known processes (based on the use of fossil

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[4] Hydrogen combustion engines are a specific modification of conventional combustion engines using hydrogen as a fuel. They currently do not play a role for road traffic but exist as prototypes. Hydrogen internal combustion engine vehicles (HICEV) need to be differentiated from fuel cell electric vehicles (FCEV). Also a combination of hydrogen with other fuels is a possible option for combustion engines (e.g. methane and hydrogen, cf. Akal et al. 2020).

fuels such as natural gas in existing large-scale industrial plants[5]). On the other hand, upstream processing steps, especially the formation of synthesis gas from green hydrogen and CO_2, are technically challenging and have not yet been put into practice on a large industrial scale.

2.1.1 Electrolysis for the production of green hydrogen

Electrolysis is considered the key technology for producing hydrogen as a feedstock for the production of synthesis gas. It represents the coupling element between renewable electricity generation and the production of electricity-based synthetic fuels. Water is split into gaseous hydrogen and oxygen using electrical energy. The hydrogen is then further processed and – under the addition of a carbon source – can be turned into synthesis gas, usually consisting of carbon monoxide and hydrogen. Synthesis gas is the primary feedstock material for a broad range of different conversion steps like methanation, Fischer-Tropsch and methanol synthesis. Furthermore, advanced electrolysis technology is also able to directly convert carbon dioxide and water into synthesis gas for further processing. This method is called co-electrolysis and is also considered in this analysis. In principle, there are many other renewable processes to produce hydrogen that do not depend (directly) on electricity consumption. Biogas could be reformed to hydrogen via steam reforming or water can directly be split using thermochemical processes. Furthermore, photolytic processes, including photochemical, photoelectrochemical, and photobiological processes, are alternative production routes. Steam reforming of biogas is not analysed in this report since RFNBOs should, by definition, not include energy of biological origin. Thermochemical water splitting processes, also called thermolysis, showed improved reaction chains to reduce the required high temperatures of about 2,500 °C (Holladay et al. 2009). Current R&D activity, however, is relatively low and the technology is still in its infancy and shows very low technology readiness levels. The same holds true for most of the photolytic processes. Therefore, this chapter focuses on electrolytic processes as the most mature technologies.

Based on the current technology readiness levels, there are, in general, three different types of electrolysis available that have reached a high enough maturity to be used in commercial applications or at least in applications in research projects underlying realistic process and system conditions that are mature enough. In this report, the threshold was a TRL of 5 or higher. The most mature one is the alkaline electrolysis (AEL), which shows the most extended history of research and development. Currently, AEL is mostly challenged by polymer electrolyte membrane electrolysis (PEMEL). Both AEL and PEMEL are LT-electrolysis procedures. Another type that belongs to the membrane electrolysis category is the alkaline electrolyte membrane or anion exchange membrane. Unlike the PEMEL, the alkaline electrolyte membrane procedure is based on the transport of anions instead of protons. Since this technology is still in its infancy and shows very low technological maturity, it is not covered in this report. The solid oxide electrolysis (SOEL) is an example of a HT-electrolysis process, which operates at a much higher operating temperature and is in principle also capable of producing synthesis gas directly in one step via the already mentioned co-electrolysis. These three technologies for the production of hydrogen (and carbon monoxide) are assessed in more detail in the following subchapters.

Since electric energy costs remain one of the most critical factors for an electrolysis system to be economically viable, ideal locations include those with very high full-load hours for

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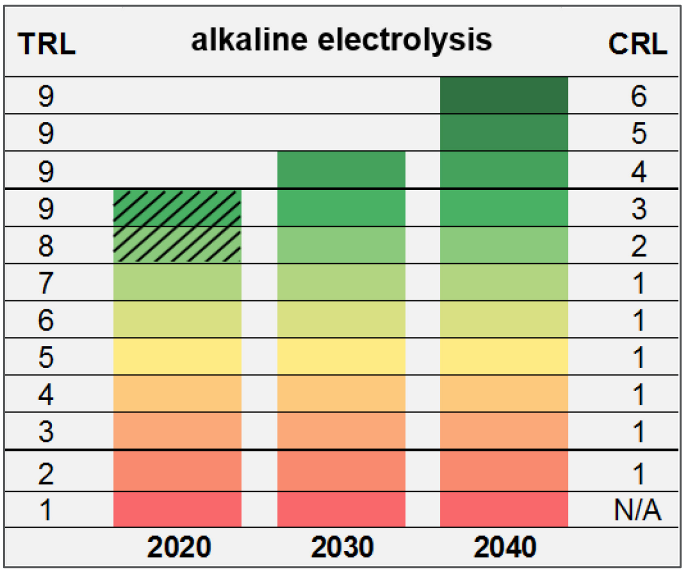
[5] Large-scale FTS plants for the conversion of natural gas have been built by various petrochemical corporations such as SASOL, Qatar Petroleum or Shell. There are several large-scale methanol synthesis plants and ExxonMobil operated MTG plants at industrial scale (see ExxonMobil process information). Besides natural gas, hard coal is a common carbon source for chemical synthesis in China or South Africa.

renewable installations like PV, wind turbines or hybrid PV-Wind power plants to reduce the levelized cost of energy[6] (LCOE). Those ideal locations are often linked to the necessity to desalinate seawater for the electrolysis feed. Seawater reverse osmosis desalination could be used for this purpose. The energy demand for such technologies is below 3 kWh/m^3 (Voutchkov 2018). The total costs for desalinating seawater based on hybrid renewable energy, including battery storage as a buffer, amount to a range between 1.00 and 4.50 €/m^3 but lie mostly below 2.00 €/m^3 (Caldera et al. 2018).

2.1.1.1 Alkaline electrolysis

As already mentioned, Alkaline electrolysis (AEL) is the oldest and, so far, most mature technology. It is already commercially available in large-scale system capacities and provides a long history of operational experience (Tremel 2018). The maturity can be indicated with a technology readiness level (TRL) of 9 and a commercial readiness level (CRL) of 3 since this level refers to an upscaling of commercial plants. Other sources estimate the degree of maturity as somewhat lower, indicating a TRL of 8 or between 8 and 9 (Brinner et al. 2018; Dickschas, Smolinka 2019). An overview of the TRL-assessment is given in Figure 4.



Source: own representation based on Dickschas and Smolinka (2019) and Brinner et al. (2018). Note:The shaded areas represent different TRL estimations between the references.

Figure 4: Maturity of alkaline electrolysis in 2020 and outlook

One disadvantage of AEL is its relatively low current density, which results in comparatively low hydrogen production per module-surface (Tremel 2018). Moreover, allowing a flexible operation of the AEL was not the primary interest during the last decades of research. Currently, the minimum load of the nominal load is about 20 % (Tremel 2018). Additional disadvantages are the gas crossover within the cell, which results in higher necessary safety measures and low operational pressure. The lower pressure level necessitates subsequent compression for further processing and transport. Finally, the electrolyte used in AEL is a corrosive liquid, which increases wear and tear (Holladay et al. 2009).

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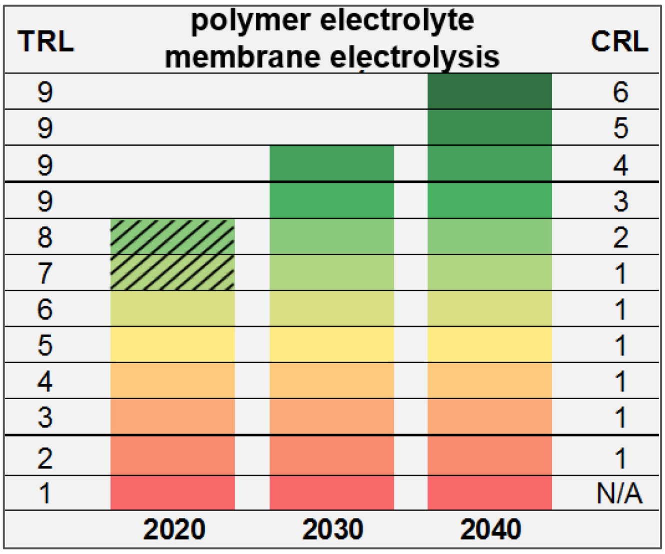
[6] Levelised cost of energy is a measure to illustrate the average present net generation cost of energy / electricity over the lifetime of a power plant.

2.1.1.2 Polymer electrolyte membrane electrolysis

PEMEL is another low-temperature electrolysis technology. Compared to AEL, PEMEL shows higher current densities that allow a more compact production of hydrogen. Additionally, no gas purging is required, as is the case for AEL (e.g. with nitrogen) (Tremel 2018). PEMEL systems have a high potential for load-flexible operation since both low partial load ranges (around 10 % of nominal load) and high overload ranges can be quickly controlled. In the future, high operating pressures can be achieved, which is advantageous for further processing and transportation/storage of the hydrogen. A disadvantage is the current lack of commercial availability of large-scale systems in the megawatt range. The necessity of precious and costly metals, serving as catalysts on the electrode surfaces, is a further disadvantage (Zapf 2017; Pitschak et al. 2017).

The maturity of PEMEL is slightly lower compared to the maturity of AEL. Usually, it is rated by technology readiness levels of 7 or 8 since various system prototypes have been demonstrated in operational environments (Brinner et al. 2018; Dickschas, Smolinka 2019). An overview of the TRL-assessment is given in Figure 5.



polymer electrolyte membrane electrolysis

TRL	2020	2030	2040	CRL
9			■	6
9			■	5
9		■	■	4
9		■	■	3
8	▨	■	■	2
7	▨	■	■	1
6	■	■	■	1
5	■	■	■	1
4	■	■	■	1
3	■	■	■	1
2	■	■	■	1
1	■	■	■	N/A

Source: own representation based on Dickschas and Smolinka (2019) and Brinner et al. (2018). Note:The shaded areas represent different TRL estimations between the references.

Figure 5: Maturity of polymer electrolyte membrane electrolysis in 2020 and outlook

2.1.1.3 Solid oxide electrolysis cell

Regarding high-temperature electrolysis technologies, literature usually refers to the solid oxide electrolysis cell (SOEL). The main difference of the SOEL, compared to AEL and PEMEL, is the high operating temperature level of the SOEL, which reduces the voltage requirements. This aspect principally enables higher energy efficiencies in the hydrogen production process. The high temperature level, however, also reduces the potential for flexible operation (Tremel 2018).

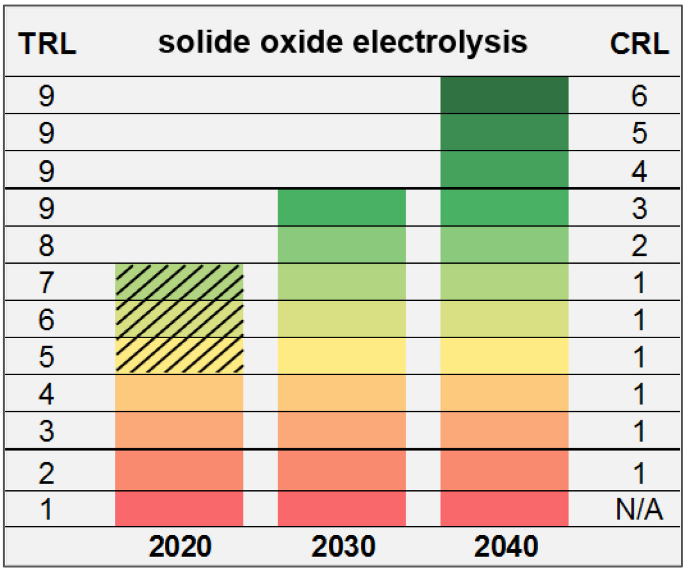
One of the significant potential advantages of SOEL is the possibility to use process waste heat for steam generation, for example, in combination with the production of synthetic fuels. Compared to PEMEL, no precious metals as catalysts are needed, which lowers the costs. A major drawback, however, is the relatively low maturity of the technology. Currently, there are no commercially available large-scale systems on the market and the recently installed systems are all part of low-scale research or demonstration projects. Material fatigue effects due to the high temperature level result in relatively low lifetimes in state-of-the-art systems compared to AEL and PEMEL (Pitschak et al. 2017; Zapf 2017).

The following paragraphs describe the possibility of co-processing of CO_2 as a part of HT-electrolysis in more detail. This is especially of interest in the context of using synthesis gas (carbon monoxide and hydrogen) as the feedstock of the synthesis processes for the production of synthetic renewable liquid fuels such as methanol, diesel, gasoline, or kerosene. The corresponding reaction equation summarises the conversion of water and carbon dioxide into synthesis gas and oxygen.

$$H_2O + CO_2 \rightarrow H_2 + CO + O_2$$

According to the equation, carbon dioxide can be reduced electrochemically in the same cell where the vaporous water (steam) is cracked, which would allow the direct production of synthesis gas in an electrolysis system (Pitschak et al. 2017). Besides this electrochemical production of carbon monoxide, the reverse water-gas shift reaction also occurs in the cell. Here, some of the hydrogen produced reacts with carbon dioxide to create water and carbon monoxide. The proportions for these two production chains of the total amount of carbon monoxide are disputed (Zhang et al. 2017).

This maturity-assessment of the HT-electrolysis also includes the possibility of co-processing CO_2 since those two technologies show rather similar basic components and some of the literature does not further differentiate between the two approaches. The literature review shows a rather diverse evaluation compared to AEL or PEMEL, starting with TRLs between 4 and 6 (Dickschas, Smolinka 2019; Brinner et al. 2018; Wang et al. 2018) up to 7 (Marchese et al. 2020; Preininger et al. 2020). An overview of the TRL-assessment is given in Figure 6.



Dickschas, Smolinka 2019; Brinner et al. 2018; Wang et al. 2018), Marchese et al. 2020; Preininger et al. 2020). Note:The shaded areas represent different TRL estimations between the references.

Figure 6: Maturity of solid oxide electrolysis in 2020 and outlook

2.1.2 CO_2 scrubbing and carbon capture technologies

Before CO_2 can be used for syngas formation, the CO_2 needs to be captured and potentially purified. Potential CO_2 sources can be point sources, where the CO_2 emerges from the underlying processes, or the atmosphere, where the CO_2 has a concentration of around 0.04 % (400 parts per million).

The capture of CO_2 from both sources is only possible with high energy expenditure. Facilities, which implement carbon capture face an efficiency loss of up to 15 % (Goto et al. 2013). This reduction is the so-called energy penalty or efficiency penalty. The increased energy use can only be justified from a purely economic point of view if the cost of emitting CO_2 (e.g. through the EU Emissions Trading System) is higher than the cost to capture and use the CO_2. This obstacle currently prevents a broad implementation of carbon capture and use technologies.

2.1.2.1 Carbon capture technologies for CO_2 point sources

The major part of CO_2 emerges from different point sources like power plants, industrial facilities or biogas or bioethanol plants. As the CO_2 concentration of the flue gas of these facilities is higher than the CO_2 concentration in ambient air, it seems logical to capture CO_2 before it is emitted into the atmosphere. Before we describe respective carbon capture technologies, the different types of point sources are explained briefly.

- **Energy-related CO_2 emissions: post combustion, pre combustion and Oxyfuel combustion**
  Energy-related industrial processes like electricity generation or steel production use combustion to generate the required energy for the underlying processes. Typically, conventional energy carriers like coal, lignite or natural gas are used in these processes, but other energy carriers like biogas and solid or liquid biomass are imaginable, too. The emitted flue gas consists of several components, which strongly depend on the energy carrier and the combustion circumstances. Three different approaches are used to capture the carbon from the flue gas.
    - The post combustion process treats the flue gas of the point source after the combustion of the energy carrier. Here, air from the atmosphere is used directly in the combustion and CO_2 is separated from the generated flue gas. The high nitrogen concentration in the air results in a high nitrogen concentration in the flue gas of around 73-77 %. The CO_2 concentration is, compared to the nitrogen concentration, rather low with around 15-16 %. Other parts of the flue gas are water, oxygen, carbon monoxide, hydrocarbons, nitrous gases, and sulphur dioxide with around 10 %.
    - The Oxyfuel-combustion process is similar to the post combustion process. Instead of conventional air, oxygen with a high purity (95 % - 99.9 %) is used. The resulting flue gas consist of >95 % CO_2 when the water vapour is condensed and only impurities need to be removed.
    - The pre combustion process removes CO_2 even before the combustion. This approach uses gasification of solid energy carriers and a subsequent treatment of the synthetic gas, or the reformation of gaseous energy carriers. In both cases, the product is a gas consisting of hydrogen and CO_2. This approach has the advantage that the separation of hydrogen and CO_2 is simpler than the separation of nitrogen and CO_2 in the post combustion process due to the difference in weight and the solubility. The gasification of

solid energy carriers results in another advantage: The pressure of the gaseous composition of hydrogen and CO_2 is significantly higher than atmospheric pressure (5-40 bar compared to 1 bar) which allows an efficient application of the adsorption using different pressure levels.

- **Process-related CO_2 emissions**
  CO_2 emissions can further emerge from industrial processes, resulting from chemical reactions that release CO_2 as a by-product. Examples for sources of biogenic process-related CO_2 emissions are the production of bioethanol or the processing of biogas to biomethane. Industrial process-related CO_2 emissions that are difficult to avoid. These occur for example in the calcination process during cement production and the reduction process in steel smelters. Additionally, steam reforming is used to produce hydrogen from natural gas (methane) and releases CO_2 in this process. It is important to note that the use of the CO_2 from steam reforming for the production of RFNBOs is not favourable, as the direct conversion of natural gas to synthetic fuels is more efficient. The advantage of using process-related CO_2 emissions is that the CO_2 is highly concentrated in the flue gas and other impurities only have small shares. Process-related CO_2 emission are often accompanied by energy-related CO_2 emissions, if energy in form of heat or pressure is needed for the underlying processes.

Adsorption and absorption

The two main methods used for CO_2 scrubbing are adsorption and absorption to separate the CO_2 in the flue gas from other chemical elements and compounds, e.g. nitrogen, hydrogen, sulphur dioxide, or nitrogen oxides.

The adsorption process uses the adhesion of a gaseous or liquid element or compound on the surface of another solid material, called adsorbent material. In the absorption process, the gaseous or liquid element or compounds enters another liquid or solid material and concentrate within the volume of the absorbent material. Both processes exist as a physical process, where physical forces cause the adhesion, or as a chemical process, where a chemical reaction bonds the element or compound to the adsorbent or absorbent material.

Adsorption and absorption need additional energy to carry out the processes. Usually, thermal and mechanical energy are used in form of heat and pressure. Temperature dependent processes are called temperature swing adsorption. Pressure dependent processes are referred to as pressure swing adsorption or vacuum swing adsorption.

Membranes

Next to adsorption and absorption, membranes are used to separate CO_2 from flue gas or other gaseous composites by using the permeability of materials. The targeted material moves through the membrane while the other components are not able to pass the membrane. This technology only uses pressure differences and does not require thermal energy. Membrane technologies can be used in successive processes or be combined with other separation approaches.

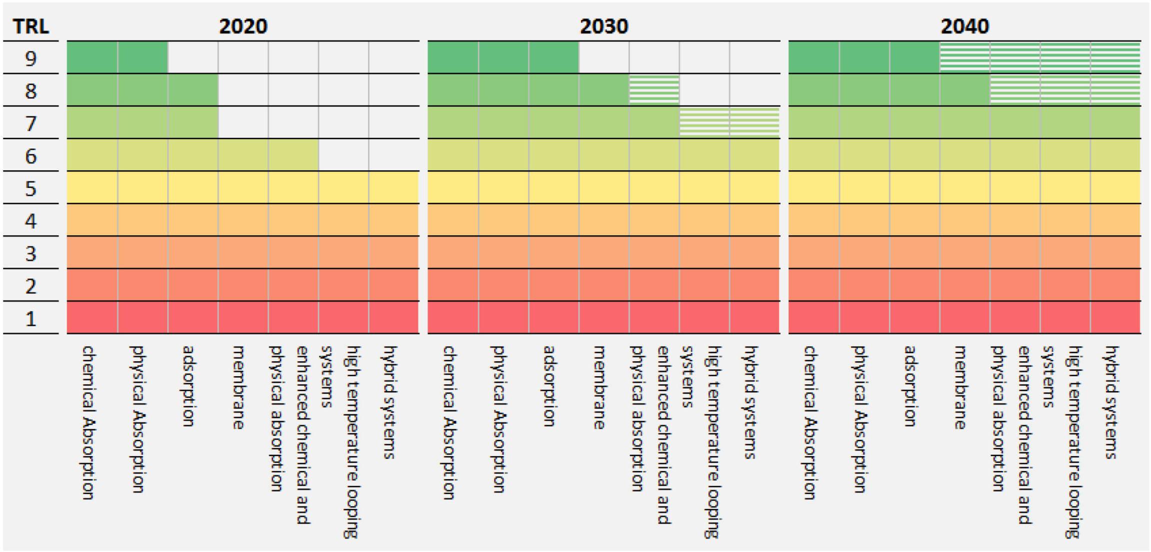
Polymeric membranes already exist on commercial levels (e.g., Polaris™ or PolyActive™) and have been tested under real conditions for the CO_2 separation off power plant flue gas (Kárászová et al. 2020) and of other facilities. However, the durability of the membranes is still an issue. Other components in the flue gas impair the permeability or selectivity of the membranes and reduce their efficiency significantly - n some cases, even irreversibly. Therefore, the reaction with other flue gas components is one focus of current research apart from the permeability and the selectivity of the membrane material. Additionally, other materials like ceramic and hybrid membranes are being assessed (Kárászová et al. 2020).

Chemical looping combustion systems

Chemical looping combustion (CLC) systems use solid sorbents to transport substances between two vessels, where different processes take place. The solid sorbent in the CLC process transports oxygen in form of metal oxides to a combustor chamber, where the oxygen is separated from the metal and the energy carrier is combusted. The sorbent is cycled back into the first chamber and the oxidation restarts. This approach has the advantage that pure oxygen is combusted and the flue gas contains a high share of CO_2 similar to the Oxyfuel combustion approach (Chen et al. 2020).

Technological readiness level of carbon capture at point source

In order to provide a brief overview of the various technologies and corresponding TRLs for carbon capture and subsequent utilisation, Figure 7 summarises the states of development and future expected developments of the respective approaches described above. As illustrated in Figure 7, chemical and physical absorption are mainly state-of-the-art technologies while adsorption and membrane technologies might achieve a sufficiently high technical standard in the coming decade.



Source: Current TRL are based on Araújo and Medeiros (2017) and Kapetaki and Miranda Barbosa (2019), and TRL development estimation based on findings of Bhown (2014). The shaded areas represent uncertain future TRL.

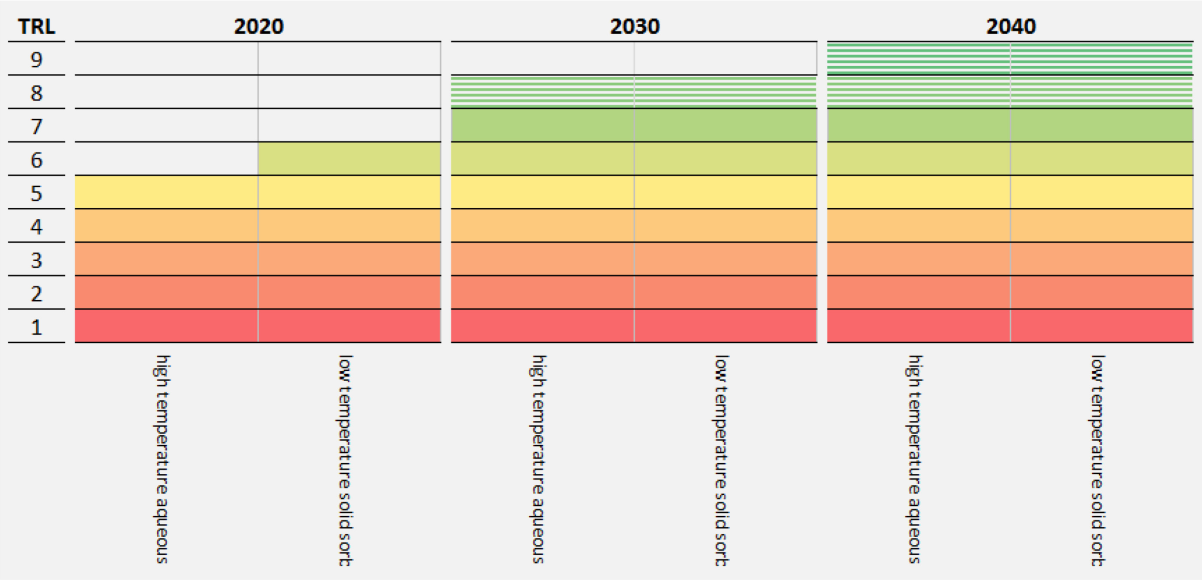
Figure 7: Current and future estimated technology readiness levels of carbon capture technologies for point source carbon capture.

2.1.2.2 Direct air capture

Direct air capture (DAC) is the alternative to capturing CO_2 at the point source directly. The advantage of this approach is the decentral implementation as it uses ambient air instead of flue gases. Therefore, this approach is especially suitable for decentral energy sources such as renewable energy, creating a negative carbon balance if the CO_2 is permanently stored. The main shortcoming is the high thermal and electrical energy demand. The regeneration process needs about 1,420 – 2,250 kWh heat per tonne CO_2 and pumps, compressors and other electrical components need another 366-764 kWh of electricity per tonne CO_2 (Fasihi et al. 2019). In general, the DAC can be divided into high temperature (HT) and low temperature (LT) processes. The temperature refers here to the temperature needed for the regeneration process.

Technological readiness of carbon capture with direct air capture

The literature review of Viebahn et al. 2019 has shown that DAC has reached a TRL of 5 for the HT aqueous sorbent approach and TRL 6 for the LT solid sorbent approach. The technical risk of these approaches is rather low, but the economic risk is high due to the high energy consumption and the competition with point source carbon capture. Based on these estimations, Viebahn et al. 2019 conclude that a TRL 9 is only possible if several development and upscaling steps are conducted to reduce costs further. Additional uncertainties regarding the future market potential, the short period to achieve carbon-neutrality by 2050, the necessary building of production capacities and lack of public and political discussions concerning the subject could prevent a large-scale implementation. Figure 8 shows the current and the estimated development of TRL based on these assumptions.



Source: based on Viebahn et al. (2019) and own assumptions. The shaded areas represent uncertain future TRL.

Figure 8: Technology readiness level of the two different DAC approaches

2.1.3 Formation of synthesis gas

For the production of renewable fuels via chemical synthesis, a wide range of different fuels can be produced applying appropriate synthesis processes. These processes vary in feedstock requirements regarding stoichiometric ratios and components. Also, the technological complexity, as well as process conditions such as temperature, pressure and state of aggregation differ.

As shown in the overview (Figure 2), all of the relevant synthesis processes (except the production of renewable ammonia) need to or are able to use synthesis gas as feedstock. Synthesis gas, also called syngas, is a mixture of CO and H_2 with a stoichiometric ratio adjusted to the synthesis process requirements. Processes based on CO_2 as feedstock therefore need to integrate a process step, which reduces CO_2 to CO, if the direct use of CO_2 is not possible, regarding the plant configuration and reaction scheme of the synthesis reactor.

For the conversion of CO_2 to CO, several processes can be considered, including catalytic and electrochemical technologies.

2.1.3.1 Reverse water-gas shift reaction (rWGS)

The water-gas shift reaction is a well-known and commercially applied process in conditioning the hydrogen content of synthesis gas, accepting the conversion and therefore loss of CO to CO_2 (Pal et al. 2018; Hofbauer and Rauch 2017). On the other hand, the reversed process (rWGS), which targets the conversion of CO_2 into CO under the loss of hydrogen in the form of water, is currently not commercially applied and far less mature (Unde 2012).

According to the literature, an industrial-scale implementation of a rWGS reactor has not yet been realised. However, the demonstration plant "Fuel 1" of the German enterprise Sunfire uses an rWGS-reactor and several experimental studies have been conducted to determine the characteristics of potential catalyst materials and reactor concepts. Furthermore, the Korean research project CAMERE used a rWGS-reactor operated in a demonstration project to investigate the production of renewable methanol bases on CO_2 and hydrogen (Olshausen and Hauptmeier 2019; Unde 2012; Joo et al. 1999).

2.1.3.2 HT-electrolysis

The functionality of high-temperature electrolysis, also called solid oxide electrolysis, has already been explained in paragraph 2.1.1.

The mode of operation as HT co-electrolysis offers an excellent benefit for producing synthesis gas regarding energy efficiency. Also, the implementation of SOEL-systems for the reduction of CO_2 to CO reduces the number of process steps in the whole production chain and therefore reduces the complexity.

In recent development projects, the German enterprise Sunfire has driven the up-scaling of its HT co-electrolysis systems on to relevant industrial-scale capacities (Olshausen and Hauptmeier 2019). The Danish company Haldor Topsoe also offers the use of a HT-electrolysis system for on-site production of CO using CO_2 as feedstock (Küngas 2020; Küngas et al. 2019).

The disadvantages of HT-electrolysis systems are mainly the low maturity for the application in large capacity systems, as well as the high CAPEX and short lifetime (Smolinka et al. 2018).

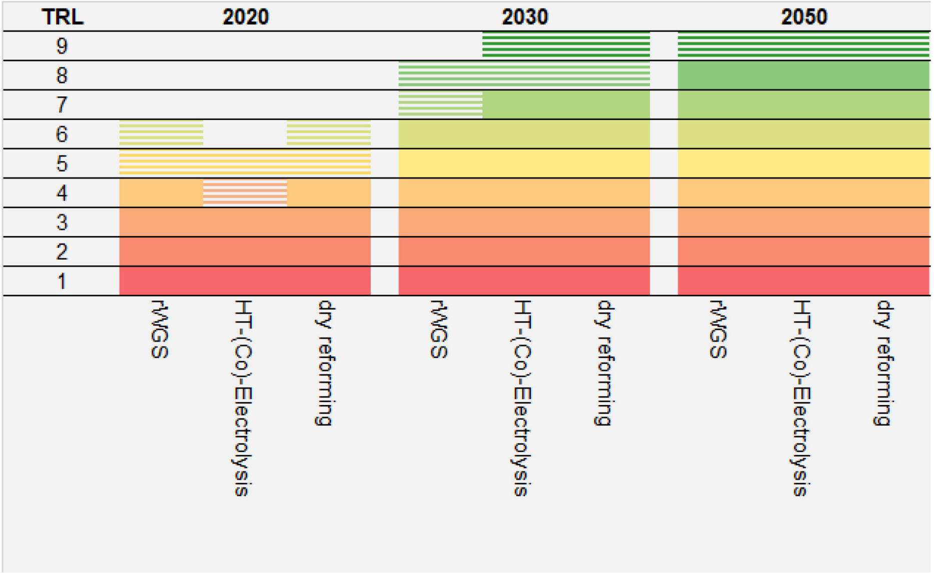
2.1.3.3 Dry reforming

Dry reforming is another way to gain CO from CO_2 and relies on industrial applied processes for the production of synthesis gas, such as steam reforming and partial oxidation.

Compared to the use of a rWGS-reactor or a HT-co-electrolysis, the overall technological maturity of a system using dry reforming is higher since the process resembles widely employed reforming processes and is offered by industrial plant engineering companies like Linde (Linde 2019). On the other hand, by applying dry reforming, the number of process steps increases, leading to higher system complexity. Also, the overall energy efficiency is lower, which is a crucial aspect since the electricity costs usually dominate the production costs of RFNBOs.

2.1.3.4 Technological readiness of technologies for synthesis gas formation

Based on the prior paragraphs and further literature, Figure 9 displays the TRL of the described processes and their estimated progress.



Source: based on Schmidt et al. (2016), Pérez-Fortes and Tzimas (2016), Jarvis and Samsatli (2018) and own assumptions

Figure 9: TRLs of technologies for synthesis gas formation

2.1.4 Chemical synthesis

This paragraph focuses on the essential chemical synthesis processes, which are usually discussed in the context of the production of renewable fuels based on CO_2 and renewable hydrogen. As explained before, some of the synthesis processes can operate using CO_2 directly as a feedstock, while others require the formation of synthesis gas as a previous process step.

The different synthesis options mainly differ regarding the output fuel and its applicability in existing means of transportation. Fuels that can be directly used without any modifications of propulsion systems are often referred to as "drop-in" fuels.

2.1.4.1 Methanation

The aim of methanation is the production of methane. The term methanation shall be used in the context of this work for the synthesis process of chemical methanation.

Currently, the use of methanation processes in power-to-gas systems with CO_2 as a carbon source is being considered in various studies and investigations. Methane produced this way can be fed into the natural gas grid and thus substitute the demand for fossil natural gas. Currently, natural gas is mainly used in industrial and heating applications. However, combustion engines running on natural gas are also available for cars, lorries and shipping (Rönsch et al. 2016; Leonzio 2017).

Methanation can be operated using synthesis gas as feedstock, as well as directly using a mixture of CO_2 and hydrogen.

In combination with high-temperature electrolysis systems, the use of waste heat from methanation for steam generation can be advantageous. According to studies of the Engler-Bunte Institute of Karlsruhe Institute of Technology (KIT) and the German enterprise Sunfire, overall energy efficiencies (based on the lower heating value) of PtG systems of up to 80 % could be achieved (Gruber et al. 2018).

2.1.4.2 Methanol synthesis

Methanol is an essential basic chemical substance for the chemical industry. It plays an important role in the production chain of many chemical key products and intermediates such as Formaldehyde and Acetic acid. Methanol is also used as a fuel component. Among other things, methanol is added to conventional gasoline or to produce additives such as methyl tert-butyl ether (MTBE), which is added to gasoline as an anti-knock agent. Another potential use of methanol as a fuel is in direct methanol fuel cells (DMFC). In 2018 the worldwide methanol production totalled over 90 million tonnes. The production is mainly based on the use of fossil energy and raw material resources such as natural gas, coal and low-grade petroleum fractions, which are converted into synthesis gas via partial oxidation, gasification or reforming (Methanol Institute 2019; Bertau et al. 2014).

The Icelandic enterprise Carbon Recycling International has been operating an industrial-scale power-to-methanol plant based on CO_2 as a carbon source since 2012 in Svartsengi (Iceland). After a plant expansion in 2015, the plant's overall capacity is up to 4,000 tonnes of renewable methanol per year. Compared to the conventional production of methanol, the CRI plant produces 90 % less carbon dioxide emissions (Stefansson and Sigurbjörnsson 2019; Carbon Recycling International).

2.1.4.3 DME synthesis

Today, dimethyl ether (DME) is mainly used as a non-toxic propellant, industrial solvent, and basic chemical. As a fuel, however, a potential use seems equally interesting. DME is particularly suitable for use in diesel engines. The emissions of nitrogen oxides (NOX), carbon monoxide, soot and hydrocarbons can be significantly reduced via the use of DME. However, DME is gaseous under ambient conditions, so that some adaptations of the drivetrain system and the tank are necessary prior to application. The liquefaction process requires little effort. DME is similar in handling to LPG fuels. When mixed with LPG, it can also be used in gasoline engines. Since DME can be easily reformed, its use in fuel cells is also conceivable (Hofbauer and Rauch 2017; Arnold et al. 2019; Poulikidou et al.).Commercial process configurations for single-stage DME production using synthesis gas are licensed from several suppliers, demonstration and pilot plants are being operated as well (Trippe et al. 2013; Ju et al. 2009).Methods for using CO_2 hydrogen mixtures as educt gas streams are being investigated in parallel. In principle, the use of CO_2 is possible by selecting suitable catalyst systems and process parameters. High DME yields can be achieved while catalyst deactivation by coking and kerosene formation is reduced. However, the formation of water also plays an important role in limiting catalyst performance. A higher hydrogen demand is also associated with the use of CO_2 (Arnold et al. 2019; Ateka et al. 2017; An et al. 2008).

2.1.4.4 Methanol-to-gasoline & DME-to-gasoline

Starting from methanol, it is possible to produce gasoline through so-called methanol-to-gasoline (MtG) processes. The properties of these fuels are similar to those of conventional gasoline, which means that there is no need to modify vehicles or the associated infrastructure (Bertau et al. 2014; Hofbauer and Rauch 2017). In the process methanol is converted via the intermediate product DME according to the following reaction equation:

$$n\,CH_3OH \rightarrow \frac{n}{2}CH_3OCH_3 + \frac{n}{2}H_2O \rightarrow (CH_2)_n + n\,H_2O$$

The term $(CH_2)_n$ represents hydrocarbons with n carbon atoms. Due to the steric hindrance of the micropores of the catalyst, the size of the hydrocarbons produced is limited to ten carbon atoms. A lower reactor temperature favours a higher gasoline yield, but the octane number also decreases, as well as the production ratio of the largest and undesirable component durene (1,2,4,5-tetramethylbenzene, $C_{10}H_{14}$). MtG processes are usually carried out at temperatures between 300 °C and 450 °C. The pressure level has a major influence on the product composition. At low pressures, more olefins are produced; high pressures lead to more aromatic compounds (Bertau et al. 2014; Arnold et al. 2019).

Since DME is an intermediate product, it can be used as an educt rather than methanol. An advantage of using DME is therefore the lower exothermicity, which reduces the effort required for heat dissipation. In addition, less water is generated in the reactor, so that the catalyst activity is better maintained. In the case of DME use, the term DME-to-gasoline (DtG) process is used. The main products of the MtG and DtG processes are hydrocarbons which can be used as gasoline. Gases that can be assigned to the LPG fraction are produced as a by-product. By changing the process parameters and process set-up, a systematic production of alternative products can be achieved. In this context, important process routes are methanol-to-olefins (MtO) and methanol-to-propylene (MtP), which, with the target products olefins and propylene, can provide important feedstocks for the chemical industry (Arnold et al. 2019; Bertau et al. 2014).

The development and first large-scale implementation of MtG technology was performed by the petroleum company Mobil and was the result of rising oil prices during the oil crisis. A commercial plant was put into operation by Mobil in New Zealand in 1985, but due to the low oil prices after the end of the oil crisis, it was sold twelve years later and retrofitted for the production of methanol. Nevertheless, several companies offer licensed MtG and DtG processes. In the Chinese province of Shanxi, a plant based on coal gasification with a target capacity of 100,000 tonnes/a gasoline has been in operation since 2009 (Hofbauer and Rauch 2017; Bergins et al. 2019; Bertau et al. 2014).

2.1.4.5 Fischer-Tropsch synthesis

Fischer-Tropsch synthesis (FTS) is a heterogeneously catalysed synthesis process. Synthesis gas is converted into a mixture of hydrocarbons of different chain length and structure, as well as into various by-products.

The aim of Fischer-Tropsch synthesis processes is the extraction of hydrocarbons for use as fuel, raw material for the chemical industry, lubricating oil, and wax. The synthesised hydrocarbons, including oxygenated compounds, differ in their chemical and physical properties. The main products of the FTS are alkanes and alkenes, while alcohols, carbonyls and carboxylic acids are also found among the products. In general, the FTS can be described by the following reaction equation (Ail and Dasappa 2016):

$$CO + 2H_2 \rightarrow (-CH_2-) + H_2O \qquad \Delta_R \mathrm{H}_{250\,°\mathrm{C}} = -158{,}5\ kj/mol$$

The CH_2 produced in this process can be seen as a building block for the composition of hydrocarbons of different chain lengths and functional groups. The mechanism that takes place at the active sites of the catalyst surface is highly complex and incompletely understood. Several potential reaction schemes are discussed controversially in the literature. No single one mechanism that by itself can explain the formation of the numerous different products is known, so that a superposition of several mechanisms is assumed (Eilers 2018).

Based on the reaction conditions, Fischer-Tropsch processes are divided into two basic categories. The reaction temperature is the determining criteria. Higher reaction temperatures favour the formation of short-chain molecules and methane. Lower temperatures increase the proportion of waxy, long-chain hydrocarbons. The high-temperature Fischer-Tropsch synthesis (HT-FTS) is operated at temperatures between 300 °C and 350 °C. Only iron catalysts are used in this process, since the (undesired) formation of methane on cobalt catalysts increases significantly at higher temperatures. The HT-FTS leads to a high yield of hydrocarbons with a chain length similar to that of conventional gasoline and short-chain olefins. Low-temperature Fischer-Tropsch synthesis processes (NT-FTS) achieve an increased yield of n-alkanes with higher chain lengths and waxy compounds. The temperature level varies between 200 °C and 250 °C. Both iron and cobalt catalysts can be employed (Ail and Dasappa 2016; Hofbauer and Rauch 2017; Hsu and Robinson 2017).

FTS processes can be implemented using fixed bed, fluidised bed, and bubble column reactors. Fixed bed reactors are usually designed as tube bundle reactors for FTS. As the FTS is a highly exothermic process, proper heat removal is necessary to achieve suitable reaction conditions and to avoid catalyst deactivation due to overheating or coking. An alternative form of fixed bed reactors are micro channel reactors. These are not yet used in commercial applications, but are being intensively researched, as high yields and high selectivity are expected (Eilers 2018; Hofbauer and Rauch 2017). Fluidised bed reactors are suitable due to their relatively homogeneous temperature distribution, but they are only suitable for use in NT-FTS systems (Neuling and Kaltschmitt 2018). In bubble column reactors, the rather homogeneous mixing and the heat storage capacity of the suspension enable a easily adjustable temperature control. High capacities can be achieved. However, the abrasion between the catalyst particles and the reactor walls implies a complex separation of the fine particles and the product stream. The scale-up of bubble column reactors is not trivial due to the complex fluid dynamics (Eilers 2018; Hofbauer and Rauch 2017).

The development of the Fischer-Tropsch synthesis originates from the research of Franz Fischer and Hans Tropsch at the Kaiser Wilhelm Institute in Mühlheim/Ruhr, Germany, in the 1920s. The implementation of large-scale FTS plants for the production of fuels and products for the chemical industry was carried out in Germany as early as 1935 by the company Ruhrchemie. In the context of fuel supply using coal gasification, capacities were further expanded in Germany during the Second World War. After the end of the war, operations were discontinued due to the availability of cheaper petroleum-based fuels and basic chemicals. Due to the political isolation and implemented sanctions responding the national Apartheid policy, the operation of FTS plants in South Africa based on domestic coal resources, carried out by the company SASOL, began in 1955. During the apartheid era and the resulting sanctions, SASOL promoted the further development of its processes and put further large-scale plants into operation. Even today, SASOL is still active in the production of synthetic fuels and waxes using Fischer-Tropsch synthesis processes. The use of FTS in GtL processes started with the commissioning of a corresponding Shell plant in Bintulu (Malaysia) in 1993. Based on the successful operation of the Bintulu plant with a capacity of approximately 500,000 tonnes of FTS product per year, the largest commercial application of the FTS in Las Raffas, Qatar was completed in 2012. The Pearl GtL plant constructed there produces about 6 million tonnes of FTS products per year based on natural gas (Eilers 2018; König 2016; Maitlis and Klerk 2013; Steynberg and Dry 2004).

2.1.4.6 *Mixed alcohol synthesis (MAS)*

The generation of a mixture of alcohols with carbon numbers from 1 to 5 can be achieved by applying modified catalysts known from methanol synthesis in Fischer-Tropsch synthesis (Hofbauer and Rauch 2017). The modification, mainly resulting from catalyst doping with alkali compounds are small compared to classical FTS. Therefore, mixed alcohol synthesis is only shortly listed here as a variation of FTS, however, the importance of MAS for synthetic fuel production is minor.

2.1.4.7 *OME synthesis*

Oxymethylene ethers (OME) can be classified as counting among the group of C1 oxygenates, which are characterised by the absence of carbon-carbon bonds and the inclusion of oxygen. These properties lead to an almost soot-free combustion, which makes them an attractive option for use in diesel engines.

The structural formula of OME compounds can be described by $CH_3O\text{-}(CH_2O)_n\text{-}CH_3$, where n represents the number of incorporated CH_2O monomers. In the term OME_n, n has the same meaning. The shortest OME compound with n=1 (OME_1) is also called dimethoxymethane (DMM) or methylal and is produced in established processes from methanol and the intermediate product formaldehyde (CH_2O). Since OME_1 has a low boiling point of 42 °C under atmospheric pressure, its use as a fuel is only possible with the use of pressure tanks and an adapted infrastructure. From as low as OME_6 onwards, the melting temperature lies above 38 °C. Therefore, a mixture of OME_3 to OME_5 is often considered a diesel substitute fuel, with physical properties close to those of conventional diesel fuels. Only a modification of the engine control system is necessary to use mixtures (also called "blends") of OME and diesel. This can result in greatly reduced soot particle emissions. The nitrogen oxide emissions remain at the same level or decrease as well, since contrary to the operation with conventional diesel fuels, hardly any trade-off effects between particle and NO_x emissions can be observed. OME fuels have a lower calorific value than conventional diesel fuels, so that when using OME, 1.7 to 1.8 litres are required to achieve the same performance equivalent to one litre of diesel. However, the power density does not suffer as OME fuels require a lower air supply due to the bound oxygen. The engine power is not affected (Beidl et al. 2019; Härtl et al. 2019; Hackbarth et al. 2018).

The currently applied synthesis processes usually rely on the use of methanol and formaldehyde, which is usually also produced from methanol. In general, there are several synthesis routes for OME production. To ensure the sustainability of the potential OME fuels, the production of the feedstocks methanol, formaldehyde and all other materials should be based on renewable raw materials and energy sources. A process configuration for the production of regenerative OME fuels must therefore also include methanol synthesis based on regenerative synthesis gas.

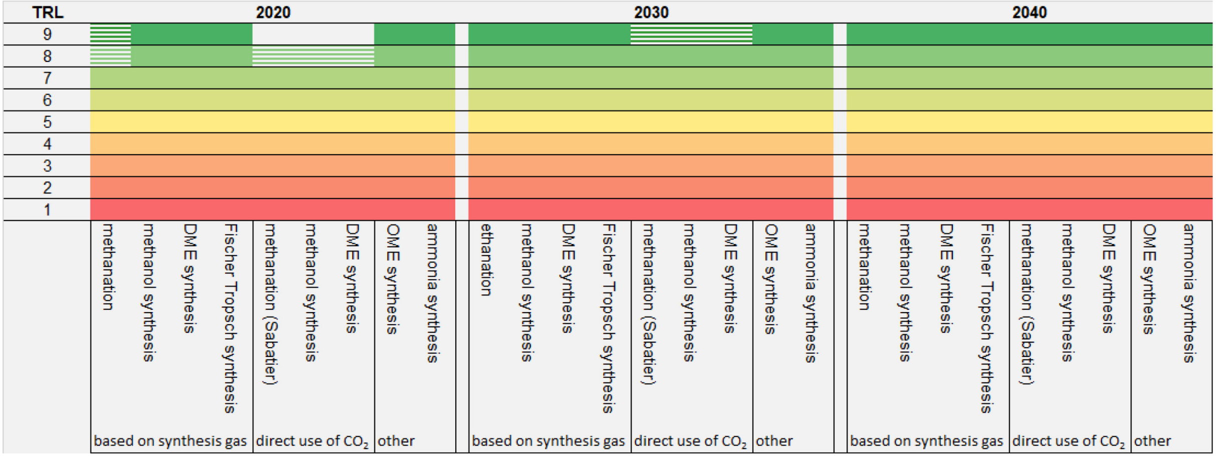
2.1.4.8 *Ammonia synthesis*

Ammonia can also be considered as a fuel component for the use in modified propulsion systems. Conventional ammonia production plants apply the Haber-Bosch process, which catalytically converts hydrogen and nitrogen into ammonia. Reaction conditions are typically temperatures of 450 to 550 °C and pressure levels of 250 to 350 bar (Tremel 2018).

In a recent study a consortium of enterprises discusses the use of ammonia as marine fuel. Since 120 ports worldwide are already equipped with ammonia trading installations, a basic infrastructure network exists (Alfa Laval, Hafina, Haldor Topsoe, Vestas, Siemens Gamesa 2020).

2.1.4.9 Technological readiness of synthesis processes

Based on the prior paragraphs and further literature, Figure 10 displays the TRL of the described processes and their estimated progress.



Source: based on Jarvis and Samsatli 2018; Pérez-Fortes and Tzimas 2016; Schmidt et al. 2016

Figure 10: TRLs of feasible RFNBO synthesis processes

2.1.5 Upgrading and refinement of fuels

The various possible products of renewable based chemical synthesis processes for the generation of RFNBOs partly require further treatment and refinement to increase the achievable yield and to optimise fuel characteristics regarding the use in current propulsion systems and infrastructure elements.

2.1.5.1 Hydrocracking

Hydrocracking is a catalytic process for decomposing long-chain hydrocarbons. In the classic refinery structure it is mainly the liquid residues of vacuum distillation, also known as "vacuum gas oil" (VGO), which are used. In potential production pathways for synthetic fuels, hydrocracking is considered above all for converting waxy Fischer-Tropsch products into fuel components (Hsu and Robinson 2017).

Applications in petroleum refining operate typically at 100 to 200 bar and 250 to 350 °C. The VGO used here contains high levels of aromatic and heteroatomic contents. In contrast, long-chain FTS products consist almost exclusively of n-alkanes. This results in modified required reaction conditions of 35 to 70 bar and 330 to 450 °C. The exothermic decomposition of the long-chain hydrocarbons takes place with supply of hydrogen, so that both unsaturated compounds and the resulting decomposition products are saturated. Parallel to the saturation and the splitting of the various components, isomerisation processes occur, which are mainly favoured by lower temperatures compared to the splitting processes. Depending on the choice of process settings and the catalyst employed, the product distribution can be specifically influenced and thus the proportions of gasoline and diesel components can be optimized (Bricker et al. 2015; Rauch et al. 2018).

Hydrocracking is classified as belonging into the superordinate category of hydroprocessing technologies. The specific removal of heteroatoms such as oxygen and sulphur out of hydrocarbons in a catalytic process with the addition of hydrogen is called hydrotreating. This process does not separate carbon-carbon bonds due to more moderate reaction conditions. Since there are usually hardly any impurities in FTS products, this step is not necessary as a separate step (Lee 2010).

2.1.5.2 Fluid catalytic cracking (FCC)

FCC processes take place in conventional oil refineries as one of the most important processes. Using suitable catalysts, heavy components are split mainly into gasoline fuels and short-chain olefins (Hsu and Robinson 2017).

In an FCC unit, a significant coking of the catalyst particles occurs. The catalyst particles are therefore fluidised in a special fluidised bed process. The particles circulate between a regenerator, in which the generated coke is burnt off the catalyst surface, and the actual cracking reactor. The regenerated catalyst is then combined with the feed stream in a tube, the so-called riser. The decisive catalytic cracking of the long-chain hydrocarbons already takes place in the riser, so that the subsequent reactor chamber primarily serves the purpose of product separation (Letzsch 2015; Hsu and Robinson 2017).

FCC processes are also being considered for the cracking of FTS waxes with the objective of producing gasoline type fuels and olefins. This includes both the admixture of FTS-waxes to conventional petroleum-based FCC feed streams, the use of pure FTS-waxes and the co-processing of plant-based oils (Kubička and Černý 2012; Malleswara Rao et al. 2012).

2.1.5.3 Technological readiness of upgrading and refinement processes

Since hydrocracking and FCC - the processes explained above - as well as other basic refinement processes such as distillation, are well-established processes applied in most of today's petrol refineries, it is not necessary to estimate development pathways regarding the TRLs.

The most relevant aspect in this context is the possibility of implementing RFNBO production paths in existing refinery infrastructures. In addition, separating RFNBO production pathways into energy-intensive production of hydrogen and crude fuel mixtures in well-suited regions with a low-cost renewable energy supply on the one hand the and the upgrading of fuels in existing European plants on the other hand, seems like an avenue worth pursuing.

2.1.6 Key process routes for RFNBO production

As shown in the previous sections, there are various processing routes for RFNBO production resulting from different electrolysis technologies, syngas formation (if required) and subsequent chemical synthesis to fuels. While all relevant technologies have been shortly introduced in the previous sections, more detailed background information of the respective technologies is provided in the appendix to this report. In order to give a comprehensive overview of the efficiencies of different processing routes, particularly regarding the efficiency of transforming electric energy into chemically bound energy in gaseous and liquid fuels, this chapter aims to summarize the energy efficiencies for the most relevant processing pathways as well as the expected development of TRLs.

Since all regarded production pathways are based on water electrolysis as the coupling element from electric energy to chemical energy, the development of water electrolysis technology is a significant aspect for the overall process efficiency and CAPEX. Table 1 shows the expected trends in water electrolysis technologies found in recently published studies, focusing on energy efficiency and investment expenditures.

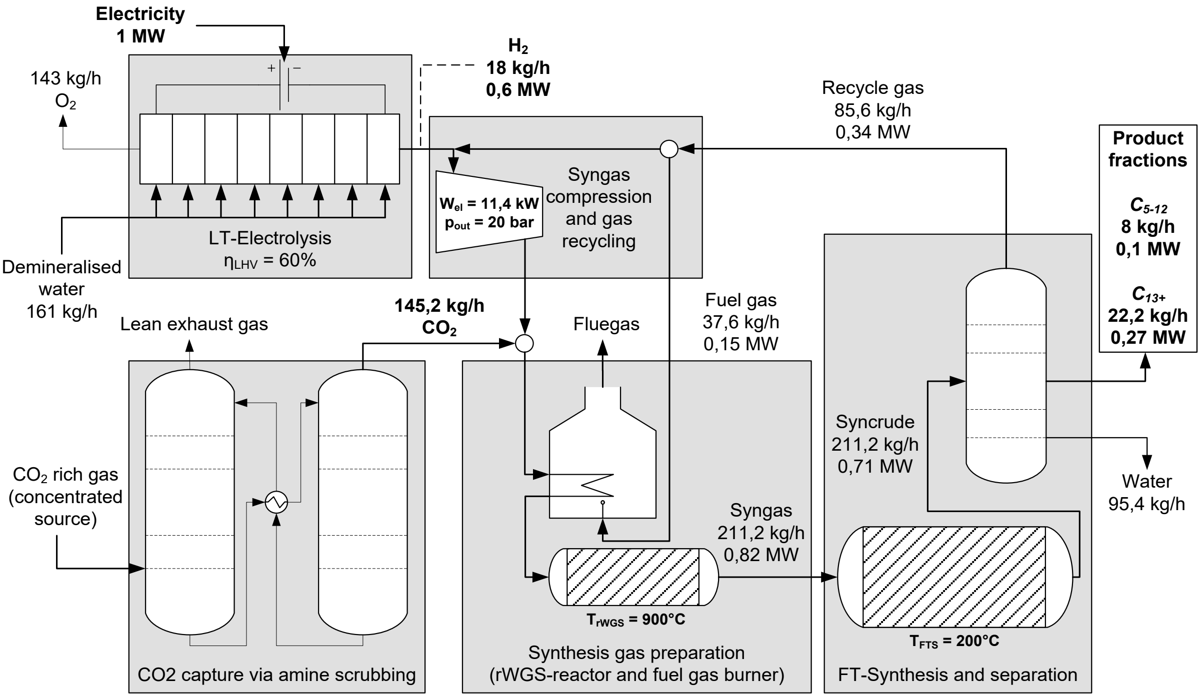
Table 1: Expected trends in water electrolysis technology regarding energy efficiency and CAPEX

Technology		Energy Efficiency based on LHV			Specific energy demand (kWh/kg$_{H2}$)			CAPEX (€/kW$_{el}$)			Source
		2020	2030	2050	2020	2030	2050	2020	2030	2050	
Low-Temperature	Alkaline Electrolysis (AEL)	63,3%	65,9%	69,2%	52,65	50,58	48,16	600	550	525	DEA
		69,3%	-	71,0%	48,06	-	46,92	650	-	250	dena LIE
		66,7%	69,4%	-	50,00	48,00	-	600	400	-	FCH2JU
		65,4%	66,7%	70,9%	51,00	50,00	47,00	980	395	241	FVV
		66,5%	68,0%	75,0%	50,12	49,01	44,44	950	625	450	IEA
		64,6%	67,7%	69,9%	51,60	49,20	47,70	850	700	490	IndWEDe
		67,0%	69,0%	72,0%	49,75	48,30	46,29	-	-	-	UBA
	Proton Exchange Membrane Electrolysis (PEMEL)	58,0%	62,0%	67,0%	57,47	53,76	49,75	1.100	600	400	DEA
		69,3%	-	71,0%	48,06	-	46,92	800	-	300	dena LIE
		60,6%	66,7%	-	55,00	50,00	-	900	500	-	FCH2JU
		65,4%	66,7%	70,9%	51,00	50,00	47,00	980	395	241	FVV
		58,0%	65,5%	70,5%	57,47	50,89	47,28	1450	1075	550	IEA
		62,1%	61,0%	68,2%	53,7	54,6	48,9	1450	800	500	IndWEDe
		67,0%	71,0%	80,0%	49,75	46,94	41,66	-	-	-	UBA
High-Temperature	Solid Oxide Electrolysis (SOEL)	76,0%	79,0%	79,0%	43,86	42,19	42,19	2200	600	400	DEA
		73,6%	-	80,3%	45,30	-	41,48	1700	-	270	dena LIE
		83,3%	90,1%	-	40,00	37,00	-	4500	1500	-	FCH2JU
		87,2%	89,9%	89,9%	38,24	37,07	37,07	2700	1500	910	FVV
		77,5%	80,5%	83,5%	43,01	41,40	39,92	4200	1800	750	IEA
		80,9%	84,4%	88,2%	41,20	39,50	37,80	2300	450	250	IndWEDe

Sources: DEA: (Danish Energy Agency 2020); dena LIE: (Deutsche Energie-Agentur GmbH 2018); FCH2JU: (Fuel Cells and Hydrogen 2 Joint Undertaking 2018); FVV: (Forschungsvereinigung Verbrennungskraftmaschinen e.V. 2016); IEA: (IEA 2019b); IndWEDe: (Smolinka et al. 2018); UBA: (Umweltbundesamt 2020)

The collected data set shows a clear trend towards increasing energy efficiencies and significantly reduced specific CAPEX values. This development mainly relies on the expected technological improvements, as well as the scale-up of both system size and production capacities to industrial relevant levels.

While the direct usage of hydrogen itself as RFNBO in fuel cells and hydrogen combustion engines is possible, the production of hydrogen derived fuels using the technologies described in the former chapters offers a wide variety of production pathways. The processes following the water electrolysis and the connections between single process stages or sectors usually reduce the production chain's overall energy efficiency. To obtain reliable energy efficiency data as well as other relevant key parameters, it is necessary to know at least crude energy and mass balances of the regarded system. To give a general understanding of relevant mass and energy flows within a processing route, we provide a representative example for a Fischer-Tropsch synthesis pathway, implementing an rWGS reactor to generate the intermediate syngas, using CO_2 captured from concentrated sources as feedstock. The background data is taken from an article by (Hannula et al. 2020). The process and its most relevant energy and mass parameters are displayed in Figure 11. To get a better overview, the flowsheet was reduced to the most relevant modules, therefore most heat exchangers and utilities (e.g. pumps) are not shown here.



Source: based on simulation data from Hannula et al. 2020

Figure 11: Mass and energy balances of an exemplary power-to-fuel process based on FTS

The overall energy efficiency from electric energy to fuels (η_{el}), based on the LHV of the products, is the sumproduct of all generated end products and the associated lower heating values divided by all energy input steams. The energy input mainly consists of the electrical power consumption of the electrolysis system. On top of that, the energy consumption of all auxiliary unit like compressors, pumps and ventilators, is added.

$$\eta_{\mathrm{el}} = \frac{\sum_{Products} m_i * LHV_i}{\sum_{Input} E_i}$$

The overall energy efficiency from power to fuels for the shown process configuration is expected to be $37\%_{\mathrm{LHV}}$, based on an assumed energy efficiency of $60\%_{\mathrm{LHV}}$ for the LT-electrolysis system.

To obtain a subordinated energy efficiency, that doesn't include the electrolysis process, system boundaries can be shifted away from the electrolysis system. The result is the hydrogen energy efficiency η_{H2} for the process based on hydrogen as input instead of electric power. The sum of energy inputs E_i doesn't include the power consumption of the electrolysis anymore. It mostly consists of power consumption of auxiliary units like pumps, ventilators and cooling systems.

$$\eta_{H2} = \frac{\sum_{Products} m_i * LHV_i}{m_{H2} * LHV_{H2} + \sum_{Input} E_i}$$

The chosen exemplary process configuration shows an chemical energy efficiency of 61,7 $\%_{LHV}$. Furthermore 65% of the captured CO_2 is converted into fuels.

To give an overview of the most relevant process configurations, which are often referred to in studies and reports, Table 2 summarises key aspects like overall energy efficiency and estimated specific CAPEX values.

As it can be seen in the overview, the overall energy efficiency usually increases by the implementation of HT-Electrolysis, with the disadvantage of higher specific CAPEX and lower TRLs in the near future. Another relevant aspect, regarding energy efficiency and CAPEX, is the origin of the feedstock CO_2, since DAC processes show significant higher energy demands and specific investment costs, due to the lower technological and commercial maturity.

Looking at the expected developments towards 2050, the at least partly high disparity of the CAPEX values in between the production pathways and as well between the considered data sources decreases. All considered studies show the same trend towards noticeably reduced specific investment costs, mainly based on the expected rise in technological readiness of recently immature technologies and scale-up effects in production capacity, mostly due to rising industrial production of large-scale electrolysis systems.

Table 2: Overview over the characteristics of different production pathways

Nr.	Production pathway	Product(s)	Implemented technologies	Current TRL	Energy efficiency (based on LHV)			Specific CAPEX in €/kW$_{output}$			CO$_2$ origin	Source
					2020	2030	2050	2020	2030	2050		
A1	LT-Electrolysis and Methanation	SNG (Methane)	AEL or PEMEL Methanation	8-9 7-8 7-8	47 %	48 %	51 %	4361	2685	2381	DAC	FVV
					44 %	-	55 %	2204	-	1696	DAC	LBST
					43 %	-	51 %	4978	-	1948	DAC	dena
A2	HT-Electrolysis and Methanation	SNG (Methane)	SOEL Methanation	5-7 7-8	57 %	58 %	58 %	3528	2528	2294	DAC	FVV
					52 %	-	57 %	-	-	-	DAC	Prognos
B1	LT-Electrolysis and MeOH Synthesis	Methanol	AEL or PEMEL Direct MeOH Synthesis	8-9 7-8 7-8	58 %	61 %	65 %	4510	3010	1500	Not included	DEA
					40 %	-	-	-	-	-	DAC	UBA
					53 %	-	-	-	-	-	Conc. source	UBA
B2	LT-Electrolysis and MtG	Gasoline	AEL or PEMEL Direct MeOH Synthesis MtG / Mobil Process	8-9 7-8 7-8 9	39 %	-	42 %	3621	-	1887	DAC	CIT
					48 %	-	54 %	2000	-	903	Conc. source	CIT
					37 %	-	43 %	6101	-	2590	DAC	dena
					37 %	38 %	40 %	4460	2760	2434	DAC	FVV
B3	HT-Electrolysis and MtG	Gasoline	SOEL Direct MeOH Synthesis MtG / Mobil Process	5-7 7-8 9	46 %	-	47 %	7615	-	2517	DAC	dena
					44 %	45 %	45 %	3491	2524	2274	DAC	FVV
C1	LT-Electrolysis and FTS	FT-Diesel / Kerosene	AEL or PEMEL rWGS FTS	8-9 7-8 5-6 9	37 %	37 %	39 %	5101	3373	3036	DAC	FVV
					37 %	40 %	50 %	3200	2500	1900	Conc. source	DEA
					36 %	-	42 %	6792	-	3198	DAC	dena
					39 %	-	42 %	4679	-	2006	DAC	CIT
					47 %	-	53 %	3000	-	994	Conc. source	CIT
C2	HT-Electrolysis and FTS	FT-Diesel / Kerosene	HT-Co-Electrolysis FTS	4-5 9	47 %	-	48 %	7795	-	2561	DAC	dena
					46 %	47 %	47 %	4281	2776	2517	DAC	FVV

Sources: FVV: (Forschungsvereinigung Verbrennungskraftmaschinen e.V. 2016); LBST: (Schmidt et al. 2019); dena: (dena 2017); Prognos: (Hobohm et al. 2018); DEA: (Danish Energy Agency 2020); UBA: (Umweltbundesamt 2020); CIT: (Schmidt et al. 2018);

2.1.7 Conclusions regarding RFNBO processes

To achieve long-term carbon-neutrality, processing routes that use carbon sources of non-fossil origin are necessary (direct air capture (DAC) or CO_2 sources of biological origin, e.g. biogas fermentation plants). However, as long as CO_2 sources from industrial exhaust gases are available, it is logical to use these sources because CO_2 is available in high concentrations and can be scrubbed and captured with comparatively low efforts. This improves the overall efficiency of the process as compared e.g. to DAC. When using industrial sources of CO_2 (exhaust gas), process-related inevitable emissions (e.g. cement industries) and emissions caused by combustion of fossil fuels need to be distinguished. There is no direct risk of double-counting credits regarding emission reduction (under EU ETS and under RED II) as, when used for further processing, CO_2-emissions from exhaust gas are still attributed to the respective process. As described in detail in the previous section, there are technical and economic challenges in producing RFNBOs at industrial scale. However, the existing pathways of chemical synthesis when using syngas from renewable sources have a large potential to produce renewable liquid transport fuels and, therefore to reduce GHG emissions in the transport sector. Due to the comparatively low efficiency levels in transforming electricity into fuels, synthetic fuels should only be used in applications where a direct electrification is difficult to realise.

2.2 Potential production pathways for RCFs

As described in Section 1.2, RCFs can be produced from various waste flows. Particularly gaseous and solid/liquid waste need to be differentiated when looking at the processing routes. Furthermore, to be considered an RCFs according to the RED II, the waste should not be of biological origin as these waste flows are counted differently, even though basic processing routes might be similar (e.g. pyrolysis). In case of gaseous or liquid process waste, it is important to consider the definition of RCFs in RED: "…which are produced as an unavoidable and unintentional consequence of the production process in industrial installations". Unavoidable and unintentional in this context means that process-related waste streams are not generated on purpose in order to increase the output of RCFs but must occur as non-avoidable process waste streams. This requires very case-specific assessments of production facilities. The same is true when considering the prerequisite of not being suitable for material recovery as defined in RED II: "…which are not suitable for material recovery in accordance with Article 4 of Directive 2008/98/EC…". As indicated before, waste streams which are processed for fuel production could also be suitable for chemical recycling processes in which mixed plastic waste is used as a source for the production of platform chemicals, which once again can be used for plastic production but also for further purposes such as resins or other chemicals. Article 4 of the European waste directive directly refers to the European "waste hierarchy" as illustrated in Figure 12. Several companies from chemical industries currently develop processes for so called "chemical recycling" where basic chemicals are recovered from mixed plastic waste through pyrolysis or gasification and subsequent synthesis (BASF 2020)[7]. It is expectable, that these chemical recycling processes are considered "material recovery" in the sense of RED II or, respectively, the waste framework directive.

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[7] See e.g.: BASF ChemCycling: https://www.basf.com/global/en/who-we-are/sustainability/we-drive-sustainable-solutions/circular-economy/mass-balance-approach/chemcycling.html

OMV ReOil: https://www.omv.com/en/news/omv-transforms-plastic-waste-into-crude-oil

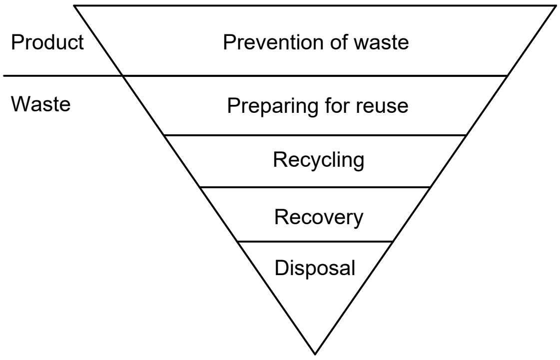

Figure 12: European waste hierarchy according to the waste framework directive (2008/98/EC)

In literature, mixed plastic waste or old tires which are currently mainly incinerated are considered an important feedstock for RCFs (Malins 2020), however, it should be kept in mind that the use of these feedstocks might violate the requirement not to be suitable for material recovery. While we further discuss these issues in combination with potential CO_2 emission reduction compared with conventional fuels in the conclusions part, in the following section we provide a basic overview of relevant processing pathways for the production of RCFs. As shown in Figure 13, major processing routes include pyrolysis (which can be seen as an umbrella term for various process specifications) and gasification. In the case of gasification, synthesis gas is formed which can be then further processed in the same manner as described for RFNBOs or which can serve as a source for hydrogen. This is also the major pathway for the use of gaseous waste flows. As the catalysts in chemical synthesis processes are very sensitive to impurities such as halogens (e.g. chlorine from PVC or fluorine from PTFE), gasification of specific fractions from pyrolysis processes are a further option to avoid catalyst poisoning. The different processing steps shown in Figure 13 are described in detail in the following section.

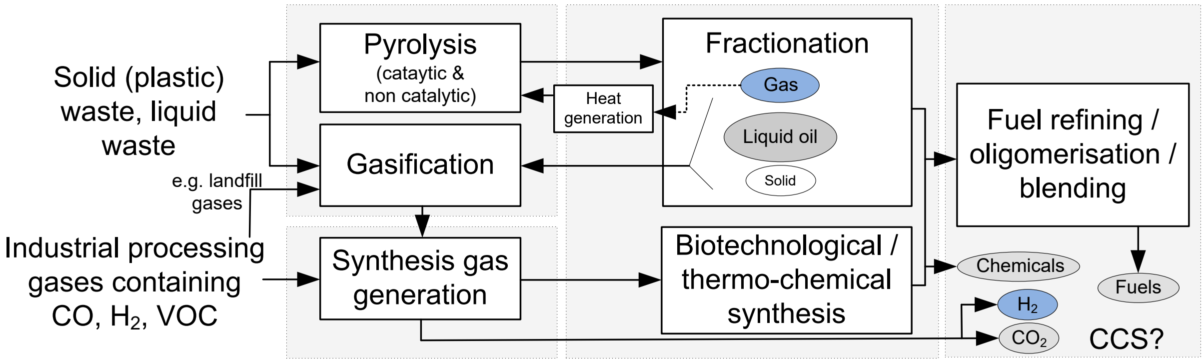

Figure 13: General processing routes of recycled carbon fuels (RCFs)

As indicated in Figure 13, the processes for the production of recycled carbon fuels require gaseous and solid or liquid waste streams as feedstocks. For gaseous waste streams, the treatment strongly depends on the chemical composition of the exhaust gases. Gaseous waste flows relevant for RCF production (containing H_2, CO, and other hydrocarbons) are among others exhaust gases from steel production (blast furnace gases, coke oven gases), refinery off-gases and further exhaust gases from chemical industries and potentially also collected landfill gases (mainly containing methane and CO_2) that could be converted into syngas through gasification. Syngas produced from gaseous waste streams can be processed in the same way as for RFNBO production (cf. process description of RFNBOs) and may be used for thermochemical or biotechnological synthesis. Currently, the mentioned waste gases are normally fed into the natural gas grid or they are directly burned for electricity and heat production (Lopez et al. 2018). This is also true for landfill gases which are formed through anaerobic fermentation of landfilled hydrocarbon waste and which mainly contain methane and carbon dioxide. Solid waste streams that are suitable for the production of liquid RCFs may concern mixed plastics and rubber waste from municipal solid waste (MSW) but also include various carbon-based residues from industrial processes. Furthermore, there are different liquid waste streams that could be used for RCF production. This are e.g. residues from chemical industries but could also refer to wastewater, slops and sludges with higher levels of hydrocarbons. One example of producing RCFs from liquid waste streams is the recovery of fuels from shipping slops and oil tanker sludges[8]. The processes of dealing with oily sludges can been seen as a variation of crude oil refining with preliminary separation of hydrocarbons and water (see process description below).

2.2.1 Processing of solid (and liquid) waste flows to produce RCFs

Mixed plastic waste streams can be transformed into fuels by thermal depolymerisation of plastics (breaking of polymer bonds with pressure and heat) in two general processing routes (Malins 2020):

- pyrolysis (catalytic or non-catalytic)
- gasification.

Also, general municipal solid waste (MSW) can be converted into fuel through pyrolysis or gasification. However, due to the moisture (water content) and the inhomogeneity of materials, the resulting gaseous and liquid fuels from MSW processing are usually directly used as a combustion fuel for heat and electricity generation or other industrial applications (cement industries) but do not serve as a source for transport fuels (Chen et al. 2014). However, there are especially gasification processes under development that can deal with broader ranges of MSW and that focus on the recovery of hydrogen from solid waste fractions (see specifications in the next section). Even though hydrogen is not a carbon fuel, the production of hydrogen from non-biological waste sources would be a RCF according to RED II definitions.

Beside the aforementioned treatments, further processes such as hydrogenation (chemical reaction with hydrogen) are possible pathways to break down the polymer structure. Compared to treatments in the absence of hydrogen, hydrogenation leads to the formation of highly saturated products, avoiding the presence of olefins in the liquid fractions, which favours their use as fuels without further treatments. Moreover, hydrogenation promotes the removal of hetero-atoms, such as chlorine (Cl), nitrogen (N) and sulphur (S), in the form of volatile compounds. Despite these advantages, hydrogenation suffers several drawbacks, mainly due to the cost of hydrogen and the need to operate under high pressure. The main outcome of the hydrogenation of plastic solid waste is hydrochloric acid, halogenated solid residue and liquid and gaseous fuels that could be utilised in the transport sector. However, there is currently no industrial process or large-scale pilot plant using hydrogenation for RCF production. Hence, the TRL is relatively low as compared to catalytic or non-catalytic pyrolysis or gasification (Dargo Beyene 2014) and therefore, hydrogenation is not further addressed in the following sections. Further processing possibilities, which shall be mentioned here but which are not discussed in more detail in the following sections as they do not directly refer to the production of RCF are based on specific chemical treatment. Chemical depolymerisation, or chemolysis, involves the reaction of the polymer used with chemical reagents for the production of its starting monomers. Different processes have been developed which are categorised according to the chemical agents employed, the most

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[8] See Ecoslops company: https://www.ecoslops.com/en/solutions-and-services/our-technology/ow2p#Mini-p2r

common being glycolysis, methanolysis, hydrolysis and ammonolysis (Dargo Beyene 2014). These processes require very clean and separated plastic waste flows. Mixed plastics can only be treated via pyrolysis, gasification, or hydrogenation. In the following two sections we describe the two most promising processing routes to produce transport fuels from plastic waste, which are catalytic pyrolysis and gasification with subsequent chemical synthesis or hydrogen separation.

2.2.2 Pyrolysis and related processes

In pyrolysis, materials are thermochemically depolymerised at elevated temperatures and in the absence of oxygen. Plastic pyrolysis involves heating and degradation of plastic polymers at temperatures between 350 °C and 900 °C in an oxygen deficient environment (Panda et al. 2010). In large-scale applications, usually rotary kilns and tubular reactors are used for the pyrolysis process (Chen et al. 2014). Pyrolysis generally results in the formation of carbonised char (5-10 %) and a volatile fraction that can be separated into condensable hydrocarbon oil and a non-condensable high calorific value gas. The proportion of each fraction and their precise composition depends primarily on the nature of the plastic waste but also on process conditions. The liquid products are usually composed of higher boiling point hydrocarbons. The yield of fuel oils in non-catalytic pyrolysis is usually under 55 % (Awasthi et al. 2017). While the general use of pyrolysis for treatment of plastic and rubber waste is relatively well-established with various industrial applications mainly to produce industrial fuel, which is then used for heat and electricity generation (Chen et al. 2014), the upgrading to transport fuels through catalytic pyrolysis is not yet a wide-spread technology. Catalytic conversion of plastic wastes implies several advantages over conventional pyrolytic methods. The most evident relates to the lower degradation temperatures at which degradation reaction takes place, which results in lower energy consumptions and higher conversion rates. By adopting customary fluid cracking catalysts and reforming catalysts, more aromatics and naphthenes in the C6–C8 range can be produced, which are valuable gasoline-range hydrocarbons (Buekens and Huang 1998). The catalysts used for catalytic pyrolysis are mainly those applied in the petrochemical refinery industry. The production of fuel oils based upon catalytic pyrolysis can reach up to 80 % of product share, depending on the composition of plastic wastes (Awasthi et al. 2017). The resulting pyrolysis oil can then be refined into diesel, jet fuel or naphtha and other chemicals (E4tech 2018).

Several industrial-scale examples for producing mainly diesel and jet fuel from plastic waste exist, however, in most cases, pyrolysis fuel is used for energy production. This is less challenging than the production of transport fuels with variations in feedstock composition and purity. For instance, the enterprise Sapporo Plastic Recycling ("SPR") in Japan established a fully commercial plastic liquefaction facility on the island of Hokkaido in 2000 that has the capacity to recycle over fifty tonnes a day of mixed plastic waste. From this waste stream, the advanced thermal process recovers light oil that is used as a chemical feedstock for the production of new plastics, a medium fuel oil equivalent to diesel and a heavy oil that is used to generate electricity for export to the grid[9]. OMV group as a classical oil and gas company has developed a process and runs a pilot plant to produce pyrolysis oil from plastic waste that can be reintroduced in the fuel refinery process[10]. A comparable strategy for the production of chemicals (ChemCycling) in which pyrolysis oil is reintroduced into the refining process of petrochemicals (steam cracker) is currently being developed by BASF[11].

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[9] http://www.kleanindustries.com/s/sapporo_plastics_pyrolysis_recycling_plant.asp

[10] https://www.omv.com/en/news/omv-transforms-plastic-waste-into-crude-oil

[11] https://www.basf.com/global/en/who-we-are/sustainability/we-drive-sustainable-solutions/circular-economy/mass-balance-approach/chemcycling.html

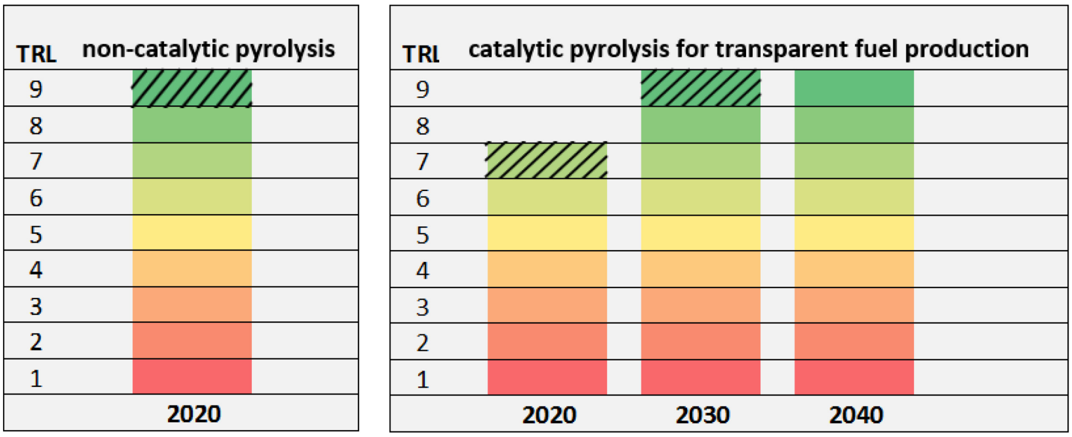

Figure 14: Current TRL and expected future development for catalytic and non-catalytic pyrolysis processes

There are several pilot plants of catalytic pyrolysis for fuel production (E4tech 2018). Nonetheless, much research and development are still ongoing particularly regarding upscaling and process optimisation. Non-catalytic processing produces low grade pyrolysis oil which is broadly commercialised mainly in emerging and developing countries (Chen et al. 2014). However, this alternative processing route is not relevant for the production of high-grade transport fuels. The current TRLs and expected developments particularly for catalytic pyrolysis are illustrated in Figure 14.

2.2.3 Gasification and potential subsequent chemical synthesis

Gasification involves the partial oxidation of organic matter at high temperatures (typically between 1,200-1,500ºC) under mildly oxidising conditions (usually steam, carbon dioxide or sub-stoichiometric oxygen) for the production of synthesis gas (syngas). This gas, consisting primarily of carbon monoxide and hydrogen can be used to produce synthetic fuels (see description of chemical synthesis of RFNBOs) or may be combusted directly to produce e.g. heat and electricity (Dargo Beyene 2014). While syngas purity and composition are not that relevant for combustion with heat and electricity generation, it is a substantial challenge to produce tailored syngas with constant quality and purity for chemical synthesis from mixed waste flows. There are various techniques for gasification which are not restricted to the use of plastic waste but are mainly developed for gasification of black coal or biomass (Lopez et al. 2018). In direct gasification techniques, a vertical fixed or fluid bed gasifier is used and air serves as a gasification agent (Awasthi et al. 2017). Direct gasification has the advantage of being a technically simple and cost-effective operation, but the produced syngas when using mixed plastics as feedstock is not of sufficient quality for chemical synthesis mainly because the catalysts used for synthesis are very sensitive to contaminants such as halogens or may lose functionality through coking. One possible way of producing high-quality syngas from plastic waste is a two-stage gasification process. After shredding mixed plastic waste, the feedstock is introduced into the first gasifier that operates at a low temperature (around 700 °C) with circulating sand. In the second stage (the high temperature gasifier) the gas from the low temperature gasifier reacts with steam at temperatures of around 1,500 °C to produce syngas composed of carbon monoxide and hydrogen. At the furnace outlet, the gas is cooled to 200 °C to prevent the formation of dioxins and chlorides from the halogens contained in plastic solid waste. The gas then passes through a gas scrubber and any remaining hydrogen chloride is neutralised by alkalines. This synthetic gas is of high quality and may be used for chemical synthesis (Awasthi et al. 2017). An alternative gasification process, which is more energy consuming and costly, but which is capable of treating inhomogeneous waste materials, is plasma gasification. For plasma gasification, a plasma torch powered by an electric arc is used to ionise gas and catalyse organic matter into syngas, with slag remaining as a by-product. Plasma gasification processes transform waste materials into gaseous products under an oxidant environment. The main advantage of plasma reactors for plastic gasification is the high temperature reached, which promotes an almost complete cracking of tar compounds, and therefore high gas yields (Lopez et al. 2018). An industrial process for recovering hydrogen from municipal solid waste (MSW) through plasma gasification has been developed by the Swedish company Plagazi AB[12]. This process is intended to recover hydrogen from mixed waste fractions. After transforming solid waste into syngas, additional hydrogen is fromed through the reaction of steam with carbon monoxide to hydrogen and carbon dioxide (water-gas-shift reaction). As discussed before, MSW is mainly based on fossil feedstock and separating H_2 from syngas leads to CO_2 emissions comparable to the production of H_2 from natural gas through steam reforming. However, in combination with CO_2 separation and CCS, such a process could be a source of 'blue hydrogen' (hydrogen production from fossil feedstock with subsequent CCS).

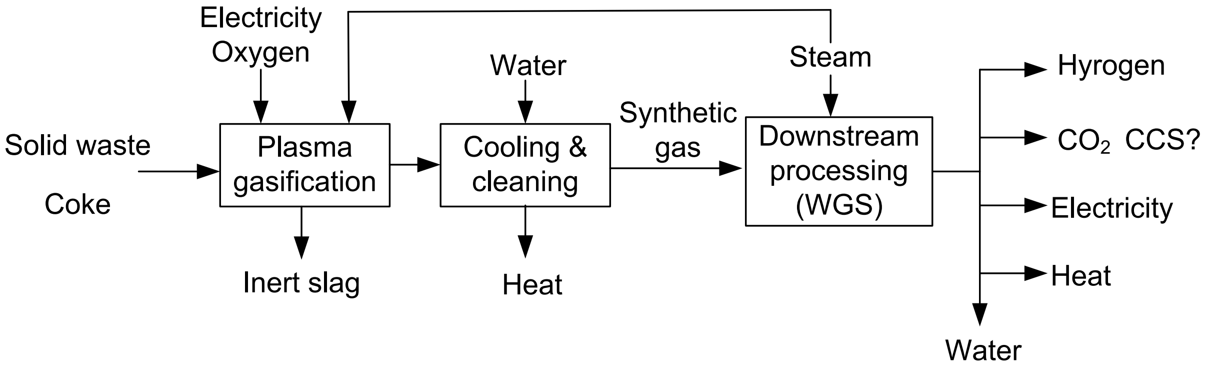

Figure 15: Example of plasma gasification via the Plagazi process

Several companies are developing gasification processes for mixed plastic waste that produce syngas of sufficient quality for chemical synthesis and run respective demonstration plants. Enerkem, for example, has developed a process for plastic waste gasification. However, an industrial-scale pilot plant does not yet exist[13]. Sierra Energy presents a gasification technology within a blast furnace, which is capable of dealing with inhomogeneous waste fractions from municipal solid waste[14]. Plasco has developed a process to produce and refine high-grade syngas that is applicable for subsequent synthesis[15]. However, there is no existing large-scale industrial example for the production of synthetic fuels through gasification of plastic waste. Therefore, the current TRL is set at a level of 6-7 with an expected industrial application and, hence, an increase of TRL to the level of 8-9 by 2030.

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[12] https://www.plagazi.com/

[13] https://enerkem.com/process-technology/carbon-recycling/

[14] https://sierraenergy.com/technology/fastox-gasification/

[15] https://plascotechnologies.com/our-technology/

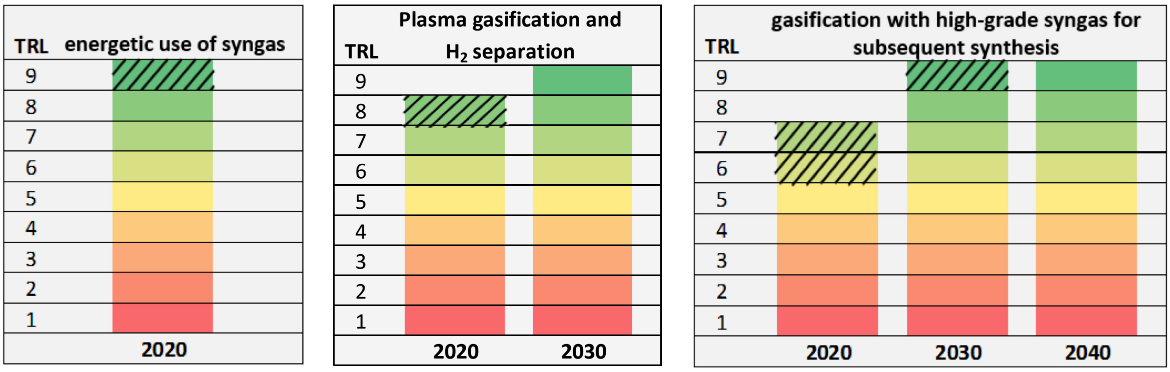

Figure 16: Current TRL and expected future development for gasification of solid waste such as mixed plastic waste

2.2.4 Biotechnological processes for gaseous waste streams

As indicated before, most industrial gaseous waste streams with high calorific value are currently used for heat or electricity production in combustion plants, often in CHP (combined heat and power generation) facilities. Theoretically, gas streams containing CO or H_2 could be directly used as syngas or in combination with a gasification process. Beside thermochemical synthesis, there is the possibility to transform carbon monoxide and hydrogen rich gas into high calorific fuels through biotechnological processes based on proprietary microbes developed for this purpose. Such a process for the treatment of industrially occurring gases that are rich in CO (steel furnace gases or coke oven gases) has been developed by LanzaTech[16]. This process converts CO and H2 into alcohols through bacterial fermentation. The main product of this process is ethanol. Ethanol may be directly used as an additive to conventional gasoline or may be further treated to produce jet fuel. The process has been demonstrated with various on-site demonstration plants using different industrial gaseous waste streams (LanzaTech 2017):

- steel mill off-gas
- gasified agricultural biomass
- chemical process off-gas
- ferroalloy production off-gas.

Figure 17 provides an overview of the LanzaTech syngas fermentation process on the example of exhaust gases from steel production. This includes coke oven gases, blast furnace gases and converter gases. A European pilot plant with an annual capacity of 80 million tonnes ethanol production is currently realised by ArcelorMittal in their production site in Gent[17]. Exhaust gases from steel production are currently mainly used for energy production, while the process described here provides a valuable alternative to the single energy recovery.

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[16] https://www.lanzatech.com/

[17] https://europe.arcelormittal.com/newsandmedia/europenews/3798/Fuel-from-steel

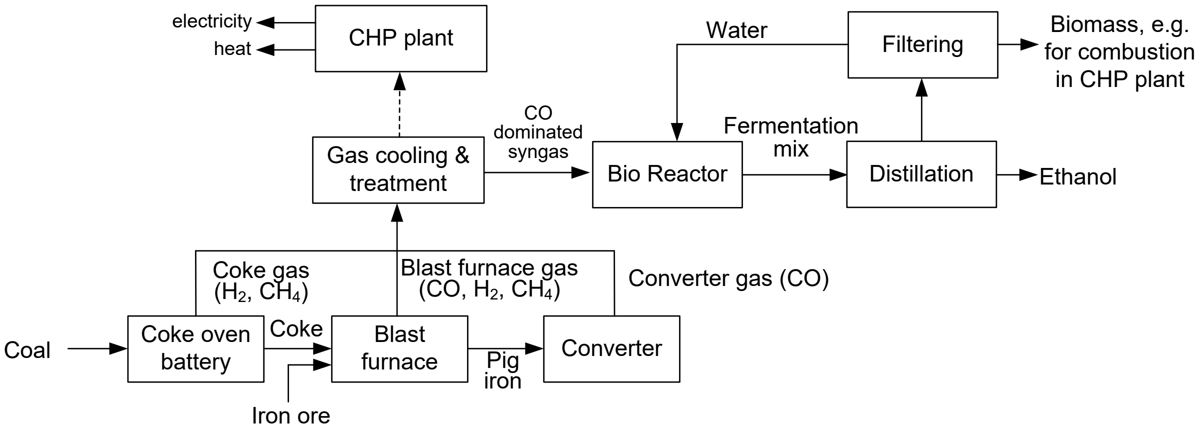

Figure 17: Basic flowchart of the fermentation process for ethanol production from furnace gases and further industrial exhaust gases provided by LanzaTech

Due to existing pilot plants of the LanzaTech process, which are ready for commercial applications and have been realised in industrial scale, the TRL for producing ethanol from CO containing industrial gas is 8-9.

Alcohol to jet fuel technology is being developed by a number of companies, including Swedish Biofuels, Gevo, LanzaTech & the Pacific Northwest National Laboratory (PNNL) (Malins 2020). These routes typically target biomass-derived alcohols in order to produce bio jet fuel, but the technologies could equally be applied to non-biogenic alcohols. Alcohol to jet fuel processes are currently assumed to have TRLs of 6-7 (E4tech 2018). However, the first commercialisation could be expected in the coming decade (see Figure 18).

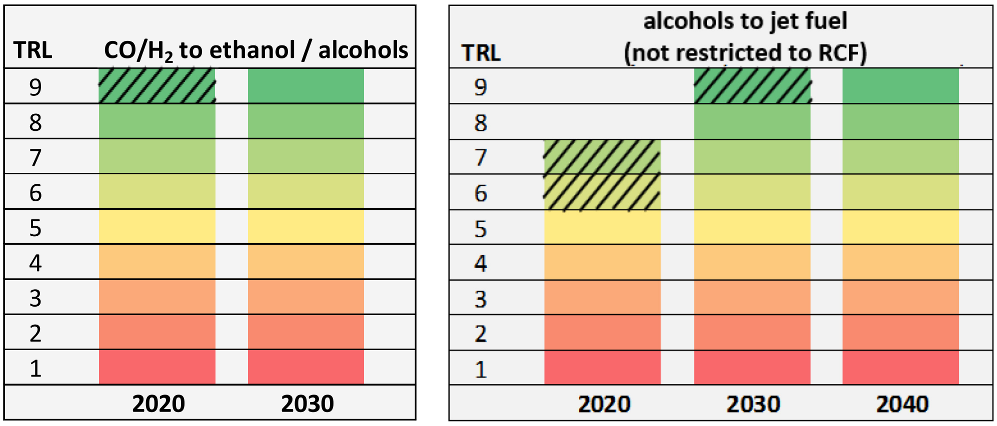

Figure 18: Current TRL and expected future development for biotechnological processing of industrial exhaust gases containing CO and H2

2.2.5 Utilisation of landfill gas as a source for RCF production

A further source of gaseous RCFs are so called landfill gases (LFGs). Landfill gases mainly consist of CO_2 and CH_4 (methane) comparable to biogas. Landfill gases are formed through anaerobic digestion in waste deposits containing hydrocarbon waste (organic residues, mixed plastics etc.). Due to their high global warming potential, landfill gases in the EU are normally collected and used for energy provision as specified in the European Landfill Directive (Council Directive 1999/31/EC of 26 April 1999 on the landfill of waste). Further possibilities of landfill gas utilisation is the cleaning and separation of CO_2, NO_x, VOC and the general use as a fuel or the introduction in the natural gas grid. The European Landfill Directive stipulates the treatment of landfill gases as follows (EC 2020):

- Appropriate measures shall be taken in order to control the accumulation and migration of landfill gas.
- Landfill gas shall be collected from all landfills receiving biodegradable waste and the landfill gas must be treated and used. If the gas collected cannot be used to produce energy, it must be flared.
- The collection, treatment and use of landfill gas shall be carried on in a manner which minimises damage to or deterioration of the environment and risk to human health.

While most LFG is directly used in CHP plants comparable to biogas utilisation (Rajaram et al. 2012), the composition of LFG is suitable for further treatment to produce RCFs. In the simplest case, methane from LFGs is directly used as a transport fuel after separation and further purification[18]. Furthermore, the transformation of LFG into syngas and subsequent chemical synthesis would be a possible processing route. In this case, particularly currently developed micro-reactor concepts at container size seem suitable (see INERATEC[19] for microreactor technology), because LFG formation changes over time and an adjustment of capacity would be necessary. Figure 19 summarises possible utilisation pathways of LFG.

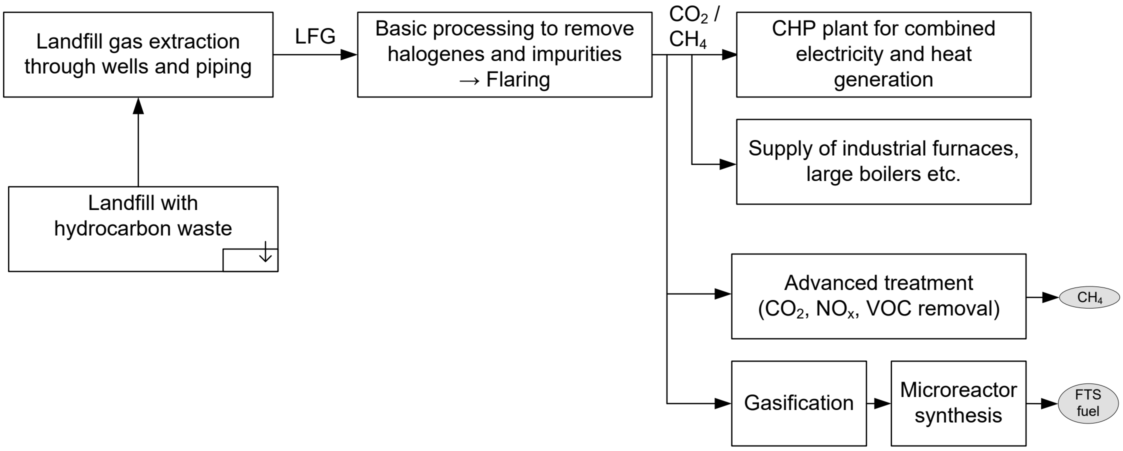

Figure 19: Basic concept of landfill gas collection and utilisation

As landfilling of biodegradable waste has strongly decreased in recent decades and is prohibited in many member states, LFGs as a source for RCFs will continuously decrease in the coming decades. The collection and utilisation of LFG is common technology and therefore the TLR for all utilisation pathways including the provision of fuels (particularly CH_4) is 9.

2.2.6 Recovery of fuels from shipping slops and sludges

In most cases, transportation of crude oil is realized via shipping in large oil tankers. Vessels filled with oil require regular cleaning to avoid sedimentation. This is usually performed by washing the tanks with water, which leads to hydrocarbon waste, so called slops and sludges. Slops may further occur from the transportation of all kinds of liquid chemicals including marine fuel residues. While the dumping of slops into the sea causes severe

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[18] https://www.epa.gov/lmop/basic-information-about-landfill-gas

[19] https://ineratec.de/en/processes/

environmental damage[20], there are alternative solutions for slop treatment. This may include the direct use as a low value fuel e.g. in cement industries but also includes more advanced recycling processes as e.g. developed by Ecoslops[21]. In this process, after collecting slops from different accumulation points, they are heated, decanted, and centrifuged to separate them within a separation unit into hydrocarbons, polluted water, and sediments. The filtered sediments already result in light bitumen, which could be used as a recycled product in the construction industry for buildings or roads. The polluted residual water is treated in a water treatment unit to separate environmentally harmful pollutants, leading to clean waste water. The hydrocarbons are further treated in a hydrocarbon recycling unit where a refining process comparable to crude oil refining through distillation takes place. This results in standard refinery products such as light bitumen and refinery fuel qualities, which may be directly reused as e.g. shipping fuel. The process of recovering high value petrochemicals from shipping slops is illustrated in Figure 20.

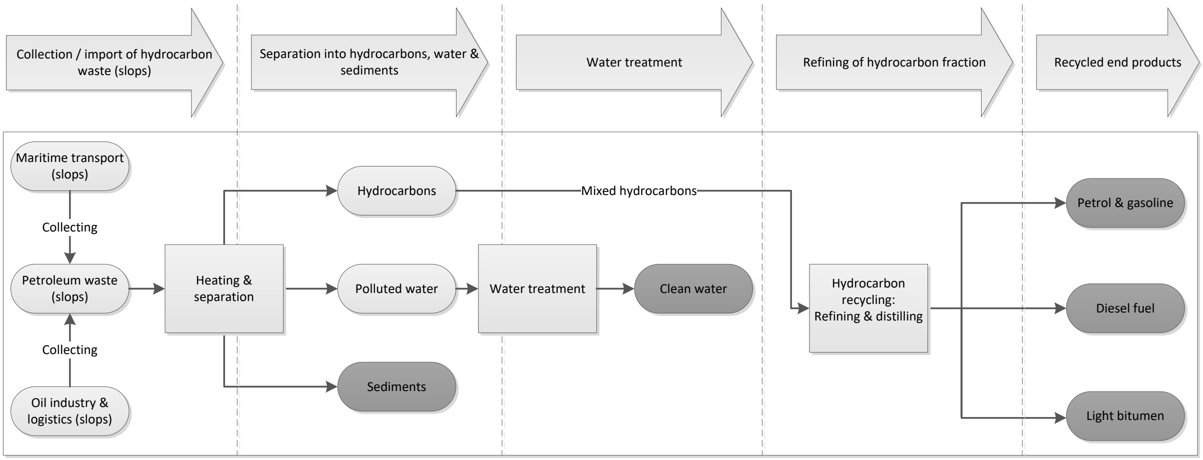

Figure 20: Basic concept of the EcoSlops process for recovery of fuels from shipping slops and sludges (EcoSlops 2016)

The overall process has a recycling efficiency of around 80%. As there is an existing industrial scale pilot plant with a capacity of around 35 kt/a slop processing at Port de Sinès in Portugal, the TRL of the recovery of fuels from shipping slops is also set at 9.

2.2.7 Most relevant processing routes for RCFs and related feedstocks and energy efficiencies

As described in the previous sections, there are a number of different processes for producing RCFs, mainly depending on the respective feedstocks. While we develop different scenarios regarding RCF production in the next chapter, here we give a first outlook on feedstock availability. In this context, it has to always be considered, that these feedstocks are already today used for other purposes, mainly for energy production in combined heat and power plants. The most relevant feedstocks for potential RCF production in accordance with the previous technology descriptions are the following:

- Solid hydrocarbon waste, mainly mixed plastic waste for pyrolysis or gasification processing

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[20] https://www.cambiasorisso.com/illegal-slops-dumping-is-an-environmental-challenge-for-shipping-but-there-are-solutions/

[21] https://www.ecoslops.com/en/solutions-and-services/our-technology/ow2p

- Furnace gases from steel production and further CO and H_2 containing industrial exhaust gases, e.g. from refineries
- Landfill gases from municipal solid waste landfills
- Sludges and slops, mainly from crude oil and petrochemicals shipping

Mass potentials of the afore mentioned feedstocks, which are of key relevance for scenario development, are partly available from existing statistics or require further assumptions as described in combination with scenario development in the following chapter (3.2). The most relevant feedstocks for RCF production in terms of mass potentials are solid waste flows containing hydrocarbons such as mixed plastics that are not suitable for recycling. These waste flows are currently mainly incinerated for energy generation. As depicted in Figure 21, solid waste being landfilled has continuously decreased in the previous decades. Most EU countries have a ban on the landfill of biodegradable waste and the major share of landfilled waste within the EU today is inorganic waste, mainly from the building and construction sector. A more detailed discussion of potential feedstocks and their availability in future is provided in the context of scenario development in chapter 3.2.

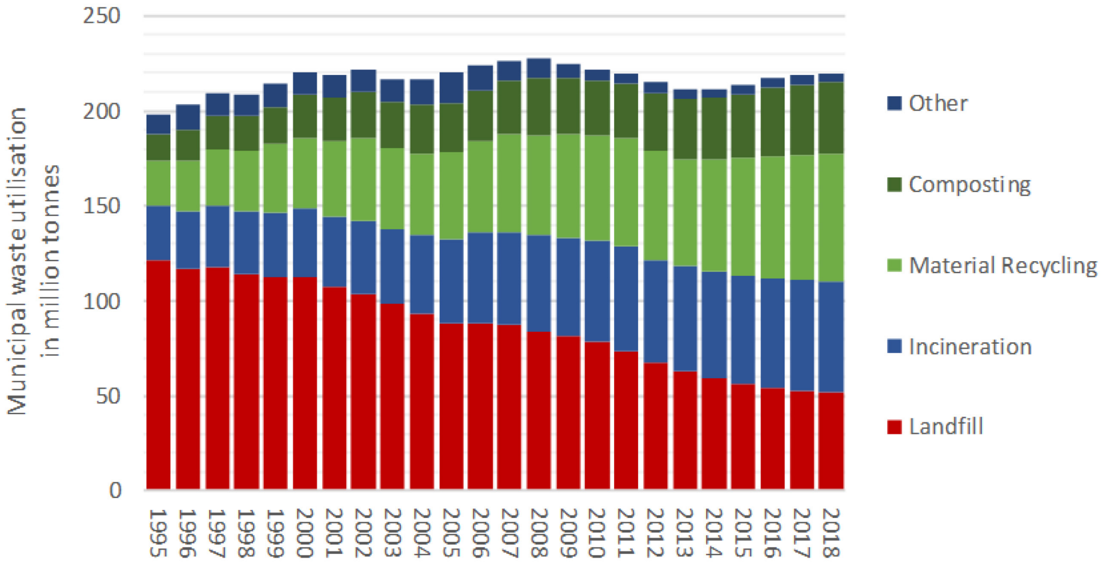


Figure 21: Municipal waste flows and their current utilisation in the EU27+UK (data based on Eurostat 2020)

In contrast to the production of RFNBOs, RCF processes mainly source their required energy directly from the feedstock and therefore these processes are relatively independent from the energy system. Furthermore, in many cases, side products or exhaust heat from other facilities may be used when RCF production is integrated in existing industrial processes (e.g. steel production). Pyrolysis processes for instance are usually directly fired by the gas fraction or solid residues of the product spectrum, while with suitable catalytic reaction concepts, around 75-80% of carbon content in the waste stream is transferred into liquid fuels (Awasthi et al. 2017). As the production of blue hydrogen through gasification of solid hydrocarbon waste is a promising pathway for RCF production, we exemplarily provide basic material and energy balances for the Plagazi process (cf. Figure 15) with a capacity of around 20 kt/a based on available literature data (Occhinero 2019). As indicated by the energy balance (Table 3), excess heat and energy content of side products can come up for major input energy requirements.

Table 3: Exemplary mass and energy balance of the plasma gasification of mixed plastic waste (Occhinero 2019)

Input flow	Mass flow kg/h	Energy flow kW	Output flow	Mass flow kg/h	Energy flow kW
Plasma Air	37 kg/h	58 kW	Slag	306 kg/h	177 kW
Feed (waste + coke)	2350 kg/h	14627 kW	Acid gas	182 kg/h	7 kW
Oxygen (from air)	1093 kg/h		Steam (excess heat)	7159 kg/h	7991 kW
Steam	8619 kg/h	3000 kW	H_2	239 kg/h	8782 kW
Compression work (electricity)		700 kW	Exhaust gases (mainly CO_2)	4213 kg/h	

Conclusions regarding RCF processes

There is a wide range of potential feedstocks for RCFs making it difficult to draw general conclusions. A very important aspect is the fact that the feedstock for RCFs is not of renewable origin. Therefore, the advantageousness of RCF production depends on the alternative utilisation pathways of the required feedstock. This may include both energy recovery through combustion with subsequent combined heat and power generation or material recovery. MSW and mixed plastics waste are an important source for RCF production, however, in contrast to other gaseous and liquid waste streams, the utilisation of MSW for fuel production bears several difficulties regarding the usefulness of RCFs. Therefore, the utilisation of plastic waste that is not suitable for direct recycling shall be discussed in the following.

As pointed out in the previous section, plastic waste can be transformed into high-quality traffic fuels. However, RED II directly refers to Article 4 of the waste directive 2008/98/EC, which addresses the waste hierarchy (cf. Figure 12):

- prevention
- re-use
- recycling
- other recovery (energy recovery)
- disposal.

Chemical recycling of plastic waste, which we define as the production of chemicals from waste fractions that can be used to substitute petrochemicals in e.g. plastic production is always an alternative to fuel production and is based on generally similar processing routes as described here for fuel production (BASF 2020). Hence, RCF production obviously competes with chemical recycling regarding feedstock of mixed plastic waste. As plastic is almost entirely produced from crude oil and, hence, fuels produced from plastics are not renewable and will – apart from upstream emission reductions – not reach a considerable GHG-abatement, it seems far more promising to close the carbon cycle through improved plastic recycling (chemical recycling of mixed plastic waste) as already suggested by Tukker et al. (1999) rather than to produce fuels which are used in combustion engines. As mentioned before, RED II allows the member states to accept RCF as a means to achieve its targets. As there is no significant reduction in GHG emissions through the production of fuels from fossil-based waste, it is questionable whether RCFs from solid waste streams will contribute to a reduction of GHG emissions in the transport sector from ab holistic perspective. Therefore, it is very likely that many EU member states will not accept RCF produced from plastic waste as an alternative fuel in their RED-II-based national quota regulation. However, what needs to be taken into account in this context is the option of gaining ‘blue’ hydrogen from waste gasification (cf. Figure 15). In this case, CO_2 resulting from the process could be captured within a CCS system resulting in a significant reduction of overall CO_2 emissions. Recent LCA studies analysing RCF production from solid waste have shown that the processing itself shows little or no advantage compared to conventional fuel production and major emissions occur during fuel combustion in vehicle operation (see Figure 22). In case of carbon capture after the gasification process, these fossil-based emissions could be eliminated making RCF production in combination with CCS a valuable source for ‘blue’ hydrogen.

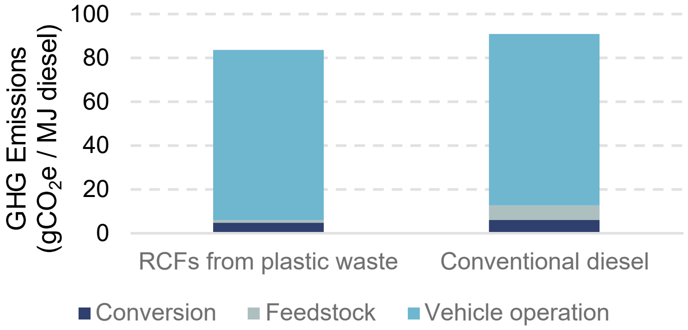


Figure 22: Comparison of GHG emissions of RCF production from mixed plastic waste and conventional fossil diesel (Benavides et al. 2017)

3 ASSESSMENT OF DEVELOPMENT POTENTIALS OF IDENTIFIED TECHNOLOGIES INCLUDING TECHNO-ECONOMIC AND ECOLOGICAL FACTORS

While the previous chapter focuses on the systematic stocktaking of individual relevant technologies and production paths for RFNBOs and RCFs, in this chapter the development potential of these individual generation paths is estimated regarding their integration into the European energy system by 2050. The aim is to derive and analyse possible development pathways in form of plausible scenarios in terms of their impact on the energy system. This includes the identification and evaluation of important factors influencing the development potential of the different RFNBO and RCF generation technologies. The scenario development and the analyses are mainly based on studies and data available in the literature, which are supplemented by our own assumptions where necessary.

Due to the different production paths and generation potentials, but especially against the background of the strongly differing data availability on RFNBOs and RCFs, these energy source groups are considered separately in the following sections. In Section 3.1, scenarios for the future use of RFNBOs in the transport sector are developed. For RCFs, corresponding analyses are performed in Section 3.2. The main findings are further analysed in Section 4.

To increase the comparability of the available data, in the following sections the energy carrier classes and groups defined in Table 4 are considered for the evaluation of the studies and the scenario generation based on them. If the available data allow a more detailed breakdown by individual energy carriers, this is done.

Table 4: Energy carrier classes and groups considered for the study evaluation and scenario generation

Class	Group	Includes fuels / products
RFNBOs	**Hydrogen (H_2)**	**H_2 or ammonia (NH_3), gaseous** from electrolysis, transport also possible in liquid form
	Synfuels	**Methane (CH_4), gaseous** as synthetic natural gas (SNG), transport also possible in liquid form
		(Power to) Liquids (PtL), fuels from Fischer-Tropsch synthesis (FTS), methanol (MeOH) synthesis, mixed alcohols synthesis, DME synthesis
RCFs	**Synfuels**	**Methane (CH_4), gaseous** from pyrolysis
		Liquids ethanol and liquid oil

3.1 Derivation of scenarios for use of RFNBOs in the transport sector

For the scenario development on the future use of RFNBOs, relevant existing long-term scenario studies on a European, but also on a national and international level are analysed and categorised (see Section 3.1.1). In this context, available data on key drivers influencing the deployment potential of RFNBOs will also be collected. These are, for example, the expected demand for energy carriers in the transport sector and in other sectors, the RES-E potential, and the cost of the energy carriers in the EU and abroad. Based on these findings, in Section 3.1.2, three demand scenarios are synthesised for this study, which estimate the possible range of future RFNBO deployment in the EU.

To derive the diffusion potential of RFNBOs, three further scenarios for the production or supply of RFNBOs for all demand sectors in the EU are generated in Section 3.1.3. Expectations for the development of relevant techno-economic framework conditions and restrictions are considered. In the final step (see Section 3.1.4), the demand scenarios are combined with the production scenarios. From this matching, insights into the coverage potential of possible RFNBO demand from domestic RFNBO production vs. imported RFNBOs are obtained.

3.1.1 Evaluation of existing scenarios and data for RFNBOs

In order to assess the development potential of RFNBOs for the transport sector in the context of this study, at first scenarios for the overall availability of RFNBOs for all consumption sectors in the EU are developed. Based on this, sub-scenarios are defined which consider different usage shares of the transport sector in the overall RFNBOs potential. For the scenarios to be developed, projections up to 2050 are required regarding the following main aspects:

- **energy demand in EU (by energy carrier, sector, and transport mode),**
- **electricity generation in EU (by energy carrier) and RES-potentials,**
- **RFNBO production and supply (cost/prices from inside/outside EU, if applicable and available also potentials incl. CO_2 sources).**

The required data are derived from already existing scenarios in published studies, which are usually based on model-based analyses. The focus initially is set on comprehensive long-term scenarios that address the energy system transformation for the entire European energy system. Since these scenarios are derived from consistent bundles of assumptions about framework conditions and data on exogenous factors, the data basis of the present study will also be primarily based on the findings and results of these long-term scenarios.

Unfortunately, the studies on the long-term scenarios do not include all the above-mentioned aspects in the required level of detail or not all the required data are sufficiently elaborated by the studies. To close these data gaps, further studies are consulted, which deal with individual aspects (e.g. costs or prices or individual technologies in the transport sector) in greater detail.

According to the large number of strategic policy options and the associated challenges and uncertainties for a successful transformation of the energy system, the literature contains a wide range of long-term scenarios. In the period from early 2017 to mid-2019 alone, over 65 scenarios have been analysed and published in more than 26 studies (JRC 2020). The scenarios differ primarily in terms of the assumed techno-economic potentials and development paths for the preferred use of individual energy sources (a more or less electric driven world, hydrogen, synfuels, etc.) and the implementation of efficiency measures, as well as the reduction in greenhouse gas emissions that is expected to be achieved by 2050.

In Table 5 an overview of published scenarios is given, which have been pre-selected for closer examination in the course of this study. Their results and data are the starting point for the scenario development. This pre-selection was done based on the following criteria:

Reduction of CO_2 emissions	The focus lies on energy transition pathways that (largely) meet the EU climate targets respectively that are mainly compatible with the Paris Climate Agreement. The scenarios selected project a CO_2 reduction of at least 90% by 2050 compared to 1990.
Technical options and behaviour	The selected scenarios cover a broad range of different technical measures (to increase efficiency, deployment of RES, etc.), but also possible changes in the behaviour of energy consumers. This is intended to adequately capture the wide range of options for decarbonising the energy system and the resulting different expectations regarding energy demand and the energy carrier mix used, as well as any competition between the consumption sectors for the (cost-dependent) availability of individual energy sources.
Data availability and harmonisation	Finally, the selection is limited to scenarios with a comprehensive view of the European energy system, for which data was available in a sufficiently evaluable form and with adequate comparability. However, following this, information from further studies was gathered on specific aspects to close data gaps.

Table 5: Evaluated long-term scenarios from existing studies

source	scenario	GHG[1]	FEC[2]	modelling, major assumptions & drivers
European Commission 2018	general information			• energy system model (PRIMES), simulating energy consumption and supply, objective: reaching climate neutrality by 2050 including LULUCF sinks
	EC 1.5 T	**-100%**	**-37%**	• 1.5TECH scenario: achieve net-zero emissions and the well-below 1.5 °C target through steep technological development and use of biomass in combination with CCS • hydrogen and power-to-X technologies become important
	EC 1.5 L	**-95%**	**-42%**	• 1.5LIFE scenario: relying less on (same) technologies of EC 1.5 T, stronger incentives for LULUCF sinks • more circular economy, lifestyle changes (less carbon-intensive diets, transport sharing, more rational demand for heating and cooling etc.)
European Climate Foundation 2018	general information			• simulation model, EU-28 emissions and available mitigation options, focus on showing how a net-zero target is technically and economically possible
	ECF T	**-90%**	**-38%**	• technology focus: reduction of emissions through energy efficiency and highest-level energy technologies (electrification, hydrogen, carbon capture utilisation and storage (CCUS))
	ECF D	**-90%**	**-60%**	• demand focus: reduction of emissions through far-reaching changes on the demand side (e.g. product life cycle, circular economy, complete transformation of the transport sector into a service, moderate ambition on technology change
	ECF S	**-92%**	**-57%**	• shared efforts: combined shares of measures from ECF T and ECF D

source	scenario	GHG[1]	FEC[2]	modelling, major assumptions & drivers
Eurelectric 2018	general information			• bottom-up demand driven model with global scope, focus on electrification • up to 96 % carbon-free electricity, national policies on nuclear/coal phase out, higher end-use efficiency (electric mobility, electric heat pumps)
	EUL 90	**-90%**	**-33%**	• steep cost reductions for mature technologies until 2030, current technologies will be applied on a large scale beyond 2040, clean technologies become progressively mainstream and increasingly competitive for consumers • regulations: major shifts in policies, tariffs, and taxes
	EUL 95	**-95%**	**-38%**	• high competitiveness of electricity against other energy carriers • regulations: implementation of EUL 90 regulations on a global scale
IEA 2017	**IEA B2DS**	**-92%**	**-39%**	• TIMES-based bottom-up, energy system model of global scope, focus on long-term technology outlook • Beyond 2 °C scenario (B2DS)**:** 1.75 °C target by 2100, net-zero emissions are achieved by 2060 • technology development pushed to the limit, considers technologies available and able be deployed on a commercial scale by 2060 assumes unprecedented level of policy action and an effort from all stakeholders
Teske 2019	general information			➢ energy GIS-based modelling framework, hybrid bottom-up/top-down interaction of seven models with no objective cost-optimisation function (resource model, power system model, transport model etc.), exogenous modelling parameter: GDP, population, techno-economics, fuel costs ➢ electrification of heat and transport, exclusion of nuclear power, unsustainable biomass use, CCUS ➢ energy inefficient behaviours (e.g. domestic aviation to rail)
	IFS 1.5	**-100%**	**-47%**	➢ 1.5 °C scenario: 450 GtCO$_2$ global emission budget, immediate action to realise all technically available options without any political or societal barriers
	IFS 2.0	**-100%**	**-41%**	➢ 2.0 °C scenario: 590 GtCO$_2$ global emission budget, delays in the transition due to political, economic, and societal processes and stakeholders allowed
JRC 2018b	**JRC 1.5**	**-96%**	**-47%**	• built on JRC-POLES and JRC-GEM-E3 models, estimate the development of international energy prices and trade with focus on emissions reduction • exogenous modelling parameters: GDP, population, techno-economic assumptions, learning rates, policy constraints • normative elements: CO$_2$ emission constraints & CO$_2$ tax • 1.5 °C scenario: reduces GHG emissions within a global carbon budget of 500 GtCO$_2$ by 2100, to achieve 1.5 °C target by 2100 with a 50 % likelihood
JRC 2018a	**JRC Zero**	**-100%**	**-30%**	1. JRC-EU-TIMES model, estimates cost-effective technology pathways, focus on future technology and market developments to meet EU climate targets 2. zero carbon scenario: achieve EU policy targets for 2030 and net zero CO$_2$ emissions by 2050, CO$_2$-reuse (CCU), nuclear expansion up to 60 years is allowed (only in countries with no nuclear restriction policies)

source	scenario	GHG[1]	FEC[2]	modelling, major assumptions & drivers
Oeko-Institut 2017	**Oeko**	**-100%**	**-45%**	• based on literature review, analysis for end-use sectors & for CO_2 emissions based on various deep decarbonisation projections, analysis for the power sector based on an hourly modelling exercise for the EU-28, sectorial integration implemented through an energy balance model • Vision scenario: emission reduction of at least 90 % by 2050, combination of medium-term objectives on energy and emission, 2 °C target by 2100, using carbon budget for the EU, socio-economic drivers based on EU Reference Scenario 2016 • massive roll-out of energy efficiency measures for all sectors and early decarbonisation of the power sector, nuclear power phased out (based on existing policies / max. technical lifetime of 40 years) • using CCS only to avoid CO_2 emissions from industrial processes • biomass restrictions (tight sustainability criteria), no extensive efforts for additional carbon sinks
WindEurope 2018	**WE PC**	**-90%**	**-30%**	• global system-dynamics feedback model, covers building, industry, transportation sectors and & feedstocks, focus on energy sources that meet demand (selected by a merit order-based algorithm) • evolution of technology costs over time shaped by learning curves - GDP, population, socio- and techno-economics • Paris-compatible scenario: below 2 °C target, additional effort in energy efficiency and electrification, decommissioning of coal-based power generation and & carbon pricing

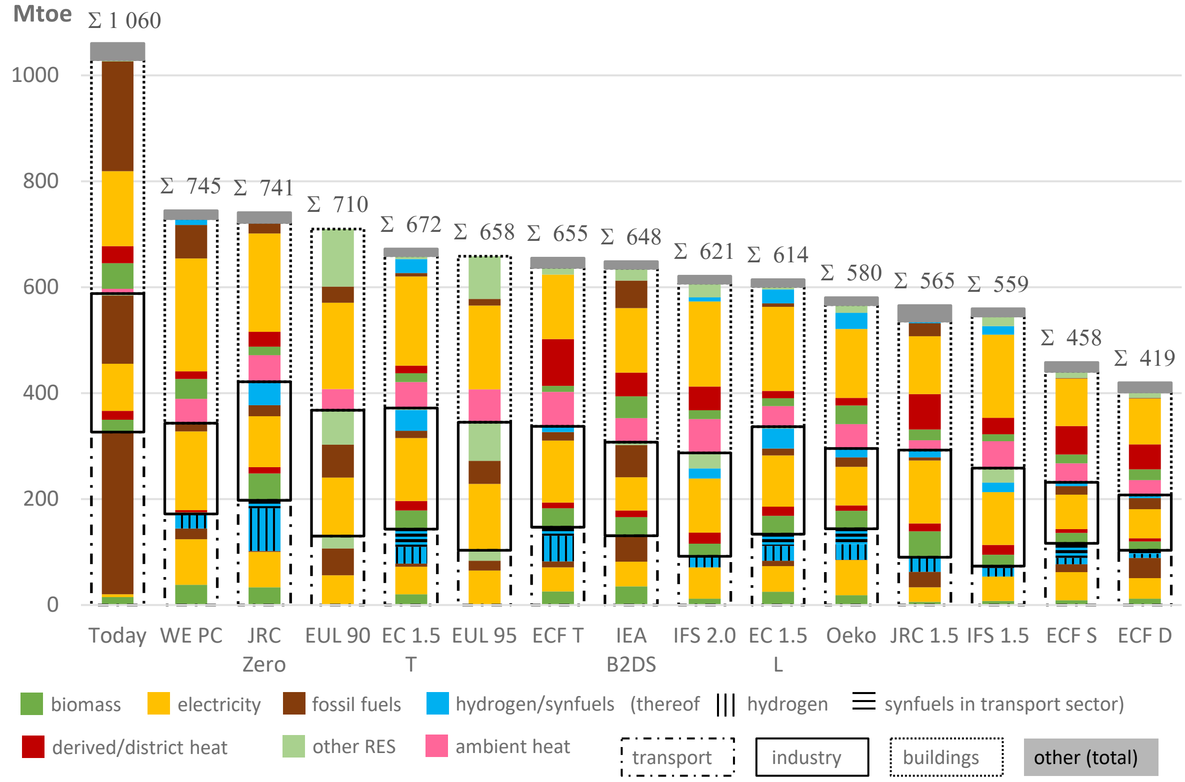
[1] *CO_2 emission reduction by 2050 compared to 1990 excl. LULUCF.*
[2] *Reduction of final energy consumption by 2050 compared to 2017.*

3.1.1.1 Projections of energy demand in EU in existing studies

In all analysed long-term scenarios, a significant reduction in final energy consumption within the EU is expected by 2050, compared to today's consumption (using 2017 numbers) of approximately 1,060 Mtoe (EUROSTAT 2020). However, the projections (see Figure 23) show a relatively wide range for the expected energy demand in 2050 from about 740 Mtoe to 420 Mtoe (30% to 60% reduction compared to 2017).

The industrial sector displays the widest variation within the projections for final energy consumption (-8% to -60% compared to 2017). However, the highest absolute and relative reduction potential for the next 30 years is assumed to be in the transport sector (on average about -200 Mtoe or -60% excluding international air and sea transport). Here, the estimated potential for reduction compared to current consumption varies between 40% and 78%. This fluctuation range is mainly due to very heterogeneous assumptions and expectations regarding the future demand for mobility and the type and utilisation or occupancy of the various modes of transport. In most scenarios, a significant reduction of road passenger transport is assumed (by -20% to more than -50%).

RFNBOs replace the use of fossil fuels, especially in the transport sector but also in the industrial and in some scenarios also in the building sector. The demand for these energy sources is estimated to be about 58 Mtoe on average in 2050 (this is composed of about 60% for the transport sector, 26% for the industrial sector and about 14% for the building sector). The share of RFNBOs in the transport sector varies between 1.5% (IEA B2DS) and 48% (JRC Zero). In the ECF S scenario, just under 70% of the RFNBOs are used in the form of synfuels and the rest in the form of hydrogen. In the scenarios ECF D, EC 1.5 T, EC 1.5 L and Oeko, the shares of hydrogen and synfuels are approximately equal. In the remaining scenarios, the proportion of hydrogen predominates with approx. 75% to 100% compared to the synfuels. In addition to RFNBOs, all evaluated scenarios assume that advanced biofuels are used in the transport sector. Projected shares of these energy carriers in 2050 vary between approx. 6% and 22% of total final energy consumption in the EU-internal transport without aviation (today approx. 4.5%).

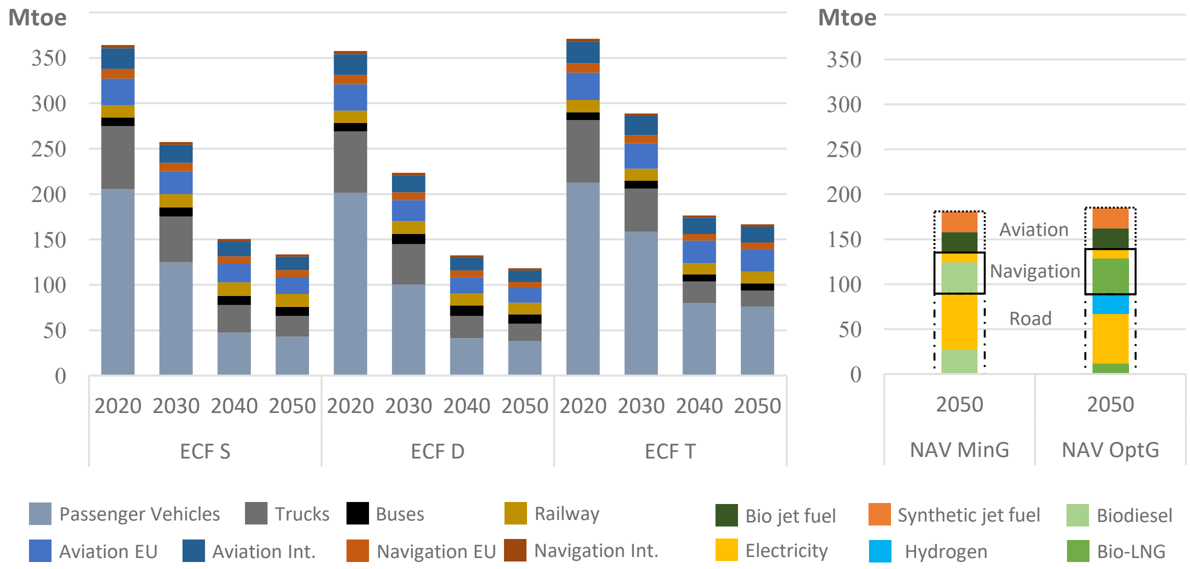


Source: Own illustration based on (Eurelectric 2018; European Climate Foundation 2018; European Commission 2018; IEA 2017; JRC 2018a, 2018b; WindEurope 2018; Teske 2019; Oeko-Institut 2017; JRC 2020)). Note: "Transport" without international aviation/navigation. "Other" includes forestry, agriculture, etc. except in EUL 90/95, which includes these in the industry sector. "Other RES" includes other renewable sources (e.g. solar thermal, geothermal heat) and in EUL 90/95 also biomass, biofuels, synthetic fuels, and hydrogen.

Figure 23: Final energy consumption today (2017) and 2050 in EU 27 + UK (Mtoe)

However, most of the scenarios analysed still expect the use of fossil fuels in the transport sector in 2050, albeit at a significantly reduced level compared to the situation today. In relative terms, the share of fossil fuels in the transport sector decreases from currently approx. 94% to less than 40%. This corresponds to a reduction of about 80 Mtoe and more. Only four scenarios assume an (almost) complete substitution of fossil fuels by electricity, biomass, hydrogen, and other renewable fuels in the transport sector.

For an adequate assessment of the future RFNBOs deployment potentials in the transport sector, a detailed breakdown of energy demand by individual energy sources and vehicle classes (car, light duty vehicle, heavy duty vehicle, bus, train, ship, etc.) or at least detailed transport modes (road passenger, road freight, railways, inland navigation, etc.) is required. However, such a high-resolution breakdown is not shown in the evaluated studies. Usually, the information is limited to the energy demand per transport mode (see Figure 24 left). Additional information is occasionally available on the expected number of vehicles, the distances covered or the passenger and freight volume. In a study from NAVIGANT (Navigant 2019) two further scenarios (NAV MinG and NAV OptG) were developed, which are not considered in Table 5 due to their limited comparability for industry and building sector.[22] Figure 24 (right) shows available data from these scenarios for the transport sector, which at least show a breakdown by energy carrier in the subsectors. The scenarios from NAVIGANT assume a complete decarbonisation (avoidable CO_2) of the European energy system by 2050.



Source: Own illustration based on (European Climate Foundation 2018; Navigant 2019).

Figure 24: Final energy consumption of transport modes in EU 27 + UK (Mtoe)

3.1.1.2 Projections of electricity generation in EU and RES potentials

In line with the targets for reducing GHG emissions, in almost all scenarios the conventional energy sources coal and oil are almost completely displaced by renewable energy sources by 2050 (see Figure 25). The projected electricity generation volumes inside the EU range from 2,687 TWh to 10,548 TWh, which is a very wide range from a slight reduction to a tripling of electricity generation compared to today's level. This heterogeneity is due to the different expectations regarding the electrification of energy applications in all consumption sectors, but especially to the production and use of hydrogen/synfuels to meet the energy demand, especially in the transport and industrial sectors. The scenarios with very high shares of hydrogen/synfuels also show the largest increase in power generation volumes up to 2050.

The scenarios in the middle and lower range with a moderate increase of electricity generation volumes or even an expected shrinkage (see ECF D) assume a higher reduction of energy consumption together with measures to increase energy efficiency. Correspondingly, the use of hydrogen/synfuels and the quantities of electricity generated to produce them tend to be lower. In five of the scenarios in Figure 25, it is assumed that electricity production is based exclusively on renewable sources. In the other scenarios, it is assumed that nuclear power, as well as natural gas will be used to varying degrees until 2050 and beyond. The latter energy sources tend to be found to a greater extent in the

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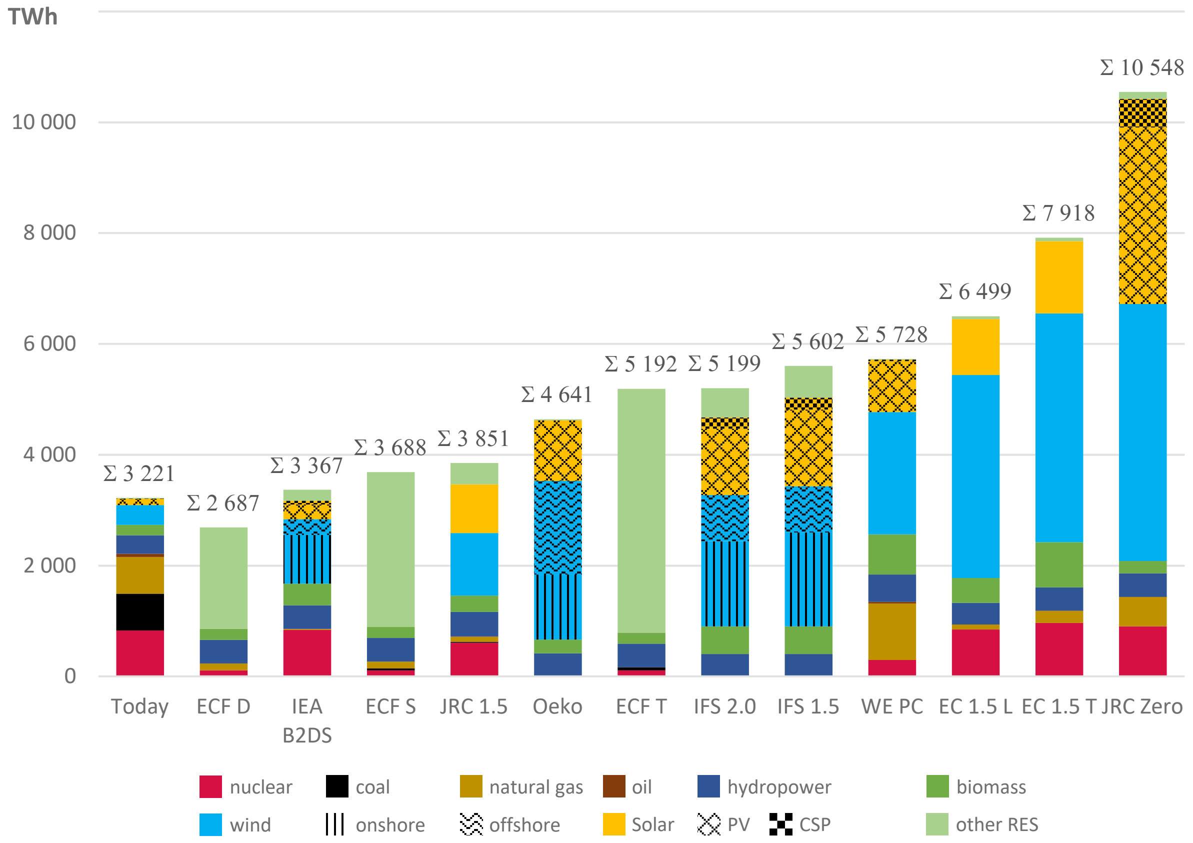
[22] The scenarios NAV MinG and NAV OptG (Navigant 2019) consider only the main industrial sectors and, in the building sector, only the energy demand for heating.

scenarios with higher expected energy consumption as well as in the scenarios with very high increases in electricity production.



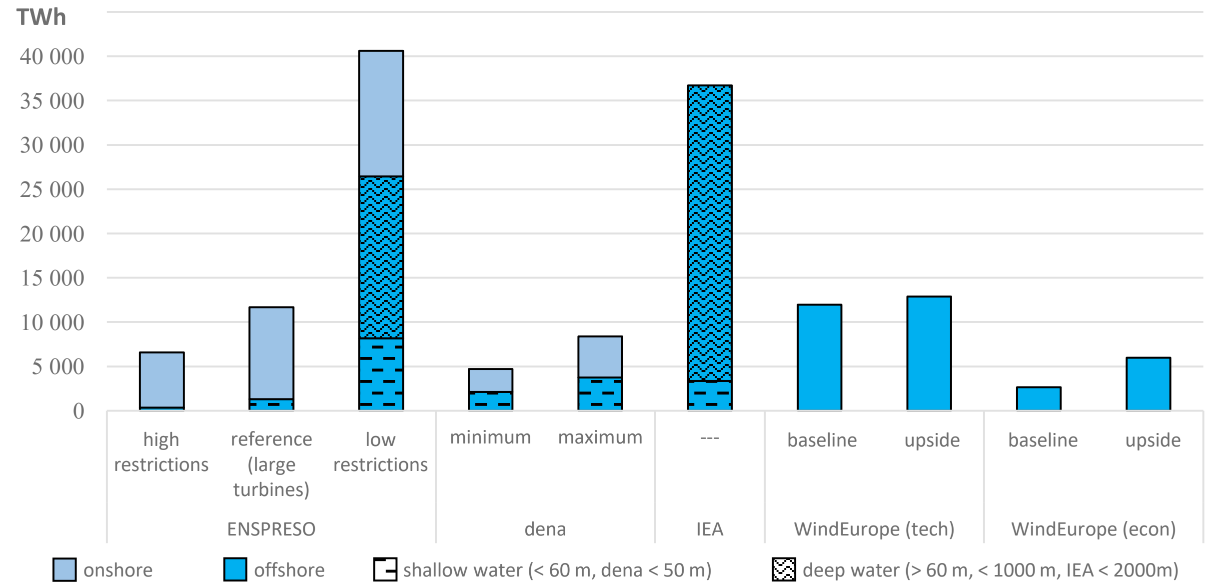
Source: Own illustration based on (Eurelectric 2018; European Climate Foundation 2018; European Commission 2018; IEA 2017; JRC 2018a, 2018b; WindEurope 2018; Teske 2019; Oeko-Institut 2017; JRC 2020). CSP: concentrated solar power, PV: photovoltaic.

Figure 25: Gross electricity generation today (2017) and 2050 in EU 27 + UK (TWh)

The partly enormous growth in renewable electricity production is mainly attributed to the expansion of wind power, but a significant increase is also expected for electricity generation from solar energy. However, data allowing an assessment of the reported electricity generation volumes in relation to the RES potentials for electricity generation and their utilisation cannot be derived from the scenarios considered or can only be derived to a limited extent. Corresponding information is therefore subsequently collected from the ENSPRESO potential studies (JRC 2019) as well as from further studies that explicitly analyse these aspects (dena 2017; IEA 2019a; WindEurope 2017).

Technical potentials for electricity generation from wind power estimated in various studies are shown in Figure 26. The greatest potential is seen in the expansion of offshore wind power (in greater water depths with floating wind farms).

ENSPRESO considers various restrictions when estimating the potentials. For wind offshore these include the distance to the coast (low restrictions 0 nm, reference, and high restrictions >12 nm), the distance to shipping lanes and the shipping density, and the use of areas of inland waters. For wind onshore, the minimum distance to settlements and other land uses is taken into account (low restrictions 400 m, reference with current country-specific legal regulations, high restrictions 1,200 m).



Source: Own illustration based on (dena 2017; IEA 2019a; WindEurope 2017; JRC 2019).
Note: IEA excludes Greece. WindEurope considers the potentials of North Sea, Atlantic (around the UK and France), and Baltic Sea. Baseline scenario based on current policy frameworks and assumptions about future policy. Upside scenario assumes more positive developments in network access, market support mechanisms, site development and supply chain development. Average turbine density: ENSPRESO 5 MW/km², dena 0.41 MW/km² (maximum), 0.24 MW/km² (minimum), 0.55 MW/km² for Germany, WindEurope 5.36 MW/km².

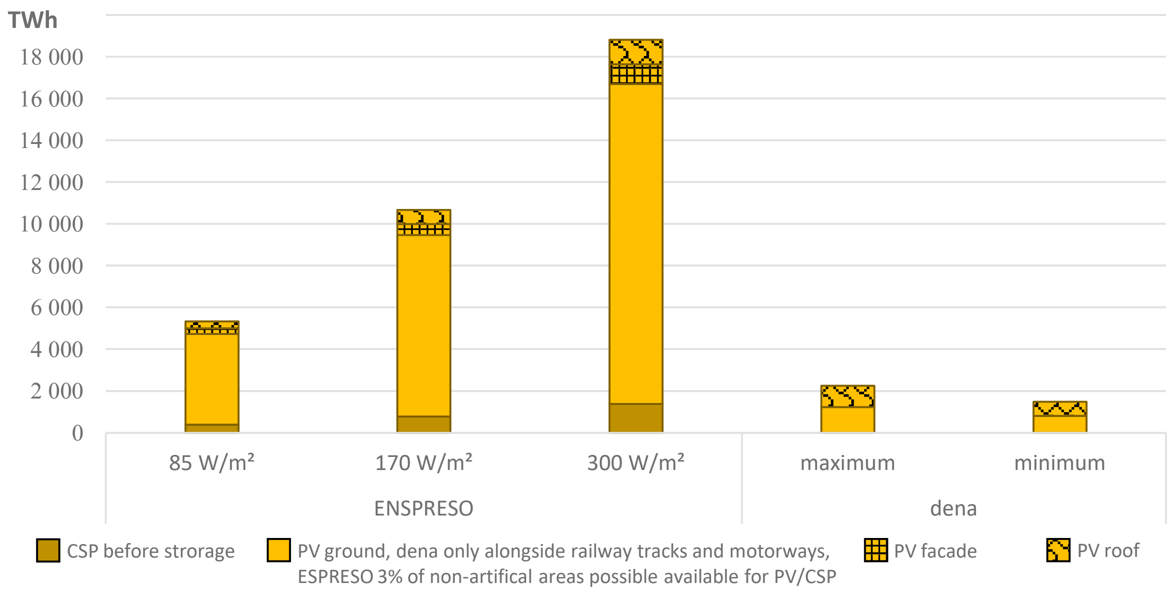
Figure 26: Potential yearly electricity generation by wind power in EU 27 + UK (TWh)

The study of WindEurope is limited to the potentials in the sea areas North Sea, Atlantic (around the United Kingdom and France), and Baltic with water depths up to 1,000 m. In addition to the technical potential, an assessment of the potential economic attractiveness is also given. Here, levelised cost of energy (LCOE) is considered a key determinant. LCOE of less than 65 EUR/MWh in 2030 are defined as economically attractive.

For the potentials for electricity generation from solar energy, estimates from the literature are shown in Figure 27. For their determination, ENSPRESO considers three different classes of power densities. The potentials of natural open spaces are derived from different shares of use for "non-artificial areas" that could be made available for open field photovoltaic (PV) and concentrated solar power (CSP).

The ENSPRESO potentials in Figure 27 assume a 3% utilisation of open areas (other arable, permanent crops, pastures, cereals, maize, root crops, abandoned arable land, abandoned permanent crops and abandoned pastures) without forest areas. On the other hand, dena's potentials only include available open spaces alongside railway tracks and motorways in the analysis. The electricity generation potential from roof-mounted PV systems includes residential and non-residential buildings. ENSPRESO also shows the potential for PV systems on building facades.

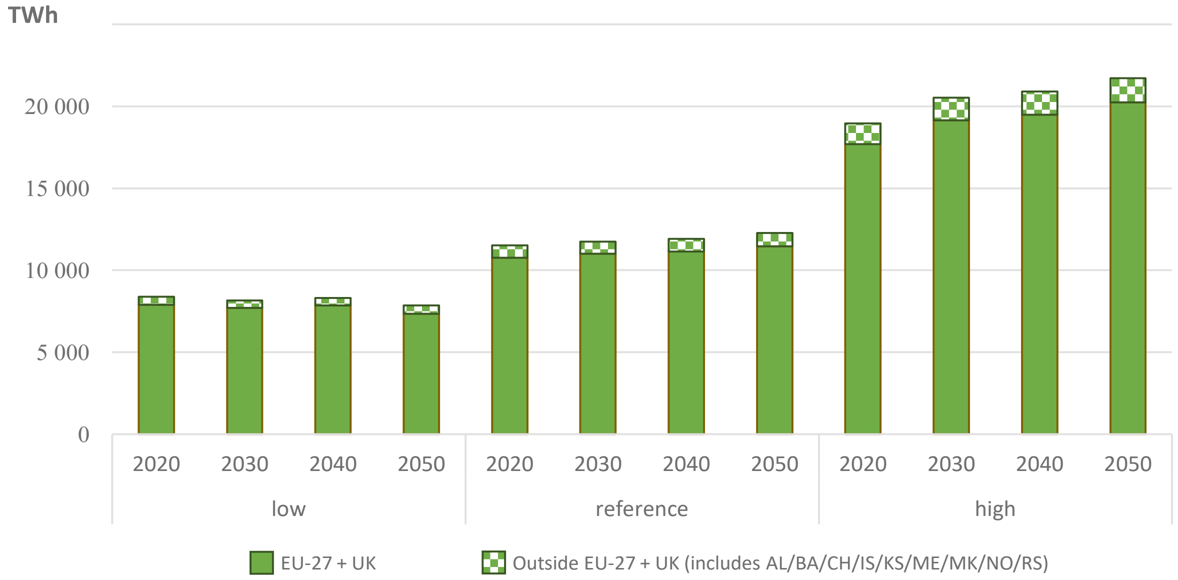
Even if no energy potentials from biomass are to be considered for RFNBOs, these are considered during data collection in the following paragraphs. They are used to check the plausibility of the RES electricity generation quantities for all demand sectors or to estimate the available CO_2 volume from biomass.



Source: Own illustration based on (dena 2017; JRC 2019).

Figure 27: Potential yearly electricity generation by solar power in EU 27 + UK (TWh)

The ENSPRESO figures for the estimated development of the bioenergy potential take into account energy crops and residues in the agricultural sector (e.g. from animal husbandry, arable farming and fruit growing) and roundwood and residues used for energy purposes in forestry (e.g. from wood processing). The waste sector includes energy biomass in the form of residues from landscape management (including roadsides and abandoned areas) as well as biomass residues from industrial production and municipal waste. The potentials are shown for three levels (low, reference and high) based on different assumptions about productivity and limitations of bio feedstocks and available land (see Figure 28). In particular, the competition between food and energy crops is taken into account.



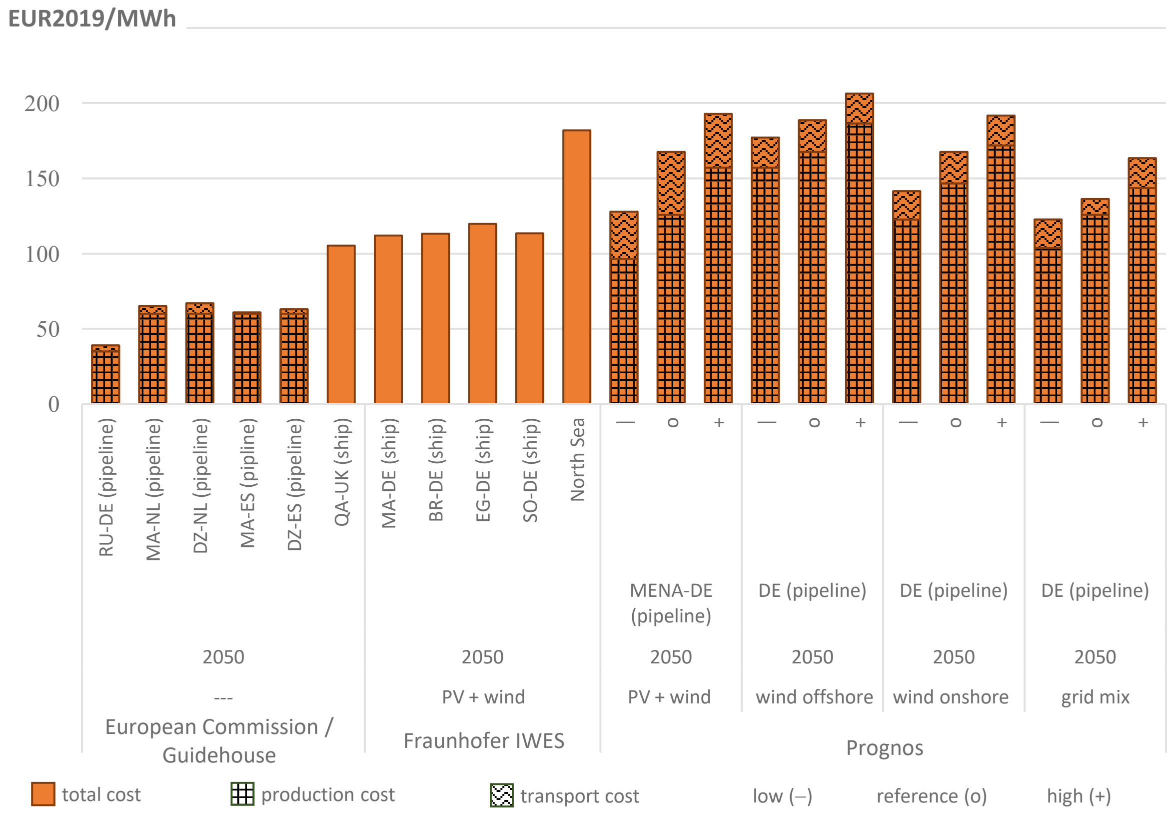
Source: Own illustration based on (JRC 2019).

Figure 28: Yearly bioenergy potential from agriculture, forestry and waste (TWh)

3.1.1.3 RFNBOs production and supply

For the assessment of the future use of RFNBOs in the transport sector, the costs or prices of the production and supply of these fuels are a significant influencing factor. Various studies have estimated these costs for different fuel supply routes. Another important question is what generation potential for these fuels can be raised within the EU-28 and what quantities of RFNBOs must be imported from outside the EU-28 to ensure sufficient supply for the European transport sector. In the following section the available supply costs in the literature for hydrogen, synthetic methane, and power-to-liquids (PTL) in the form of Fischer-Tropsch (FT) and methanol fuels are considered.

Figure 29 first shows the estimated supply costs for hydrogen in 2050 for various production sites outside the EU (MENA region, Russia, and Brazil). The hydrogen is transported in gaseous form via pipeline or in liquefied form by ship to various border points in the EU. The costs vary between 39 EUR/MWh and 120 EUR/MWh depending on the production and landing location (European Commission 2020a; Fraunhofer IWES 2017; Prognos 2020). In addition, Fraunhofer IWES 2017 and Prognos 2020 show the estimated costs for the production and supply of hydrogen in the EU (North Sea and DE cases). Here the expected costs fluctuate between approx. 120 and 205 EUR/MWh. The costs shown by Prognos also include distribution within Germany to the consumer. In the other studies the costs refer to the respective border crossing.

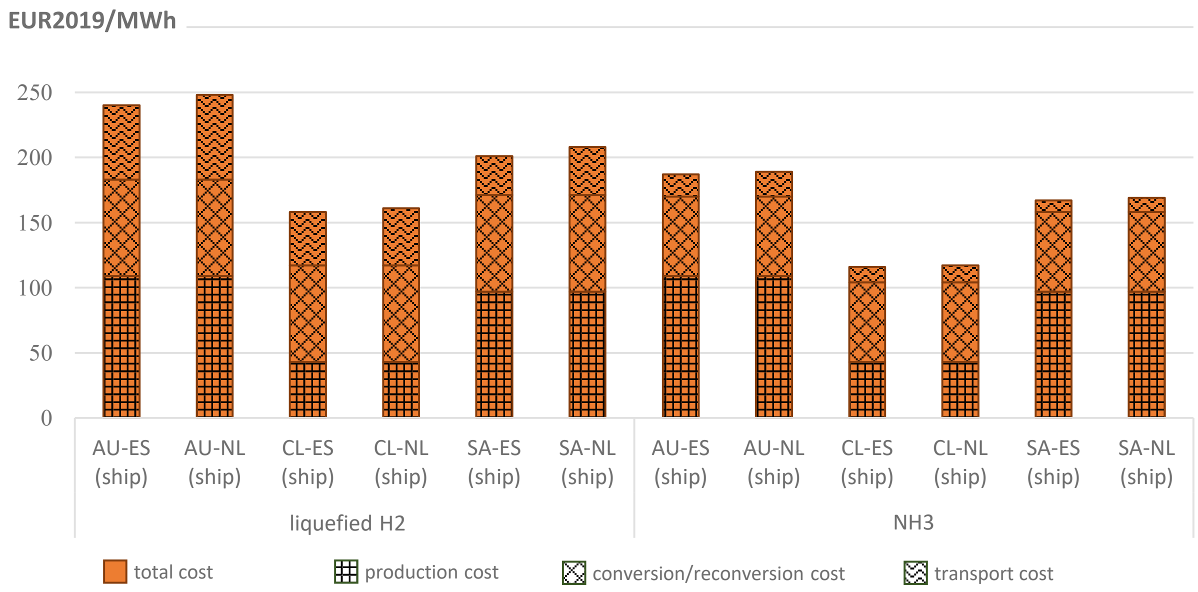


Source: Own illustration based on (European Commission 2020a; Fraunhofer IWES 2017; Prognos 2020).

Figure 29: Cost for hydrogen supply in EU in 2050 for different production sites within and outside of the EU (EUR2019/MWh)

A more detailed breakdown of the import costs of hydrogen as a function of the transport form (liquefied vs. ammonia) for the production sites Australia, Chile, and Saudi Arabia in

2020 is shown in Figure 30. Due to the low volumetric energy density of gaseous hydrogen, its liquefaction by cooling to -253 °C is required for transport. Transport in the form of ammonia may be an alternative, but energy is also required for conversion. Estimated marginal costs vary from 115 EUR/MWh to almost 250 EUR/MWh depending on the landing point in the EU.

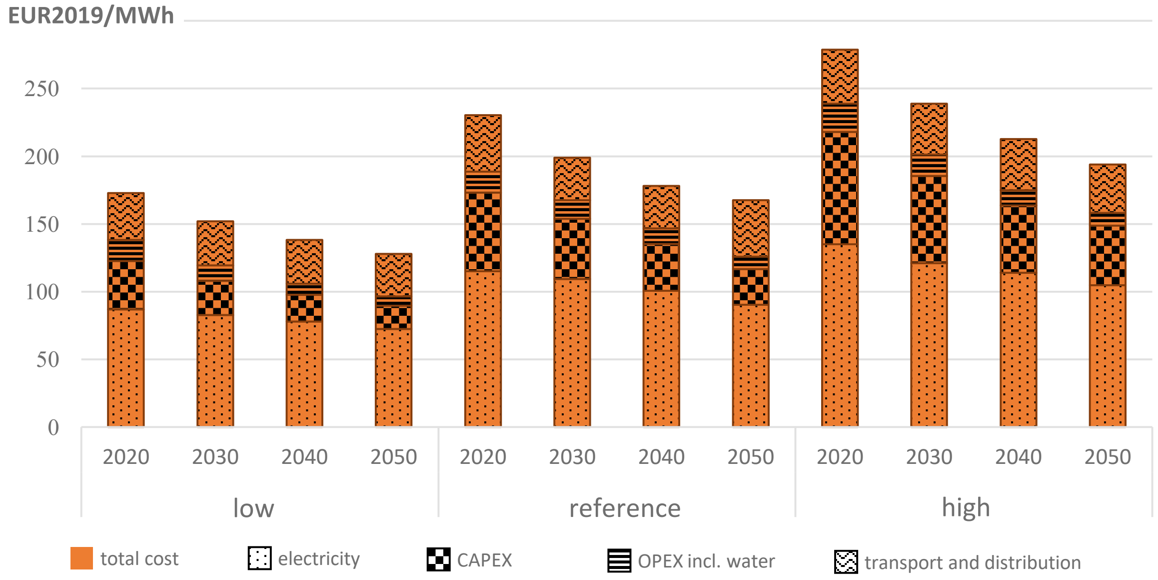


Source: Own illustration based on (European Commission 2020a).

Figure 30: Cost for liquified hydrogen and ammonia supply in EU in 2020 for different production sites outside the EU (EUR2019/MWh)

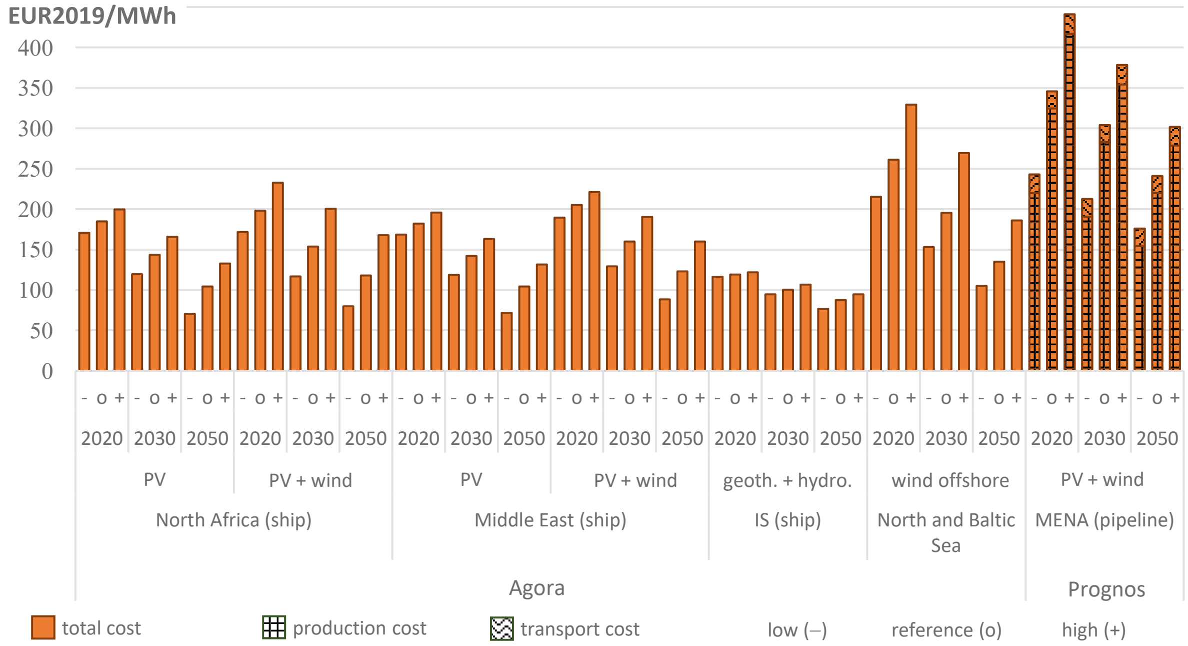
Figure 31 shows an expected development of the cost components for the gaseous hydrogen transport from the MENA region via pipeline to Germany, including domestic distribution. Among other things, various capital costs (interest rate 6% (low), 10% (reference), 12% (high)) and full-load hours of the generating plants (8,000 h (low), 7,000 h (reference), 6,000 h (high)) were assumed. The costs of water supply are set at 1.42 EUR/tonne in 2020 for the reference case and are reduced to 1.18 EUR/tonne by 2050. For the cases "high" and "low" the water costs vary between -40% and +36% compared to the reference case. Depending on the scenario, a cost reduction of between 25% and 35% is expected by 2050.

Figure 32 and Figure 33 show the development of the estimated supply costs in Germany for synthetic methane and PtL fuels (Fischer-Tropsch and methanol) from the MENA region and Iceland. The transport takes place in gaseous form via pipeline or in liquefied form by ship. The costs in 2050 range from 70 EUR/MWh to 200 EUR/MWh for synthetic methane and from 76 EUR/MWh to 350 EUR/MWh for PtL fuels, depending on the location of production and form of transport. The costs shown by Prognos also include the distribution within Germany to the consumer.



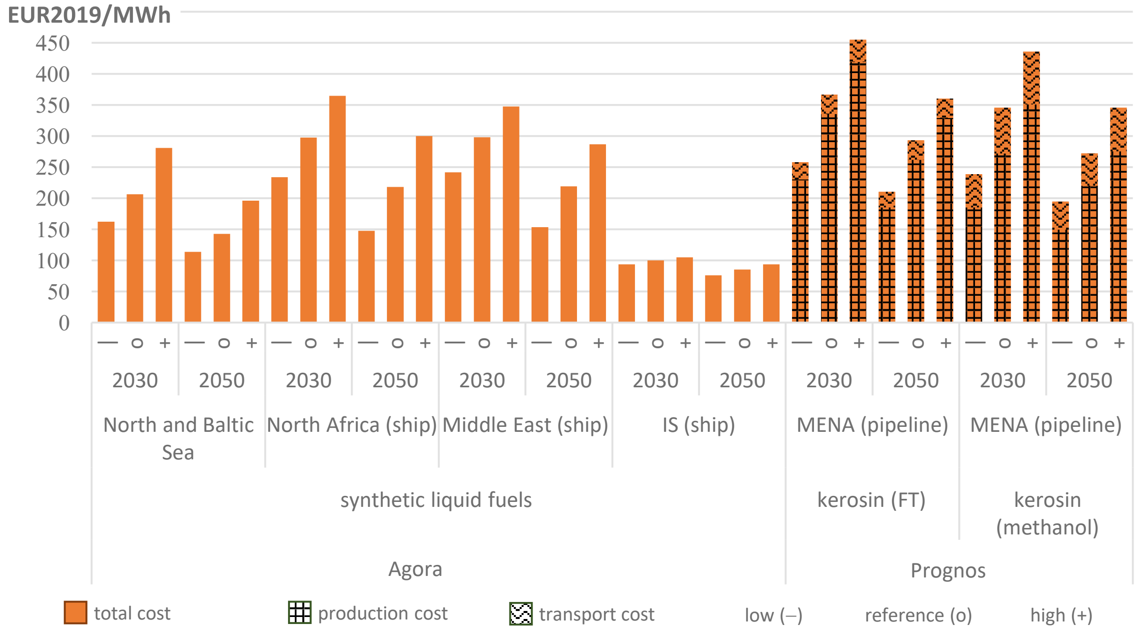
Source: Own illustration based on (Prognos 2020).
CAPEX: capital expenditures, OPEX: operational expenditures.

Figure 31: Development of cost components for hydrogen supply via pipeline from MENA to final consumers in Germany (EUR2019/MWh)



Source: Own illustration based on (Prognos 2020; Agora 2018).
Note: Prognos: cost to final consumer, Agora: import cost.

Figure 32: Cost for synthetic methane supply to Germany from different production sites within and outside of the EU (EUR2019/MWh)



Source: Own illustration based on (Prognos 2020; Agora 2018)
Note: Prognos: cost to final consumer, Agora: import cost.

Figure 33: Cost for PtL fuel (Fischer-Tropsch and methanol) supply to Germany from different production sites within and outside of the EU (EUR2019/MWh)

While numerous estimates for the cost of hydrogen and synthetic hydrocarbons can be found in the analysed literature, information on the potential production volume of electricity-based fuels within and outside of the EU is hard to find. The amount that could potentially be produced mainly depends on assumptions regarding the amount of renewable electricity and (in the case of hydrocarbons) CO_2 available for the fuel production. One study (dena 2017) explicitly states that the total renewable electricity (RES-E) potential in the EU-28 is assumed to be 12,000 TWh. Depending on the assumed electricity demand for other purposes, a certain amount auf RES-E would remain for RFNBO production. But there is also a study that, based on detailed energy system modelling, estimates the European hydrogen production potential to be roughly 4,000 TWh_{H2} in the year 2050, when setting a limit of 150 $€_{2020}/MWh_{H2}$ for the hydrogen sales price (Lux and Pfluger 2020). RFNBOs demand exceeding this potential within the EU would therefore have to be covered by fuels imported from outside the EU. Unfortunately, the studies analysed in the literature review did not state explicitly which fraction of the projected RFNBOs demand would be covered by production within the EU and how much would have to be imported.

The amount of CO_2 potentially available for the production of synthetic hydrocarbons is also subject to discussions, especially considering the environmental sustainability of the CO_2 sources. Biogenic CO_2 from stationary installations (allowing CO_2 capture) would be rather limited and might be reserved, at least partially, for negative emission technologies like bioenergy with CCS (BECCS) in the future. Geological CO_2 sources would also be very limited and might become unavailable if the CO_2 was directly re-injected into the source, e.g. in closed-loop geothermal plants (dena 2017). CO_2 from industrial processes could be a relevant source in the short and mid-term, but it would not be completely sustainable (not climate-neutral).In the long term, the level of unavoidable process emissions of CO_2 might decrease considerably. Therefore, CO_2 from direct air capture (DAC) could become the dominant source of CO_2 in the future, as it is in principle only limited by the available energy and land for the capturing facilities. However, despite projected cost reductions according to

(Prognos 2020) the cost of CO_2 from DAC could still be approximately 204 (120 to 264) EUR2016/tonneCO_2 in 2050.

3.1.2 Derivation of scenarios for the RFNBO demand in the EU's transport sector and other sectors

A key aspect of the scenario analysis is the determination of the potential share of RFNBOs in both the overall gross final energy consumption and the energy consumption that can be counted towards the share of renewable energy in the transportation sector included in RED II Article 25. Based on the evaluated scenarios in Section 3.1.1, we derive three demand scenarios for RFNBOs in the EU for the year 2050. Due to the currently (2021) still very low market maturity of corresponding technologies and the necessary restructuring measures, as well as the associated investments, no major market penetration of RFNBOs is to be expected in the current decade. By 2030, RFNBO demand will therefore not yet be a significant driver.

The demand assumed in this study for the year 2030 is therefore based on the RFNBO supply potential expected by then, which is explained in more detail in Section 3.1.3. Further projections for the years between 2030 and 2050 are not considered in this study. Also, in the studies evaluated, hardly any quantifiable information is shown for this period. This underlines the still existing uncertainties concerning concrete implementation paths for RFNBOs in the energy landscape of the EU. Similarly, the use of RCFs is not addressed in the studies evaluated. These energy sources are considered in more detail in Section 3.2.

The development of the three RFNBO demand scenarios for the year 2050 is guided by the following basic definitions:

Scenario MUST	Scenario MUST represents the expected minimum demand for RFNBOs. This lower limit results mainly (but not exclusively) from future energy applications in which the use of PtX technologies to the required extent is without alternative according to current knowledge. This applies, in particular to certain industrial sectors (basic chemicals, refineries) and international transport (aviation and navigation).
Scenario CAN	This scenario represents a possible medium demand for RFNBOs with applications in which the use of PtX technologies competes with direct electrification processes and where the respective use is subject to the evaluation of economic, infrastructural, social and other advantages and disadvantages of the respective technologies. These include among others the areas of industrial process heat (e.g. in the glass and paper industry, etc.) and the long-distance transport within the EU (rail transport, long-distance truck transport, coaches, national air and sea transport, etc.).

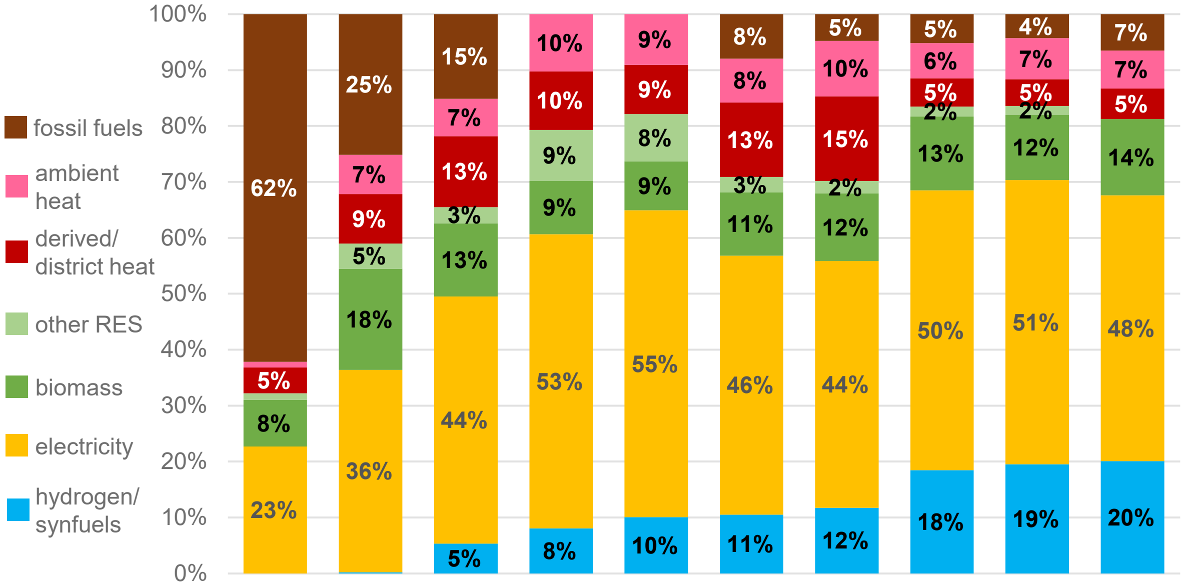
Scenario COULD	Scenario COULD represents the expected upper bound for RFNBO demand. In addition to the "Can" scenario, applications are also considered for which the use of RFNBOs is possible in principle but not the most likely option or only useful in individual cases due to the corresponding alternatives (e.g. passenger cars, light-duty vehicles, urban buses, flexibility in the power grid, energy storage, areas of low temperature heat, etc.).

The wide range of possible demand situations for the year 2050 in the evaluated studies (see Figure 34) illustrates the current uncertainties regarding the scope of future energy demand and the deployment of RFNBOs in the EU. These uncertainties result from the numerous interdependent factors that influence the market ramp-up of RFNBOs in the European energy system. In particular, these uncertainties concern the expected costs and prices for the provision of energy sources, technological developments and the future use of energy sources on the demand side, as well as the potential for the production of RFNBOs within and outside of the EU. Accordingly, both the absolute demand for these energy carriers and their relative share in meeting projected energy demand vary in the evaluated scenarios. The distribution of the future use of RFNBOs in the individual demand sectors varies as well.

For the derivation of the scenarios MUST, CAN and COULD, only those scenarios from the evaluated studies are considered which achieve a 100% reduction in CO_2 emissions compared to 1990 (CO_2 sinks included). This is in line with the European Green Deal targets of a climate-neutral economy with net-zero greenhouse gas emissions by 2050. The scenarios are summarised in Figure 34 together with further information showing the variability of the underlying assumptions regarding the expected development for the use of RES, nuclear power generation and CCS.

To mitigate the influence of the different assumptions and expectations concerning the energy demand and the energy carrier mix within the individual demand sectors in the evaluated studies, only the projected share of RFNBOs in total energy demand in 2050 is considered as an initial indicator. This allows for a first rough classification of the long-term scenarios, which form the framework for the MUST, CAN and COULD scenarios. In the table part of the Figure 34 this classification is shown together with the shares of RFNBOs of the final energy demand and the resulting absolute range of the RFNBO demand (both excl. international transport and feedstocks for industry).

In the following sections, the required detailed breakdown of RFNBO demand by sector and individual energy carriers is based on one of the evaluated long-term scenarios as a representative in each case, to ensure the highest possible consistency of the values within the individual demand scenarios. However, the data’s level of detail in the selected long-term scenarios is partially limited. Neither quantitative nor qualitative information on individual industrial sectors or transport modes are shown to a large extent in the studies, if they are included at all.. Nevertheless, it can be assumed that corresponding differentiations were considered in the modelling to create the projections. The selection of the representatives is therefore mainly based on comparisons of the expected energy demand and RFNBO shares in the individual sectors, which best plausibly reflect the defined distinctions between the definitions of the MUST, CAN, and COULD scenarios.



Scenario	Today (2017)	IEA B2DS	ECF D	IFS 2.0	IFS 1.5	ECF S	ECF T	EC 1.5 L	EC 1.5 T	JRC Zero
Total final energy consumption (TWh)	12'328	7'539	4'878	7'219	6'502	5'328	7'616	7'142	7'818	8'616
Total final energy consumption vs. today (2017)	100%	61%	40%	59%	53%	43%	62%	58%	63%	70%
RES in gross inland consumption vs. today (2017)	100%	> 250%	> 150%	> 350%	> 350%	> 150%	> 150%	> 250%	> 350%	> 350%
Nuclear power generation vs. today (2017)	100%	> 100%	< 35%	0%	0%	< 35%	< 35%	> 100%	> 100%	> 100%
CCS-Usage (MtCO2/yr)	No CCS	> 200	35-100	No CCS	No CCS	35-100	> 200	35-100	> 200	> 200
Categorization: share of RFNBOs in final energy consumption		< 10%			10 - 15%			15 - 20%		
Range of RFNBO final energy consumption (excl. feedstocks and international transport)		20 - 580 TWh			560 - 900 TWh			1'320 - 1'730 TWh		
Possible framework for development of RFNBO scenario		**MUST**			**CAN**			**COULD**		

Source: own illustration based on (IEA 2017; European Climate Foundation 2018; Teske 2019; European Commission 2018; JRC 2018a, 2020).

Figure 34: Final energy consumption in EU 27 + UK in 2050 in selected long-term scenarios from existing studies for the derivation of scenarios for the RFNBO demand in the EU

Existing data gaps are closed – as far as acceptable – by adequate combinations of the scenario data. If necessary, further assumptions are made. Among others, this affects the energy demand for international transport as well as the demand for hydrogen as a feedstock, which is largely not considered in the energy balances in the evaluated long-term studies. That is why the demand for hydrogen as a feedstock is assumed to be constant for all scenarios at 460 TWh per year (Fleiter et al. 2019). The demand for aviation (EU-internal and international) was assumed to be uniform for all scenarios based on data from the EC 1.5 T scenario (European Commission 2018). The demand for international navigation is based on the data of the scenario variant "Mare" in the same study. The result of this synthesis for the demand scenarios "MUST, CAN, and COULD is shown in Table 6.

Table 6: Expected RFNBO demand (TWh) by sector in 2050 in the EU27 + UK for the developed scenarios

Sector in EU	MUST based on ECF D			CAN based on IFS 1.5			COULD based on EC 1.5 T		
	H_2	CH_4	PtL	H_2	CH_4	PtL	H_2	CH_4	PtL
Transport (EU-internal without aviation)	95	47	30	188	14	30	369	142	243
Transport (international and EU-internal aviation)	22	59	155	22	59	155	22	59	155
Industry (final energy demand)	0	67	0	88	124	0	338	124	0
Buildings	0	0	0	0	187	0	80	254	0
Other	0	0	0	0	0	22	0	0	22
Total final energy demand	117	173	185	298	385	207	810	579	420
Feedstock for industry	460	0	0	460	0	0	460	0	0
Sum final energy and feedstock demand	**577**	**173**	**185**	**758**	**385**	**207**	**1270**	**579**	**420**

Source: based on European Commission 2018; Teske 2019; European Climate Foundation 2018 and own assumptions.

The energy demand of the **MUST** scenario is essentially based on the projections of the long-term scenario ECF D (European Climate Foundation 2018). As the lower limit of RFNBO use, a very low expected final energy demand is combined with a low RFNBO coverage share. While in this scenario the ambitions regarding technological change are rather moderate, the significant reduction in energy demand results primarily from societal changes in consumption (e.g., through the complete transformation of the transport sector into a service) and a forced circular economy with high recycling rates and increased product lifetimes. The use of RFNBOs is limited to processes for which, according to the current state of knowledge on technological development, no alternative energy sources can be used for their decarbonisation. Accordingly, the focus of the final energy use of RFNBOs lies on the transportation sector (about 86% of the 475 TWh RFNBO final energy consumption in total). The remaining 14% RFNBO use in the form of SNG lies in the industrial sector. The building sector relies mainly on electric heating (heat pumps) and on district heating and does not use RFNBOs. With 185 TWh, PtL-fuels account for the largest share of RFNBO final energy consumption. About 84% of this is used in aviation and international navigation. Furthermore, in this scenario, the use of RFNBOs primarily in the form of hydrogen is also expected to a limited extent in land transport and inland navigation in the EU. In addition, around 582 TWh of advanced biofuels are used in aviation and international navigation. In the case of EU-internal land transport and inland shipping, biofuels reach approx. 134 TWh. The remaining energy demand in the transport sector is covered in roughly equal parts by electricity and fossil energy sources.

The **CAN** scenario is mainly based on the projections of the long-term scenario IFS 1.5 (Teske 2019). While the final energy consumption for aviation and international navigation (incl. 582 TWh of advanced biofuels) is the same as in the MUST scenario, the use of RFNBOs is expected to be moderately higher for EU-internal land transportation and shipping. In comparison to the MUST scenario, the consumption of methane in the transport sector (see Table 6) is 33 TWh lower. This can be explained by the expected deviations in the technological composition of the vehicle fleet. In the long-term scenario ECF D as the basis for the MUST scenario, conventional fuels are still present in the energy carrier mix in 2050, which also includes propulsions with conventional gas. Therefore, it can be assumed that in the MUST scenario there is a larger proportion of vehicles with drive systems converted to methane than in the CAN scenario. Whereas in the CAN scenario the focus lies more on fuel cell electric vehicles, which is reflected in the significantly higher demand for hydrogen. Overall, this scenario assumes a very high electrification share of domestic transport. The remaining final energy demand in EU-internal transport without aviation is covered by biofuels. More significant changes in RFNBO use are seen in the other demand sectors. In the industrial sector, the consumption of SNG increases to 124 TWh and 88 TWh of hydrogen are used for energy purposes in this scenario. An even higher consumption of methane in the form of SNG is projected in the building sector (187 TWh).

The final energy demand of the scenario **COULD** is based on the projections of the long-term scenario EC 1.5 T (European Commission 2018). On the one hand, a steep technological development, and the increased use of RFNBOs in all demand sectors is projected in this scenario. On the other hand, no strong behavioural changes on the demand side are assumed. The projected final energy consumption for EU internal transport without aviation is therefore approx. 460 TWh higher than in the scenario MUST. For the related transport modes, RFNBOs are expected to have a significantly higher penetration (approx. 45%) than in the other scenarios. The focus lies again on hydrogen (around 370 TWh). However, PtL also reaches a high level with more than 240 TWh in total for domestic transport. Furthermore, energy consumption in EU internal transport without aviation is covered by electricity (36%) and advanced biofuels (14%). Fossil fuels account for a small share of 4% in this scenario. The final energy consumption for aviation and international navigation (incl. 582 TWh of advanced biofuels) is the same as in the scenario MUST. A significant increase in RFNBO deployment is also assumed for the industrial sector. This results exclusively from the additional energy use of 250 TWh hydrogen compared to scenario CAN. In addition, in the scenario COULD, hydrogen is also used in the building sector (80 TWh), while the use of SNG increases moderately by less than 70 TWh compared to the scenario CAN.

3.1.3 Derivation of the potential diffusion of RFNBO production (supply scenarios)

To estimate which quantities of RFNBOs could be produced in the years 2030 and 2050 and at which cost, several assumptions have to be made. In order to show a range of possible results, an optimistic, a medium and a pessimistic supply scenario are defined.

The starting point for the production of RFNBOs is the renewable electricity (RES-E) available for the production of RFNBOs. In this context we only consider the RES technologies wind onshore, wind offshore and solar power, since bioenergy is explicitly excluded in the definition of RFNBOs and other RES (like hydro power) are less likely to supply large quantities of additional renewable electricity in the future. The RES-E potential for the EU in the optimistic supply scenario is derived from own potential calculations within the Horizon 2020 project "SET-Nav"[23], which include RES-E cost potential curves (needed for the calculation of hydrogen cost potential curves). A description of the methodology behind these RES-E potentials can be found in Sensfuß et al. 2019. In the medium supply scenario, RES-E potentials are taken from dena 2017, using the "maximum" potential therein, whereas for the pessimistic supply scenario the "minimum" RES-E potential from the same study is used.

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[23] http://www.set-nav.eu/

The RES-E potential is then limited by the maximum plant capacity that could be installed until 2030 and 2050. To estimate this, the observed capacity growth of wind onshore, wind offshore and solar power in the EU between 2009 and 2019 (WindEurope 2020; SolarPowerEurope 2019) is extrapolated to 2030 and 2050 (for each technology individually), assuming a doubling of the historic growth rate in the optimistic supply scenario and a halving in the pessimistic scenario. In the medium supply scenario, the achievable RES-E generation in the EU is set to the average generation in the EU's 2030 Climate Target Plan (CTP) (European Commission 2020b). From the resulting achievable RES-E generation in the EU, only a part would be available for the production of RFNBOs. Therefore, in the analysis we make sure that the RES-E demand of other applications (as projected in the evaluated scenarios, including the CTP) could still be met.

Besides the available renewable electricity, the capacity, utilisation and efficiency of the electrolysis plants is a major factor determining the amount of RFNBOs that can be produced. For the electrolyser capacity in the EU we set a range of 7/21/40 GW in 2030 and 341/426/600 GW in 2050 (for the pessimistic/medium/optimistic supply scenario, respectively). The upper limit is taken from the EU Hydrogen Roadmap for 2030 and from Guidehouse 2020 for 2050, while the medium and the pessimistic values in 2030 and 2050 are derived from the average and minimum values in Fraunhofer 2019.

In all three supply scenarios, the utilisation of the electrolysers is set to a medium value of 5,000 full-load hours as default, which is the same as in the publication that was used for the cost of imported RFNBOs (Prognos 2020). But higher and lower utilisation is also studied and discussed in the context of the impact of additionality requirements in Section 4.2.

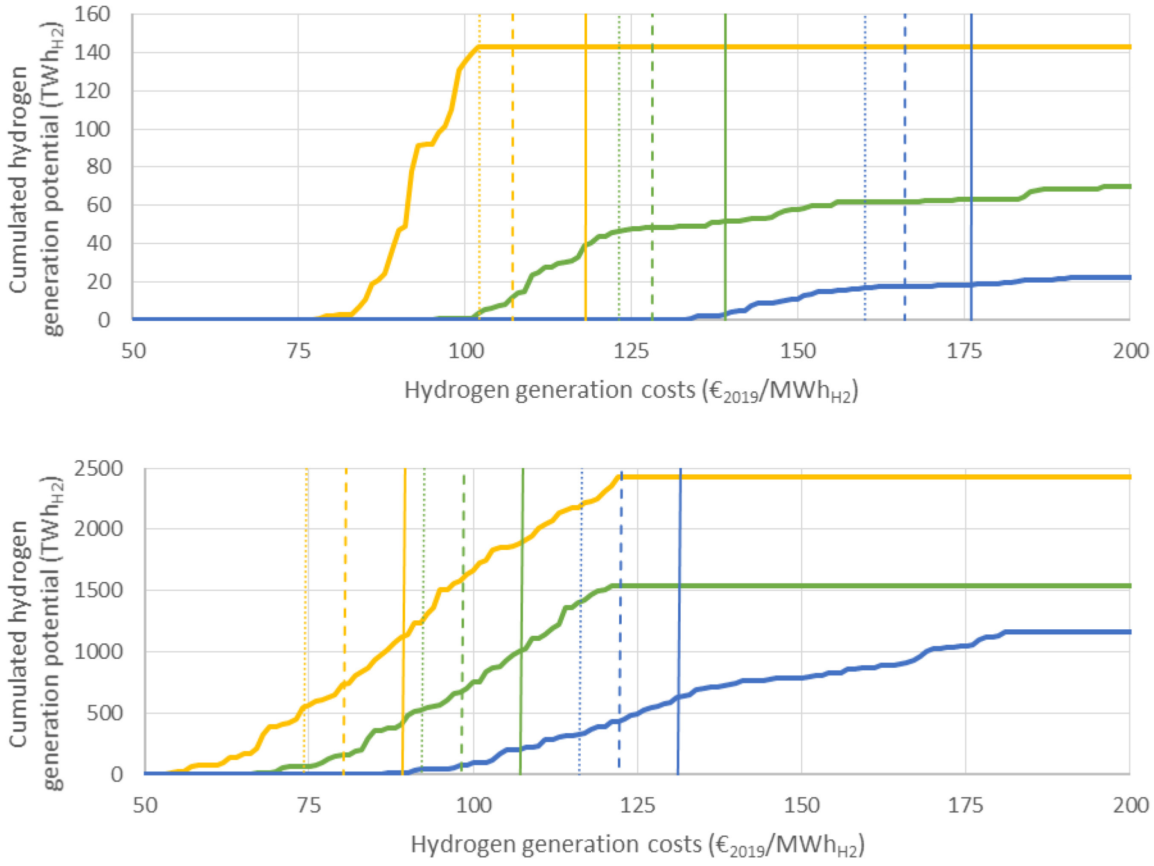
The efficiency and cost of the electrolysers are derived from the range found in recent publications. For this purpose, a technology mix between AEL, PEMEL and SOEL is assumed and then the efficiency and cost of this electrolyser mix is calculated from the most optimistic, the average and the most pessimistic values found in the literature for the individual technologies. Table 7 summarises the assumptions concerning electrolysis. An interest rate of 6% is assumed for converting investment costs to annual capital cost,. As in Prognos 2020, annual operational costs (excluding electricity costs) are set to 4% of the investment costs.

Table 7: Assumptions concerning electrolysis used in the RFNBO supply scenarios

	2030			2050		
	optimistic	medium	pessimistic	optimistic	medium	pessimistic
Technology mix: **AEL** **PEMEL** **SOEL**	 49% 49% 2%	 49.5% 49.5% 1%	 50% 50% 0%	 45% 45% 10%	 47.5% 47.5% 5%	 50% 50% 0%
Efficiency	71%	67%	63%	81%	72%	68%
Lifetime (a)	25	20	15	30	25	20
Investment costs (€/kW$_{el}$)	396	677	1175	205	416	800
Full-load hours (h/a)	5,000	5,000	5,000	5,000	5,000	5,000
Capacity in the EU (GW$_{el}$)	40	21	7	600	426	341

Sources: own assumptions and calculations based on efficiency and cost data from Fuel Cells and Hydrogen 2 Joint Undertaking 2018; Schmidt et al. 2019; Forschungsvereinigung Verbrennungskraftmaschinen e.V. 2016; Danish Energy Agency 2020; Umweltbundesamt 2020; dena 2017; Gruber et al. 2018; Tremel 2018; Schmidt et al. 2018; Smolinka et al. 2018; IEA 2019b; Deutsche Energie-Agentur GmbH 2018.

From these assumptions concerning renewable electricity and electrolysers, we can calculate the potential amount and cost of green hydrogen produced in the EU. While the RES-E cost potential curves from SET-Nav can be directly used for the hydrogen cost calculations in the optimistic supply scenario, they have to be adapted to the lower RES-E potential assumptions in the medium and pessimistic supply scenarios. This is done by scaling the size of every RES-E cost potential step by the ratio between the achievable RES-E generation in this supply scenario and in the optimistic supply scenario[24]. Based on the resulting RES-E cost potential curves, we then calculate hydrogen cost potential curves by allowing electrolysis plants to use a fraction of every RES-E cost potential step, depending on the share of the RES-E demand for electrolysis in the total RES-E demand[25]. The resulting generation cost potential curves for hydrogen produced in the EU are shown in Figure 35.



Note: for the years 2030 (upper panel) and 2050 (lower panel) and for the optimistic (yellow), medium (green) and pessimistic (blue) supply scenarios. The vertical lines indicate the hydrogen generation cost up to which the production of hydrogen (solid line), methane (dashed line) and PtL (dotted line) in the EU would be cost competitive to imports under the chosen assumptions. Source: own calculations.

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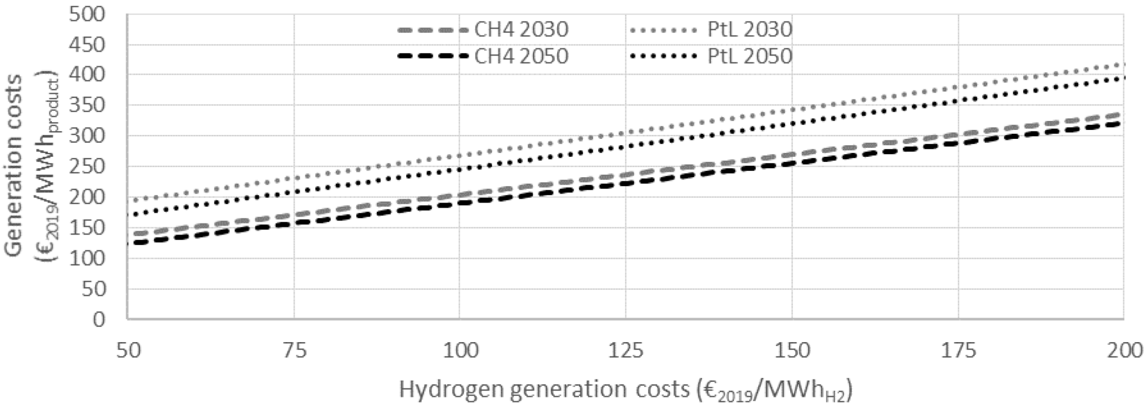
[24] This approach ensures that not only the cheapest or the most expensive, but fractions of all RES-E cost potential steps are used in the supply scenarios with lower RES-E potential assumptions.

[25] Again, this is done in order to ensure that electrolysers do not only use the cheapest or the most expensive RES-E potentials, but a fraction of every cost potential step, according to their share in the total RES-E demand.

Figure 35: Hydrogen generation cost potential curves for production in the EU

The total production potentials of green hydrogen in the EU (i.e. the maximum values in Figure 35) lie in the range of about 20 to 140 TWh_{H2} in 2030 and 1,200 to 2,400 TWh_{H2} in 2050. In all the supply scenarios, this total hydrogen potential is limited by the assumed maximum capacity and usage of the electrolysers and not by the available amount of renewable electricity. However, a relevant fraction of this potential would have production costs probably not competitive with imported RFNBOs due to limited potentials of cheap renewable electricity.

Based on these hydrogen cost potential curves, the generation costs of methane and PtL can be determined by adding the cost of the CO_2 used and of the plant for the fuel synthesis process, thereby considering the efficiency of the conversion process (assumed as 76% for hydrogen to methane and 67% for hydrogen to liquid fuels). Since the costs of RFNBOs produced in the EU have to be compared to the costs of imports (e.g. when estimating the share of imported RFNBOs in the combined demand and supply scenarios in Section 3.1.4), we have to take care of the consistency of assumptions. Therefore, the cost and technology assumptions concerning the fuel conversion processes in the EU were taken from the same publication as the costs of imported RFNBOs (Prognos 2020). As direct air capture with relatively high costs was assumed to be the only source of CO_2 therein, the actual costs of synthetic hydrocarbons might be lower in reality, if alternative sustainable carbon sources (e.g. biogenic) were used for at least part of the fuel production. The resulting fuel generation costs as a function of hydrogen costs are shown in Figure 36.



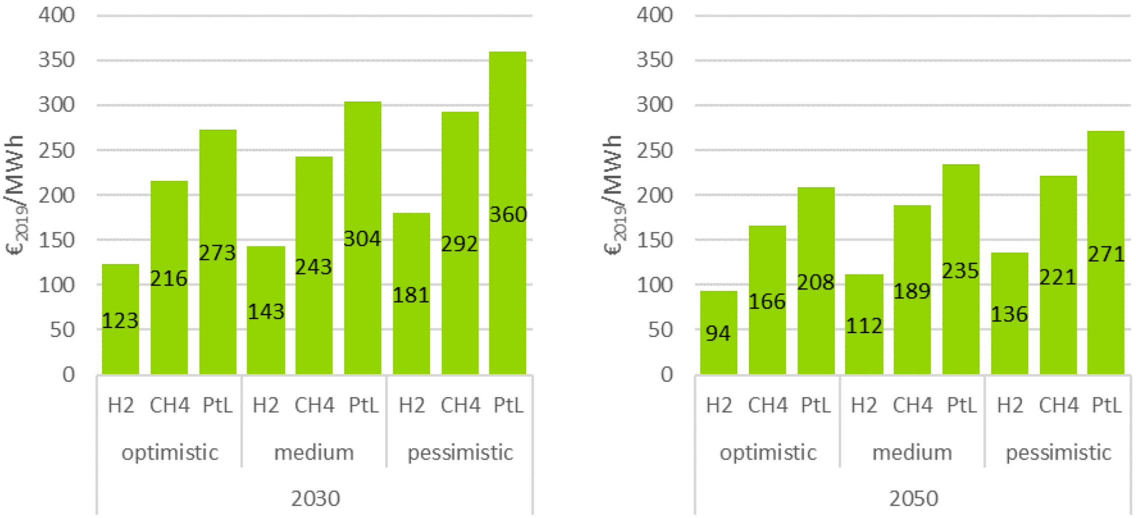
Note: CH4 = methane and PtL = liquid fuels from Fischer-Tropsch synthesis. Source: own calculations based on results from Prognos 2020.

Figure 36: Generation costs of synthetic hydrocarbons as a function of hydrogen generation costs

In contrast to RFNBOs produced in the EU, we do not use cost potential curves for imported RFNBOs, since these could not be found in the literature. Instead, we assume that the amount of fuels available for import at the given cost would be unlimited in relation to the EU's demand. When RFNBO cost potential curves become available for a larger number of countries (or even on a global scale) in the future, these could be compared to the cost potential curves for the EU. This would allow a more detailed study of the competition between domestic production and imports.

The costs of imported RFNBOs are not directly taken from Prognos 2020, but are recalculated based on updated assumptions concerning electrolysers in order to ensure consistency between the cost estimation of domestic and non-domestic RFNBO production[26]. The pessimistic, medium and optimistic import cost scenarios differ in the assumptions concerning electrolysers, but not in the other assumptions (on electricity/CO_2/conversion/transport cost), which are taken from the reference case in Prognos 2020. As the electrolysis efficiency is assumed to be higher and the investment costs are assumed to be lower in this study, hydrogen generation costs decrease considerably compared to Prognos 2020. This also leads to lower methane and PtL costs, since these are recalculated as well using the updated hydrogen costs. Figure 37 shows the resulting costs of imported RFNBOs that were used in the combined scenarios for estimating how much of the fuels would be produced in the EU. The shown and compared costs include the cost of renewable electricity, CO_2 (where applicable), capital, and transport via pipeline (assuming 4000 km from MENA to the EU for imports and 500 km within the EU for domestic production).

Overall, the results of the RFNBO supply scenarios presented in this section show that there is a substantial potential for the production of green hydrogen and derived fuels in the EU. Under the chosen assumptions described above, this potential is rather more limited by the assumed maximum capacity and usage of the electrolysers than by the available amount of renewable electricity. However, the RFNBO potential in the EU being cost-competitive with imports is limited by the available potentials for cheap renewable electricity.



Note: costs in 2030 (left panel) and in 2050 (right panel), including 4,000 km transport via pipeline from MENA to the EU.
Source: own calculations based on cost assumptions in Prognos 2020 and own assumptions concerning electrolysers.

Figure 37: Costs of imported RFNBOs

3.1.4 Combination of RFNBO demand and production scenarios

After having developed independent scenarios for the potential demand and production of RFNBOs in the previous sections, we now combine these scenarios. This means that we study how low RFNBO demand (MUST demand scenario), medium RFNBO demand (CAN demand scenario) and high RFNBO demand (COULD demand scenario) could be covered, given the RFNBO costs and potentials resulting from the optimistic, medium or pessimistic

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[26] Furthermore, unlike in the original publication, here we refer to the lower heating value.

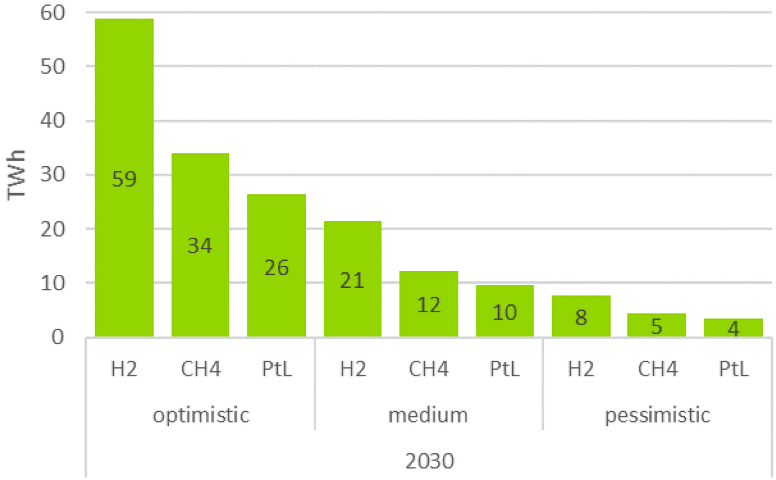
supply scenario. This allows us to gain an impression of the range of possible outcomes for the development of RFNBOs in the EU.

For this purpose, starting from the lowest hydrogen generation cost potential step (for production in the EU) from the respective RFNBO supply scenario, we distribute each potential step among those energy carriers (hydrogen, methane, PtL) that are still competitive with imports at this cost and for which the demand from the respective demand scenario is not yet fully satisfied. This approach assumes that the use of green hydrogen for the production of synthetic methane and liquid fuels competes with other (direct) uses of hydrogen (e.g. in the industry or transport sector) for the cheapest hydrogen generation potentials. As a result, we receive a certain amount of hydrogen, methane and PtL that could be produced in the EU at costs competitive with imports. If the demand for the respective fuel is not fully met by competitive production in the EU, the rest is assumed to be imported at the cost shown in Figure 37. Regarding the transport of the RFNBOs, we assume a distance of 500 km within the EU for domestic production and 4,000 km from MENA to the EU for imported fuels, both via pipeline (as in Prognos 2020).

However, this approach can only be used for the year 2050. For the year 2030, no RFNBO demand could be derived from the scenario studies that were used for the demand scenarios in 2050. Furthermore, the actual RFNBO demand in 2030 would probably exceed the realistically achievable production potential up to this point if sufficient support for the use of RFNBOs through regulation was provided. Therefore, the RFNBO supply scenarios for the year 2030 were chosen in such a way that the amount of RFNBOs is equivalent to the competitive domestic hydrogen production potential in the EU. The distribution among the energy carriers hydrogen, methane and liquid fuels (PtL) was chosen as being similar to the one in the EU's 2030 Climate Target Plan (CTP), where hydrogen and synthetic hydrocarbons each make up 50% of the RFNBO amount. However, here we assumed a higher share of methane than in the CTP, where only hydrogen and PtL are seen in 2030.

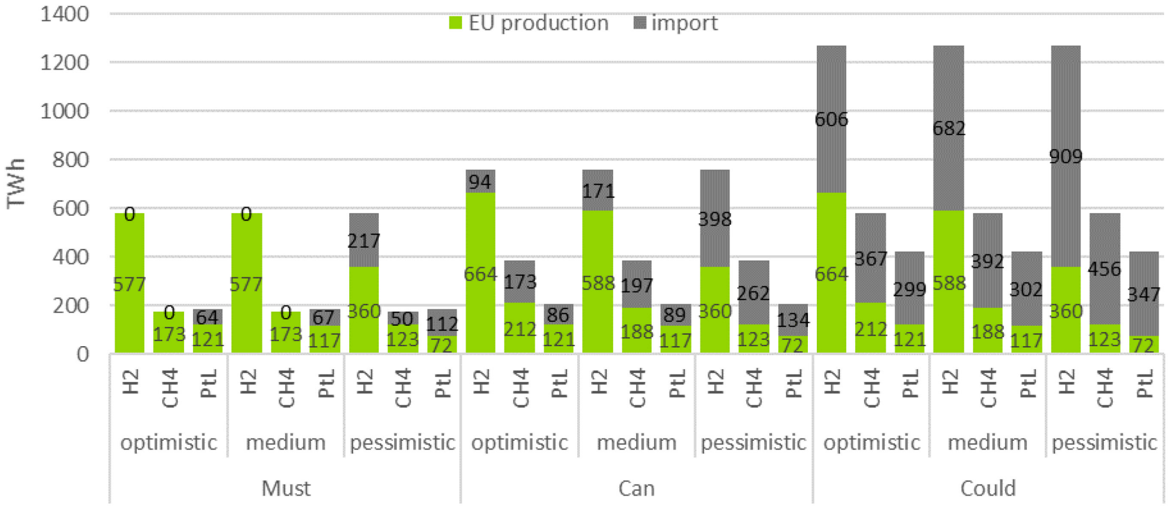
The RFNBO supply in the different scenarios (resulting from the approach described above) is shown in Figure 38 for the year 2030 and in Figure 39 for the year 2050. In 2030, the amount of RFNBOs produced in the EU is between 16 and 119 TWh, i.e. in the medium and optimistic scenario the fuel amount exceeds the maximum of 24 TWh of RFNBOs in the CTP. As the demand for RFNBOs might be higher in 2030, imports of a similar order of magnitude might add to the domestic production (thereby assuming that electrolysis and synthesis plant capacities outside the EU would develop similarly to those within the EU).

In 2050, all combinations of demand and supply scenarios result in both domestic production of RFNBOs in the EU and imports, but with very different shares depending on the exact scenario. The lower RFNBO demand in the MUST scenario could be covered by competitive domestic production to a larger extent than the higher demand in the CAN and COULD scenarios that would require larger imports. Compared to the optimistic supply scenario, the importance of imports increases in the medium and pessimistic supply scenarios, since the competitive domestic RFNBO production potential is smaller. Among the different energy carriers, hydrogen has the highest share of domestic production while liquid RFNBOs have the highest share of imports.



Note: the RFNBO amount in 2030 was chosen to be equal to the amount that could be produced in the EU at costs competitive with imported RFNBOs in the different supply scenarios. Source: own calculations

Figure 38: RFNBO supply 2030 in the developed scenarios



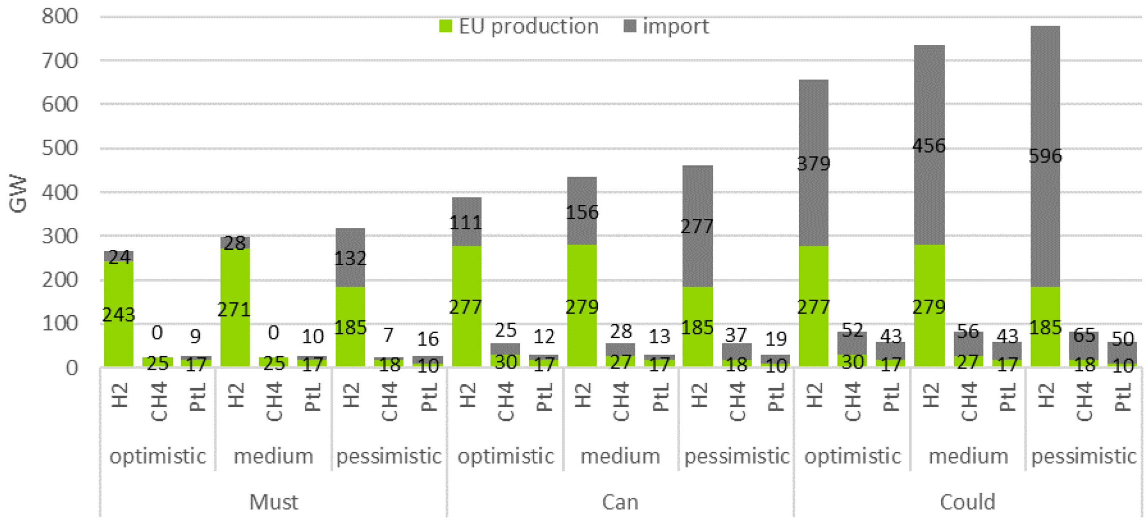
Note: including demand of all sectors and of international transport. Source: own calculations

Figure 39: RFNBO supply 2050 in the developed scenarios

Figure 40 shows the RFNBO production capacities required in 2050 in the EU and abroad for producing the amount resulting from the different scenarios (under the chosen assumptions regarding efficiencies, full-load hours, etc.). Based on the assumption of 5,000 full-load hours on average, the electrolyser capacities in the EU lie in a range of 185 to 280 GW, which is well below the 340 to 600 GW assumed as maximum achievable capacity. The sensitivity to variations of full-load hours are considered in Section 4.2. The electrolyser capacities needed for imported RFNBOs show larger variations between 24 and roughly 600 GW. The required capacities of synthesis plants for the conversion of hydrogen to methane or liquid fuels are much lower than those of electrolysers with 42 to 47 GW in the EU and 9 to 115 GW abroad. In 2030, the electrolyser capacities required for the competitive amount of RFNBOs from the EU (not shown) are equal to the assumed maximum of 40 GW in the optimistic supply scenario and below the assumed maximum in the medium scenario (16 of 21 GW needed) and pessimistic scenario (6 of 7 GW needed). Synthesis plant capacities range between 2 and 9 GW in 2030. The investments required for building these electrolysis and synthesis plant capacities are discussed in Section 4.3.2.

In all the scenarios results of which include imports, the marginal costs of RFNBOs produced in the EU are equal to the costs of imported RFNBOs (shown in Figure 37). In cases without imports (only occurring for hydrogen and methane in the demand scenario MUST in combination with the optimistic and medium supply scenario), marginal production costs are slightly lower in the EU than for imports. With a share of 75 to 90% (80 to 100 €/MWh$_{H2}$), electricity costs constitute the most important cost component of hydrogen produced in the EU, followed by capital, operational and transport costs (distribution costs are not included here). For methane and liquid RFNBOs, the relative importance of electricity costs decreases due to the additional capital and operational costs of synthesis plants and CO_2 (and upgrading in the case of liquid Fischer-Tropsch fuels).

In this context it has to be noted that not all combinations of demand and supply scenarios are equally likely. The optimistic assumptions for RFNBO production are more likely to be realised in a world with a high demand for RFNBOs (as in the COULD scenario) due to economies of scale and enhanced technological learning. Furthermore, the transport costs for fuels within the EU and from the exporting regions (here MENA) to the EU might actually be higher than assumed in the scenarios, since pipelines would not be built for the small fuel amounts resulting from some of the scenarios. In these cases, transportation via ship would probably be more economical (but still more expensive per MWh than pipelines in scenarios with larger fuel flows).



Source: own calculations

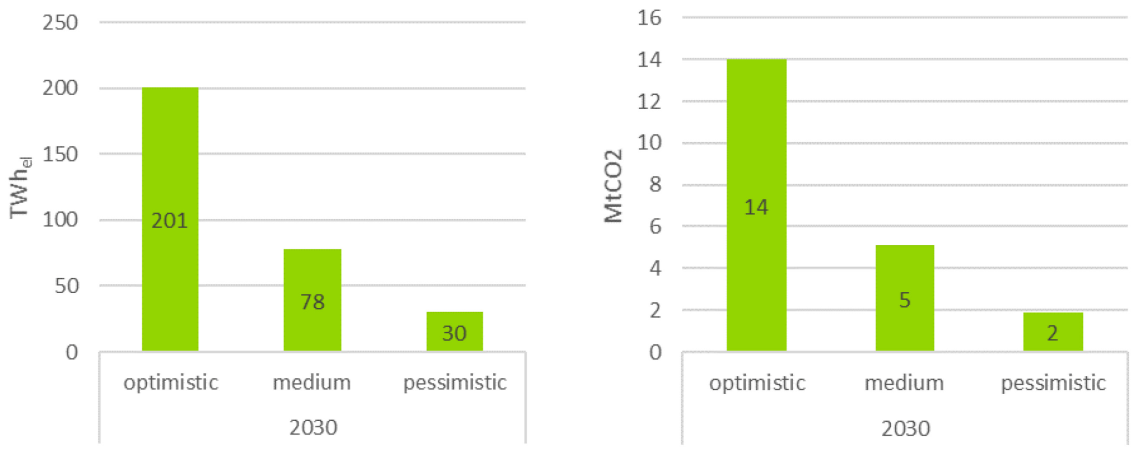
Figure 40: RFNBO production capacities required in the developed scenarios

The consumption of feedstocks for the production of the previously shown RFNBO amount is depicted in Figure 41 for the year 2030 and in Figure 42 for the year 2050. The renewable electricity (RES-E) consumption for RFNBOs in 2030 ranges from 30 to 200 TWh, with the upper limit being determined by the assumed maximum electrolyser capacity of 40 GW and the assumed 5,000 full-load hours. In 2050, the RES-E consumption for RFNBOs lies in a much higher range of roughly 900 to 1,400 TWh in the EU and 100 to 3,000 TWh for imports. The RES-E demand for RFNBO production is highest in the pessimistic supply scenario due to the assumed lower efficiency of the electrolysis process.

The CO_2 demand in 2030 for the production of synthetic methane and liquid fuels ranges from 2 to 14 $MtCO_2$, which could probably be covered by less expensive carbon sources than the assumed direct air capture (DAC). In 2050, the CO_2 demand rises to a range of 44 to 75 $MtCO_2$ in the EU and 17 to 186 $MtCO_2$ for imports. This amount of CO_2 might still be partly covered by biogenic sources, depending on the actual potential of sustainable biogenic CO_2 in 2050. But DAC would probably be required to a certain extent for the production of RFNBOs in the EU and abroad.

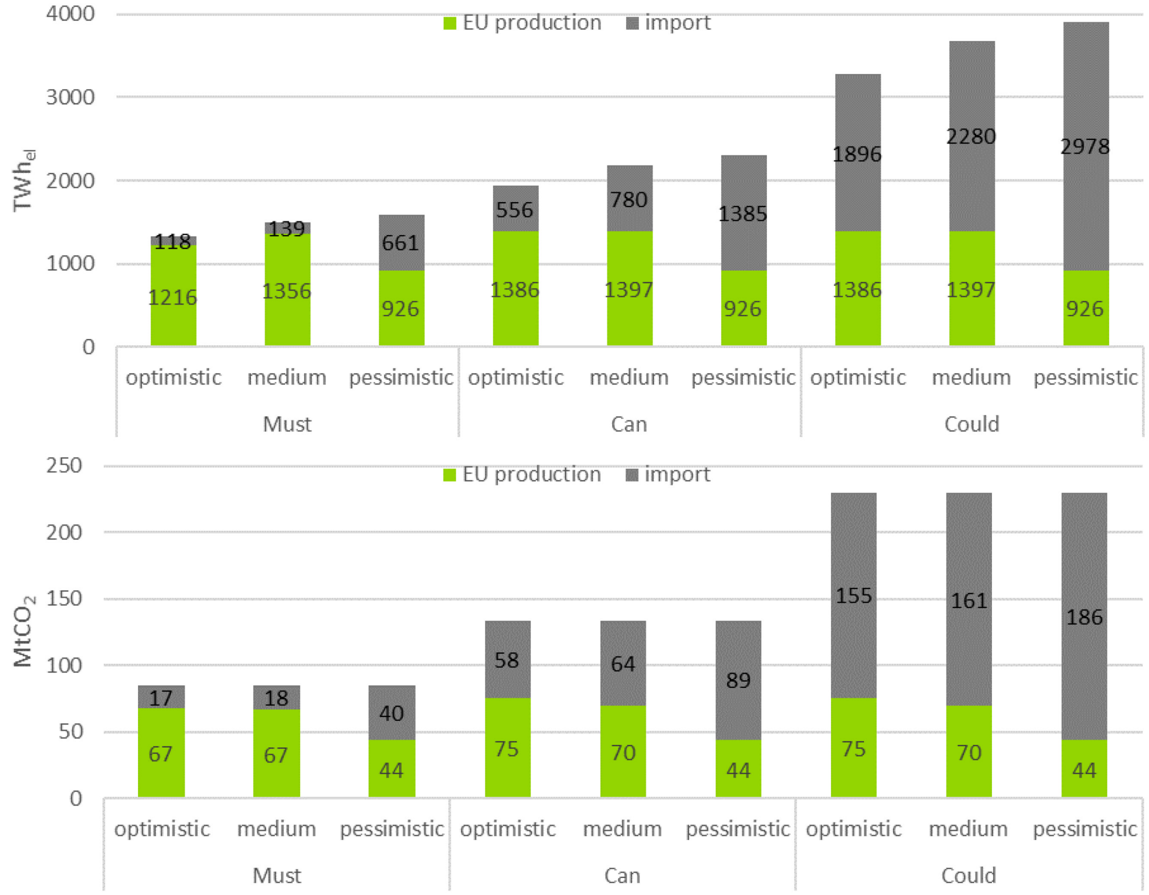
Overall, the results of the combined RFNBO demand and supply scenarios presented in this section show that there is a substantial potential for RFNBO production in the EU at costs competitive with imports (at least 550 and up to 1,000 TWh in 2050). Under optimistic supply assumptions, the demand in sectors without sustainable alternatives to the use of RFNBOs (demand scenario MUST) could be covered cost-effectively with only minor imports. However, under less optimistic supply assumptions and/or with demand for RFNBOs in further sectors and end uses, a considerable amount of RFNBOs (up to 1,700 TWh in 2050) would probably be imported due to lower supply costs. It has to be noted that the ratio between domestic production and import of RFNBOs might change when using (not yet available) cost potential curves instead of fixed costs for imports. On the one hand, RFNBOs being less expensive than the assumed fixed cost can increase the share of imports in scenarios that show few imports in this study. On the other hand, the limited amount of RFNBOs available at the assumed fixed cost could decrease the share of imports in scenarios that result in large imports in our analysis.

The feedstock demand for RFNBO production in the EU could be up to 1,400 TWh of renewable electricity and up to 75 $MtCO_2$ in the year 2050, which would require building up considerable RES-E generation capacities and probably also capacities for the direct air capture of CO_2.



Source: own calculations

Figure 41: Consumption of renewable electricity (left panel) and CO_2 (right panel) as feedstocks for RFNBO production in the year 2030



Source: own calculations

Figure 42: Consumption of renewable electricity (upper panel) and CO_2 (lower panel) as feedstocks for RFNBO production in the year 2050

After having focussed on the development of RFNBOs in the previous sections, in the following section we will treat the potential of RCFs before proceeding to the joint assessment of RFNBOs and RCFs in Section 4.

3.2 Derivation of scenarios for production and use of RCFs in the transport sector

As discussed in the technical descriptions (Section 2.2), there are various potential feedstocks (waste streams) and processing routes for the production of RCFs. We have identified the most important pathways in the conclusions of Section 2. Based on these pathways, we now develop potential scenarios for RCF production and use in this section. These scenarios are mainly driven by the availability of relevant feedstocks, as both waste flows are limited and there might be competing alternative utilisation pathways such as energy recovery from waste combustion. In order to enable comparability, the product spectrum is restricted to one major fuel and specified in the form of its lower heating value (LHV) for each feedstock and utilisation pathway. The following feedstocks and products are considered in the scenario analysis:

- Solid waste flows of non-biological origin such as mixed plastic waste are the most commonly mentioned feedstock for RCFs in literature. As discussed in the technical part, there are two major issues that make the direct conversion of non-fossil waste to carbon fuels questionable:

  - There might be a competition of feedstock with chemical recycling processes.
  - The carbon content of the fuel is of fossil origin, leading to comparatively little GHG mitigation from a holistic perspective.

  As significant reduction of emissions compared to fossil fuels will only be possible through the combination of gasification and subsequent CCS, the scenarios developed here focus on blue hydrogen production from solid waste in Europe. This seems reasonable also against the background of combining these scenarios with RFNBO potentials.

- The most commonly discussed industrial waste gases in the literature that might serve as a feedstock for RCF production are exhaust gases from steel production. These include coking gas, blast furnace gas and converter gas. However, it is important to take into account that these gases only occur in case of steel production via a blast furnace or a basic oxygen furnace. Worldwide, more than 70% of steel is produced via this route, while in Europe about 58% of steel is produced in blast or oxygen furnaces (EUROFER 2020). In this context, it needs to be considered that steel reduction in oxygen furnaces is expected to be replaced by direct reduction technology with hydrogen in the future, which will limit the availability of feedstock in the future (see Table 8). In the scenarios, we consider the LanzaTech process for ethanol production as a base case (Figure 17), as this seems to be the most established and industrialised process with various applications and a first pilot plant in Europe (ArcelorMittal Gent)[27].
- Beside current waste flows, landfilled municipal solid waste could also be used for RCF production. Landfill gas, mainly consisting of CO_2 and CH_4, is a gaseous waste stream which is currently mainly used for thermal energy or electricity production (as long as it is collected). Landfill gas is produced through anaerobic digestion and could directly serve as gaseous feedstock for RCFs. In the scenarios, we only consider the potential contribution of methane from landfill gas to overall RCFs, keeping in mind that landfill gas could also be transferred into syngas for subsequent synthesis in small synthesis plants based on micro reactor technology (see Section 2.2).
- There are various further waste streams that could potentially serve as a basis for RCF production. This includes additional exhaust gases from chemical industries that may contain hydrocarbons, hydrogen or carbon monoxide or liquid residues and sludges e.g. from oil and gas industries. As described in the technical background information, these processes are in part very specific and it is difficult to precisely quantify their contribution. However, it is certain that their contributions are limited. We provide some exemplarily estimations regarding liquid fuels production from shipping slops which seems to be the most important source of liquid waste streams when regarding RCF production (see Figure 43d). Shipping slops and sludges mainly occur during cleaning of oil tankers and the transportation of petrochemicals. These slops are collected in ports and may serve as feedstock for fuel production.

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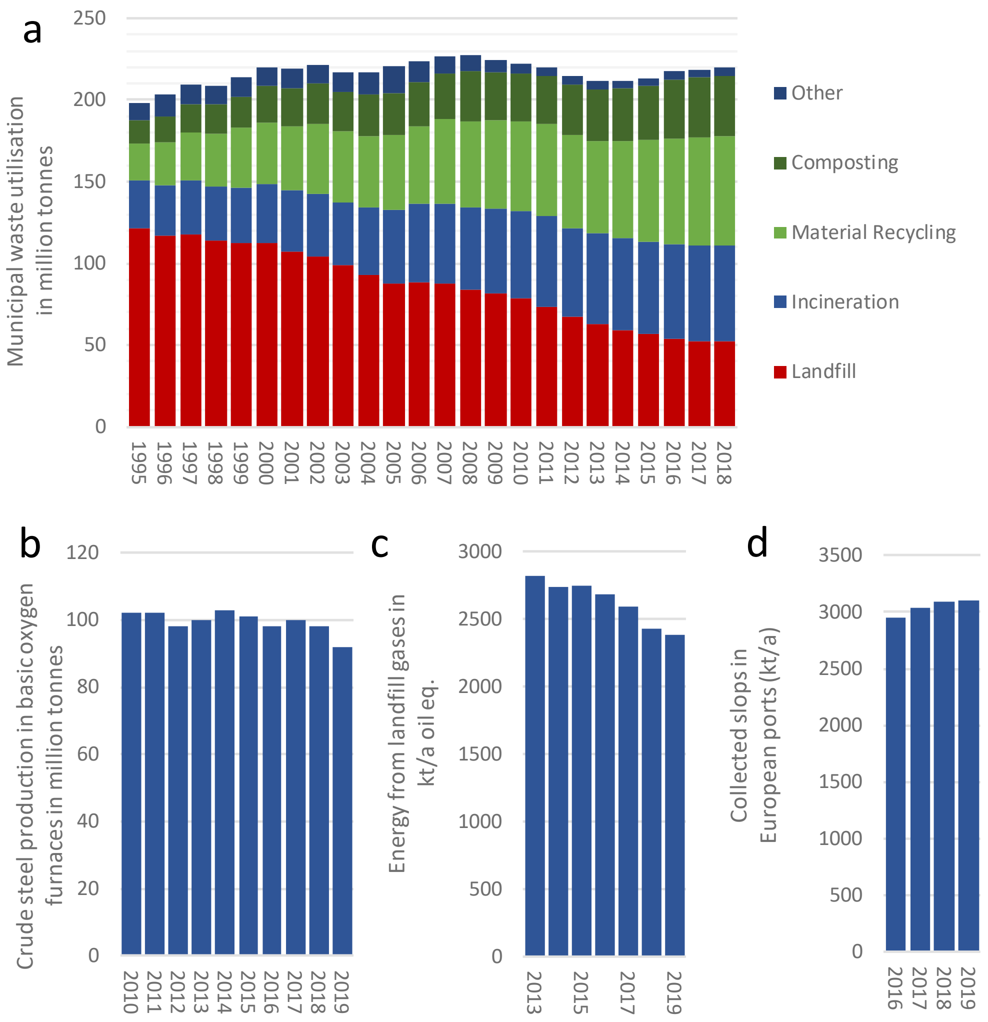
[27] https://europe.arcelormittal.com/newsandmedia/europenews/3798/Fuel-from-steel

3.2.1 Feedstock availability for RCFs as the basis for scenario derivation

As discussed in the context of technical process descriptions, beside economic issues and aspects of GHG emission reduction, the availability of respective waste feedstock forms the main limitation for RCF production. It is therefore of key relevance to assess current and future feedstock availability for the derivation of respective scenarios. Figure 43a illustrates the utilisation of municipal solid waste (MSW) within the EU. While landfill of hydrocarbon waste has continuously decreased in recent decades and, in most EU Member States, there is a ban on landfilling of biodegradable waste, incineration of non-recyclable hydrocarbon waste is currently the main pathway for the treatment of relevant feedstock for RCF production. Therefore, RCF production will mainly compete with waste incineration for energy generation (combined heat and power generation). In the context of mixed plastic waste, it has to further be considered that the separation of different plastic fractions and the chemical recycling of waste streams will improve in the coming years leading to a further limitation of feedstock availability for RCF production (see also increasing share of recycled material in Figure 43a). These developments are considered in the scenario derivation in the next section.



Note that the figures are based on available statistics, while the respective RCF potentials in TWh need further calculation (see following section). Sources: Eurostat (2020), (EUROFER 2020), Statista (2020)

Figure 43: Current feedstock potentials for RCF production

Regarding production of RCFs from furnace gases, it is difficult to quantify this waste stream precisely, as exhaust gases for internal energy use are not reported and depend on site-specific properties. However, from production statistics of steel from oxygen furnaces in Europe (Figure 43b) and the pilot plant of ArcelorMittal in Gent using the LanzaTech fermentation process[28] with an overall capacity of 80 million l/a of ethanol production, it is possible to extract theoretical feedstock potentials from steel production statistics and the reference capacity of steel production at the ArcelorMittal production site in Gent (4 million t/a crude steel production).

Landfill gas (LFG) is mainly used for in situ heat and power generation. There are figures on overall energy recovery from landfill gas (Figure 43c) that may serve as a reference for potential recovery of RCFs from LFG. The potential use of LFG as a traffic fuel mainly refers to methane comparable to biogas. Subsequently the total amount of shipping slops (Figure 43d) is estimated from reference numbers of selected European ports and their capacity of freight treatment in relation to overall European port capacities (based on Eurostat data).

3.2.2 Scenarios for RCF production based on feedstock availability

Based on current feedstock potentials shown in Figure 43, we have derived three scenarios regarding an optimistic, a medium and a pessimistic development of the production of RCFs in Europe. As indicated in Figure 44, all scenarios are limited by feedstock availability. RCF production will compete with the direct use of hydrocarbon waste streams for heat and power generation and feedstock availability will partly decrease due to technological change (replacement of oxygen furnaces in steel production) or changes in waste treatment (avoidance of landfilled waste, increasing recycling efficiencies for mixed plastic waste). Therefore, the diffusion of RCF production facilities will strongly depend on the policy framework and the economic attractiveness of fuel production in comparison to alternative uses of the respective waste streams. The scenarios shown in Figure 44 are based on s-shaped diffusion curves and variations in potential feedstock availability. Table 8 summarises the assumptions regarding potential feedstock availability for the corresponding future scenarios of RCF production building upon current feedstock flows (Figure 43).

The fact that most potential feedstocks will show declining availability in the future is a clear obstacle for investments in RCF production facilities. Declining feedstock availability is expected for all potential pathways considered in the scenario analysis. Especially oxygen furnace steel production is expected to be replaced by alternatives such as direct reduction of iron ore with H_2 and the availability of landfill gases will strongly decrease due to the continuously declining levels of landfilled waste. However, as discussed before, the share of hydrocarbon-based solid waste (mainly mixed plastic waste) that cannot be used for recycling is also expected to decline in moderately due to improvements in waste treatment and recycling technologies. Subsequently, a reduction of crude oil consumption in Europe, e.g. through a stronger diffusion of electro-mobility will lead to declining availability of shipping slops in future. In this context, RCFs are rather more a short-term possibility to increase alternative fuel production than a sustainable long-term source of alternative transport fuels. The scenarios shown in Figure 44 should therefore be interpreted as an assessment of theoretical potentials under different framework conditions.

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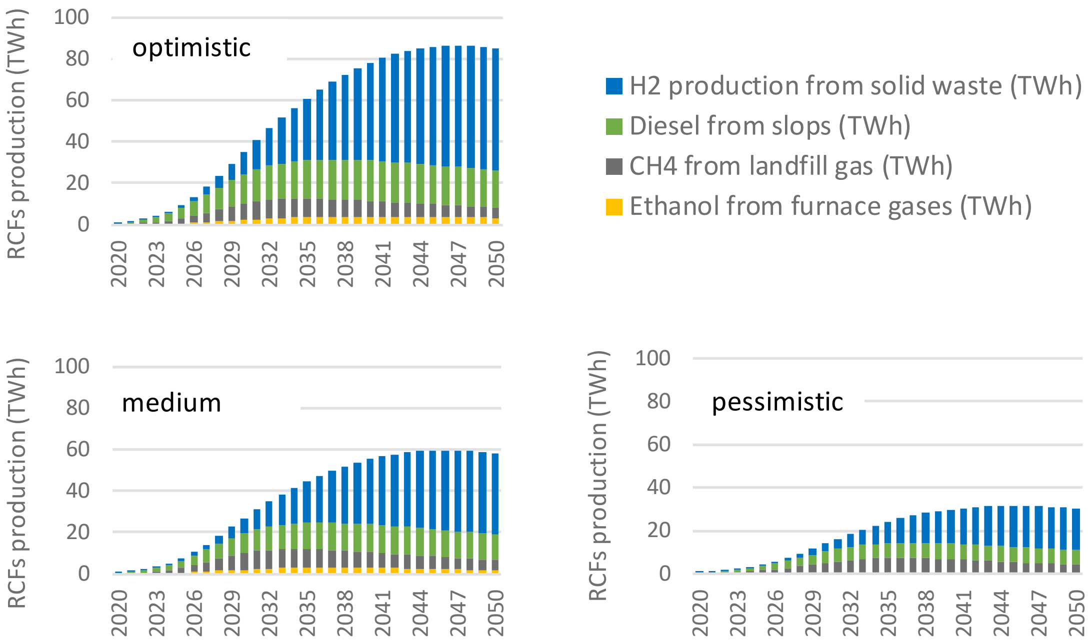
[28] https://europe.arcelormittal.com/newsandmedia/europenews/3798/Fuel-from-steel

Table 8: Feedstock development for respective scenarios of potential RCF production in Europe based on assumptions

Waste stream	Optimistic scenario	Medium scenario	Pessimistic scenario
Solid hydrocarbon waste (mixed plastics)	Feedstock limit at 30% of waste fraction based on current incineration shares and slightly decreasing overall solid waste flows until 2050	Feedstock limit at 20% of waste fraction based on current incineration shares and slightly decreasing overall solid waste flows until 2050	Feedstock limit at 10% of waste fraction based on current incineration shares and slightly decreasing overall solid waste flows until 2050
Furnace gases from steel production	Reduction of oxygen furnace steel production by 50% until 2050, 60% of furnace gases used for RCF production	Reduction of oxygen furnace steel production by 75% until 2050, 60% of furnace gases used for RCF production	Reduction of oxygen furnace steel production by 100% until 2050, 30% of furnace gases used for RCF production
Landfill gases (LFG)	Continuation of decreasing trend of LFG availability until 2050 (Figure 43c), limit of potential use as fuel at 60% of overall LFG	Continuation of decreasing trend of LFG availability until 2050 (Figure 43c), limit of potential use as fuel at 45% of overall LFG	Continuation of decreasing trend of LFG availability until 2050 (Figure 43c), limit of potential use as fuel at 30% of overall LFG
Slops and sludges from crude oil and chemicals shipping	Feedstock limit at 80% of available slops, slight reduction (-20%) of overall slop availability until 2050	Feedstock limit at 50% of available slops, slight reduction (-20%) of overall slop availability until 2050	Feedstock limit at 30% of available slops, slight reduction (-20%) of overall slop availability until 2050

Source: own assumptions



Note that we have only considered the most promising fuel from each feedstock. For the sake of comparability all potentials are listed in TWh based on their lower heating value (LHV). Source: own calculation.

Figure 44: Optimistic, medium and pessimistic scenario for overall production of RCFs from major feedstocks

3.2.3 Economics of RCF production

The production costs of RCFs including both operational expenditure (OPEX) and capital expenditure (CAPEX) strongly depend on the respective feedstock and site-specific aspects such as plant capacity and existing infrastructure. Therefore, it is reasonable to assess the cost structure for specific reference plants for which relevant information is partly available or may be extrapolated from existing literature data. In the following section, we shortly describe reference production facilities and respective cost structures based on literature data and additional own calculations for each of the cases considered in the scenario analysis. All cost structures calculated below are based on a depreciation time of 20 years and weighted average costs of capital (WACC) of 6%. All cost figures shown here build upon current literature data and refer to the base year 2020. Unlike in the case of RFNBO production, where a significant improvement in efficiencies is expected (mainly in electrolysis), we do not expect significant cost reductions for RCFs in future.

- Solid hydrocarbon waste flows of non-biological origin are the most relevant feedstock for RCFs in terms of mass potentials (see Figure 43 and Figure 44). As indicated before, gasification and subsequent carbon capture would enable a significant reduction of CO_2 emission making this pathway a promising source for blue hydrogen. In the technical process descriptions, we briefly described the plasma gasification developed by Plagazi AB (Figure 15). A European pilot plant on an industrial scale with a capacity of 6 kt of H_2 production is planned to be installed in Premnitz, Germany[29]. The overall investment volume for this production facility is reported as about € 50 million[30]. Combined with assumed operational costs gained from literature (Kayfeci et al. 2019), this leads to the following overall cost structure (see Table 9).

Table 9: Estimated cost structure of H_2 production from hydrocarbon solid waste

Plant reference data	Cost structure	
Capacity: 6,000 t/a H_2 **CAPEX: €50 million**	Operational costs	15,000,000 €/a
	Depreciation + capital costs	4,359,228 €/a
	Production costs	3.23 €/kg H_2
	Production costs	97 €/MWh H_2

Sources: calculations based on direct data from Plagazi AB (see footnote 30 and 31)

Other sources estimate the production costs of hydrogen from waste as 3 to 5 US-$/kg, while due to "economy of numbers" and learning effects, a reduction to 3 US-$/kg seems possible[31]. In this context, average OPEX of around 2.5 €/kg and CAPEX of 0.5 €/kg with additional capital costs seems reasonable.

- Biotechnological treatment of furnace gases to produce ethanol via the LanzaTech process is considered the most promising processing route to produce liquid fuels from exhaust gases from steel production. As mentioned before, a European pilot plant with a capacity of 80 million l/a of ethanol is being built by ArcelorMittal in Gent[32]. The following cost structure builds upon literature data (Medeiros et al. 2020) regarding cost per litre of ethanol production through syngas fermentation and takes the pilot plant of

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[29] https://www.ipg-potsdam.de/gruener-wasserstoff-aus-dem-industriepark-premnitz-ipp/

[30] https://www.plagazi.com/plagazi-ab-receives-german-order-worth-50-million-euros/

[31] https://www.rechargenews.com/transition/its-much-cheaper-to-produce-green-hydrogen-from-waste-than-renewables/2-1-801160

[32] https://europe.arcelormittal.com/newsandmedia/europenews/3798/Fuel-from-steel

ArcelorMittal as a reference case in terms of capacity. Table 10 displays the assumed cost structure for ethanol production from furnace gases based on syngas fermentation.

Table 10: Estimated cost structure of ethanol production from furnace gases

Plant reference data	Cost structure	
Capacity: 80 million l/a EthOH	Operational costs	45,920,000 €/a
CAPEX: €22.4 million	Depreciation + capital costs	1,952,934 €/a
Utilisation of exhaust gases of steel production facility with a capacity of ca. 4 million t/a	Production costs	0.76 €/kg EthOH
	Production costs	102 €/MWh EthOH

Sources: Medeiros et al. 2020 and direct information from ArcelorMittal (see footnote 33)

- A comparatively simple-to-access source of gaseous waste for RCF production are landfill gases. Landfill gases are formed through the anaerobic digestion of hydrocarbon waste in landfills and mainly consist of CO_2 and CH_4 comparable to biogas. As described before, landfill gases are usually collected in order to avoid GHG emissions and used for energy provision in CHP plants. However, with an additional refining step, methane from landfill gases could be directly used as a fuel (see Figure 19). The following cost structure of providing methane from landfill gas builds upon literature data (IEA 2020). The reference plant has a capacity of 4 MW power generation (LHV of methane), which is a common capacity range (Dace et al. 2015). Table 11 displays the assumed cost structure for methane recovery from landfill gas.

Table 11: Estimated cost structure of methane recovery from landfill gases

Plant reference data	Cost structure	
Capacity: 32 million kWh/a LHV methane (4 MW with 8000 h/a full-load hours **CAPEX: €14.8 million**	Operational costs	1,483,034 €/a
	Depreciation + capital costs	1,292,977 €/a
	Production costs	0.087 €/kWh CH_4
	Production costs	86.75 €/MWh CH_4

Sources: IEA 2020, Dace et al. (2015)

- Slops and sludges from crude oil and petrochemicals shipping is the most important source of liquid waste streams that may serve as feedstock for RCF production. As described in the technology section, the process for the treatment of shipping slops is comparable to crude oil refining with several additional separation and purification steps, particularly the removal and treatment of waste water. The aforementioned process, developed by EcoSlops, is realised in a pilot plant at Port de Sinès in Portugal with a capacity of around 35 kt/a of slop treatment[33]. The following cost structure is based on reference information from EcoSlops (EcoSlops 2016). The economics of the process strongly depend on oil prices. Additionally slops also have a value based on current oil prices as they may be used as low quality fuel in industrial processes such as cement production facilities. Therefore, estimated feedstock prices are listed separately in Table 12.

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[33] https://www.ecoslops.com/en/solutions-and-services/our-technology/ow2p

Table 12: Estimated cost structure of liquid fuel production (mainly diesel) from shipping slops

Plant reference data	Cost structure	
Capacity: 35 kt/a slops **CAPEX: €12.3 million**	Operational costs	3,000,000 €/a
	Feedstock costs	15,312,500 €/a
	Depreciation + capital costs	1,072,370 €/a
	Production costs	47.5 €/MWh diesel

Sources: EcoSlops (2016) with feedstock prices based on current oil price level (50$/barrel)

The cost structures for the different feedstocks and processing routes described above all refer to the base year 2020 and represent current literature data. As indicated in the context of solid waste treatment, due to economy of numbers and learning effects, a certain cost reduction, particularly regarding CAPEX seems realistic. However, this is a moderate potential of cost reduction compared to the expected future efficiency gains regarding RFNBO processes. As feedstock for RCFs is limited and almost all feedstock potentials regarded are expected to decline in future, RCFs in particular seem to be an interim or transitional solution for alternative fuel production. This seems particularly relevant against the backdrop that RCFs have generally lower production costs than RFNBOs but build upon fossil-based waste.

4 ASSESSMENT OF THE DEVELOPMENT AND IMPACTS OF RFNBOS/RCFS

In this section, we assess the development and impacts of the potential large-scale diffusion of RFNBOs and RCFs. This assessment will be mainly based on a further evaluation of the scenarios developed in the preceding section. It will focus on the following aspects:

- Share of final consumption of renewable energy in the transport sector: what is the potential contribution to the RES target in the transport sector by RFNBOs and RCFs?
- Requirements for additional RES-E: what are the impacts of potential additionality requirements for the use of RES-E that may apply to the production of RFNBOs?
- Expected prices of RFNBOs/RCFs and resulting investment requirements: how will the wholesale prices of RFNBOs and RCFs develop in comparison to other fuels? What does this imply for the market volumes and investment requirements?
- Greenhouse gas emissions: what GHG emission savings of RFNBOs and RCFs are claimed by the producers and how do they relate to scientific evidence?
- Local environmental impacts: what are the potential local environmental impacts of RFNBOs and RCFs, e.g. with respect to land use, water scarcity and air pollution?

Each of these aspects is covered within one subsection in the following text.

4.1 Potential contributions of RFNBOs to an increase of the shares of renewable energies

RFNBOs are defined within the revised Renewable Energy Directive (RED II), in order to be able to take their use into account when calculating both the overall RES share in the gross final energy demand and the RES share in the final energy consumption of the transport sector (RES-T). In this section, we assess which contributions to the RES share would be provided by RFNBOs and RCFs according to the various scenario variants considered in the previous section. RED II contains some special provisions with respect to RFNBOs and RCFs worth noting here. For the RES-T target, the consumption of any renewable fuel (including RNFBOs and RCFs) in the maritime and aviation sectors is weighted with a factor of 1.2, while any use of renewable electricity in the transport sector is weighted with a factor of 4. For the overall RES target, the electricity used in the domestic production of RFNBOs is counted instead of their final energy content. This does not apply to RCFs, as these are not electricity-based.

We consider the RED II methodologies for the RES share but also a simpler approach without factors and based on the energy content only. The reason for this is that for the 2030 targets the RED II methodology will very likely apply. In the longer term, however, the methodology could be simplified, as renewable energy use becoming dominant is expected across all sectors. For 2030, the potential shares of RFNBOs and RCFs are estimated based on the corresponding production potentials compared to the future demand, as given in the Climate Target Plan. For 2050, we calculate the resulting RFNBO share by comparing the RFNBO demand in the MUST, CAN and COULD scenarios to the total consumption in the scenarios evaluated for their construction (compare Section 3.1.2). The evaluated scenarios show quite different assumptions about the future development of the transport activity and thus final energy demand of the transport sector. However, the diffusion of RFNBOs also has a large impact on the total demand, as a lower electrification of the transport sector leads to an increased final energy demand. We therefore consider a range for the total demand based on the relevant set of evaluated scenarios. For instance, we compare the RFNBO demand in the MUST scenario to both the total demand in the MUST and the CAN scenarios. We do not consider the role of RCFs in 2050 in detail, as their role is limited compared to RFNBOs in the long term due to the limited potentials. Additionally, they may also not be counted as renewable in the longer term due to the non-renewability of waste carbon streams.

In 2030, the share of RFNBOs in the final energy demand (FED) of the transport sector could amount to 4.2% if the optimistic supply scenario is considered, where the electrolysis capacity reaches the upper bound in the EU's hydrogen strategy of 40 GW and the average full-load hours amount to 5,000 per year, and the whole production is used for the transport sector. Even in the latter case, however, the share could also be limited to only 0.6% if the pessimistic supply scenario with only 7 GW of electrolysers in 2030 is considered. For RCFs, the pessimistic share of 0.5% is similar to that for RFNBOs. The optimistic share of 1.3% is substantially lower due to the limited waste stream potentials, but it is at least comparable to the share for a medium expansion of electrolysers. When we assume that all the RFNBOs and the RCFs are used in the maritime and aviation sectors and apply the factors from RED II to them but also to the electricity use in the transport sector, this may lead to lead a slight increase of the share by 0.1-0.2%-points (see Table 13). A decrease of a similar magnitude may also occur, if RCFs and RFNBOs are not used in the maritime and aviation sectors and the RED II methodology is applied. In summary, the use of RFNBOs and RCFs can substantially contribute to reaching the RES targets in the transport sector, if a medium to optimistic production scenario can be realised.

The overall share of RFNBOs in the gross FED reaches only 1.2% in 2030 even in the optimistic supply scenario, while it would be 0.2% in the pessimistic supply scenario. This range is increased to 0.3-2.3%, if the electricity used to produce the RFNBOs is considered instead of the energy content, as currently foreseen in the RED II (see Table 13). For RCFs, the shares range from 0.1% to 0.4%, which is not affected by the provisions of the RED II. Altogether, the contribution of RFNBOs and RCFs to the overall RES target in 2030 can be expected to be limited.

Table 13: Potential contributions of RFNBOs and RCFs to RES shares

	2030		2050		
	RFNBOs	RCFs	MUST	CAN	COULD
Share in FED of the transport sector	0.6-4.2%	0.5-1.3%	14-20%	19-27%	45-63%
Share in FED of the transport sector with RED II multiplier	0.5-4.4%	0.5-1.4%	8-10%	9-11%	25-29%
Share in gross final energy demand (FED)	0.2-1.2%	0.1-0.4%	3-5%	7-12%	13-17%
Share in gross FED with RED II methodology	0.3-2.3%	0.1-0.4%	4-7%	12-19%	20-26%

Source: own calculations

In 2050, the share of RFNBOs in the FED of the transport sector strongly depends on the demand scenario considered due to the different assumptions about diffusion of RFNBOs. In the MUST scenario with RFNBO/RCF use only in essential sectors such as the maritime and aviation sectors, the share in the transport sector can reach as high as 14-20%. This reflects the fact that the total demand will be low in case of high electrification. In the CAN scenario with the additional use of RFNBOs/RCFs in long-distance freight transport, the share can reach 19-27%. In case of an unlimited use of RFNBOs/RCFs in the transport sector as in the COULD scenario, the share could even reach 45-63%. All these shares are reduced by about 40% to 60%, if the factors from RED II are applied (see Table 13). This is the case since these give a high weight to the use of renewable electricity in the transport sector, which plays a large role in all scenarios in 2050.

The contribution to the overall RES share in gross FED also strongly depends on the demand scenario considered. It amounts to 3-5% in the MUST scenario, 7-12% in the CAN scenario and 13-17% in the COULD scenario. The relatively low share in the MUST scenario shows that there are alternative mitigation options in the majority of applications including electrification, the direct use of RES as well as carbon capture and storage. When the current RED II methodology is applied so that the RES electricity used to produce the RFNBOs is accounted for, the shares increase by more than 50% in all cases (see Table 13). For the COULD scenario, the resulting range of shares is 20-26%. The large increase of the shares shows that the high demand for electricity caused by the RFNBO production substantially contributes to the gross FED, in particular in case of a widespread use of RFNBOs.

In summary, RFNBOs will substantially contribute to the RES share in energy consumption, both in the transport sector and overall. However, the amount of RFNBOs produced will also have a damping impact on the overall RES share due to the high electricity input. RCFs can play a substantial role as a bridging fuel in the transport sector in 2030, but have a limited potential compared to RFNBOs in the long term until 2050.

4.2 Impacts of requiring additional renewable electricity

The production of RFNBOs uses large amounts of renewable electricity and comes with relatively high conversion losses compared to other uses of electricity. If RFNBO production diverts renewable electricity away from other such applications, this may result in an overall increase of GHG emissions, since the gap would have to be closed by non-renewable power generation plants. Therefore, it is reasonable to ensure to a certain extent that any RFNBO production mainly uses renewable electricity that is additional in some way, as is already laid down in the RED II.

In turn, one potential benefit of any RFNBO production is the potential to use electrolysers as a flexibility option in the electricity system. In times of low RES production, the electrolysers can decrease their load, while they can increase their load to produce green hydrogen in times of high RES production, using RES electricity that would need to be curtailed otherwise. Situations like this are expected to strongly increase in number, when the share of wind and solar power becomes dominant, and there are electrolysis technologies that show the potential to ramp up load fast enough to deal with fluctuations in wind and solar power (cf. Section 2.1). However, there are competing flexibility options, which are partly expected to be cheaper, for instance the expansion of electricity grids. Moreover, the surplus electricity will not be sufficient to ensure the economic viability of hydrogen production and an increasing hydrogen production may even increase the amount of surplus electricity (see e.g. Lux and Pfluger 2020). Thus, the potential for RES-E integration via RFNBO production strongly depends on the overall system transformation.

Recent studies show that in cost-efficient scenarios, the full-load hours of electrolysers will be relatively low in 2050 (e.g. 1,670-2,550 hours in the EU in Lux and Pfluger 2020). However, certain plausible developments such as fragmentation of markets or strong localisation of RES-E generation may lead to an increasing number of full-load hours (e.g.

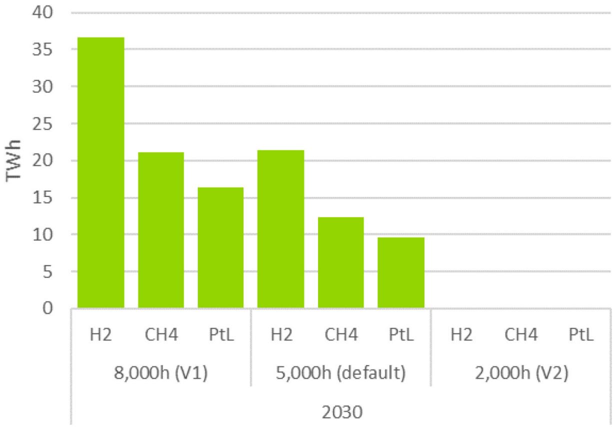
2,300-3,200 full-load hours in the EU in the SET-NAV scenarios, see Sensfuß et al. 2019). Given these possible diverse developments, it remains open what the impact of requiring only additional or otherwise curtailed renewable electricity for RFNBO production will be. We therefore discuss this based on the scenarios developed.

The issues related to the requirements for sourcing RES-E in the production of RFNBOs are investigated in detail in the Interim Report on Task 2. In particular, detailed provisions for RFNBO producers on how to ensure additionality of their RES-E use as well as temporal and geographical correlation with RES-E generation are developed for the different cases under the RED II. It is out of the scope to assess them in detail here, as this would require a simulation with high spatial and time resolution. Here, we use stylised model cases to reflect the differing full-load hours achievable under the various options:

- In the *default case*, we consider moderate requirements on RES-E sourcing in the future that can be fulfilled by grid-coupled electrolysers, utilising smart-grid technologies and/or power purchase agreements (PPAs). This is meant to reflect a moderate implementation of Case 3 in Task 2, which requires temporal and geographical correlation of RFNBO production with RES-E generation only on the system level. For the default case, we assume 5,000 full-load hours for electrolysers in 2030 and 2050. The reasoning here is that cost reductions are balanced with slowly increasing additionality requirements, keeping the full-load hours roughly constant. Note that this case corresponds to the default case that we used in the development of the scenarios in the preceding section.
- In *Variant 1* (V1), we consider lax requirements on RFNBO producers in the future. This corresponds to production in countries which fulfil the requirements of Case 1 in Task 2, i.e. the RES-E share is so high that RFNBO production based on the grid mix already leads to a GHG reduction of at least 70% compared to a fossil reference case. We note that this is likely to apply to most Member States in 2050, given the rising number of Member States aiming for GHG neutrality in 2050. For V1, we assume 8,000 full-load hours for electrolysers, meaning that they will reduce production only for maintenance reasons. We apply this assumption also for 2030. The reasoning here is that it may turn out that the first RFNBO producers choose sites in countries already fulfilling the criteria for Case 1 in 2030.
- In *Variant 2* (V2), we consider strict requirements on RES-E sourcing in the future, asking producers to either have a direct connection to a RES plant decoupled from the grid or to use surplus electricity only. This reflects Case 2 under Task 2 as well as a very strict interpretation of Case 3. For V2, we assume 2,000 full-load hours for electrolysers in 2030 and 3,000 full-load hours in 2050. The reasoning behind this is that surplus electricity will be too limited to ensure economic viability in 2030 so that a direct connection is the only option, while there will be more surplus electricity generated in an electricity system strongly dominated by RES and lower costs in 2050, enabling the viability of avoiding curtailment at selected sites but also of direct connections.

We apply the variants V1 and V2 only to domestic production of RFNBOs within the EU and leave the assumptions for imports unchanged here. On the one hand, applying the variants also to imports would result in the following issue: When the variants are also applied to imports, the change in production costs in the EU and abroad are quite similar. Slight differences result from the different assumptions for the capital costs and from a shift in the RES-E cost curves. The latter cannot be considered for imports due to the lack of such curves for exporting countries. Even more, this would be highly sensitive to assumptions. On the other hand, fixing the costs for imported RFNBOs is meaningful in the context considered here. For, it may well be the case that a change in the requirements for RES-E sourcing has substantially less impact on the imported RFNBOs than on domestic production. For instance, this applies if these are produced in countries where RES-E plants are built solely for the purpose of RFNBO production or if the compliance with the requirements is difficult to validate for imports. Nevertheless, the results of the analysis here need to be interpreted in light of this assumption.

Given that a major constraint concerning the RFNBO production in 2030 is the construction of electrolyser capacities at a relevant scale, the assumptions on RES-E requirements and resulting full-load hours strongly affect the potential for domestic production of RFNBOs. Moreover, the import of RFNBOs will be less competitive in V1 and more competitive in V2, under the assumption that the full-load hours in RFNBO exporting countries remain unchanged. Therefore, the competitive production potential of 43 TWh in 2030 in the default case would increase to 74 TWh under the lax conditions of V1. However, production under V1 conditions in countries with lower renewable electricity shares would mean that RFNBO production would very likely use non-renewable electricity. A universal application of V1 conditions as shown in Figure 45 would hence increase the availability of electricity-based fuels, however with a limited renewable share. It would also cause significant incremental emissions in the power sector because of increased demand for (fossil) baseload power. The production competitive with imports could decrease as much as to 0 TWh under the strict requirements of V2 (see Figure 45). This suggests that posing strong requirements on RES-E sourcing can limit the market uptake of domestic RFNBO production substantially. However, such strong requirements can be expected to lead to a shift of the production to EU Member States fulfilling the conditions of V1 so that the effect of a lower domestic market uptake is reduced.



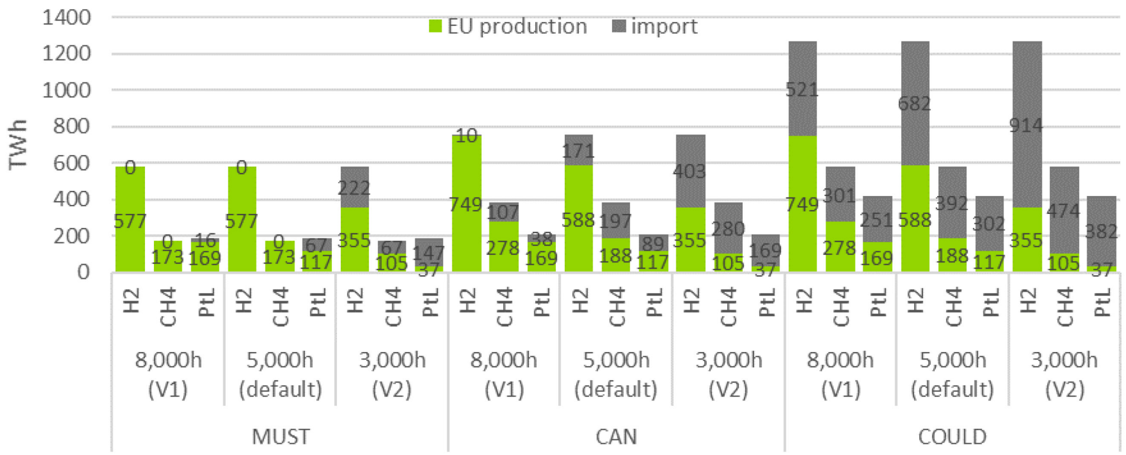
Source: own calculations

Figure 45: RFNBO production potential in 2030 for different levels of full-load hours in the medium supply scenario

For 2050, the situation is more complex, as scaling up the installed electrolyser capacity is less of a constraint in the longer term than in 2030, though still an important factor. The limited full-load hours due to RES-E sourcing requirements will therefore not change the production of RFNBOs to such an extent as in 2030. Nevertheless, the import of RFNBOs will become more competitive, thereby increasing the share of imported RFNBOs, under the assumption that the full-load hours for imported RFNBOs remain unchanged. The extent of this effect depends on the considered demand scenario for RFNBOs. In the MUST scenario, the lower additionality requirements of V1 will only slightly decrease imports of liquid RFNBOs, while the stronger requirements of V2 will lead to increased imports for all types of

RFNBOs (see Figure 46). In the CAN and the COULD scenarios, there are substantial decreases of imports in V1 and increases of imports in V2 of a similar extent, both in comparison with the default case. The largest increase of imports by about 230 TWh occurs for hydrogen production. The impacts in the CAN and the COULD scenarios are similar. This is due to the domestic production potentials being fully used in both scenarios so that the change in the domestic production potentials due to a change in full-load hours translates directly into an additional need for imports. The latter effect is solely dependent on the domestic production capacities, so independent of the requirements on imports.

In summary, the strictness of RES-E sourcing requirements can have substantial impacts on the competitiveness of domestic production of RFNBOs. In particular this applies in the shorter term until 2030 due to the constraints stemming from limited production capacities, but there are also relevant impacts in the longer term. However, the benefits from less strict requirements for competitiveness need to be seen in light of the lower stringency of the achieved GHG emission avoidance (see Section 4.4). Moreover, the lower competitiveness in case of stricter requirements for RES-E sourcing can also be mitigated if these requirements are applied to imports of RFNBOs in an equally strict manner and compliance with the requirements is checked carefully.



Source: own calculations

Figure 46: The shares of domestically produced and imported RFNBOs in 2050 for different levels of full-load hours in the medium supply scenario

4.3 Expected economic development of RFNBOs/RCFs and implications

4.3.1 Expected prices of RFNBOs/RCFs and comparison with fossil fuel comparators

As is the case for conventional fuels today, the formation of global markets and thus global prices for RFNBOs can be expected in the future. For today's conventional fuels, there is a lack of competition on the global markets due to the unevenly distributed gas and oil resources. This leads to an oligopoly situation, where the suppliers achieve margins that are far beyond their production costs. This is not too likely for RFNBOs, as cheap sources for RES-E and water are widespread among different countries and regions so that a high degree of competition between producers can be expected. As an aside, we note that the situation is rather different for fuels based on blue hydrogen, i.e. natural-gas-based hydrogen in combination with CCS. Here, the main potential producers are the limited number of countries with vast amounts of natural gas resources and the production costs are expected to be lower than those for green hydrogen. As long as this is the case, they will probably exploit a substantial share of the price difference between blue and green hydrogen as their profit margin.

Still, the production potential of RFNBOs can be small compared to the demand, which may also result in prices much higher than the production costs. To understand the potential relations and impacts on global markets will require a detailed global market outlook and analysis. This is currently not available in the literature (including grey literature) and goes beyond the scope of this report. However, given that the GHG neutrality target could be met by other means apart from international transport, qualitative reasoning suggests that the demand for RFNBOs will probably remain moderate as long as carbon prices are moderate. We therefore assume that the profit margin of RFNBO producers will be limited due to competition.

Both RFNBOs and RCFs will compete with conventional fuels in the transport sector, mainly with petrol, diesel and kerosene, but possibly also fossil hydrogen. As there are no additional benefits for the end users stemming from the use of RFNBOs compared to fossil fuels except for its green label, the main barrier for a market uptake of RFNBOs is the price difference compared to fossil fuels. Here, we consider this difference in more detail and draw conclusions on the level of a carbon price sufficient to close the price gap. Therefore, we compare the wholesale price developments to those of competing fossil fuels and derive implications on policy measure to close the price gap. For the power-to-liquid fuels and synthetic methane, we use the wholesale prices of crude oil and natural gas as fossil comparators, respectively. For green hydrogen, we use the market price of fossil hydrogen based on steam reformation of natural gas as the fossil comparator. In all cases, we consider the wholesale market price of RFNBOs to be given by the marginal costs of production for meeting the corresponding demand. It is assumed that there is only a small profit margin of 5%, as strong competition is to be expected both among the RFNBO producers in various countries but also with potential producers of blue hydrogen who tend to have lower production costs.

We use the assumptions about the future development of fossil fuel wholesale prices from the impact assessment underlying the Commission‘s Climate Target Plan (European Commission 2020b). This sees an increase of the oil and natural gas prices until 2050 by 4 %-points and 2.5 %-points per year on average, respectively. It is well-known that there is substantial uncertainty about these developments, as they were strongly driven by geopolitical events in the past. In scenarios with a highly ambitious climate policy, however, the demand for fossil fuels can be expected to shrink substantially. This suggests that price increases of fossil fuels will be limited in such scenarios – if they occur at all. For hydrogen, we use the average of today’s market price for hydrogen of 1.5-2 € per kilogram as a starting value and assume that the price stays proportional to the natural gas price. The resulting wholesale price developments can be found in Table 14.

Table 14: Assumed future developments of fossil fuel wholesale prices

	2020	2030	2040	2050
Oil [€$_{2019}$/MWh]	32	48	56	69
Natural gas [€$_{2019}$/MWh]	19	23	31	32

Hydrogen [€$_{2019}$/MWh]	46	53	73	75

Source: own calculations based on Climate Target Plan (European Commission 2020b)

Not surprisingly, there is a substantial price gap between the RFNBOs and their fossil comparators in 2030 but also in 2050 in all scenario variants. The following presentation focuses on the CAN scenario for the demand and the optimistic and medium scenario for the RFNBO supply (see Section 3.1). In these scenarios (see Table 15 and Table 16), the price gap for hydrogen lies in the range of 43-67 €$_{2019}$/MWh in 2030 and 23-42 €$_{2019}$/MWh in 2050. For methane and power-to-liquids, the price gap lies in the range of 130-168 €$_{2019}$/MWh in 2030 and 148-195 €$_{2019}$/MWh, respectively. The large differences between the price gaps for the different RFNBOs is due to both the higher market prices for fossil hydrogen and the much lower production cost of green hydrogen compared to the less efficient production of synthetic fuels. Nevertheless, this means that all kinds of RFNBOs will be far from being cost-competitive with fossil fuels without additional measures.

The large price gap reflects that external cost (e.g. for environmental damages) are not included. Pricing of carbon emissions is one way to take these external costs into account and thereby improve the cost competitiveness of RFNBOs. There are various ways to implement this on the level of end-user prices. The end-user prices differ from the wholesale prices by including distribution and sales costs, a profit margin as well as taxes and levies. In particular taxes and levies could be adjusted based on the carbon footprint of the fuels or wholesale prices could be influenced directly by implementing a carbon market for fossil transport fuels similar to the EU ETS. In order to show the extent of the incentives required, we derive the required carbon price level to close the wholesale price gap based on the standard carbon emission factors for oil (74 tCO$_2$e / TJ) and natural gas (56 tCO$_2$e / TJ) as well as the EU ETS benchmark for hydrogen production (8.85 tCO$_2$e / t H$_2$). We do this on the level of the wholesale price gap because distribution and sales costs will be mainly the same for the RFNBOs and their fossil comparators, whereas taxes and levies pose a lever for an adjustment in itself, as explained above.

The required carbon price level strongly varies between the different kinds of RFNBOs in 2030. While for hydrogen the level lies in the range of 187-292 €$_{2019}$/tCO$_2$e for the optimistic to medium production conditions discussed above, it is in the ranges of about of 643-835 and 579-732 €$_{2019}$/tCO$_2$e for methane and power-to-liquids, respectively. This again reflects the higher market prices for fossil hydrogen and the much lower production cost of green hydrogen compared to the other RFNBOs.

Table 15: Price gap between RFNBOs, fossil comparators and blends in €$_{2019}$/MWh in 2030

	Hydrogen		Methane		PtL	
	Optimistic	**Medium**	**Optimistic**	**Medium**	**Optimistic**	**Medium**
Wholesale price RFNBO	96	120	152	191	202	243
Fossil reference price	53	53	23	23	48	48
Price gap from fossil ref. to RFNBO	43	67	130	168	154	195
Required CO_2 price level [€$_{2019}$/tCO_2e]	187	292	643	835	579	732
Wholesale price RFNBO-Blend 10%	58	60	36	39	63	67
Price premium of RFNBO blend	4	7	13	16	15	19

Note: all figures are based on the optimistic scenario and the medium scenario for supply, as constructed in Section 3.1.
Source: own calculations

A rather different option to incentivise the market uptake of RFNBOs is a quota for blending fossil fuels with RFNBOs. This can be a useful instrument to ramp up the production of RFNBOs. We note that the required carbon price level to close the gap between a blend and the fossil comparator will always be the same as for the RFNBO itself, but the relatively low price premium for a blend is more likely to match with the willingness to pay for a less carbon-intensive fuel. As an example, we consider here the case of blending fossil fuels with RFNBOs with a quota of 10%. The wholesale price for such a blend is estimated to be 58-60, 36-39, and 63-67 €$_{2019}$/MWh for hydrogen, methane and liquid fuels in 2030, respectively. The resulting price premium for hydrogen is only 4-7 €$_{2019}$/MWh, while it amounts to 13-16 and 15-19 €$_{2019}$/MWh for methane and liquid fuels, respectively.

For 2050, it does not make sense to consider a blend of fossil fuels and RFNBOs anymore because the EU's objective of GHG neutrality requires the complete phase-out of fossil fuels. However, blending of sustainable bio-based fuels and RFNBOs may become relevant for market integration while reflecting limited potentials of sustainable bio-based fuels. Based on our calculations, the required carbon price level to close the price gap between RFNBOs and fossil fuels is somewhat lower for hydrogen with a range of 101-183 €$_{2019}$/tCO_2e (see Table 16), reflecting the increase of the fossil reference price but also the decreasing costs of electrolysis. This overcompensates for the fact that the higher demand requires the use of RES-E production potentials with higher costs. For methane and liquid fuels, however, there is even a slight increase of the required carbon price level. This is due to a combination of the need to use more expensive RES-E production potentials and the fact that the marginal costs of production will include the use of direct air capture because of the limited carbon availability in 2050.

Table 16: Price gap between RFNBOs and fossil comparators in €$_{2019}$/MWh in 2050

	Hydrogen		Methane		PtL	
	optimistic	**medium**	**optimistic**	**medium**	**optimistic**	**medium**
Wholesale price RFNBO	98	117	173	198	218	246

Fossil reference price	75	75	32	32	69	69
Price gap of RFNBO	23	42	141	166	148	177
Required CO_2 price level [$€_{2019}/tCO_2e$]	101	183	701	824	557	663

Note: all figures are based on the CAN scenario for demand and the optimistic and the medium scenario for supply, as constructed in Section 3.1. Source: own calculations

For RCFs, the price gap with respect to their fossil comparators is of a similar magnitude as for hydrogen in 2030 for most of the production pathways (see Table 17). Accordingly, the required CO_2 price level and the price premium for blending fossil fuels with RCFs would be comparable to those for hydrogen. The only exception here is the production of Diesel from shipping slops. The estimated wholesale price is only marginally higher than the assumed Diesel price. So for these RCFs, cost competitiveness could be reached in 2030, in particular if a CO_2 price applies. A price premium for blending fossil Diesel with Diesel based on shipping also would also be marginal.

Table 17: Price gap between RCFs, fossil comparators and blends in $€_{2019}$/MWh in 2030

	Hydrogen from solid waste	Ethanol from furnace gas	Methane from landfill gas	Diesel from shipping slops
Wholesale price RCF	102	107	91	50
Fossil reference price	53	48	23	48
Price gap from fossil ref. to RCF	48	59	68	2
Required CO_2 price level [$€_{2019}/tCO_2e$]	212	223	340	7
Wholesale price RCF-Blend 10%	58	54	30	48
Price premium of RCF blend	5	6	7	0.2

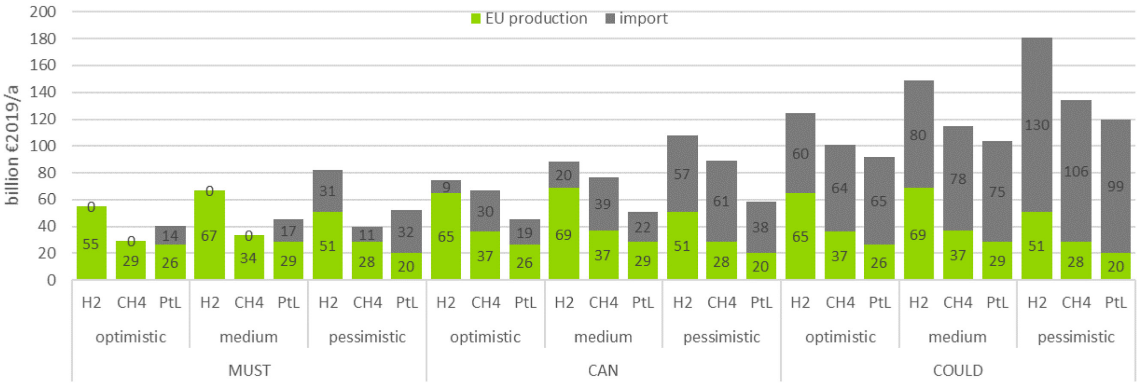
Note: all figures are based on the optimistic scenario and the medium scenario for supply, as constructed in Section 3.2. The required CO_2 price does not reflect GHG emissions related to the production of RCFs. Source: own calculations

In summary, there is a large gap between the expected wholesale prices for all kinds of RFNBOs and fossil fuels not only in the shorter term until 2030 but also in the long term until 2050. Compared to hydrogen, the price gap is substantially larger for methane and liquid RFNBOs due to the higher conversion losses and the necessary carbon input. Accordingly, the required carbon price to close the gap for hydrogen could be reached in the longer term, while this seems questionable for methane and liquid RFNBOs. However, when total costs of ownership (TCO) are considered instead of fuels only, this is partially compensated for in the case of vehicles running on standard combustion engines due to the higher costs of fuel cells. For gaseous and liquid RFNBOs, blending quotas for sectors with a particular need for RFNBOs, such as the maritime and aviation sectors could provide a more promising option to promote market uptake. For RCFs, the situation is similar to that for hydrogen with the exception of RCFs based on shipping slops, which might become cost-competitive by 2030.

4.3.2 Expected market volumes of RFNBOs/RCFs and resulting investment needs

As the next step, we consider the total market volume and the investment requirements resulting from the different scenario variants, in order to assess the economic implications of different pathways for the scale up of the use of RFNBOs and RCFs. The total market volume refers to the amount of money spent on wholesale markets. For RFNBOs, the total market volume in 2050 is estimated by looking at the product of the total demand for RFNBOs in 2050 and the marginal production costs of the different RFNBOs to meet this demand. For RCFs, the total market volume is estimated by the product of the production potential and the corresponding production cost.

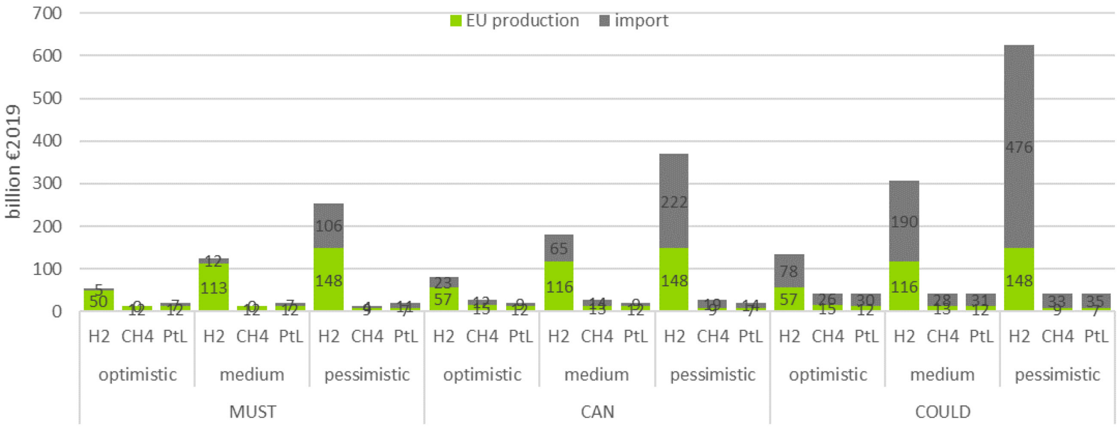
The total market volume for RFNBOs primarily depends on the demand scenario considered and less on the production scenario (see Figure 47). This is due to the large differences in the demand for RFNBOs across the scenarios. If the demand for RFNBOs is strongly limited to essential applications as in the MUST scenario, the market volume of all RFNBOs in total varies between 124 and 175 billion €$_{2019}$ in the optimistic and pessimistic production scenario respectively. Hereof, 14 to 74 billion €$_{2019}$ are spent on imports. In the less restrictive CAN scenario, the total market volume ranges from 186 to 256 billion €$_{2019}$, with 58 to 156 billion €$_{2019}$ spent on imports. In the COULD scenario with abundant use of RFNBOs, the total market volume reaches 317 to 435 billion €$_{2019}$, with 189 to 324 billion €$_{2019}$ spent on imports. The market volume of renewable hydrogen holds the largest share in all scenario variants, but the market volumes of renewable methane and power-to-liquid fuels have similar extents. In 2050, the RCF potentials only cover a small share of demand. Accordingly, the total market volume will also be quite limited, namely it ranges from 2 to 7 billion €$_{2019}$. The total market volume of hydrogen from waste carbon streams is substantially higher than those of methane and liquid fuels from waste carbon streams in 2050. This is due to the larger potential RCF production from solid waste, but also due to the lower cost of production of liquid RCFs from shipping slops.



Source: own calculations

Figure 47: The total market volume by RFNBO in 2050 for the various supply and demand scenarios

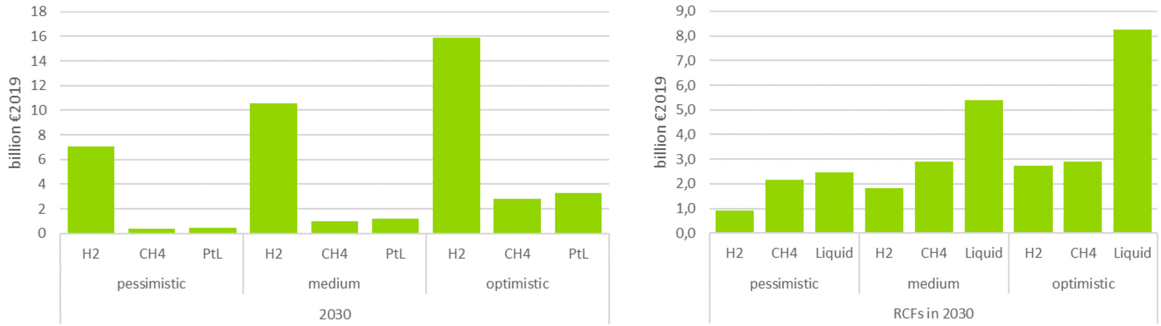
Building up the production capacities for large-scale production of RFNBOs requires substantial investments in production facilities, in particular RES plants and electrolysers but also synthesis plants for the conversion of hydrogen into carbon-based fuels. Here, we focus on the directly relevant investments in electrolysers and synthesis plants, but we emphasise that the need for investments in RES plants can be expected to be even higher given the contribution of the RES-E input to the total RFNBO costs (see Section 3.1). Again, the necessary investments until 2050 differ largely depending on the assumptions used concerning the future demand for RFNBOs (see Figure 48). If the demand for RFNBOs is limited as in the MUST scenario, the required investments for all RFNBO plants is about 155 billion €$_{2019}$ in the medium production scenario. Hereof 18 billion €$_{2019}$ are spent on non-domestic production capacities. In the CAN scenario with more widespread use of RFNBOs, the required investment is 230 billion €$_{2019}$, with 88 billion €$_{2019}$ spent on non-domestic capacities. In the COULD scenario with an even greater use of RFNBOs, the required investment reaches 390 billion €$_{2019}$, with about 250 billion €$_{2019}$ spent on non-domestic capacities. In all cases, roughly 80% of the investments go to the installation of electrolysers, while the remaining investments are almost equally spread between the gaseous and liquid synthesis routes. The small role of RCFs in 2050 still results in investment requirements of about 10 to 30 billion €$_{2019}$ until 2050 due to the higher CAPEX share in the production of RCFs compared to RFNBOs.



Source: own calculations

Figure 48: Total investment requirements into production capacities by plant type in 2050 for the various supply and demand scenarios

In 2030, the potential production capacity of RFNBOs and RCFs within the EU is comparable, as can be seen from the corresponding potential contributions to the RES share derived in Section 4.1. The corresponding investments into production plants amount to 8 to 22 billion €$_{2019}$ for RFNBOs and to 5.5 to 13 billion €$_{2019}$ for RCFs, respectively. The smaller investment needs of RCFs reflect that the corresponding technologies are mainly already established, while the CAPEX of electrolysers are still relatively high (see Section 2.1). Accordingly, the main share of investments in RFNBO plants is again directed towards electrolysers. For the RCF plants, the highest share of investments goes to the liquid RCFs due to the higher short-term production potentials of liquid RCFs from blast furnace and shipping slops compared to other waste carbon streams. Given that the waste carbon streams necessary for RCF production may disappear in the long term, the investments into RCF production plants bear the risk of becoming stranded investments to a certain extent.



Source: own calculations

Figure 49: Total investment requirements into production capacities for RFNBOs (left panel) and RCFs (right panel) in 2030 for the various supply scenarios

In summary, there is a large potential market volume for RFNBOs in the long term, which corresponds to large investment requirements, in particular with respect to the building up of electrolyser capacities. Substantial investments are required as early as in the lead up to 2030 in order to foster the necessary scale up of investments afterwards. If RCFs are meant to play a major role as a bridging fuel, there are similar investment requirements into RCF plants until 2030 as well. However, these bear the risk of becoming stranded investments to a certain extent due to the non-renewability of waste carbon streams. The market potential for imported RFNBOs is also substantial and will become even larger than that for domestic production in case the demand for RFNBOs becomes widespread across different sectors and applications.

4.4 Greenhouse gas emissions

RFNBOs and RCFs are both accounted for in the RED II with the aim to achieve a higher share of renewables, particularly in the transport sector, and reduce GHG emissions. Their use is seen as one component to decarbonise the energy system, as described in detail above (Section 1.1). This section assesses how far the use of RFNBOs and RCFs actually leads to GHG emission reductions. This is of particular importance in the transitional phase in which the power system is not fully decarbonised and related emissions need to be considered. In addition to energy demand during production, GHG emissions from the use of RFNBOs and RCFs in principle come from the delivery of educts to the site of production, the transportation to their place of use and their combustion.

These different sources of GHG emissions need to be considered in relation to the fossil comparators of the respective fuels. The fossil comparators are also associated with emissions during their production, transportation and use. For most of what follows, the transport emissions are therefore disregarded as processes and average emissions of both fossil and renewable fuels are similar at each moment in time. What remains are the emissions during production and use. We do not assess secondary emissions from providing the materials necessary to build and run the production facilities, though these are non-negligible (Ricardo Energy & Environment 2020).

GHG emissions from fossil fuels during production are those generated during the extraction and refining (energy and non-energy related emissions in both cases). For RFNBOs and RCFs, the energy and feedstock supply need to be considered to account for total CO_2 emissions. In case of RFNBOs, the energy stems from renewable sources per definition. The feedstock, i.e. material source stream, differs greatly between RFNBOs and RCFs. The carbon supply for RFNBOs comes either from exhaust gas CO_2 or from direct air capture.

RFNBOs can be considered carbon-neutral products (except if the sourced electricity is not fully renewable, see below). This is obvious in case of CO_2 from direct air capture. In case of a pure CO_2 waste stream used to produce RFNBOs, the emissions are accounted for with the original source of the CO_2, alleviating the emission burden from CO_2 for accounting for RFNBOs. In case of RCFs, the feedstock is supplied by waste streams containing carbon in general. This waste stream may be of gaseous nature but could also be liquid or solid in state. In every case, the carbon is seen as an additional burden to the atmospheric budget. RCFs are therefore not seen as carbon-neutral. The emissions associated with the energy supply for RCF synthesis also need to be considered.

RFNBOs are electricity-based fuels and the RED II envisages three cases for accounting for the electricity that is used in their production. The RED II specifies in Art. 25.2 that "*the greenhouse gas emissions savings from the use of renewable liquid and gaseous transport fuels of non-biological origin shall be at least 70% from 1 January 2021*". This 70% threshold can therefore be considered a lower limit of GHG emission savings by RFNBOs. In two cases of production (direct connection and renewable grid electricity, respectively referred to as case 2 and 3 in the accompanying Task 2 report of this project), the production of RFNBOs sources only renewable electricity and regulations are set to ensure that the electricity generation capacity required for this production is additional. Therefore, RFNBOs produced under these cases is fully renewable and no GHG emissions are associated with their production, i.e. 100% savings are achieved compared to their fossil comparators. This statement is without prejudice to a delegated act on the GHG emissions associated with RFNBOs and RCFs, which is currently under development

In the default case of using average grid electricity (referred to as case 1 in the accompanying Task 2 report of this project), the situation is different. The share of renewable electricity in the grid (two years prior to production, see RED II Art. 27.3 for the definition) determines the share of the product which counts as RFNBO. The grid emission factor is essential to determine whether the GHG savings requirement is met, in addition to the efficiency of the production site. The Task 2 report shows the grid emission factor of selected Member States. Only France and Sweden, with large shares of nuclear power (and renewables in case of Sweden), come within reach of the production under case 1, with Austria following closely. Norway and Iceland also undercut the indicative threshold in grid emissions, being close to 100% renewable electricity share. This shows that RFNBOs will likely not be produced by making use of this default case in the EU. If so, depending on the country of origin, the savings will range between 70% and 100%, the latter also being the value for production in case of renewable electricity only. As long as the European electricity supply is not fully decarbonised, the use of case 1 in RFNBO production will lead to an increase in emissions, as the renewable electricity used in their production needs to be replaced by conventional energy sources. How this is taken into account will be clarified in the respective delegated act.

For RCFs, such fixed thresholds or definitions do not exist in the RED II. The delegated act which specifies the greenhouse gas accounting methodologies and thresholds for RCFs is currently being developed and the statements made here are therefore preliminary. All emissions along the process chain and use need to be considered to assess the GHG emission savings. As for RFNBOs, the emissions depend on the electricity supply contracted by the production facility and the efficiency during the production process. In addition, the material input to the RCF (i.e. the carbon containing waste stream) is diverted from other uses, likely incineration or landfilling. An incineration could also make use of the energy content without reprocessing to RCF. Diverting a waste stream from landfilling to RCF has - depending on the nature of the carbon stream - other benefits than a reduction of GHG emissions, making the emission savings one among several indicators to consider in assessing the value of RCF production. From the perspective of a full life-cycle assessment (LCA), the GHG emissions related to the specific materials for an RCF production facility are also considered. The calculation of GHG emission avoidance through the use of RCFs therefore needs to consider many aspects. As specified above, a separate delegated act is currently being developed on this subject.

Several studies give a detailed LCA of RFNBOs and RCFs. Ricardo Energy & Environment (2020) give values for different production chains, assuming renewable electricity for production, but average grid electricity for transportation and distribution. The authors consider only gaseous CO_2, diverted from emission to the atmosphere. The LCA of GHG emission values reported therefore correspond to RFNBOs in the nomenclature here. The authors report values between approximately 20 gCO_2/MJ for H_2 and 70 gCO_2/MJ for synthetic gasoline, including transport of the final product. ifeu analyses a greater number of production pathways, products and locations, all of which would be considered RFNBOs in this nomenclature. For a full LCA of GHG emissions, the authors report between 7 gCO_2/MJ[34] and 13 gCO_2/MJ[35] for synthetic natural gas and 12 gCO_2/MJ[36] to 18 gCO2/MJ[37] for methanol. For fossil reference emissions, the authors specify 63 gCO_2/MJ for natural gas and 95 gCO_2/MJ for methanol. The synthetic counterparts therefore correspond to a substantial reduction, reaching close to 90%.

RCFs from solid plastic waste are treated in an overview by Malins (2020), who points out that the GHG avoidance alone may present limited benefits, particularly when compared to landfilling or incineration with energy recovery, the latter depending on its efficiency. Recycling of plastic waste needs to be considered as another alternative use. RCFs can only compete with alternative downcycling routes. As pointed out by Bellona 2020, care should be taken that the feedstock to RCFs is made up of waste streams only and not diverted from recycling. Benavides et al. (2017) perform an LCA of fuels from non-recycled plastics by pyrolysis, resulting in ultra-low sulphur diesel fuel. The authors consider average US electricity grid emissions in accounting for related emissions. They calculate a reduction between 1% and 14% relative to a fossil comparator of 91 gCO_2/MJ, corresponding to emissions of 90.1 gCO_2/MJ and 78.3 gCO_2/MJ. Apart from the efficiency of the production site, the exact value is determined by the use of by-products[38] The main reduction stems from the feedstock preparation, where GHG emissions occur only from the separation of the waste in case of the RCF. The conversion to fuels is also less GHG emission-intensive than fossil fuels, the exact value depending on the accounting and use of the by-products. The largest share of emissions, however, come from the use of the fuel, which naturally leads to equal emissions in both cases. This assessment is in line with the fact that technology providers for the conversion of plastic waste streams to fuel do not argue with GHG emission savings as the main benefit they offer, but instead see avoiding plastic waste landfilling or disposal in oceans as the main advantage.[39]

With regards to the scenarios, we assume a medium production of approximately 37TWh RCFs in 2030 (cf. Figure 44). Adopting the minimum emissions of 78.3 gCO_2/MJ of

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[34] production in Germany, sourcing onshore wind, lignite power CO2 and transport in pipelines

[35] production in Germany, sourcing open area PV, cement production CO2 and transport in pipelines

[36] production in Germany, sourcing open area PV electricity from Saudi Arabia (linked via HVDC), cement production CO2 and transport in trucks

[37] production in Germany, sourcing open area PV electricity from Germany, cement production CO2 and transport in trucks

[38] Main products being diesel (62wt%) and naphtha (13wt%), with by-products being fuel gas (16wt%), which can be used to generate electricity and heat) and char (9wt%), which can be landfilled or used as energy product.

[39] e.g. https://biofabrik.com/white-refinery/wastx-plastic/ or https://www3.wipo.int/wipogreen/en/news/2020/news_0018.html, both accessed on 23 March 2021

Benavides et al. (2017), this scenario would correspond to minimum GHG emissions of 10.4 Mt CO_2. This is the minimum value of emissions, compared to 12.5 Mt CO_2 if we adopt the fossil fuel comparator given in the RED II (94 gCO_2/MJ as set out for biofuels in Annex V C.19, only an indicative reference). For RFNBOs, we apply the minimum threshold of 70% GHG emission savings and the fossil fuel comparator given in the RED II (94 gCO_2/MJ) to estimate emissions for the medium scenario (21TWh H2, 12TWh CH_4, 10TWh PtL; cf. Figure 38). We assume approximate overall efficiencies in production for hydrogen, methane and PtL of 65%, 50% and 40%, respectively (cf. Table 2). Emissions then amount to a maximum of 8.3 Mt CO_2 from RFNBO production and use in the scenario. This is the maximum value of emissions, which can potentially drop to zero if the electricity supply is fully decarbonised.

4.5 Local environmental impacts

Local environmental impacts and land use change risks from RFNBOs are generally assumed to be much smaller than from conventional crop-based biofuels. However, several impacts are still possible and need to be understood. The sustainable land use aspect must be examined to determine whether land occupied with the production of RFNBOs is taking away space needed for agriculture and forestry and whether the land could be used more efficiently for other purposes. Another important aspect to consider is the sustainable use of water. Hydrogen production through electrolysis and certain DAC technologies consume large amounts of water, which could exacerbate water scarcity problems in countries with hot and dry climates. There is little information available on RCFs, thus the following sections will focus on RFNBOs.

4.5.1 Sustainable land use

Renewable power generation, electrolysis, fuel synthesis and CO_2 capture all need space and are competing over land that could be used otherwise, e.g. for food production and forestry. Every local and regional situation must be analysed individually to decide how the space required to produce synthetic fuels has been used to date and which uses may potentially be displaced. Unlike the production of biofuels, the use of necessary agricultural land or productive forests to produce synthetic fuels is not needed. For example, arid areas in southern Europe can be used just as effectively (Agora 2018). For RFNBOs, the future scalability could perhaps represent the most appealing aspect. Renewable energy can in theory be generated much more efficiently in terms of land requirements and water use by wind and solar power plants than is possible for biofuel production. The enormous amounts of fuel consumed by modern society could therefore be produced with fewer sustainability concerns (Malins 2020). In the medium supply scenario, the renewable electricity needed for the EU production of RFNBOs amounts to about 1,400 TWh for all demand scenarios (MUST, CAN, COULD). Assuming 75% is produced from wind (predominately onshore due to lower costs) and 25% from solar, 1,400 TWh would translate to roughly 97,000 km² of land use,[40] about the size of Hungary. Raising the share of offshore wind would decrease the land use due to higher full load hours but result in increasing renewable electricity costs. The land use outside of Europe can be twice as high in scenarios with high demands and thus high import shares. Transport & Environment estimated that if 50% of the expected energy demand for aviation in 2050 were supplied through RFNBOs the area occupied by renewable electricity generation through solar PV installations would amount to 8 million ha (80,000 km²). While supplying the same amount through crop biofuels would require roughly 4 times that amount at 33 million ha (330,000 km²) of farmland. This example underlines that

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[40] Solar yield: 170MW/km², wind yield: 5MW/km². Full load hours solar: 1100h, full load hours wind: 2200h

compared to crop biofuels, electricity generation for synthetic fuels is much more land efficient (Calvo Ambel 2017).

A study conducted by the Institute for Sustainable Process Technology (ISPT) in the Netherlands, in which they closely examined a 1 GW alkaline and PEM plant came to find that the maximum land use for a PEM and an alkaline electrolyser plant were 13 ha and 17 ha respectively (Institute for Sustainable Process Technology 2020). Through compact design a potential decrease of the land requirements down to 8 ha and 10 ha is believed to be possible. The majority of the area is occupied by the electrolyser building and the electrical equipment (e.g. switchgears and transformers), while the hydrogen processing section takes up the least space (The International Renewable Energy Agency 2020).

The spatial footprint for direct air capture (DAC) is significant and varies depending on technology and project design ranging from 0.5 to 25 km^2 per million tons of CO_2 captured annually. The land requirements can be minimised drastically by aligning the units vertically or by dividing the system into smaller units spread out over different regions to avoid overlapping CO_2 shadows. A capture plant with 18 units located in 3 rows on top of each other built by Climeworks has a footprint of only 0.4 km^2 per million tons of CO_2 annually (Fasihi et al. 2019). Assuming a vertically aligned DAC system with a footprint of 1 km^2 per million ton of CO_2 annually, around 70 km^2 of land would be required to supply the 70 million tons of CO_2 for the EU production of RFNBOs in the medium supply scenario for all demand scenarios (MUST, CAN, COULD). If the DAC system is not designed in a space efficient way, that number could increase to over 1,400 km^2 (assuming 20 km^2/Mt CO_2a). Depending on the demand scenario, the land required for CO_2 supply in countries outside the EU can be up to 120 km^2.

4.5.2 Sustainable use of water

Hydrogen generation through electrolysis is the first step in almost all PtX technologies, and water electrolysis requires water as a main input. Therefore, the water supply is crucial. From a purely stoichiometric approach, in order to produce 1 kg of hydrogen 9 kg of water are needed. However, after taking process inefficiencies and the process of water demineralisation into consideration, the typical water consumption amounts to between 18 - 24 kg of water per kilogram of hydrogen. If only fresh water is considered as an input a 1 GW electrolyser, operating with an efficiency of 75% for 8,000 hours per year would generate 0.15 million tonnes of hydrogen and consume 3 million tonnes of water (assuming 20 kg of water use per kilogram of hydrogen) which is comparable to the current freshwater consumption for thermal power plants. The medium supply scenario expects an EU hydrogen production of around 590 TWh in 2050 for all demand scenarios (MUST, CAN, COULD), which equates to 15 million tonnes.[41] Now applying the previously mentioned 20 kg of water per kg of hydrogen, total water consumption would be around 300 million tonnes or 300 cubic hectometres. By comparison, the EU agriculture sector uses around 98,000 cubic hectometres of water (European Environment Agency 2018). Depending on the demand scenario, the water required for imported RFNBOs in countries outside the EU can be up to 500 million m^3. Against the backdrop of rising temperatures and changing precipitation, existing and expected regional water supplies must be analysed carefully to ensure that local water supplies are not depleted for water electrolysis. In hot and dry areas like southern Spain local water supplies should not be considered as sources for electrolysis. If feasible, seawater desalination plants can be used with limited cost and efficiency impacts,

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[41] Based on higher heating value of hydrogen of 39.41 kWh/kg.

and multipurpose desalination facilities can potentially be implemented to provide local benefits (The International Renewable Energy Agency 2020).

The production of hydrogen is not the only process that relies on a supply of water. Some DAC units also require water as a key input. They can lose up to 50 tonnes of water per ton CO_2 captured, determined by the humidity of the ambient air, the concentration of the solution and the temperature. This water demand limits the locational flexibility of DAC plants, especially in dry and remote desert regions (Fasihi et al. 2019).

4.5.3 Air quality

The production of RFNBOs has no major negative impact on local air quality. On the contrary, most pathways of hydrogen production yield major benefits in terms of air quality, if renewable electricity is used as feedstock. A common concern regarding DAC is local CO_2 depletion, which may affect vegetation and the environment, but also the system efficiency. Thus, it is important to assess the recovery time and the minimum distance between DAC units to avoid such issues.

5 BARRIERS FACING RFNBOS AND RCFS AND OPTIONS TO OVERCOME THEM

Multiple barriers determine the overall potential of RFNBOs / RCFs and may slow down their deployment. Based on literature, conclusions from the economic and technological assessment of RFNBOs and RCFs in the prior sections of this report and expert knowledge, we have identified key barriers (Uslu et al. 2018). In this chapter, we analyse these barriers systematically and discuss measures to overcome them.

5.1 Barriers facing RFNBOs and RCFs

The barriers facing RFNBOs and RCFs can be assessed systemically along five distinct categories.

- **Economic barriers**: based on the analysis in Section 4.3 it is evident that economics present a central barrier for RFNBOs / RCFs. Today and in the mid to long term, no type of RFNBO / RCF is competitive to its fossil or biogenic competitors.
- **Structural barriers**: there are critical limitations regarding the availability of infrastructure, energy and feedstocks that can delay the ramp-up of RFNBOs / RCFs.
- **Regulatory barriers**: the lack of a comprehensive regulatory framework for RFNBOs / RCFs providing long-term certainty inhibits investments in the production and use of these fuels.
- **Technical barriers**: promising technologies for RFNBOs and RCFs are not yet available on an industrial scale.
- **Societal barriers**: uncertainty surrounding novel technologies and their impact can lead to opposition from civil society.

Table 18 provides an overview of barriers identified facing RFNBOs / RCFs. While some of the barriers apply to both, differences in their production processes and energy and feedstock needs lead to barriers specific to the fuel type.

Table 18: Barriers facing RFNBOs and RCFs

Category	Barrier	RFNBOs	RCFs
Economic (see Section 4.3)	Investment	High capital investment for hydrogen electrolysis, carbon capture, and fuel synthesis.	Uncertainty regarding the future availability of feedstocks for RCF production (e.g., furnace gases, landfill gases, solid waste streams) may hinder long-term investments.
	Operation	High costs for feedstock electricity (hydrogen production) and carbon (fuel synthesis).	Varies strongly depending on local costs for feedstocks.
	Other	Limited availability of financing options due to high risks associated with investments.	

Category	Barrier	RFNBOs	RCFs
Structural	Infra-structure	Limited availability of hydrogen and CO_2 transport infrastructure (e.g., pipelines).	Differences in local / regional infrastructure, e.g. for waste treatment requires individual site-specific evaluation of RCF production facilities.
	Energy and feedstock	Limited availability of renewable electricity, green hydrogen, and concentrated CO_2 sources. Feedstock competition with other sectors (CO_2 and renewable electricity / green hydrogen).	Feedstock availability and competition with alternative uses (thermal use in CHP facilities), chemical recycling etc.
Regulation		Pending definition for renewability, temporal correlation, geographical correlation and additionality criteria for power (addressed in Task 2). Lack of certification and harmonisation throughout the EU concerning applied blends and fuel standards. Unclear accounting rules for unavoidable process emissions (e.g., from cement production). Strict environmental and spatial restrictions for additional renewable electricity.	
Technical (see Section 2)		Technologies with highest efficiencies are not yet available on an industrial scale (TRL below 8): • high temperature solid oxide co-electrolysis for syngas production • Adsorption technology for direct air capture (DAC) Reverse water gas shift reaction in large-scale production remains difficult to control. Flexible storage systems (electricity, hydrogen) will be necessary to guarantee a continuous operation of the chemical synthesis).	Inhomogeneity of feedstock poses severe challenges for maintaining constant quality of pyrolysis oil / syngas that is of sufficient quality for transport fuels (in most cases direct use in CHP).
Societal		Public awareness of CO_2 as feedstock is poor and may suffer from its negative role as being a GHG. The use of CO_2 as a feedstock (CCU) may suffer from concerns related to CCS. Acceptance of large-scale construction (e.g. wind or solar farms, electrolysers). Lack of customer awareness and market acceptance.	

Economic barriers

As there are few benefits for the end users (e.g. airline operators, vehicle fleet operators or individual car owners) resulting from the use of RFNBOs or RCFs compared to fossil fuels, the main barrier for a market uptake of RFNBOs is the price difference to fossil fuels. Prices are expected to be 2-6 times higher in 2030 (see Table 4 in Section 4.2). Significant upfront investment costs and even more so the very high operational cost for RFNBO production lead to its high price. For RFNBOs, substantial investments in RES-E capacity, hydrogen electrolysis, carbon capture, and fuel synthesis are needed. The main cost drivers are the operational costs for feedstock electricity to produce hydrogen and carbon for the fuel synthesis. For RCFs, economic feasibility strongly depends on local conditions, feedstock availability and alternative processing possibilities and is difficult to generalise. The uncertainty surrounding the availability of feedstocks in the mid to long term may inhibit investments. The costs disadvantage of RFNBOs/RCFs compared to fossil fuels and the associated risks can limit potential financing options for investors, further increasing overall costs. Blending synthetic fuels with fossil fuels or advanced biofuels could be an option to lower costs in the early market phase.

Structural barriers

To realise RFNBO production, an infrastructure is needed to transport hydrogen and carbon, which as of today only exists to a very limited extent. The build-up of such infrastructure is time-consuming and subject to uncertainty regarding regulatory issues and permissions. Related to this is the competition for energy and feedstock with other end use applications and sectors (Uslu et al. 2018). Electrification of transport and heat will require large amounts of renewable power. Renewable electricity is scarce. Thus, additionality criteria are necessary. Feedstock competition is also relevant for RCFs as they can be used, amongst others, in CHP facilities to produce heat and electricity.

Regulatory barriers

The lack of a comprehensive regulatory framework for RFNBOs / RCFs, including standards and certification schemes, is a key barrier for their deployment (Uslu et al. 2018). As laid out in Article 27 of the RED II, the type of power purchase for RFNBO production is subject to four criteria (renewability, temporal correlation, geographical correlation and additionality), the exact definitions of which are still pending. Also, there is no standard concerning RFRNBO/RFC fuels and blends. Experiences in road transport and aviation show that such a dedicated fuel standard accelerates market acceptance and introduction of the fuels (Florentinus et al. 2012). The same holds true for certification schemes. Currently, there are none for RFNBOs and RCFs and the introduction of such a scheme would support their market entrance.

Carbon is a main feedstock needed for the production for RFNBOs. If the captured carbon relates to unavoidable process emissions (e.g. from cement production), the accounting rules are unclear. The question is whether the CO_2 reduction is attributed to the cement plant for capturing the carbon, the RFNBO producer for utilising the carbon or split between the two. The second important feedstock for RFNBO production is renewable electricity. Large amounts of additional capacity are needed but strict environmental and spatial restrictions, varying by country and region, may limit the build-up.

Technical barriers

RFNBO production is a novel technology. Production technologies with the highest efficiency such as high temperature solid oxide co-electrolysis for syngas production or adsorption technology for direct air capture have a technology readiness level of 8 or below which indicates that they are not yet available on an industrial scale (see Section 2.1). Reverse water gas shift reaction, essential for the fuel synthesis, remains difficult to control in large-scale production. To allow for continuous operation of the fuel synthesis flexible storage systems (electricity, hydrogen) will be necessary, in particular in the light of volatile renewable power production and the absence of hydrogen pipeline infrastructure. Continuous operations are important as there is little flexibility in the fuel synthesis.

For RCFs, the inhomogeneity of solid waste feedstock poses severe challenges for maintaining a constant quality of pyrolysis oil / syngas that is of sufficient quality for transport fuels (see Section 2.2). To this end, most products from gasification and pyrolysis are currently used as industrial fuels or for heat and power generation but not for RCF production.

Societal barriers

Societal concerns can seriously impact the introduction of a novel fuel to the market. For example, biofuels (e.g. E10) were criticised by environmental groups for taking up land that could otherwise be used for food production and driving up crop prices. In the context of RFNBOs / RCFs societal concerns relate to the negative public perception of CO_2 being the main GHG responsible for climate change and risk associated with carbon capture technologies (Uslu et al. 2018). Some environmental groups criticise carbon capture as risky (e.g. CO_2 leakage during transport and storage) and expensive, diverting investments from other solutions to mitigate climate change. The required build-up of infrastructure including renewable power capacity, hydrogen electrolysis, transport pipeline, etc. may negatively impact the acceptance of RFNBOs and RCFs. Currently, new transmission lines or wind parks already face fierce local opposition.

5.2 Options to overcome key barriers

The barriers identified above lead to a need for policy support, both for market entrance and market diffusion. A clear commitment to a long-term strategy for RFNBOs / RCFs would send a strong signal to all involved stakeholders. The most important issues to address in the current phase of market development are the high costs and the regulatory uncertainty. Investment support and reduced taxes and levies for electricity can bring down production costs, while a quota can create long-term certainty for investors by creating a market for RFNBOs and RCFs. Equally important is establishing a comprehensive and coherent regulatory framework that addresses the uncertainties surrounding power criteria, standards, certification, and accounting rules for utilised process emissions. Table 19 provides a detailed overview of options based on the barriers identified in Section 5.1.

Table 19: Options to overcome barriers

Category	Recommendations
Economic	• **Investment support** for electrolysers, carbon capture or synthesis. While some instruments already exist today (e.g. EU innovation fund), additional funds on a national or regional level are needed. • **Quotas** for RFNBOs and RCFs can create long-term certainty for investments. While this may be appropriate for the aviation or maritime sector, a quota for road transport may not be the best option due to the availability of cheaper decarbonisation options, e.g. direct electrification through battery electric vehicles. • **Creating demand** for RFNBOs and RCFs e.g. through high carbon prices in the transport sector. One option could be the inclusion of the transport sector in the EU Emission Trading Scheme (ETS), another option a CO_2 tax for transport fuels as already implemented by some Member States (e.g. Germany or Sweden). Including transport in the EU ETS may not be as effective, as the required CO_2 prices to incentive RFNBO / RFC deployment are significantly higher (> 100€/tCO_2) than current prices (30€/tCO_2). • **Reduced taxes and levies** on renewable electricity or **subsidised hydrogen production** (e.g. through feed-in premium for hydrogen producers **or a contract for difference** that cover the cost gap between the production cost of H_2 and its fossil counterpart) can bring down operational costs.
Structural	• Further incentivise the **build-up of renewable generation** capacity (e.g. through auctioning schemes) and set ambitious renewables targets. • Facilitate the build-up of a **hydrogen and CO_2 transport infrastructure**. While in the short term, the hydrogen infrastructure will be rather localised, the EU should aim for a common European hydrogen backbone in their mid- to long-term TEN-E (Tran-European Networks for Energy) planning.
Technical	• **Research and development support** to quickly commercialise high temperature solid oxide co-electrolysis for syngas production and adsorption technology for direct air capture (DAC). Another area for additional R&D are hydrogen, carbon and electricity storage technologies.

Regulatory	• Creating a **harmonised regulatory framework for RFNBOs / RCFs** with clear
	  ◦ criteria for renewability, temporal correlation, geographical correlation and additionality of power for RFNBO production criteria (addressed in Task 2)
	  ◦ fuel standards,
	  ◦ certification schemes, and
	  ◦ accounting rules.

Societal	• **Raise end-customer awareness** of the benefits of RFNBOs and RCFs (e.g. lower carbon footprint compared to conventional fuels) to facilitate acceptance. Awareness raising should include the benefits and risks of carbon capture utilisation and storage (CCUS). • Develop an **information platform** that provides data on technical standards and funding guidelines in the EU for project developers. • Create programmes that allow **communities to profit** from additional local infrastructure (e.g. wind farms, pipelines).

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7 APPENDIX

7.1 Further technical details

The following chapter will give a deeper view of the technologies themselves.

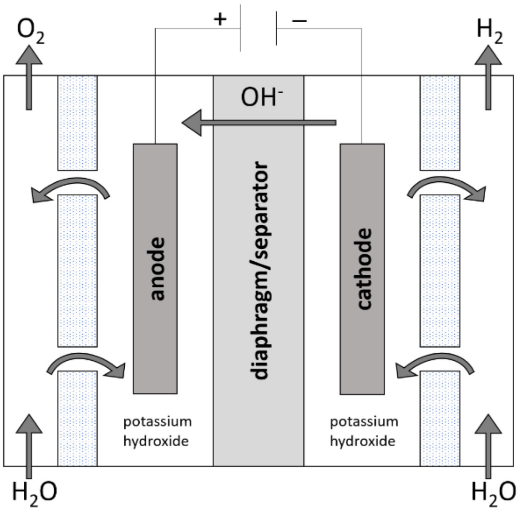
7.1.1 Electrolysis

7.1.1.1 Alkaline electrolysis

AEL belongs to the low-temperature electrolysis technologies. As an electrolyte, the system usually needs an aqueous solution of potassium hydroxide (KOH) or sodium hydroxide. The KOH is needed to ensure electric conductivity and build up high enough concentrations of OH- ions. It circulates around the electrodes, consisting of an anode and a cathode – each located in one of the two half-cells. The half-cells are separated by an ion-permeable ceramic diaphragm. The diaphragm is usually also called a separator. Figure 50 summarises the structure of an AEL cell. At the cathode, the splitting of water takes place (Pitschak et al. 2017; Zapf 2017), while oxygen generation occurs at the anode:

$$2\,H_2O + 2\,e^- \rightarrow H_2 + 2\,OH^- \qquad \text{(Cathode reaction)}$$

$$2\,OH^- \rightarrow \frac{1}{2}\,O_2 + H_2O + 2\,e^- \qquad \text{(Anode reaction)}$$



Source: Own illustration according to Pitschak et al. (2017)

Figure 50: Structure of an alkaline electrolysis cell

This cathode reaction includes the generation of hydrogen, which then leaves the cell. The co-generated hydroxide ions diffuse through the diaphragm to the anode. There, these hydroxide ions convert to oxygen and water by taking up electrons, as described in the anode reaction equation above.

The operating temperature of an AEL usually is 60-80 °C. The system pressure can vary between atmospheric pressure and pressure levels up to 30 bar (Pitschak et al. 2017; Zapf 2017). For the production of one kilogram of hydrogen, which is equivalent to almost 40 kWh (higher heating value/gross calorific value) regarding the energy content, between 48.7 kWh and 55 kWh electricity is needed (Smolinka et al. 2018). Other sources even indicate a range of 46.7 to 64.6 kWh (Dickschas, Smolinka 2019).[42] More characteristics of AEL-systems are summarised in Table 20.

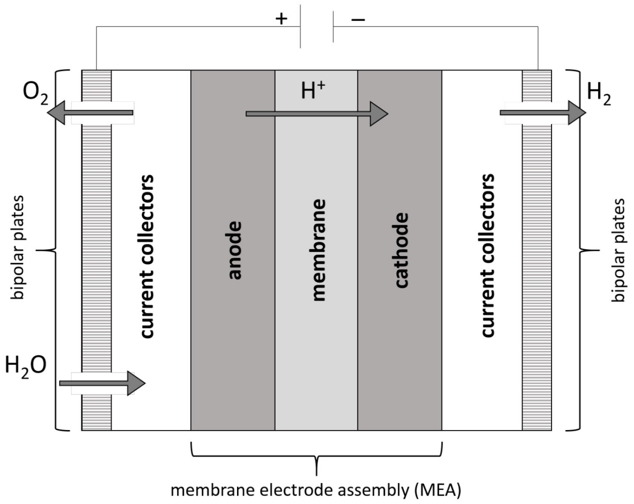
7.1.1.2 *Polymer electrolyte membrane electrolysis*

The basic structure a PEMEL relies on is a cell consisting of one anode side and one cathode side, separated by a proton-permeable solid membrane, together also called membrane electrode assembly (MEA). Unlike with AEL, the membrane not only serves as the separator but also as the electrolyte. The electrodes are usually made of carbon-bearing precious metals. The cell is framed by bipolar plates. Those bipolar plates have small canals to transfer targeted amounts of water and gases. The plates are connected to so-called current collectors that can also transfer gases and electricity (Pitschak et al. 2017; Zapf 2017). The functioning of a PEMEL cell is summarised in Figure 51.

Unlike with AEL, the inserted water is not decomposed into hydroxide ions but into oxygen and protons/atomic hydrogen. The hydrogen passes the membrane from the anode to the cathode to form molecular hydrogen by the absorption of electrons. This process can be described using the following reaction equations (Zapf 2017; Pitschak et al. 2017; Tremel 2018):

$$2H^+ + 2\,e^- \rightarrow H_2 \qquad \text{(Cathode reaction)}$$

$$H_2O \rightarrow 2H^+ + \frac{1}{2}\,O_2 + 2\,e^- \qquad \text{(Anode reaction)}$$



Source: Own illustration according to Pitschak et al. (2017)

Figure 51: Structure of a polymer electrolyte membrane electrolysis cell

The operating temperature of a PEMEL usually is 50-80 °C. The system pressure can vary between pressure levels of 30 bar used in commercial plants and pressures of up to 350 bar achieved in prototypes (Pitschak et al. 2017; Brinner et al. 2018). To produce one kilogram of hydrogen, which is equivalent to almost 40 kWh (higher heating value/gross calorific value), at least 52.9 kWh electricity is needed. This amount of electricity can also rise to a level of about 55.1 kWh (Smolinka et al. 2018). Other sources refer to a wider range for the

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[42] Own calculation based on the hydrogen density of 0.0899 kg/Nm^3.

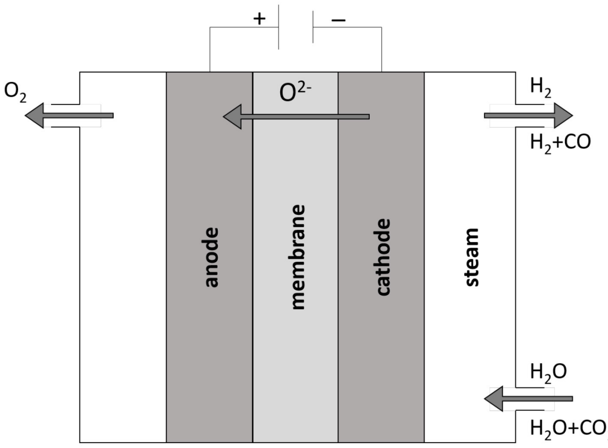
required electricity between 50.1 and 75.7 kWh (Dickschas, Smolinka 2019).[43] More characteristics of PEMEL-systems are summarised in Table 20.

7.1.1.3 Solid oxide electrolysis

The solid oxide electrolysis is an example of high-temperature electrolysis technologies (HT-electrolysis). Analogous to the previously described PEMEL cell, the HT-electrolysis cell also consists of a solid electrolyte that separates the two half-cells into the anode and the cathode (ceramic). The electrolyte usually consists of yttrium-stabilised zirconium oxide. This separator does not allow gas throughput but the passing of oxygen ions. As illustrated in Figure 52, the (gaseous) water is fed into the cell on the side of the cathode. This steam is then split into hydrogen and oxygen ions. The oxygen ions pass the electrolyte and give off electrons to form molecular oxygen on the anode-side. On the cathode-side, the molecular hydrogen leaves the electrolysis cell. This process is described by the following reaction equations (Tremel 2018; Pitschak et al. 2017; Zapf 2017; Brinner et al. 2018):

$$H_2O + 2\,e^- \rightarrow H_2 + O^{2-} \qquad \text{(Cathode reaction)}$$

$$O^{2-} \rightarrow \frac{1}{2}\,O_2 + 2\,e^- \qquad \text{(Anode reaction)}$$



Source: Own illustration based on Pitschak et al. (2017), extended by co-electrolysis process.

Figure 52: Structure of a solid oxide electrolysis cell/co-electrolysis

The operating temperature of a SOEL is usually much higher than that of AEL or PEMEL. HT-electrolysis can operate between temperatures of 700 and 1,000 °C. The state-of-the-art system operates at atmospheric pressure (Brinner et al. 2018; Wietschel et al. 2015). The high temperature level allows the system to be fed by steam instead of liquid water, which leads to a reduction of the electric energy demand. This aspect enables the usage of waste heat for steam generation, which can lead to a significant improvement of the overall energy efficiency in PtX systems. For the production of one kilogram of hydrogen, equivalent to almost 40 kWh (higher heating value/gross calorific value), between 41.2 and 43.4 kWh of electricity is needed (Smolinka et al. 2018). Other sources indicate a range of 40.1 to 44.5 kWh (Dickschas, Smolinka 2019).[44] For more characteristics of SOEL-systems, see Table 20.

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[43] Own calculation based on the hydrogen density of 0.0899 kg/Nm^3.

[44] Own calculation based on the hydrogen density of 0.0899 kg/Nm^3.

7.1.1.4 Comparison

The following table gives an overview over the three different electrolysis technologies and a direct comparison.

Table 20: Characteristics of the different electrolysis systems AEL, PEMEL and SOEL

Category	Unit	AEL	PEMEL	SOEL	Source
electrolyte		potassium hydroxide/sodium hydroxide	polymeric membrane (e.g. Nafion^{TM})	yttria-stabilised zirconia	Schmidt et al. 2017; Tremel 2018
charge carrier		OH$^-$	H$^+$	O_2^-	Guandalini et al. 2016
cathode		Ni, Ni-Mo alloys	Pt, Pt-Pd	Ni/YSZ	Schmidt et al. 2017
anode		Ni, Ni-Co alloys	RuO$_2$, IrO$_2$	LSM/YSZ	Schmidt et al. 2017
current density	A/cm^2	0.2-0.6	1-2.5	~1	Dickschas, Smolinka 2019
cell voltage	V	1.8-2.4	1.8-2.2	0.7-1.5	Schmidt et al. 2017
cell area	m^2	<4	<0.3	<0.01	Schmidt et al. 2017
operating temp.	°C	60-80	50-80	650-1000	Schmidt et al. 2017
pressure	bar	1-30	1-50 (350)	1	Dickschas, Smolinka 2019
production rate H$_2$ per stack	Nm^3/h	800 (up to 1,000)	250	5.7 (up to 10)	Brinner et al. 2018 (Dickschas, Smolinka 2019)
size of module	kW$_{el}$	500-5,000	100-1,500	10-50	Dickschas, Smolinka 2019; Brinner et al. 2018
stack efficiency[45]	%$_{HHV}$	61-84 (60-84)	52-79 (64-84)	89-98 (110)	Dickschas, Smolinka 2019 (Schmidt et al. 2017); own calculations
system efficiency[46]	%$_{HHV}$	71.7-76.4 (54-79)	72.4-73.4 (54-84)	95.7[47] (<75)	Smolinka et al. 2018 (Schmidt et al. 2017); own calculations
lower dynamic range	%	17 (10-40)	5 (0-10)	20 (>30)	Smolinka et al. 2018 (Schmidt et al. 2017)
system response		seconds	milliseconds	seconds	Schmidt et al. 2017
start time warm/cold	min.	5-6/50	2/20	10/600	Smolinka et al. 2018
stack lifetime	h	60,000-90,000	20,000-60,000	3,500-10,000 (up to 20,000)	Schmidt et al. 2017; Brinner et al. 2018; Smolinka et al. 2018

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[45] Data provided in terms of kWh$_{el}$ per Nm^3 of hydrogen. Own calculation of efficiency based on higher heating value of hydrogen of 3.54 kWh/ Nm^3.

[46] Data provided in terms of kWh$_{el}$,kWh$_{total}$ per Nm^3 of hydrogen and kWh$_{el}$ per kg of hydrogen. Own calculation of efficiency based on higher heating value of hydrogen of 3.54 kWh/ Nm^3 and 39.41 kWh/kg respectively.

[47] Efficiency without energy for steam production.

7.1.2 CO_2 separation

7.1.2.1 Absorption and adsorption

Absorption into liquid materials: solvents

The absorption process is possible with chemical and physical solvents. Which solvent is more suitable depends on the condition of the flue gas. Chemical solvents use chemical reactions to bind the component to the absorbent and are used if the flue gas has about atmospheric conditions. Physical solvents use physical forces for absorption and are preferred if the flue gas either has a high temperature or pressure.

Chemical absorption is the state-of-the-art process used at post combustion facilities, because the low pressure of the flue gas lends itself toward the chemical absorption, rather than to the physical one (Jansen et al. 2015). Especially aqueous alkanolamines, e.g. monoethanolamine (MEA), are well researched and closest to a commercial usage. To increase the interaction ratio between absorbent and CO_2, secondary or tertiary alkanolamines can be used or be mixed with MEA (Sumida et al. 2012).

The regeneration process of the absorbent is the main driver of the energy penalty of this process. For MEA, the thermal energy demand is around 3.8 – 4.0 GJ/tonne CO_2 (Wang et al. 2017). This energy demand has a significant impact on the energy penalty, as processes with chemical absorption have efficiency losses of around 4-14 %. Next to the thermal energy demand, the mechanical energy demand plays a significant role in the regeneration process. Especially high pressure can support the regeneration process but needs an additional energy supply (Goto et al. 2013).

The reduction of the energy demand for the regeneration process is the biggest challenge regarding the absorption process. Studies with different solvents have shown that the thermal energy demand can be reduced to 2.2 – 3.12 GJ/tonne CO_2 depending on the chemical solvent (Goto et al. 2013). Next to the thermal energy demand, other attributes also play a significant part in the application. Another challenge for alkanolamines is the stability of the solution, which is reduced with high temperatures, thereby limiting the regeneration temperature possible. In addition, they have a corrosive property, which results in a limited concentration in the solvent to prevent damaging the vessels. Current research focuses on the development of other solvents. Ionic liquids have a low volatility, tunable solvation capacity and high thermal stability (Riva et al. 2017). Ammonia-based solvents are cheaper than amine-based solvents, have a higher tolerance towards impurities, and consume around half the energy needed for regeneration (Zhuang et al. 2011). Still, the majority of these alternatives are still at the lab or pilot plant stage.

The gasification of solid energy carriers in the pre combustion approach increases the pressure significantly. Use of the tertiary alkanolamine MDEAs is the current state-of-the-art as the low thermal energy demand supports their application but need a higher circulation rate of the liquid as MDEA have a slower reaction than primary or secondary alkanolamines. Typical solvents are Selexol©, Rectisol© and Purisol© (Jansen et al. 2015).

Adsorption with solid materials: sorbents

An alternative to the absorption process is the adsorption process with solid porous adsorbent materials. This process has the main advantage that the adsorbents in general have a lower heat capacity, which results in a lower thermal energy demand when releasing CO_2 and regenerating the adsorbent (Goto et al. 2013; Sumida et al. 2012).

One possible sorbent are zeolites. The main advantages of these materials are the rapid adsorption and the lower energy penalty of the process. Furthermore, these materials in general are cheaper and have a well-developed structural chemistry. Disadvantages are that they are readily saturated with water vapour and require a high regeneration temperature (Hedin et al. 2013). Future developments of solid porous adsorbent materials include the usage of carbon-based materials. These have the advantage of higher volumetric CO_2 adsorption capacities and that a lower temperature for regeneration is necessary. In addition, these materials can have a hydrophobic nature, which helps prevent the negative impact of water vapour in the flue gas. Furthermore, a combination of these materials with alkanolamines or other materials is possible in order to benefit from the joint advantages of several different materials (Sumida et al. 2012; Hedin et al. 2013).

Another form of solid porous materials are the metal-organic frameworks (MOFs). These materials represent a 1 to 3-dimensional structure consisting of metal nodes and organic bridges, which allow an individual design regarding surface areas and pore surface properties. Additionally, a high potential industrial scalability is possible. MOFs currently have several disadvantages which make a rapid use unlikely. On the one hand, the synthesis of the MOFs is sensitive regarding several parameters, such as concentration, pressure, temperature etc., which results in difficult production processes. On the other hand, MOFs have a lower chemical or thermal stability in general due to weak coordination bonds between metal and ligand components. This results in a degradation when exposed to air or water vapour for some MOFs. Therefore, a careful handling of the material is necessary. Still, MOFs have promising attributes regarding thermal capacity and volumetric capacities. (Sumida et al. 2012; Hedin et al. 2013).

7.1.3 Synthesis gas formation

7.1.3.1 Reverse Water gas shift reaction (rWGS)

The rWGS is carried out to the following reaction equation (Vidal Vázquez et al. 2017):

$$CO_2 + H_2 \rightarrow CO + H_2O \qquad \Delta_R H^0_{298K} = 41{,}5\ kJ/mol$$

Since CO_2 is a relatively stable compound, a high energy input must be realised to achieve the reduction to CO. The endothermal reaction is usually performed at temperatures between 700 °C and 1,000 °C. A complete conversion of CO_2 even at these temperature levels cannot be achieved due to thermodynamic limitations. Catalysts usually investigated in (research-) reactor concepts are mainly based on nickel (Ni), iron (Fe) and furthermore rhodium (Rh), indium (In) and molybdenum. Competitive reactions can disturb the desired product composition or lead to catalyst deactivation by coking. Due to these potentially disturbing competitive reactions, a high temperature level is preferable, since this leads to a higher selectivity towards the rWGS (Unde 2012; Wolf et al. 2016).

7.1.3.2 Dry reforming

Dry reforming can be seen as a modified steam reforming, in which water is substituted with CO_2 to produce a synthesis gas with a low H_2/CO-ratio, according to the following reaction equation.

$$CH_4 + CO_2 \rightarrow 2CO + 2H_2 \qquad \Delta_R H^0 = 247{,}3\ kJ/mol$$

Apart from CO_2, methane (CH_4) is also needed. Analogous to steam reforming, the process takes place at elevated temperatures higher than 800 °C to obtain technical feasible conversion levels. As the dry reforming reaction is endothermal, thermal energy has to be added, usually through the operation of a fired bundle tube reactor (Wittich et al. 2020).

Regarding the production of synthesis gas for the production of RFNBO, dry reforming can only be applied if the methane feedstock is renewable. Since biogenic sources are excluded, synthetic methane, produced by methanation of CO_2 and H_2, could be used. Figure 53 shows the process chain of a system including dry reforming for the production of synthesis gas.

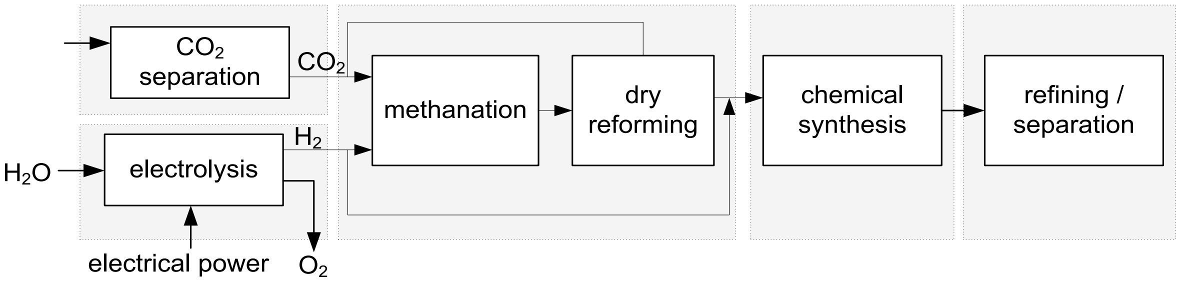

Figure 53: Process chain of RFNBO production using a combination of methanation and dry reforming

7.1.4 Chemical synthesis

7.1.4.1 Methanation

The methanation of synthesis gas can be described by the following reaction equation:

$$CO + 3H_2 \rightarrow CH_4 + H_2O \qquad \Delta_R H^0 = -206{,}17\ kj/mol$$

The methanation of CO_2 follows the so-called Sabatier reaction:

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \qquad \Delta_R H^0 = -166{,}01\ kj/mol$$

Both reactions are exothermal, so that temperature control is a crucial aspect for the operation of methanation reactors to obtain feasible reaction conditions and conversion levels.

According to the principle of LeChatelier, low temperatures and high pressures favour the formation of methane. Due to the limited kinetics of the reactions under the most favourable thermodynamic conditions, catalysts are used, whereby nickel, ruthenium, rhodium, and cobalt are particularly suitable as active materials. Due to the high selectivity and the favourable price, nickel catalysts are usually chosen. However, these are susceptible to interfering components, especially sulphur compounds, so that extensive upstream gas purification is necessary.

The lower limit of the reactor temperature is at about 200 °C, since on the one hand the catalyst activity decreases strongly and on the other hand the formation of volatile, highly toxic nickel-carbonyls begins at lower temperatures. In order to achieve a higher temperature level and a sufficient conversion, the pressure can be increased. For CO_2 conversions of 98 % at a pressure of 1 bar, the temperature must be reduced to below

225 °C. The maximum temperature for the same conversion is 300 °C under 30 bar pressure. Reactor pressures of up to 100 bar are investigated. Temperatures above 500-700 °C can lead to sintering of the catalyst particles. Competing reactions that lead to coking of the catalyst surfaces, such as the Boudouard reaction, should be minimised to achieve a stable operational environment (Zapf 2017; Götz et al. 2016).

There are several basic reactor principles for the implementation of methanation. The technologically most developed concept is the fixed bed reactor, which is usually designed as a tube bundle reactor. Fixed-bed reactors are designed either as several adiabatic stacked reactors connected in series with intercooling or as liquid-cooled (polytropic) tube bundle reactors. For both variants there is a risk of hot-spot formation.

In fluidised bed reactors, the catalyst particles are fluidised by the incoming educt gas. Fluidised bed reactors for methanation are not yet commercially available but are being further developed in pilot and demonstration plants. The largely homogeneous mixing of the reactor chamber results in an easier to realise temperature control. A further advantage is the simple construction. However, the movement of the fluidised bed causes considerable abrasion on the reactor walls and among the catalyst particles, so that they lose catalytic activity over time. The partial and overload range is severely limited by the minimum gas velocity required to maintain the fluidised bed and the maximum gas velocity above which catalyser particles are discharged from the reactor.

Three-phase reactors for methanation are also part of the current research efforts. In so-called bubble column reactors, the educt gas flows through a suspension of a liquid heat transfer medium and catalyst particles. The reactor temperature can be well controlled via the heat transfer medium. Even with strong load changes in flexible operation, almost isothermal energy can be achieved thanks to the heat storage capacity of the suspension, which makes the reactor concept very interesting for power-to-gas applications using volatile power sources. Due to the necessary additional phase transition, the efficient reaction speed can be reduced. Evaporation and decomposition of the heat transfer medium (mostly thermal oils) are also potential problems. The use of three-phase reactors for methanation has not yet been commercially implemented (Rönsch et al. 2016; Götz et al. 2016; Forschungsstelle für Energiewirtschaft 2016).

7.1.4.2 Methanol synthesis

The reaction of CO_2 and CO with hydrogen to form methanol is performed according to the following reaction equations:

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O \qquad \Delta_R H^0 = -49{,}31\ kj/mol$$

$$CO + 2H_2 \rightarrow CH_3OH \qquad \Delta_R H^0 = -90{,}64\ kj/mol$$

Both reactions are exothermic and reduce the gas volume, so that in methanol synthesis low temperatures and high pressures also lead to a high methanol yield in the state of chemical equilibrium. Catalysts are used to achieve a sufficiently rapid conversion of CO and CO_2 under favourable reaction conditions. Commercial methanol synthesis processes based on synthesis gas are carried out at temperatures of 220-290 °C and 50-125 bar. As catalyst, copper-zinc-aluminium mixtures are the conventionally used materials (Hofbauer and Rauch 2017; Ouda et al. 2019; Aresta et al. 2019).

In conventional methanol synthesis processes, a desired CO_2 content of 2-10 % in the synthesis gas helps to improve the yield and leads to a reduced formation of by-products such as higher alcohols and ketones. In the context of power-to-liquid processes, the use of CO_2 and renewable hydrogen for the production of methanol (power-to-methanol) is given more attention. The potentially suitable process concepts are close to those of classical methanol production. However, educt streams rich in CO_2 slow down the reaction kinetics. The formation of water has a negative effect on catalyst activity since the water molecules occupy the active catalyst interface area. Nevertheless, suitable processes for methanol production based on CO_2 and H_2 already exist. Improvements with regard to catalyst materials and process configuration are still being attempted (Bertau et al. 2014; Ouda et al. 2019; Aresta et al. 2019).

7.1.4.3 DME synthesis

DME can be formed by dehydrogenating methanol according to the following reaction equation.

$$2CH_3OH \rightarrow CH_3OCH_3 + H_2O \qquad \Delta_R H^0 = -23{,}93\ kj/mol$$

The production of DME from synthesis gas can be performed in two steps. First, the synthesis of methanol is carried out, followed by the dehydrogenation of methanol to DME in a second reactor. However, it is also possible to produce DME from synthesis gas in a single reactor, where methanol occurs as an intermediate product and is dehydrogenated.

$$3CO + 3H_2 \rightarrow CH_3OCH_3 + CO_2 \qquad \Delta_R H^0 = -94{,}34\ kj/mol$$

In a single-stage DME synthesis using bifunctional catalysts, the chemical equilibrium shifts further to the side of the products. Higher efficiencies and CO conversions per reactor throughput can be achieved (Ju et al. 2009; Trippe et al. 2013).

Since the reaction is exothermic and occurs while the gas volume decreases, low reactor temperatures and high pressures favour high conversions. Typical reaction conditions of a single-stage DME synthesis are temperatures of 250 °C and 35 bar pressure.

7.1.4.4 Methanol-to-gasoline & DME-to-gasoline

In the MtG-process methanol is converted via the intermediate product DME according to the following reaction equation:

$$n\, CH_3OH \rightarrow \frac{n}{2} CH_3OCH_3 + \frac{n}{2} H_2O \rightarrow (CH_2)_n + n\, H_2O$$

The term $(CH_2)_n$ represents hydrocarbons with n carbon atoms. Due to the steric hindrance of the micropores of the catalyst, the size of the hydrocarbons produced is limited to ten carbon atoms. A lower reactor temperature favours a higher gasoline yield, but the octane number also decreases, as well as the production ratio of the largest and undesirable component durene (1,2,4,5-tetramethylbenzene, $C_{10}H_{14}$). MtG processes are usually carried out at temperatures between 300 °C and 450 °C. The pressure level has a major influence on the product composition. At low pressures, more olefins are produced; high pressures lead to more aromatic compounds (Bertau et al. 2014; Arnold et al. 2019).

Since DME is an intermediate product, it can be used as an educt rather than methanol. An advantage of using DME is therefore the lower exothermicity, which reduces the effort required for heat dissipation. In addition, less water is generated in the reactor, so that the catalyst activity is better maintained. In the case of DME use, the term DME-to-gasoline (DtG) process is used. The main products of the MtG and DtG processes are hydrocarbons which can be used as gasoline. Gases that can be assigned to the LPG fraction are produced as a by-product. By changing the process parameters and process set-up, a systematic production of alternative products can be achieved. In this context, important process routes are methanol-to-olefins (MtO) and methanol-to-propylene (MtP), which, with the target products olefins and propylene, can provide important feedstocks for the chemical industry (Arnold et al. 2019; Bertau et al. 2014).

7.1.4.5 Fischer-Tropsch synthesis

In general, the FTS can be described by the following reaction equation (Ail and Dasappa 2016):

$$CO + 2H_2 \rightarrow (-CH_2-) + H_2O \qquad \Delta_R \mathrm{H}_{250\,°\mathrm{C}} = -158{,}5\ kj/mol$$

The CH_2 produced in this process can be seen as a building block for the composition of hydrocarbons of different chain lengths and functional groups. The mechanism that takes place at the active sites of the catalyst surface is highly complex and incompletely understood. Several potential reaction schemes are discussed controversially in the literature. No single one mechanism that by itself can explain the formation of the numerous different products is known, so that a superposition of several mechanisms is assumed (Eilers 2018).

Based on the reaction conditions, Fischer-Tropsch processes are divided into two basic categories. The reaction temperature is the determining criteria. Higher reaction temperatures favour the formation of short-chain molecules and methane. Lower temperatures increase the proportion of waxy, long-chain hydrocarbons. The high-temperature Fischer-Tropsch synthesis (HT-FTS) is operated at temperatures between 300 °C and 350 °C. Only iron catalysts are used in this process, since the (undesired) formation of methane on cobalt catalysts increases significantly at higher temperatures. The HT-FTS leads to a high yield of hydrocarbons with a chain length similar to that of conventional gasoline and short-chain olefins. Low-temperature Fischer-Tropsch synthesis processes (NT-FTS) achieve an increased yield of n-alkanes with higher chain lengths and waxy compounds. The temperature level varies between 200 °C and 250 °C. Both iron and cobalt catalysts can be employed (Ail and Dasappa 2016; Hofbauer and Rauch 2017; Hsu and Robinson 2017).

FTS processes can be implemented using fixed bed, fluidised bed, and bubble column reactors. Fixed bed reactors are usually designed as tube bundle reactors for FTS. As the FTS is a highly exothermic process, proper heat removal is necessary to achieve suitable reaction conditions and to avoid catalyst deactivation due to overheating or coking. An alternative form of fixed bed reactors are micro channel reactors. These are not yet used in commercial applications, but are being intensively researched, as high yields and high selectivity are expected (Eilers 2018; Hofbauer and Rauch 2017). Fluidised bed reactors are suitable due to their relatively homogeneous temperature distribution, but they are only suitable for use in NT-FTS systems (Neuling and Kaltschmitt 2018). In bubble column reactors, the rather homogeneous mixing and the heat storage capacity of the suspension enable a easily adjustable temperature control. High capacities can be achieved. However, the abrasion between the catalyst particles and the reactor walls implies a complex separation of the fine particles and the product stream. The scale-up of bubble column reactors is not trivial due to the complex fluid dynamics (Eilers 2018; Hofbauer and Rauch 2017).

7.1.4.6 OME synthesis

The structural formula of OME compounds can be described by $CH_3O\text{-}(CH_2O)_n\text{-}CH_3$, where n represents the number of incorporated CH_2O monomers. In the term OME_n, n has the same meaning. The shortest OME compound with n=1 (OME_1) is also called dimethoxymethane (DMM) or methylal and is produced in established processes from methanol and the intermediate product formaldehyde (CH_2O).

Since OME_1 has a low boiling point of 42 °C under atmospheric pressure, its use as a fuel is only possible with the use of pressure tanks and an adapted infrastructure. From as low as OME_6 onwards, the melting temperature lies above 38 °C. Therefore, a mixture of OME_3 to OME_5 is often considered a diesel substitute fuel, with physical properties close to those of conventional diesel fuels. Only a modification of the engine control system is necessary to use mixtures (also called "blends") of OME and diesel. This can result in greatly reduced soot particle emissions. The nitrogen oxide emissions remain at the same level or decrease as well, since contrary to the operation with conventional diesel fuels, hardly any trade-off effects between particle and NO_x emissions can be observed. OME fuels have a lower calorific value than conventional diesel fuels, so that when using OME, 1.7 to 1.8 litres are required to achieve the same performance equivalent to one litre of diesel. However, the power density does not suffer as OME fuels require a lower air supply due to the bound oxygen. The engine power is not affected (Beidl et al. 2019; Härtl et al. 2019; Hackbarth et al. 2018).

7.1.5 Upgrading and refinement of fuels

7.1.5.1 Hydrocracking

Hydrocracking applications in petroleum refining operate typically at 100 to 200 bar and 250 to 350 °C. The typical feedstock VGO used in fossil-based refineries contains high levels of aromatic and heteroatomic contents. In contrast, long-chain FTS products consist almost exclusively of n-alkanes. This results in modified required reaction conditions of 35 to 70 bar and 330 to 450 °C. The exothermic decomposition of the long-chain hydrocarbons takes place under supply of hydrogen, so that both unsaturated compounds and the resulting decomposition products are getting saturated. Parallel to the saturation and the splitting of the various components, isomerisation processes occur, which are mainly favoured by lower temperatures compared to the splitting processes. Depending on the choice of process settings and the catalyst employed, the product distribution can be specifically influenced and thus the proportions of gasoline and diesel components can be optimized (Bricker et al. 2015; Rauch et al. 2018).

Hydrocracking is classified as belonging into the superordinate category of hydroprocessing technologies. The specific removal of heteroatoms such as oxygen and sulphur out of hydrocarbons in a catalytic process with the addition of hydrogen is called hydrotreating. This process does not separate carbon-carbon bonds due to more moderate reaction conditions. Since there are usually hardly any impurities in FTS products, this step is not necessary as a separate step (Lee 2010).

7.1.5.2 Fluid catalytic cracking (FCC)

In an FCC unit, a significant and inevitable coking of the catalyst particles occurs. The catalyst particles are therefore fluidised in a special fluidised bed process. The particles circulate between a regenerator, in which the generated coke is burnt off the catalyst surface, and the actual cracking reactor. The regenerated catalyst is then combined with the feed stream in a tube, the so-called riser. The decisive catalytic cracking of the long-chain hydrocarbons already takes place in the riser, so that the subsequent reactor chamber primarily serves the purpose of product separation (Letzsch 2015; Hsu and Robinson 2017).

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