Ministerie van Infrastructuur
en Waterstaat

Energy chains for carbon neutral mobility

Efficiency, costs and land use in perspective

Background report

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The summary of this report can be found in the brochure Energy chains for carbon neutral mobility, which can be downloaded from KiM's website in addition to this report.

Summary

Electric transport is an efficient way to make mobility carbon neutral, but electricity it is not suitable for all modes. Transport using hydrogen and synfuels is an alternative, but requires 2 to 5 times more wind turbines.

To achieve carbon neutral mobility, carbon neutral energy is crucial. To this end we look at four options: electricity, hydrogen, synfuels (made from hydrogen and CO_2 or N_2) and biofuels. We focus on complete energy chains: from production of energy carriers, transport, storage and distribution, loading/refuelling up to and including use in the vehicle. The question is always: what is the energy efficiency, the cost per distance travelled and the use of space?

In all four chains, carbon neutrality is in principle achievable, but they differ greatly in how this is achieved and in their suitability for various modalities.

The application of electricity in mobility has the smallest energy loss, small land take and low cost per distance travelled of the options studied. The energy losses and space requirements of hydrogen and synfuels are 2-5 times greater.

The amount of space taken up by biofuels for mobility depends very much on the origin of the biomass used: if it comes from (agricultural) residues, the land take is zero and thus the smallest of all options, but if it comes from specially cultivated energy crops, the land take is the largest. In terms of cost, transport using biofuels can be competitive with electric mobility, although the uncertainties are large.

Electricity (like hydrogen) is mainly suitable for road transport and inland navigation, and not so much for long-distance sea and air transport. Synfuels and biofuels can be produced in a form ('drop-in') that is suitable for all modalities without modification. Other types of synfuels and biofuels do require vehicle engine modifications.

The use of space does not have to be in the Netherlands: electricity, hydrogen, synfuels and biofuels (or the biomass) can also be imported from abroad, although the energy losses (and therefore the costs) increase with the distance from the Netherlands.

Contents

List of abbreviations

AC	Alternating current
AEL	alkaline electrolyser
BEV	battery-electric vehicle
GNP	Gross National Product
CAPEX	capital expenditure
CBS	Central Statistics Bureau
CCS	CO_2 capture and storage
CH_3OH	methanol (aka: MeOH)
CO	carbon monoxide
CO_2	carbon dioxide
CRL	commercial readiness level
DAC	direct air capture
DC	direct current
DME	dimethyl ether
EHS, HS, IS, MS, LS	extra-high voltage, high voltage, intermediate voltage, low voltage
EL	electrolysis
ERS	Electric Road System
EV	electric vehicle
EVSPL	electric vehicle smart parking lot
FC	fuel cell, fuel cell
FCEV	Fuel Cell Electric Vehicle
FT	Fischer-Tropsch
G	giga, factor 10^9 (billion)
GH2	Gaseous (or compressed) hydrogen
GJ	gigajoule (giga = 10^9)
GWh	gigawatt hour (giga = 10^9)
H_2	hydrogen
HVDC	high voltage direct current
ICE	internal combustion engine, combustion engine in vehicle
IPCC	Intergovernmental Panel on Climate Change
J	joule
kilo	factor 10^3 (thousand)
KEV	Klimaat en Energie Verkenning
kWh	kilowatt hours
LFP	Lithium ferrophosphate (a type of battery)
LH2	liquid H_2, liquid hydrogen
LHV	Lower heating value
LIW	landscape, infrastructure and water
LOHC	Liquid organic hydrogen compounds (liquid hydrogen carriers)
M	mega, factor 10^6 (million)
MeOH	methanol
MJ	megajoule (mega = 10^6)
MWh	megawatt hour (mega = 10^6)
N_2	nitrogen
NAL	National Charging Infrastructure Agenda
NCP	Dutch Continental Shelf
NH_3	ammonia
NMC	Nickel-Manganese-Cobalt (one type of battery)
NO_x	oxides of nitrogen (generic term, x is variable)
OPEX	operational expenditure
PEM electrolysis	polymer electrolyte membrane electrolysis
PEM-FC	proton exchange membrane fuel cell
PJ	petajoule (peta = 10^{15})
PM10	particulate matter up to 10 micrometres in diameter
PV	photovoltaic, photovoltaic

SMR	steam methane reforming
SOE	solid oxide electrolyser
T	tera, factor 10^{12} (trillion)
TCO	Total cost of ownership
TRL	technology readiness level
TTW	tank-to-wheel
TWh	terawatt hour (tera = 10^{12})
V2G	vehicle-to-grid
W	watt (1 watt is 1 joule per second)
WGS	water gas shift
WLTP	worldwide harmonised light vehicle test procedure
WTT	well-to-tank
WTW	well-to-wheel
ZA	rare earths

1 Introduction

1.1 Context

Making the mobility system climate neutral is a major challenge. It fits in with the European Green Deal's goal of climate neutrality in 2050 and reducing transport emissions by 90% (European Commission, 2020) and the Ministry of Infrastructure and the Water Management's vision of working towards a "mobility sector with zero emissions in 2050"[1] (Ministry of Infrastructure and Water Management, 2022; 1). Such a large CO_2 reduction in the total economy requires a comprehensive transition involving major investments, policy choices and behavioural changes.

The 2019 Dutch Climate Accord sets out plans up to 2030 that will set this transition in motion with policy. The report of the Commission Van Geest (2021) shows that even more is needed to reach the EU interim target of 55% greenhouse gas reduction by 2030 (*Fit for 55*). The coalition agreement of 2022 even aims for a 60% reduction in the Netherlands compared to 1990.

In this report, KiM describes several implications that 100% carbon neutral mobility will have for the supply of energy. In doing so, we not only focus on reducing the exhaust emissions from mobility, but also on the CO_2 emissions in the entire energy chain, from the production of carbon free energy carriers to the use of mobility. Whether it is really necessary and possible to avoid CO_2 emissions from mobility altogether is not relevant to this report.

Strategies for CO_2 emission reduction
The first question is: which (technical) solutions are available to achieve a large CO_2 emission reduction in the mobility system? CO_2 emissions from mobility are the product of 4 factors that together determine the emissions (with the unit in which the factor expressed between square brackets):

1) Activities: mobility demand [total distance travelled by people or freight],
2) Modal split: the choice of transport mode [number of passengers or load per vehicle],
3) Energy efficiency [energy consumption per distance travelled per vehicle type],
4) CO_2 emission factor associated with the energy carrier [emission per energy use].

The multiplication of these 4 factors is also called the ASIF-formula (A=activity, S=(modal) split, I=(energy) intensity and F = fuel[2] carbon factor) (Schipper et al., 1999). See figure 1.1.

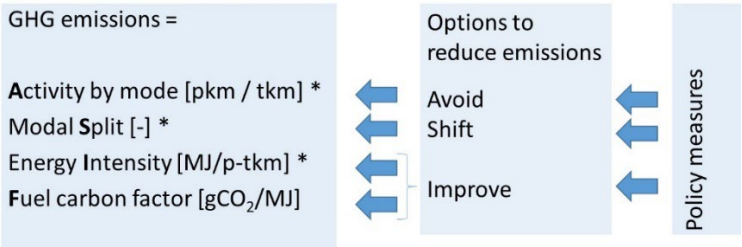

Figure 1.1 **Emissions and emission reduction measures in mobility**
Source: KiM, based on Schipper et al. (1999).

[1] This often refers to emissions at the tailpipe, not necessarily emission-free over the entire chain.
[2] This need not only include fuels.

In connection with these 4 (ASIF) factors, emission reduction strategies are classified into 3 groups (IPCC, 2022; Berveling et al., 2020), also called the Trias Mobilica (VNG, 2019):

- **Avoid**: Reducing the demand for mobility (related to 'A', activities),
- **Shift**: shift to more sustainable modes (related to 'S', modal split),
- **Improve**: make the modality more sustainable by improving energy efficiency and the carbon content of the energy used (related to 'I' intensity and F 'fuel carbon factor').

A strategy that falls under 'Avoid' is, for example, shortening travel distances or travelling less. Shifts include for example:

- A shift from car to public transport and bicycle,
- A shift from truck to train or barge,
- A higher occupancy of the car,
- Increase the load factor for lorries, goods trains or inland navigation vessels.

'Improve' includes:

- Strategies aimed at improving the energy efficiency of vehicles such as the use of a more efficient powertrain,
- Strategies aimed at improving the carbon emission factor, i.e. using energy sources other than fossil fuels.

The F-factor is often related to the I-factor. A switch to another type of energy, with a different F-factor, often requires a switch to another drive system (I-factor) with a different energy efficiency. Think of the switch to electric driving: this involves both the replacement of petrol or diesel by electricity (F-factor) and the replacement of the combustion engine by a much more efficient engine, namely an electric motor (I-factor).

In principle, this report focuses on improving F, up to the level of carbon neutrality (0 gCO_2 /MJ). As mentioned, this will often be combined with deployment of a different (more efficient) powertrain, so that the I-factor is also improved. Other aspects covered by the I-factor, such as improving aerodynamics of vehicles and application of lightweight materials or compact vehicles, have not been included.

Zooming in on improving the F (fuel carbon factor, gCO_2/MJ)

There are roughly 4 energy carriers with which the mobility system can be made carbon neutral:

1. **Electricity**, used in a battery + electric motor,
2. **Hydrogen**, applied in a fuel cell+electric motor or in an internal combustion engine (ICE),
3. **Synthetic fuel** (synfuel) other than hydrogen, used in an internal combustion engine,
4. **Biofuel**, used in a combustion engine.

In order to be carbon neutral, the energy carriers must be produced from renewable, carbon neutral sources. Subsequently, all processes in the trajectory between the production location and the end user must also be carbon neutral. Think of processes such as the overseas transport of a fuel by ship or compression to store a gaseous fuel. In other words, the entire energy chain from production to the user must be carbon neutral.

Carbon (C) is required for the production of the synfuels. In order to be carbon neutral, the requirement applies here that this comes from either CO_2 from the air or from CO_2 residual flows from industry that would otherwise be released into the atmosphere. The question is, of course, to what extent there will still be CO_2 residual flows in the future. By 2050, the entire society must be carbon neutral. This means

that the electricity sector, the chemical industry and other factories must have switched to carbon neutral alternatives. If this alternative is biomass, then a relatively concentrated CO_2 stream becomes available (the waste product from biofuel production) which could be used to produce synfuels. A CO_2 waste stream based on fossil fuels (anywhere in the chain) does not fit into a carbon neutral society.

Our scope: carbon neutral on a well-to-wheel (WTW) basis
In the IPCC system, a mobility system is carbon neutral if there are no CO_2 emissions from the vehicle exhaust, i.e. if the tank-to-wheel emissions are zero. Biofuel counts as carbon neutral in the IPCC calculation method, regardless of the physical CO_2 emissions that result from burning the biofuel. In view of the European ambition of carbon neutrality in the total economy, in this research project we want to consider the mobility system in a broader sense: we also count the CO_2 emissions that arise during the production, transport, distribution, storage and fuelling or charging of the energy carriers as part of the mobility system. The scope is therefore well-to-wheel (WTW) and not tank-to-wheel (TTW).

This scope still does not mean that all CO_2 emissions are covered. Emissions that fall outside the WTW approach are, for example, those that occur during the construction and installation of production facilities such as wind turbines, fuel plants and electrolysers. If these emissions were to be included, carbon neutrality would only be achieved if all materials and energy for these production facilities were produced in a carbon neutral manner. The amount of emissions involved will only become apparent through a life cycle assessment (LCA)[3]. In 2050 it is probably unfeasible to make energy chains carbon neutral over the entire life cycle, because it is unlikely that the global production of materials will be carbon neutral by then.[4] In this report we do not consider this wider scope, but focus on WTW.

A closer look at the energy chains
In this study, we see an energy chain as a combination of the following chain stages:
1. **Production** of the energy carrier (electricity, hydrogen, biofuel and synfuel) from raw materials.
2. **Transport, storage and distribution** of the energy carrier. The difference between transport and distribution is that transport is large-scale and distribution is fine-scale.
3. **Refuelling or loading** of the energy carrier in the vehicle.
4. **Use in the vehicle**: conversion of the energy carrier into vehicle propulsion.

Chain steps 1, 2 and 3 represent the well-to-tank (WTT) part of the chain (in which storage can also be seen as a separate step), the 4th chain step represents the tank-to-wheel (TTW) part of the chain:

Well-to-tank				Tank-to-wheel
Productie	Energiedrager	Transport, Opslag en Distributie	Laden/tanken	Gebruik in voertuig

The chains for electricity, hydrogen, synfuel and biofuel each have their own technical, economic and political challenges. These may differ per transport mode in which the energy carrier is used, for instance for light or heavy road transport and

[3] Such an LCA also includes emissions from the production and demolition of capital goods and distributes them over the amount of energy produced during their entire life cycle.
[4] The EU and 4 non-EU countries have set the goal of climate neutrality in 2050 or earlier by law, another 21 countries have set such a goal in a policy document, and 14 others in their pledge to the UNFCCC. The rest of the world does not have such a goal (yet), or for later than 2050 (e.g. China for 2060). See https://eciu.net/netzerotracker.

shipping. These specific advantages and disadvantages include costs, specific requirements for road, shipping or aviation infrastructure, loading or refuelling times, impact on the electricity grid, impact on the land use, use of (possibly scarce) raw materials, social acceptance and so on. But there are also common challenges, for example because energy chains are interconnected. For example, electricity is an input for the production of hydrogen, and hydrogen in turn is an input for the production of synfuels. A challenge from the electricity chain can therefore have an effect on the other two chains.

There are also connections between the 4 energy chains in other ways. Choices made within one energy chain can make future choices in other energy chains difficult or impossible. We then speak of path dependencies or lock-in effects. For example: using hydrogen as a transport fuel for trucks will make a system with electric overhead wires for electric trucks (an electric road system, ERS[5]) relatively more expensive because there will be fewer trucks to use it, and vice versa.

Choices in energy supply for mobility can also have consequences for other sectors such as industry and the built environment, as they also need electricity, hydrogen and biomass. This will not be considered further in this study.

1.2 Research questions

This study focuses on the physical, technical and cost characteristics of the energy chains for electricity, hydrogen, synfuel and biofuel used in mobility.[6] We look at the above-mentioned chain stages: 1) production of energy carriers from raw materials, 2) transport, storage and distribution, 3) charging or refuelling, and 4) use in vehicles.[7] Together, these 4 constitute a well-to-wheel approach. The starting point is that all energy chains should be (virtually) carbon neutral.

Within a carbon neutral energy chain, we consider several variants. The variants differ, for example, in the production method of the energy carrier - in the case of hydrogen one might think of production from electricity (via electrolysis) or from (bio)methane in combination with CO_2 storage (via a process called steam methane reforming, SMR). Another variable is the production location - in the Netherlands or abroad - and the method of transport, for example by ship or pipeline. Furthermore, we put together various combinations of vehicles and energy carriers. A condition is that these have a Technological Readiness Level (TRL) of 6 or higher (TRL≥6), which means that a complete prototype at scale exists (figure 1.2).

Technologies (vehicle-energy-carrier combinations) with a TRL below 6 (TRL<6) are still too experimental, so there is little reliable information available on large-scale applications and, moreover, they are less likely to play a major role in 2050 as much progress is still needed. It is also uncertain whether such progress will be made.

[5] In such systems truck batteries are charged while driving via a charging infrastructure above, beside or below the road surface, so that fewer large batteries are needed than for trucks that can only charge at charging stations.

[6] Compared to scenario studies on renewable energy in the mobility sector, for example Cuelenaere et al. (2014), our study is not a scenario analysis but a factual approach to the well-to-wheel chain, reporting what is known about the chains. In doing so, we go deeper than these, and many other, studies. In addition, we look at the land use and the bottlenecks and uncertainties in the chains. Finally, it is important to update the knowledge from time to time, because there are advancing or new insights.

[7] Not all of the chain stages are fully relevant in practice for all combinations of vehicles and energy carriers; for instance, in the case of maritime shipping there is usually no need for fine-meshed distribution (as part of chain stage 2), because sea-going vessels are fed from storage tanks in seaports that are fed directly from the larger transport network.

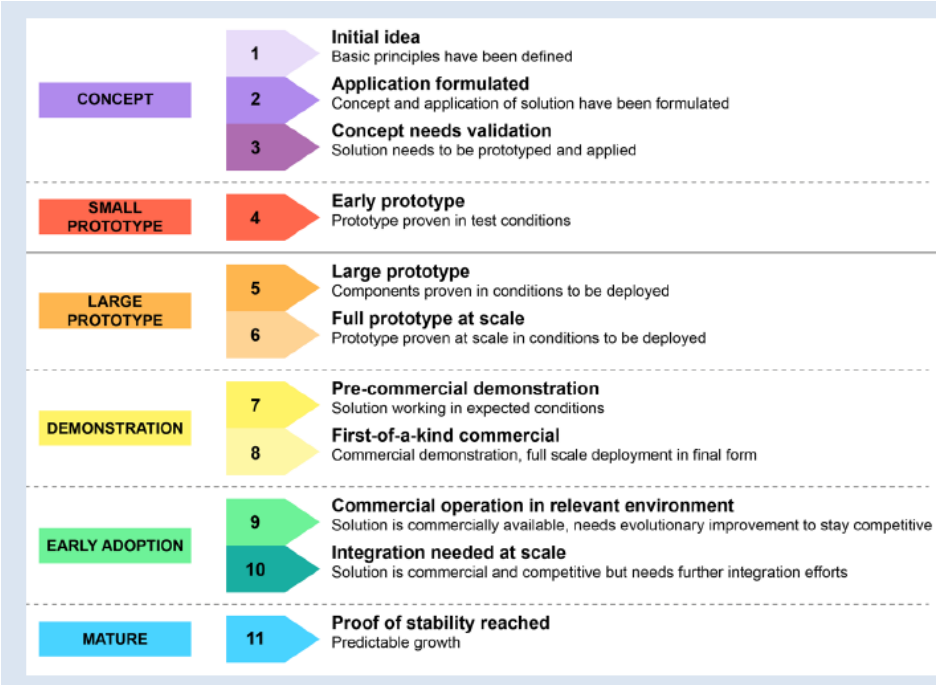

Figure 1.2 **Description of technology readiness levels**

Source: IEA, 2021.

This leads to the following research question:

What are the main energetic, spatial and cost characteristics and possible bottlenecks of well-to-wheel chains (and their steps) of carbon neutral energy carriers for mobility in the Netherlands?

We therefore focus on the 'F' and, to a limited extent, the 'I' in the ASIF formula (see section 1.1) and on characteristics of the chain steps and not on transition paths, scenarios, trade-offs between characteristics or cost-benefit analyses.

We distinguish the following subquestions:

- Energy: What are the energy yields of the steps in energy chains? What proportion of the total energy used in the entire chain remains as energy to be used in the vehicle?
- Land use: For which chain steps and energy carriers is land use important, and how large is it in relation to the energy unit?
- Costs: What are the costs of the chain steps?
- Bottlenecks and uncertainties: Which bottlenecks can be identified that could hinder the (large-scale) development of the 4 sustainable energy chains, such as the use of scarce materials? And what uncertainties do we see, the implications of which are not yet clear, but which are potentially important for future development?

1.3 Scope and definitions

This study is about carbon neutral energy chains for mobility in 2050, from production of the energy carrier to use in the vehicle. With a further defined scope as follows.

carbon neutral is not necessarily the same as climate neutral: greenhouse gases such as methane and nitrous oxide, and other substances such as water vapour at high altitudes and in flight, also contribute to the greenhouse effect. We do not investigate the contributions of non-CO_2 emissions, but we do mention these non-CO_2 effects when relevant.

We do not perform a life cycle assessment (LCA). For example, we do not look at the steel production (and associated CO_2 emissions) required for various technologies in the chains, such as wind turbines and filling stations. We focus on well-to-wheel (WtW).

This study provides insights that are relevant for making policy choices. However, we do not provide a framework for possible choices as to which energy carrier is the most desirable per modality.

We analyse and compare the energy chains in terms of *their energetic, spatial and cost characteristics*, but do not weigh these against each other, for example whether land use is more important than energy use. Technical feasibility *at the system level is* only included in the analysis to a limited extent. This concerns, for example, the required capacity increase of the electricity grid, the spatial integration in cities of the required charging infrastructure or the feasibility of hydrogen production on a large scale.

The target year of this study is carbon neutrality in 2050, but the cost and efficiency estimates are mostly for 2030, because literature for after that is scarce and these estimates are too uncertain. For this study, it is particularly important whether a technique has already been fully developed or whether there is still much room for improvement. Estimates for 2030 are also helpful here.

Energy prices in turbulent times: At the time of writing, natural gas prices are around 4 times higher than at the beginning of 2021. This increase began at the end of 2021 and has been reinforced by the war in Ukraine. This is also expected to have an effect on oil prices. Geopolitics can also affect prices of other commodities. In addition to an effect on prices, there may also be an influence on how society generally views raw materials, including natural gas. In our study we do not directly address such effects, but in a sensitivity analysis we also take into account higher gas and electricity prices.

We used a discount rate of 2.25% based on the Netherlands' guidelines for social cost and benefit analyses (Koopmans and Rhee, 2021).

We do not investigate techniques with a low Technological Readiness Level (<6). However, we sometimes indicate which alternatives are being developed that currently have a lower TRL without discussing them in detail.

The criteria efficiency, space and cost

The chains we analysed are in principle all (nearly) carbon neutral. In terms of CO_2 emissions, therefore, they all score roughly the same. In order to be able to make a comparison with each other, we have measured all chains against three yardsticks: energy efficiency, land use and costs.

Energy efficiency

With energy efficiency, we distinguish between:
- The efficiency of the entire well-to-wheel chain (R_{WTW}),
- The well-to-tank efficiency (R_{WTT}) and

- The tank-to-wheel efficiency (R_{TTW}).

R_{WTW} is the product of R_{WTT} and R_{TTW}. In formula:

$R_{WTW} = R_{WTT} - R_{TTW}$

With
R_{WTW}: $Energy_{propulsion}/Energy_{input\ in\ the\ chain}$
R_{WTT}: $Energy_{refuelled\ or\ charged\ by\ vehicle}/Energy_{input\ in\ the\ chain}$
R_{TTW}: $Energy_{propulsion}/Energy_{refuelled\ or\ charged\ by\ vehicle}$

If R_{WTT} is high, the energy input has been economically converted into energy for refuelling or charging. R_{WTT} is suitable for assessing how much of the energy input to the chain is ultimately input to the vehicles (by either refuelling or charging), and how many losses there are along the way. It should be noted, though, that a comparison is particularly useful for chains based on the same substance (electricity, methane or biomass) and somewhat less so for chains with a different basis.[8]

R_{TTW} indicates how efficiently the vehicle has converted its energy input, by refuelling or charging, into propulsion. The higher, the lower the losses in the vehicle.

If R_{WTW} of a chain is high, relatively little energy input has been required throughout the chain to propel the vehicle. The entire chain has therefore used energy efficiently to reach the goal (propulsion).

Space usage

We include space usage for the following reasons. Space is a scarce commodity, particularly in the Netherlands, and the transition to a sustainable energy supply will make heavy demands on space (Gordijn et al., 2003; Kuijers et al., 2020). It is possible that we will come up against spatial boundaries on land and at sea (Scheepers, 2022). The current land use, or a future choice for the land use, may limit the sustainable fulfilment of other functions in the future (Bertels et al., 1996), such as food production or housing. When space is scarce, efficient land use is important.

In addition, land use is an impact indicator for sustainable development. For example, in the Donut economics (Raworth, 2021) 'land-use change' is one of the indicators which reflect the 'planetary boundaries'. Spatial compatibility is also mentioned as a criterion in a letter to Dutch Parliament on a national plan for the energy system in 2050 (MinEZK, 2021). Land use as an economic 'factor' is to some extent factored into the costs of the various chain stages. However, because the total amount of space available for sustainable energy chains for mobility is not unlimited, it is relevant to obtain a quantitative picture of land use.

In our analyses of space for the various chain stages, we look at land use from a quantitative point of view. The *net* land use is the land area that is primarily used for energy production, e.g. the piece of land occupied by a wind turbine or used to erect solar panels. You can still have animals grazing around the solar panels, and they can also make use of the shadow of the panel, but the primary land use is for solar energy. The *gross* land use gives the total area needed to produce a certain amount

[8] Electricity, methane and biomass differ in energy quality. For example, 1 MJ electricity and 1 MJ methane are equal in energy content, but the quality of 1 MJ electricity is higher than that of 1 MJ methane, because 1 MJ electricity enables more work than 1 MJ methane.

of energy. This includes the space between the turbines, which can be used for many other purposes. This measure is useful to determine what the spatial possibilities and limitations are for producing a certain quantity (or capacity) of energy. Combinations of energy production can also take place on the same surface, for example biomass cultivation between the turbines of a wind farm, but this will be ignored here.

Qualitative aspects, such as horizon pollution from wind turbines, have not been investigated (some other studies, such as Londo & Kramer (2019), do address this). Nor do we distinguish where the land use takes place, i.e. where factors other than scarcity of space are involved. In addition, underground space usage, such as that required for CO_2 storage or cables in the electricity grid or for charging stations, falls outside the scope of our study. This is in accordance with, for example, UNECE (2022).

Glossary

Energy carrier: a product containing chemical, thermal or electrical energy. In this study, the common energy carriers are: electricity, hydrogen, synfuels and biofuels. For example, a battery is not an energy carrier in the terms of this study, but it is a storage medium for the energy carrier electricity.

Energy chain: the whole of 1) production of the energy carrier (electricity, hydrogen, biofuel and synfuel) including any raw materials, 2) transport, distribution and storage of the energy carrier, 3) refuelling or charging of the energy carrier, 4) conversion of the energy carrier into vehicle propulsion.

(**Energy) efficiency or (energy) yield**: this is the quotient of the outgoing useful energy and the incoming energy. We use this term both for the efficiency of a chain step and for the entire chain.

Energy use: the use of energy, usually in a chain step or part thereof. The unit of energy can vary: GJ, MJ, kWh, MWh etc. If it concerns energy use per travelled distance, this is explicitly mentioned, also by using the unit MJ/km or GJ/km.

Renewable electricity: This means electricity from the sun and wind.

Costs: These are financial costs, for example for a technical installation or raw materials, without taxes and duties and also without business profits as far as possible. To be distinguished from prices and tariffs (which include a profit margin) and also from social costs.

Transport (of the energy carrier): This involves the bulk transport of a large quantity of energy carriers over long distances.

Distribution: This, too, involves moving the energy carrier, but in the final part of the chain to the end users. Distribution is generally more finely-meshed and small-scale than transport.

Space: This refers to the land take of chain stages or of the entire energy chain, and is expressed in the unit m^2 or km^2. The land take of an energy carrier-vehicle combination is the amount of space required by the various steps in the chain to produce and deliver the annual amount of energy required for this vehicle.

1.4 Method

This research was mainly based on literature review, but also on primary data from previous research. Calculations for efficiency, costs and space were carried out on this basis. In addition, several experts were consulted and reviewed the draft report or chapters thereof.

The literature search was carried out on the basis of snowballing (backward and forward), i.e. looking at the source lists of articles or reports and extracting relevant studies, and using Google Scholar to find out which studies refer to certain articles or reports. In the first instance, we mainly consulted meta-studies and overviews of renowned international institutions and consultancies. For specific subjects about which less is known, such as the land use in the various chain stages, we also used scientific and grey literature. Sources other than the above, such as presentations, news articles or blogs, were used when there was no alternative. We have used as many different sources as possible for each individual topic.

Assumptions for KiM and TNO calculations are then often an average from various literature sources, whereby outliers or less robustly substantiated values are excluded. In addition, TNO also made extensive use of primary data from previous TNO research, particularly of vehicle energy consumption for various energy carriers and modalities.

Finally, the quantitative and qualitative results of the four energy chains have been put side by side in a synthesis, in order to be able to draw overall conclusions from this comparison.

1.5 Overview of energy chains and modes of transport

Variants within chain steps

In each energy chain, many variants are possible within the various chain stages, such as in the way in which the energy carrier is transported. The variants chosen in this study are explained in the specific chapters per energy chain. At this point, we would like to highlight two of these chain stages:

1. Variants within the production chain step
For the production step we have chosen (see also figure 1.3):

- Electricity
  - Wind energy on land and sea in the Netherlands
  - Solar energy in the Netherlands
  - Solar energy produced in North Africa and then transported to the Netherlands
- Hydrogen
  - Electrolysis using electricity, in the Netherlands
  - Electrolysis using electricity, in North Africa; the hydrogen is then transported to the Netherlands in liquid form (cooled), gaseous form or in compounds such as ammonia
  - (Bio-)methane via steam methane reforming (SMR) and CO_2 capture and storage
- Synfuels other than hydrogen
  - Ammonia from hydrogen and nitrogen from air
  - Drop-in fuels or FT-synfuels, produced with the Fischer-Tropsch (FT) process using hydrogen and CO_2 captured from the air or from point sources
  - Methanol from hydrogen and CO_2 captured from the air or from point sources
- Biofuel

- Drop-in biofuels or FT-biofuels produced with the Fischer-Tropsch (FT) process using advanced biomass (such as residues or non-food crops, according to Renewable Energy Directive)
- Bioethanol from advanced biomass (as defined in the Renewable Energy Directive)

As the description of this chain step shows, there are cross-links between the energy chains. For example, electricity is not only the product in the electricity chain, but also an input for hydrogen production. Hydrogen in turn is one of the input for synfuels. Use of hydrogen or synfuels is therefore also called indirect electrification (Ueckerdt et al., 2021).

If transport fuels are made using CO_2 from point sources, e.g. from industrial installations, we do not attribute the CO_2 that results from burning the fuels in vehicles to the transport sector. Instead, it is a 'delayed' emission from the industrial sector. The assumption here is that if mobility did not use the CO_2, industry would emit it. In other words, the use in synfuels does not lead to *additional* CO_2 emissions. We note that this could also be looked at differently, for example by allocating CO_2 emissions partly to mobility and partly to industry (Kleijne et al., 2022; Ueckerdt et al., 2021). Such an allocation of emissions could also take into account which sector has paid for the emissions in the form of CO_2 credits or rights.

Energy chain	subroute	Mode of transport of the energy carrier (in chain step transport/distribution/storage)
electricity	wind	
	solar	
	solar import	
hydrogen	electrolysis	liquid
		ammonia
		gaseous
	SMR+CCS	liquid
		ammonia
		gaseous
synfuels	FT liquids	
	ammonia	
	methanol	
biofuels	Bio-FT liquids	
	bioethanol	

Figure 1.3 **Overview of variants for the production step and possible variants in the transport of the energy carrier**

2. Variants within the final step "use in vehicle"

For the final step in the energy chain, 'use in vehicle', we distinguish between various vehicles. We selected the five vehicle types with the largest share of CO_2 emissions based on the fuel tanked in the Netherlands (figure 1.4), with the exception of non-road mobile machinery (such as leaf blowers and excavators), which are very diverse and may require specific investigation.

These 5 are:

- Light-duty vehicles (passenger cars),
- Heavy-duty vehicles (trucks),
- Inland shipping,
- Seafaring,
- Aviation.

Trains are not included because they are mainly electric and therefore only cause indirect emissions.

With this selection of 5 vehicle types, this study into carbon neutral energy chains for mobility covers the vast majority of current CO_2 emissions from mobility. Incidentally, the emissions from fuel used in the Netherlands for international aviation and shipping are higher than the emissions from fuel used for domestic mobility. See figure 1.4.

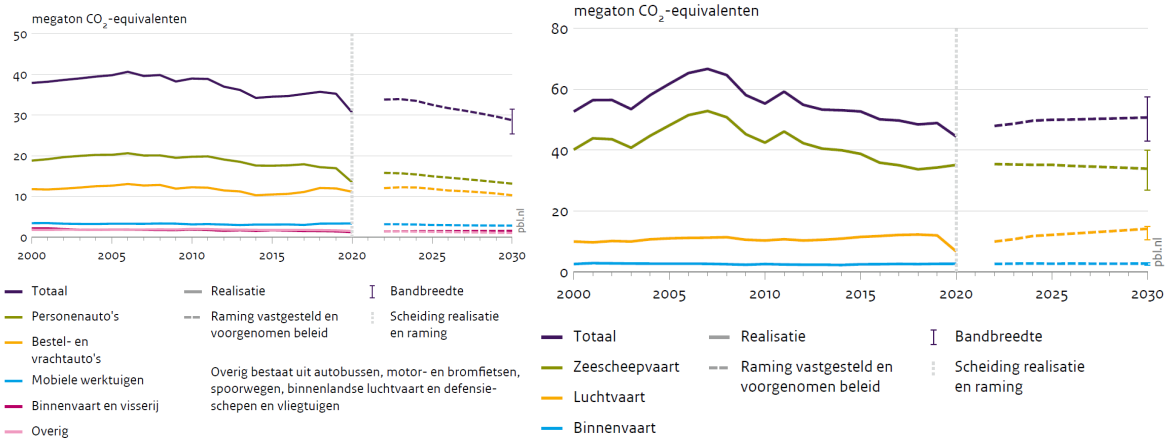

Figure 1.4 **Greenhouse gas emissions from domestic mobility (IPCC definition, left) and from bunker fuels sold in the Netherlands (right)**

Source: PBL, 2021.

Reference vehicles

For each of the 5 vehicle types, a reference vehicle has been defined, that within its vehicle type accounts for a relatively large amount of CO_2 emissions. This is the reason why for aviation we have chosen an aircraft that flies long distances (intercontinental) (intercontinental flights longer than 4000 km cause more than half of the emissions of flights to and from EU airports, flights longer than 1500 km cause three quarters (Eurocontrol, 2021)). These reference vehicles are listed in table 1.1.

Table 1.1 **Reference vehicles for the 5 vehicle types**

Vehicles		**Reference vehicle (Emission[9]/weight class and example)**	**Reference fuel**
Light duty transport	Passenger car	Average actual consumption (data 2019)	Diesel and petrol
Heavy duty transport	Tractor-trailer combination	Average actual consumption (data 2019)	Diesel
Inland shipping	Inland vessel	Emission/weight class: Stage V (M8[10]) Example: Large Rhine Ship M8 (110m)	Diesel
Shipping	Shipping	Emission/weight class: IMO II or III Example: General Cargo Ship	Diesel
Aviation	Intercontinental	Emission/weight class: n.a. Example: Boeing 787 Dreamliner (250-330 passengers; 13,000-15,700 km)	Kerosene

[9] For road transport, Euro 6/VI is currently mandatory for new vehicles, for inland waterways and maritime transport the Stage V emission standard applies.
[10] The M-class is an indication of the weight class of a ship.

Combinations between energy carriers and vehicles

A selection of energy carriers and vehicles is necessary in order not to make the scope of this study too large, but still include the most important combinations. Our selection is shown in table 1.2.

The most important factor in the selection was whether an energy carrier-vehicle combination, given its stage of development, has the potential to play a major role in 2050. In selecting the energy carrier-vehicle combinations, we therefore took the current TRL as our most important selection criterion. This should be at least equal to 6.

Another selection criterion was whether an option was frequently mentioned in authoritative literature (e.g. from the IEA, IPCC and ITF). Finally, the practical applicability of the vehicle-energy combination played a role in the selection. For example, the use of **ammonia** in light road vehicles, although possible in terms of the TRL, is not considered a realistic option, because ammonia is highly toxic and entails safety risks for users (Duijm et al., 2005; Berenschot and Arcadis, 2021). Ammonia may be an option for shipping (sea and inland waterways), though, because only professionals need to be able to handle the fuel. We have examined **bioethanol** only for light road vehicles, because ethanol is a petrol substitute and petrol is now used only in light road traffic. For **aviation**, we are only investigating combinations with synthetic kerosene (based on hydrogen and CO_2) and bio-kerosene (based on biomass). **Electric** aircrafts for long distances is generally not seen as a realistic option, because the weight of the batteries becomes too large. Even for smaller planes for regional flights, the energy content per unit weight of batteries must be at least twice that of current lithium-ion batteries. Such batteries are only considered viable in the longer term (2050) (Graver et al., 2022)[11]. Nor do we consider long-distance flights on **hydrogen** to be very realistic, partly because of the large amount of space the fuel tank and fuel cell system would take up and partly because of their weight, which is a very important criterion for aircraft. (Space requirements and weight are discussed in the chapter on Hydrogen.) Moreover, for use as an aviation fuel in a modified aircraft engine, a complex and lengthy approval process will have to be gone through for reasons of flight safety.

Table 1.2 Selection of the investigated energy carrier-vehicle combinations based on TRL and practical feasibility

			mode				
energy chain	subtype	conversion in vehicle	light duty vehicles	heavy duty vehicles	inland shipping*	sea shipping	aviation
electricity		Battery electric	9	8-9	8		3
		ERS	na	6-9	na	na	na
hydrogen		FC electric	8-9	8-9	7	<6	3
		ICE modified	8-9	8-9	8	4-5	low TRL (+ safety?)
synfuels	drop-in (FT)	ICE	5-6	5-6	5-6	5-6	5-6
	NH3	ICE modified	safety	safety	7-8	7-8	
	methanol	ICE modified	7-8	7-8	7-8	7-8	
biofuels	drop-in (FT)	ICE	5-9	5-9	5-9	5-9	5-9
	bioethanol**	ICE modified	~8				

*including shipping on short and medium distance
** ethanol is a gasoline substitute

Explanatory notes to the table: Unconsidered energy carrier-vehicle combinations are shown with a black block. Numbers in the table represent the TRL. The source for the TRL values is the IEA (2021), with the exception of the TRL values in green, which are based on the Umwelt Bundesamt (2016), and in red, which are KiM's own estimates. For the synfuels and

[11] For flights up to 500 km departing from the Netherlands, a target has been set that these will all be operated with electric aircraft (letter to the Dutch Parliament, 18 February 2022).

biofuels that do not require engine modifications ('ICE'), the TRLs mentioned are only those for the fuel (the vehicle engine is already in commercial use and logically has the highest TRL).

Figure 1.5 combines table 1.2 and figure 1.3 and thus gives the scope of this study. It shows which variants in terms of production method, transport and loading and refuelling of energy carriers are included, and for which vehicle types. It also shows the interconnections between the chains.

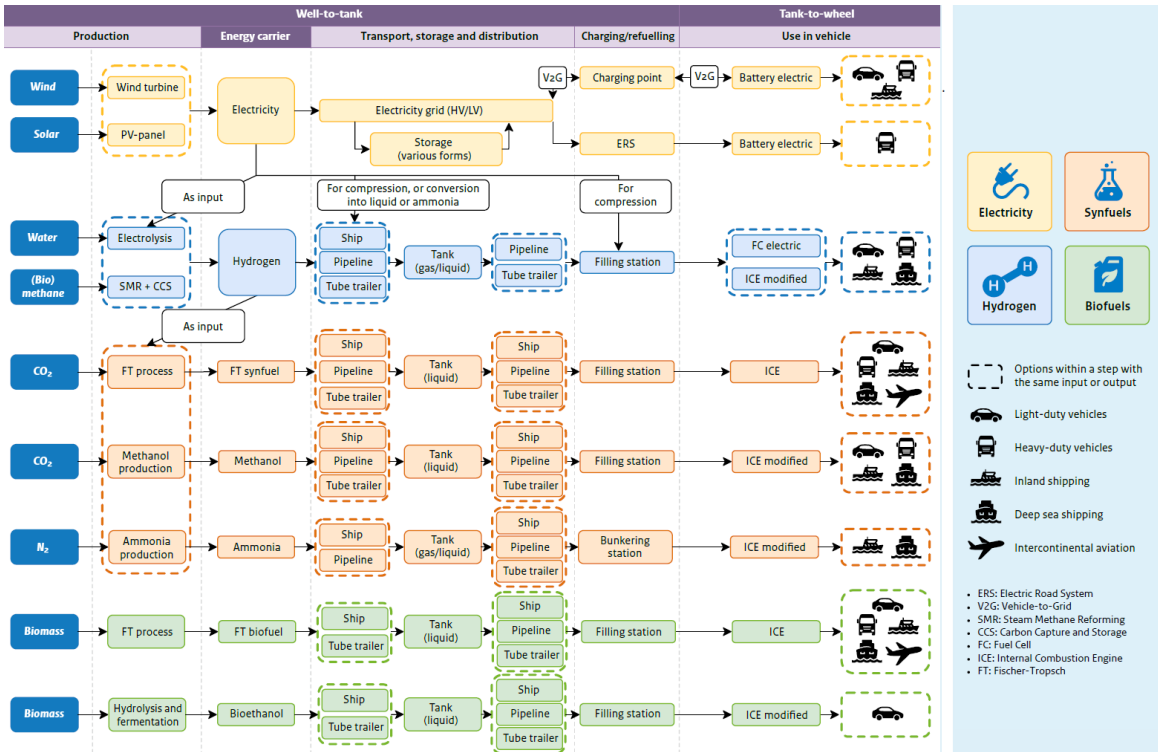

Figure 1.5 Overview of the analysed energy carriers and their energy chains

2 Electricity

Main points

- Energy efficiency is around 60-75% for the whole chain (well-to-wheel). Electric vehicles achieve relatively high energy efficiency in a dynamic driving pattern (different speeds and many start-stops) because braking energy is recovered, in contrast to combustion engine vehicles.
- Available space for on and off-shore wind turbines on land and sea in the Netherlands is not unlimited and a climate-neutral electricity system in the Netherlands in 2050 will require a lot of space. For offshore wind, a substantial part of the available spatial potential of the Dutch Continental Shelf of the North Sea is needed, taking into account for example shipping and ecological values. The same applies to the available roof area for PV, and solar farms will also require a few percent of the agricultural area. All in all, this is a major spatial challenge. The spatial integration of electricity grid expansions can also cause problems.
- For an electric passenger car, about 7-50 m^2 is needed for carbon neutral energy supply. With 100% electrification of road transport, the total built-up area of the energy chain is about one-fifth of the area occupied by mobility-related infrastructure (roads, parking). However, if we also consider the space between wind turbines, the area needed for energy is much larger, comparable to the province of Utrecht.
- Scarce materials are needed, especially for batteries. There is uncertainty about the availability of, for example, lithium, nickel, cobalt and rare earth metals.
- Circular economy concepts are not yet sufficiently applied in the electricity chain: 100% recycling of used materials, especially for batteries, is still a long way off, although EU and Dutch policies are being developed.
- Smart charging means that the charging rate can be adapted to minimise the load on the electricity grid. In vehicle-to-grid systems (bidirectional charging), the battery in vehicles can be used to temporarily store electricity and feed it back into the grid. Both strategies can play an important role in the future electricity system, especially to reduce the need for reinforcement in the medium and low voltage grid. However, it must be possible to produce the total annual electricity demand. Overproduction must be stored and the storage capacity needs to be more than sufficient to cope with long periods of low sun and wind.
- The impact of vehicle-to-grid systems on battery life is uncertain
- The required extensions of the electricity grid in different mobility electrification scenarios. This applies to low and medium voltage (especially for electric cars; possibly also for megawatt truck chargers) but also deeper into the grid. The effect of electric road systems on the electricity grid is still unclear.
- There appears to be a lack of technicians to build the charging infrastructure and extend and reinforce the electricity grid.
- Safety risks of electric vehicles (EVs) seem to be limited and well addressed by regulations.
- The effect of EVs on "non-exhaust" particulates compared to combustion engine cars is limited: slightly more tyre wear due to extra battery weight and higher torque at low speed, but less particulate matter from braking.
- The cost of battery-electric trucks (the heaviest class) and electric inland waterways compared to alternatives is uncertain. The volume and weight of batteries for heavy road transport reduce vehicle capacity
- Charging may be a problem for carriers, especially for heavy road transport, but applies to a lesser extent to other modes.

Introduction

This energy pathway includes electricity generated by climate neutral sources of wind and photovoltaic (PV) energy, distributed through the electricity grid to charging infrastructure to recharge vehicle batteries, which power the vehicle's electric motor (figure 2.1). This assumes climate neutrality in the use phase of the generation sources: possible emissions from wind turbine production or land use change for solar meadows are not included. Electricity can be generated in the Netherlands, but also abroad, closer to the equator. Therefore, we include a scenario in which solar energy is generated in North Africa and transported to the European and Dutch grid based on ECF (2010; p 74-75).

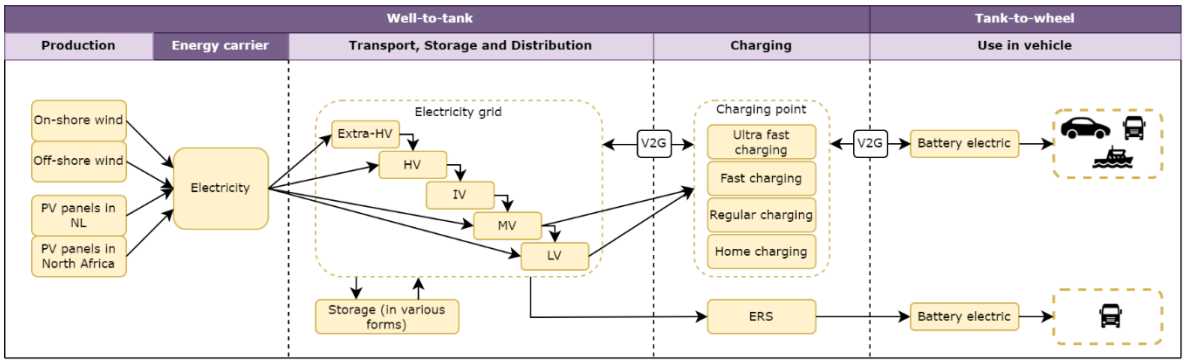

Figure 2.1 **Overview of electricity chain steps**

This section covers each of the individual chain stages (2.1 - 2.5), and finally the chain as a whole (2.6). In doing so, we have taken into account energy efficiency, costs and land use, as well as other aspects where relevant. The main points of this analysis are set out below.

2.1 Production

This step involves the production of alternating current that can be fed into the public electricity grid. PV panels and wind turbines are seen as the most important sources in most scenarios for climate-neutral electricity in the Netherlands in 2050 (see e.g. Daniels & Koutstaal, 2016; Den Ouden et al., 2020[12]), and by 2030 these sources are expected to generate about 75% of the expected electricity demand (MinEZK, 2021). Wind turbines generate alternating current (AC), while PV panels generate direct current (DC) that is converted to AC for the grid via an inverter.

However, solar and wind power are variable sources with large fluctuations in production per day and per month, as a result of which they cannot always meet demand. In order to absorb these fluctuations, in addition to investments in solar panels and wind turbines, investments must also be made in controllable sources such as gas power stations, interconnection with international networks and various forms of storage (see the section on storage), see figure 2.2. In addition, the demand for electricity can also be shifted, by industry and households, to different times so that the peak in demand for electricity is reduced (TenneT, 2021). Finally, when supply exceeds demand, the output of solar and wind power can be scaled down. In any case, the electricity network of 2050 will need to be considerably reinforced compared to the current situation (Netbeheer Nederland, 2021).

[12] This study analyses four scenarios for climate-neutral energy supply in the Netherlands in 2050, focusing on regional, national, European or global development (see Appendix C Electricity for an overview of the assumptions of the scenarios).

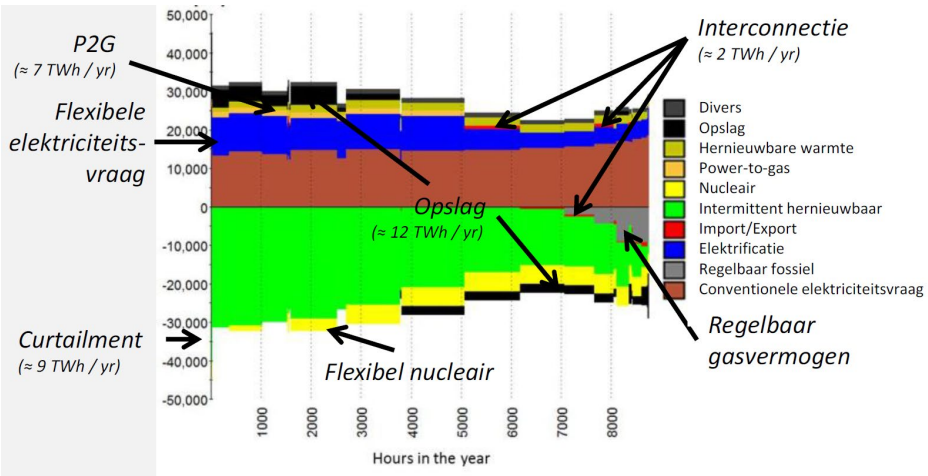

Figure 2.2 **Illustration of a possible climate-neutral electricity system in 2050 for the Netherlands**

Excluding electricity for possible bunker fuels for aviation and shipping. Above electricity demand, below supply with PV+wind in green. The horizontal axis shows the hours in the years of availability of PV+wind.

Source: Daniels & Koutstaal (2016).

Efficiency

For energy efficiency, our starting point is the total amount of energy, generated in 2050 by PV panels or wind turbines. In the efficiency calculations, we do not include the conversion efficiency, or the quotient of the energy from the sun or the wind that falls on the panels or hits the blades of the turbines and the electrical energy produced by the panels or turbines[13], as is common in energy efficiency studies (see e.g. Haugen et al., 2021). The efficiency of a PV inverter, which transforms the direct current generated by PV panels into alternating current, is generally around 90-98% (Vignola et al., 2008).

Land use

The area needed to generate electricity from solar panels and wind turbines varies greatly. Generally speaking, fossil or nuclear power plants take up less space (0.1 - 1 m^2/MWh per year) than renewable sources. Appendix C Electricity provides estimates for land use of solar and wind for the Dutch or European situation where possible.

For wind, the space between the turbines that is also used for other purposes is not included in the net land use for wind energy. For offshore wind energy, the space used is the space that can no longer be used for other purposes. Passage for shipping and co-use by passive fishing, for example, can still take place within the boundaries of a wind farm, subject to conditions. A distance of 50m to the turbines and 500m to the net-to-sea platforms, the so-called safety and maintenance zone, applies as a limit. Some activities are not permitted, such as diving, kite surfing and trawling (Wind op Zee, n.d.).

There is some variation in the values found in the literature. This can be explained by differences in where exactly the geographical boundary of a project is set

[13] Conversion of wind energy into electrical energy with the current wind turbines takes place in a fairly close to theoretically most efficient manner (approximately 40-45%). The energy losses that occur during this conversion are not taken into account. Solar energy is currently converted into electrical energy with an efficiency of around 15%. Further improvements are conceivable, but in this report we assume that these energy losses are unavoidable for the time being and do not include them in the calculations.

(Saunders, 2020). Furthermore, for PV, east-west or south orientation is possible and there are differences in solar irradiation. Also, for the different types of surfaces (roofs, on infrastructure, in the landscape or on water) different spacings are possible and it is not always possible to choose the optimal angle. For wind, the electricity production depends on the wind supply, but also on the size of the turbine and the total installed capacity per km^2.

For further calculations we take the net space usage for wind as an average from 4 literature sources 1 m^2/MWh per year (0.3 m^2/GJ per year), for solar (on land, infrastructure and water bodies, LIW) in the Netherlands 12 m^2/MWh per year (3 m^2 /GJ per year) from 5 sources. For solar energy generated in North Africa, a twice as high yield per panel is possible (SolarGIS, 2021). For land use of PV we therefore assume half (6 m^2/MWh per year). Appendix C Electricity lists all sources for land use.

For **onshore wind**, the effect of the land use is broader than the area mentioned above, with impact on nature and cultural landscape, horizon pollution and cast shadow. Wind turbines are generally not placed close to residential areas. The 2030 targets from the Dutch Klimaatakkoord (Climate Agreement) (35 TWh from onshore wind and PV) and the SER Energieakkoord (Energy Agreement) (6 GW onshore wind) are probably feasible (PBL, 2021). The potential of onshore wind is higher than 6 GW (RVO, 2018), but it is unclear how much the total capacity of onshore wind can grow further towards 2050.

In the case of **offshore wind energy**, bottlenecks may also arise in the long term. In addition, there is the space required (such as the transformer station needed to make the connection to the high-voltage grid) for bringing the generated electrical energy ashore (see the section on transport). Of the total 54,000 km of space in the Netherlands Economic Zone in the North Sea, it is estimated that 18,000 km^2 is available for offshore wind energy, assuming constraints due to safety, noise nuisance and the risk of failure of basic facilities (Kuijers et al., 2020). The 11.5 GW target for 2030, or 49 TWh per year, is spatially well feasible. In a scenario with 72 GW in 2050, a substantial part of the available space, i.e. 40-67%, is needed (Kuijers et al., 2020).

Due to ecological and economic considerations, not all space in the North Sea can be used for wind energy. This means that by 2050 there may be bottlenecks. Wind turbines at sea can influence currents, waves, the mixing of water layers and sedimentation. This in turn can affect the quality of the habitat of marine fauna. Fishing, especially with trawls, is restricted by offshore wind farms. In addition, shipping routes must remain available (RVO, 2018).

For **PV** in 2050, Den Ouden et al. (2020) estimate a growth to 42 to 125 GW_p installed capacity (about 37 - 109 TWh per year at current efficiencies[14]) in the four scenarios mentioned above. For 70 TWh generation in 2050, some 15-30% of the PV potential on Dutch rooftops will be needed, in addition to a few percent of the potential on infrastructure (see picture 2.1 for an illustration), in agricultural land and on inland waterways (Van Hooff et al., 2021). Looking only at solar farms, 2-4% of the agricultural land area in the Netherlands is needed for about 50 GWp of capacity (Kuijers et al., 2020), which amounts to about 48 TWh per year. The projected growth therefore falls within the spatial potential, but it is not clear whether bottlenecks are expected here in terms of practical realisation.

[14] This is a conservative assumption: in 2050 the efficiency of PV panels could be more than one and a half times today's value (RVO, 2021).

Picture 2.1 **PV integrated with the motorway**

Source: https://www.solarhighways.eu/

With 100% electrification of road mobility, assuming the average projected growth in the low and high scenarios in the Integral Mobility Analysis (RWS/WVL, 2021), the electricity demand will be approximately 47 TWh (see Table 2.1), or 52 TWh if we take into account a 90% loading efficiency (see Section 2.4). This is about 20-25% of the total expected electricity demand[15] in 2050 (Den Ouden et al., 2020). By way of comparison, 3 million e-bikes in the Netherlands use 50 GWh per year, or 0.04% of the current total, which 1 turbine of 11 MW of the Hollandse Kust wind farm currently under development can generate in a year (Visser, 4 March 2022).

Table 2.1 **Illustration of electricity demand from road mobility at 100% electrification in 2019 with extrapolation to 2050**

Mode	Vehicle-kilometres 2019 [billion km][1]	Typical efficiency [kWh/km][2]	Electricity demand 2019 [TWh/year]	Electricity demand 2050 [TWh/year]
Passenger car	122.5	0.2	25	28
Vans	18.7	0.22	4	5
Heavy duty vehicles	7.5	1.4[3]	11	13
Buses	0.6	1*	0.6	1
Total			40	47

[1] CBS (2020),[2] Berveling et al. (2020),[3] TNO (see Appendix B Efficiency), *estimation

Based on the aforementioned averages for the land use per MWh per year, a maximum of 600 km^2 of surface area is needed to generate the electricity required for current mobility (2019), in the case of 100% PV in the Netherlands. In case of generation with 3/4 wind and 1/4 solar[16] it will be about 250 km^2. For comparison, the total surface area of road infrastructure in 2015 was 1044 km^2 (CBS, 2021a[17]), and the surface area for car parks is about 200 km^2 (Zijlstra et al., 2022). The direct land take associated with mobility is thus about five times greater than the area required for energy generation. However, this is based on the built-up area of wind energy, i.e. the net land take.

If we consider the surface area required for wind farms, the land take of energy production is much greater than the direct land take of mobility. This gross land take

[15] Based on the average of the total electricity demand (219 TWh) in the four scenarios of Den Ouden et al. This does not include 100% electrification of mobility, but we have corrected for this in the percentages. The total demand could also be higher, for example 300 TWh or even 500 TWh, if all bunker fuels were also produced using electricity in the Netherlands (Scheepers, 2022). Obviously, the share of road mobility in electricity demand would be correspondingly lower.

[16] Berenschot & Kalavasta (2020) in Hoogervorst (2020): 68% wind, 21% solar, 11% other sources in 2050

[17] https://www.cbs.nl/nl-nl/cijfers/detail/37105

amounts to over 1500 km^2 (on land or at sea), comparable to the province of Utrecht.

Costs

The cost of producing electricity from sun and wind has been steadily declining over the past decades, and a further decline is expected by 2030 and 2040. Learning effects are expected through optimisation of production processes, scale effects, but also through higher efficiency of solar panels and larger wind turbines (Xiao et al., 2021). Cost estimates for the Netherlands and Western Europe for 2030 and 2040 range roughly from 30 to 50 Euros per MWh for onshore wind, 40 - 75 for offshore wind, and 40 to 60 Euros per MWh for PV (see Appendix C Electricity). These are the costs for the PV panels and wind turbines, including installation and maintenance costs.

For wholesale prices, the climate and energy Projections (PBL, 2021) assume 47 [32-68] EUR/MWh for 2030, and Den Ouden et al. (2020) 50 [25-100] EUR/MWh for 2050. For 2021, the wholesale price was on average EUR 56/MWh, of which EUR 11 was network costs for transport and distribution (CBS, 2021).

However, fully climate-neutral electricity could have higher costs. Hoogervorst (2020) performed a meta-analysis for PBL and arrived at a production cost of 85 EUR/MWh. We assume 75 EUR [50-100] in our cost analysis for production, transport and distribution.

Scarce resources

This box covers several lifecycle stages, mainly use in vehicle, but as it is also relevant for electricity generation, we place it here.

The energy transition required for a climate-neutral scenario has implications for the demand for materials. For the electricity network, PV panels, wind turbines, batteries and electric motors, a number of critical or scarce materials are important (see table 2.2 and figure 2.3). These are mainly copper, lithium, silicon, cobalt, nickel, manganese, platinum and rare earth elements (REE), for example neodymium, dysprosium, praseodymium and iridium (IEA, 2021)[18] . For example, a Tesla S has enough lithium for 1000 laptops, and 1 electric car (EV) with a 60 kWh battery (NMC111) needs as much cobalt as 3300 iPhones. REE are amply available in the earth's crust, but in very low concentrations.

Lithium, cobalt, platinum and SA are on the EU's list of critical materials: raw materials that are essential to the economy but whose supply the EU considers to be at risk (EC, 2020).

[18] But lower demand for catalysts for exhaust treatment also save some critical metals (ZA and platinum)

Table 2.2 Application of (critical) materials in electricity system and EV batteries

Application	Rare earth elements	Other (critical) materials	Comments and alternatives
Wind turbines	Neodymium, praseodymium	Copper, nickel	Permanent magnets, especially for marine turbines and EV electric motors. Gearbox turbines can do with less REE, but require more maintenance and have lower efficiency
PV (silicon / thin film)	Indium, Tellurium, Selenium	Silver, silicon, copper	
Storage (electrolysers, system batteries)	Iridium, scandium	Platinum, nickel, cobalt, lithium	Iridium is essential for PEM fuel cell
EV batteries		Lithium, cobalt, nickel, manganese, copper	Cobalt comes >50% from Congo, as a by-product of copper mining. China controls 90% of processing. New battery technologies, such as lithium iron phosphate (LFP) or solid state batteries, can save a lot of cobalt and nickel (but have less capacity)
Electric motors	Neodymium, praseodymium		Non-magnet electric motors are in development
Electricity network (cables, stations)		Copper	

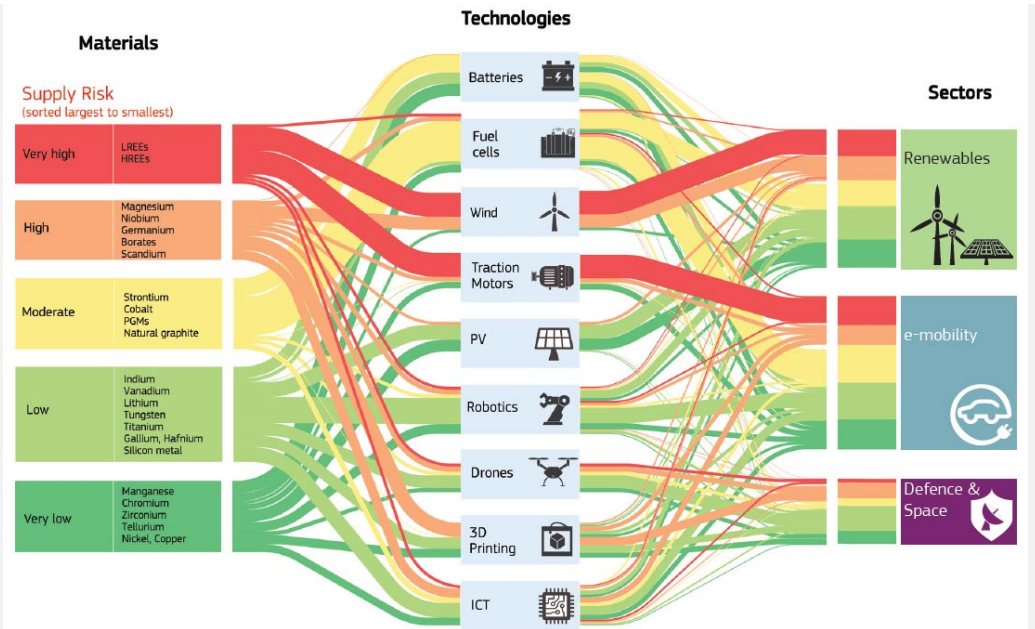

Figure 2.3 Critical metals needed for different technologies, based on the expected development of these technologies within the EU

Source: European Commission, Joint Research Centre (2020).

Resource depletion for lithium is estimated after 2060 based on current production volumes, while for nickel[19], cobalt and manganese this point is between 2030 and 2060 (Mulvaney et al., 2021; see also Zijlstra et al., 2022). In a scenario where the global temperature increase remains well below 2°C, requiring a lot of PV, turbines and electric vehicles, the demand for lithium, cobalt and copper in 2030 is about twice as high as production from mines currently in use or under development (IEA, 2021).

Van Exter et al. (2021) also consider availability of some metals a risk for the energy transition: "For example, [assuming current technology] the annual demand for lithium for the Dutch energy transition grows to an average of 12-15% of current global production in 2040-2050. For neodymium, dysprosium, praseodymium, iridium, cobalt and platinum, the demand increases to well over 5% of global production. This is significantly more than the Dutch share of global GNP (1.0%), final energy consumption (0.5%) or number of inhabitants (0.2%)" (p. 2). The more generation capacity for solar and wind energy (and batteries) in the Netherlands, the higher the risk of shortages. This can be limited by reducing the demand for these metals (through energy conservation and a different energy system design), innovation for technologies that contain fewer metals, extending the lifetime of installations, and improving the capacity to recover metals (modular design for PV).

In addition, there are substantial environmental and social impacts of metal mining. Cobalt mining in Congo is associated with human rights violations including forms of child labour (GIZ, 2021). Half of lithium and copper mining takes place in regions with high water stress, which in turn may increase supply risks due to climate change (IEA, 2021). Nickel mining in Indonesia has local impacts on water quality (The Guardian, 19 February 2022). In addition, price fluctuations on the commodity market, which may become more frequent due to increasing changes in supply, have a greater impact on developing countries than on richer countries.

2.2 Transport and distribution of electricity

From the place of generation, the electricity is transported to a power point[20], charging station or road transport station or inland waterway vessels. This may be a short distance, if the charging station or point is fed by local solar energy[21], or longer, in the case of large-scale solar parks at peripheral locations or offshore wind[22]. In this paragraph, we consider the electricity distribution network as a whole. In addition, there is also a role for, for example, home charging systems that can charge vehicles partially on home-generated solar energy.

In order to bring electricity from high voltage to low voltage, there are four or five levels[23] of electricity networks in the Netherlands, with currently a total of 310,000 km of cable. The largest wind and solar parks, as well as power plants, are connected at the highest level, while smaller parks and PV plants are connected at

[19] At the time of writing, there was a 300% increase in the price of nickel in one week following the invasion of Ukraine (not due to scarcity, but due to speculation in the market). The lithium price quadrupled in 2021. There is a mismatch between growth in battery production and mine development.

[20] With 99.99% availability of power, the Netherlands is the world champion of 'enjoying power without interruption' (Dekker, 2022)

[21] Or even shorter, without a charging station, by integrating PV into the vehicle itself (https://www.pv-magazine.com/2021/02/24/vehicle-integrated-pv-reduces-ev-charging-time-in-sunny-regions-by-40/)

[22] Intermediate storage of electricity can also be part of transmission and distribution, and is dealt with separately below.

[23] Extra high voltage (EHS) (230-380 kV), high voltage (HS) (110-150 kV), intermediate voltage (TS) (25-66 kV), medium voltage (MS) (3-23 kV) and low voltage (LS) (0.4 kV). All are alternating current.

the second, third or fourth level (Netbeheer Nederland, 2019). Between the levels are transformer stations that take care of the conversion between the voltage levels.

Efficiency

The transport from the source to the point of loading of electricity, and the conversion between the different voltage levels, cause energy losses in the network. At high voltage the losses per km are the lowest, approximately 1.5% per 100 km. Based on the table in Appendix C Electricity, we assume a transmission and distribution efficiency of 92-98%, with an average of 95%.

For transport over longer distances, such as from North Africa to Europe, direct current is used instead of alternating current to reduce losses to 3% per 1000 km. Such a cable is already in operation in China, with a direct current of over 1 MV[24] .

Land use

The electricity transmission system - the transformer stations, high-voltage pylons and cables of the electricity network - takes up quite a lot of space in the Netherlands, especially in and around urban areas. We will consider the whole system here, noting that road mobility may account for no more than about 25% of total electricity demand (see section 2.1). Locally, the connection capacity for recharging an electric car can be as large as the electricity connection of several households combined.

We all know the small transformer stations in the city or along the road in the countryside. These are 10-35 m^2 each. MS-MS stations are also ubiquitous with about 20 per city of 100,000 inhabitants (200-4000 m^2 each). Of the high-voltage medium-voltage stations, some 4-6 are on the outskirts of an average city, 10,000-40,000 m^2 (1-4 ha) each. The largest stations, a few per region, are around 10 hectares in size each (NetbeheerNL, 2019). In addition to the direct land take, rules for the minimum distance of transformer stations from dwellings and other buildings must be taken into account. See Figure 2.4 for an illustration of the various power stations.

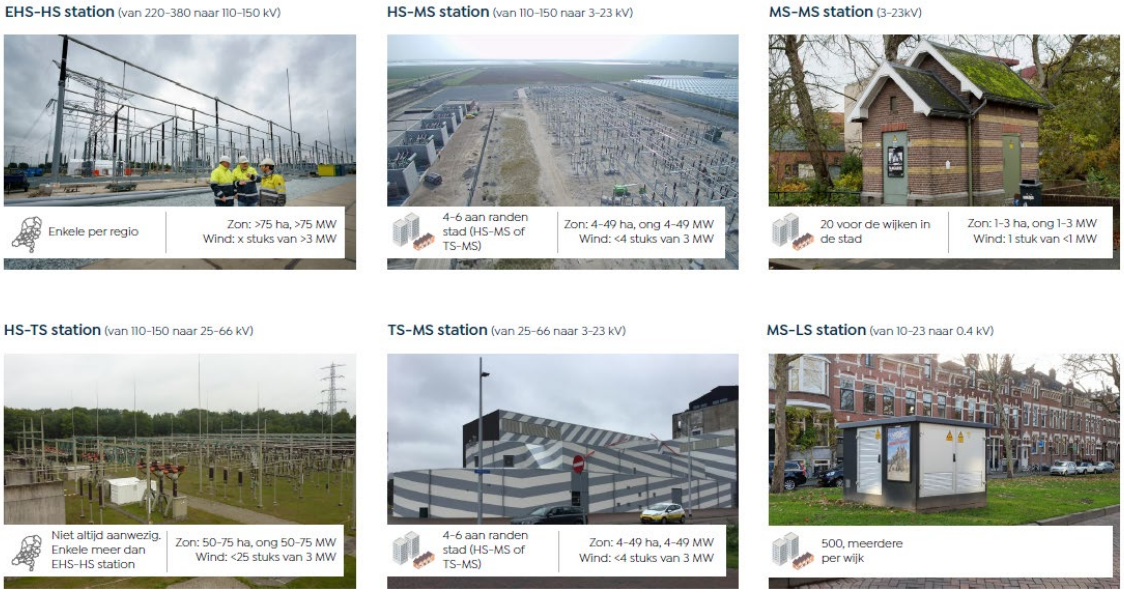

Figure 2.4 Types of power transformer stations

Source: Netbeheer Nederland (2019).

[24] https://global.chinadaily.com.cn/a/202201/25/WS61ef4f1ca310cdd39bc8303b.html#

The land use for the cables should also be mentioned. The most eye-catching are the 60m high high-voltage pylons with the 380 kV cables. The width of the strip for these cables is approximately 100m. This can vary from 19 to 162m and is referred to as the 'obstructed strip', whereby restrictions apply to buildings and other activities in connection with the maximum permissible exposure to magnetic fields (TenneT, 2020a). Virtually the entire 220/380 kV grid is above-ground. Recently, a statistically increased risk of leukaemia has been observed when living at a distance of 0-50 m from a high-voltage line (Gezondheidsraad, 2022). This provides an "additional argument for a precautionary policy around high-voltage lines"[25]. For voltages up to 150 kV, undergrounding is the norm, despite higher construction and repair costs and lower reliability. A strip width of between 1 (low and medium voltage) and 10 metres (medium and high voltage) is used for this (Netbeheer Nederland, 2019; 2021).

More solar and wind energy in the electricity mix can have consequences for the network. Decentralisation can partially reverse the direction of transport, as the geographical distribution of supply and demand changes. Part of the generation will take place in rural areas, directly on the distribution networks, which are not equipped for this. But even in cities, the limited transmission capacity on the demand side is already visible[26] .

In order to meet the expected growth and change in total electricity demand, 400-700 km of 220/380 kV lines will have to be added to the current 1500 km in the period up to 2050, taking up a total of some 40-70 km^2 of additional space (Netbeheer Nederland, 2021). The upper end of the range is relevant to high growth in offshore wind (52 GW in 2050). For the 110-150 kV grid, the increase is about 1000 km (10 km^2) on the current total of 4400 km.

Medium- and low-voltage cables must be laid primarily to facilitate the expected increase in electric transport and heat pumps, and the current underground space requirement for these is around 250 km^2. This will double if 60,000-80,000 km of cable are added, and for this purpose 1 in 3 streets will have to be opened up (Netbeheer Nederland, 2021).

Specifically for electric vehicles, the possible effects on the electricity grid that need to be overcome are: voltage variability, due to variable and sometimes high power demand, increase in peak demand, frequency changes (harmonic disturbance), phase unbalance, voltage dips, losses and overloading of transformers in the distribution network (Shareef et al., 2016).

In the coming decades, about half of the current 250 high-voltage to medium-voltage stations will have to be added, 600-800 medium-voltage stations and 7500-12000 small transformer houses out of the current total of 84,000. The total extra space required comes to 6-11 km^2. This may seem a limited area, but it is nevertheless a considerable challenge in the densely populated Netherlands.

In total, the above-ground electricity network, including EHS cables and stations, could take up some 250 km^2 (comparable to the surface area of Amsterdam) of above-ground space in 2050, of which about 2/3 is already in place. Per MWh per year, this would amount to an average of about 1 m^2.

To import electricity, various connections will have to be made from North Africa to Europe and connected to national electricity grids (ECF, 2010). The infrastructure to be built in North Africa and in Europe will therefore be used by different countries[27] .

[25] https://www.gezondheidsraad.nl/actueel/nieuws/2022/06/29/extra-argument-voor-voorzorgbeleid-rond-hoogspanningslijnen
[26] https://www.at5.nl/artikelen/210982/opnieuw-twee-delen-in-de-stad-waar-stroomnet-aan-maximum-zit-geen-plek-voor-nieuwe-grootverbruikers
[27] See e.g. https://en.wikipedia.org/wiki/Desertec#/media/File:DESERTEC-Map_large.jpg

It is not possible to say exactly which length of HVDC cable will then be used to supply electricity to the Netherlands. We have therefore assumed 1000 km. This would bring the space usage per MWh to about 3 m^2/MWh for the transport of solar-imported electricity.

Costs

The roll-out of charging infrastructure requires expansion and reinforcement of grid capacity, especially of the LS and MS grids. On the other hand, vehicle-to-grid systems can also contribute to reducing the need for grid capacity expansion. It is not possible to indicate which part can be attributed to electric mobility. Therefore, we consider the costs of grid expansion for all sectors together.

Costs, excluding land, for realising transformer stations range from 250,000 euros or less for the smallest stations to 100 million euros for EHS/HS stations. High-voltage cables of 220-380 kV cost 5-10 million euros per km, the low-voltage network 70,000-150,000 euros per km (Netbeheer Nederland, 2019).

Connecting offshore wind farms requires investments in the high-voltage grid. By 2023, this 'offshore grid' will require investments of €4 billion, or approximately €14 per MWh supplied, amortised over a period of 20 years (windopzee.nl, n.d.). Hoogervorst (2020) assumes €15 per MWh for additional grid costs in 2050. We have taken these costs as an intermediate estimate for transport costs in further calculations, on top of the aforementioned €11 distribution costs in 2020.

There are various estimates of the total network investments that will be required to facilitate the broader energy transition (across all sectors). PWC (2021), for example, estimates that TenneT and the three largest regional transmission system operators together will have to invest around 100 billion euros up to 2050 (or over 10,000 per household). KIVI (2021), on the other hand, concludes that it can be done with limited investments, through optimisation of storage techniques such as smart charging, a network of fuel cells, etc. TenneT (2020b) estimates some 8 billion for the high-voltage grid for the period 2020-2029 is required, the bulk of which will be expansion investments.

Apart from the costs, grid expansion or reinforcement is a large, complex and time-consuming task (see e.g. Leguijt et al., 2020). For example, the construction of an EHS/HS station takes around 7-10 years (Netbeheer Nederland, 2019).

2.3 Storage of electricity

Generation of electricity from sun and wind fluctuates daily and throughout the year. In Western Europe, for example, long periods of foggy and windless weather occur, during which the supply of energy from these sources drops dramatically (the so-called 'Dunkelflaute' - dark silence) (KIVI, 2020). Figure 2.5 illustrates how the fluctuation of solar + wind in December 2021 was, and how it could be in 2030 (based on current policies for expanding energy production from solar and wind, and based on the actual supply of solar and wind in December 2021).

At the moment, the difference between supply and demand due to the fluctuation is compensated by natural gas power plants. In the future, CO_2 -free power plants may be flexibly deployed, generating electricity from sources such as biomass (possibly with CCS), biogas, hydrogen (power to gas via electrolysis) or synthetic methane (Rooijers & Jongsma, 2019). The latter two options will involve large energy losses (see chapters 3 and 4), but if hydrogen or synfuels are to be imported on a large scale, for example to produce bunker fuels, this may still make sense in order to store fluctuations in production. However, the first two are even less less efficient, if one considers the efficiency of photosynthesis compared to PV.

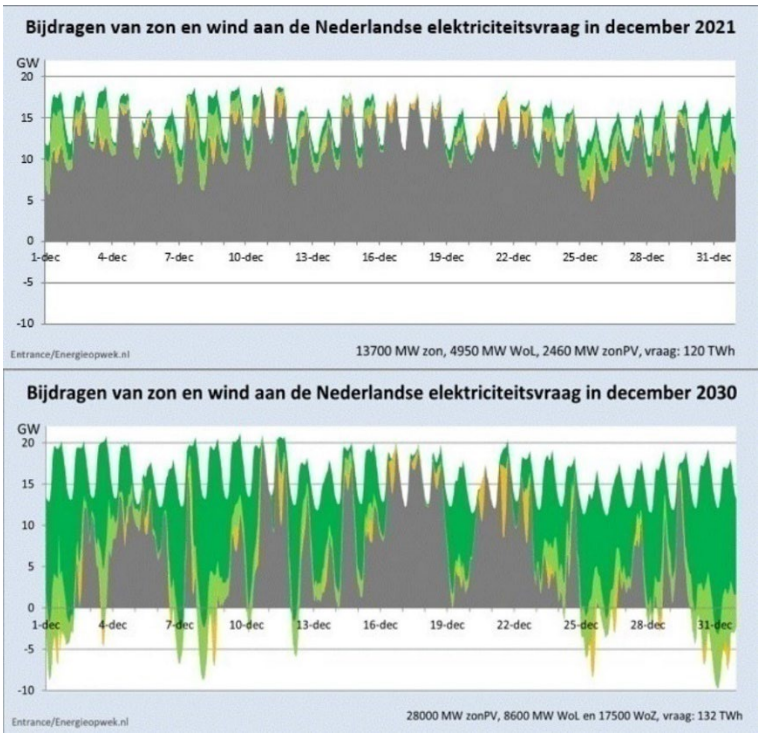

Figure 2.5 **Fluctuation of solar+wind contribution to the electricity supply over a December month)**

Yellow: solar, light green onshore wind, dark green offshore wind; grey: shortfall in supply of solar and wind based on hourly energy demand.

Source: Visser, 2022.

The frequency on the electricity grid must fall within very narrow limits of 50 Hz, otherwise damage may occur to appliances. Demand and supply management, especially in industry and mobility (smart charging), and interconnectivity with foreign electricity grids also help to bridge the gap between supply and demand. Curtailment of PV and wind energy is also an important option to avoid peaks in the future. This is already being applied to new solar parks and to peaks in generation at small PV installations.

In smart charging, the charging rate is varied so that the electricity demand is adapted to the supply, but in such a way that the battery is charged when the user wants it (Elaad, 2019). As a result, there is in principle great potential to prevent and/or postpone grid upgrades, especially for the low-voltage grid[28] . According to Elaad (2019), staggered charging can reduce peak load on the grid by 2 GW (current peak demand: 18 GW), which can generate €1.4bn in cost savings for grid upgrades. There may also be benefits for users if variable tariffs apply.

In addition, short-term (days, weeks) and long-term (seasonal) storage of electricity at higher renewable generation than demand will be needed in the future to absorb fluctuations. There are various technological options for storage:

- Power-to-gas, where hydrogen is produced via electrolysis. Hydrogen storage can take place, for example, in salt caverns or empty gas fields (see Chapter 3).

[28] Some electric cars have an electrical charging capacity equivalent to the peak demand of about 10 households, which can cause local congestion on the grid when many EVs are charged simultaneously. A household connection (usually 8 or 17 kW) does have a much higher capacity than the peak demand (usually 1 - 1.5 kW). In addition, cars are stationary 96% of the time and on average an EV with a 50 kWh battery is charged only 1.1 times per week, so spreading the charging is theoretically very well possible.

- Stationary batteries, also called system batteries. These exist in various types and applications (IRENA, 2017; Den Ouden et al., 2020). Electricity is stored when there are peaks in supply and fed into the grid at a later time.
- Batteries in vehicles: vehicle-to-grid (V2G), also called bidirectional charging. The battery of an EV can temporarily act as a buffer capacity in the grid, by means of storage or feed-in. This technology is under development, and both the charging stations and the vehicle must be suitable for it. In addition, there must be communication between the vehicles, the charging station, the power grid and the household energy system, and this must all be organised between the various parties (ElaadNL, 2019). Here, privacy of stakeholders must also be considered. One uncertainty is the extent to which V2G will affect battery life (PwC strategy&, 2021). The storage potential is substantial: if 9 million passenger cars have a battery of an average of 40 kWh, this represents a theoretical storage capacity of 360 GWh, which is roughly equivalent to the current total daily electricity consumption in the Netherlands.

Efficiency and cost of electricity storage

Netbeheer Nederland (2021) expects that some €3-8 billion per year in conversion and storage will be needed for flexibility in 2050, most of it for batteries and power-to-gas. Table C.4 in Appendix C Electricity gives efficiencies (round-trip, i.e. storage and conversion back into electricity) and investment costs of the most commonly mentioned storage technologies (for hydrogen, see chapter 3). For lithium-ion batteries, which are often considered suitable for system batteries (at house or neighbourhood level), this is around 75-95%. Investment costs range from under €100 per MWh capacity to over €1000 per MWh.

Hoogervorst (2020) assumes €6 per MWh as imbalance costs (costs for back-up and storage in a climate-neutral electricity system) for 2030.

Land use of electricity storage

Space usage for storage is generally limited compared to other steps in the chain. In the four climate-neutral scenarios[29] for the Netherlands mentioned earlier (Den Ouden et al., 2021), it is estimated that some 20 - 40 km^2 of space will be required for storage, mainly for system batteries, but also hydrogen production and storage (Netbeheer, 2021). For e.g. Zuid-Holland alone this could be around 1 - 1.5 km^2 (Leguit et al., 2020). It is not known what proportion of this can be attributed to mobility. Table 2.3 provides key figures for a number of techniques.

Table 2.3 Space requirements of some storage technologies

Storage technology		Unit	Source
System batteries	71	m^2 /MWh	Grid Management NL 2021, based on Generation Energy
Hydrogen storage (underground)	0.13	m^2 /MWh	Netbeheer NL 2021 based on Gasunie

2.4 Charging

In principle, there are three ways of charging electric vehicles: conductive, inductive (wireless), and battery-changing systems.

[29] See Appendix C for the assumptions of these scenarios

Conductive charging works through direct physical contact between metals, and can take place through a cable and plug or through an overhead wire, as in the case of the trolley bus, train or Electric Road System for trucks.

With wireless or inductive charging, there is an electromagnetic field between two coils, i.e. no cable is needed. Such charging systems can be stationary, where the vehicle can be charged while parking or waiting at a traffic light, or dynamic, where charging can be done while driving. Distance between charger and receiver is usually up to 20 cm (Bi et al., 2016). Disadvantages of inductive charging can be expensive infrastructure, lower efficiency (especially for dynamic systems this can be below 80%) and electromagnetic compatibility. As a result, these systems are still relatively little developed (Brenna et al., 2020). However, research into inductive charging is taking place, for example through pilots in Japan, Sweden and the UK (Robinson, 2020). Verbeek & Culenaere (2019) also list it among longer-term technologies.

In battery swapping systems, a flat battery is replaced by a charged battery at a battery swapping station. The biggest advantage of this is the reduction in charging time that can be gained. In addition, Vallera et al. (2021) see a benefit in this due to the possibly lower peak demand and thus the impact on the electricity grid. However, it involves high investment costs (Al Hanahi et al., 2021). There are at least two pilot projects for trucks in Germany and Australia. In China, battery swapping systems are already relatively well developed for passenger cars (CnEVPost, 2021), and in Taiwan for electric scooters. In the Netherlands, there is one container ship with exchangeable batteries (see section 2.5). Outside China, this is hardly considered for passenger cars at the moment, mainly because of the diversity of car models and thus the complexity of standardising batteries, which is necessary for an effective battery swapping system.

We will mainly discuss the first and most common way of charging, conductive charging, and pay attention to the other techniques where relevant.

Efficiency of charging

Charging requires the conversion of alternating current from the electricity grid to direct current. Table 2.4 presents some characteristics of different types of chargers.

Table 2.4 Overview of charger types

	Output (kW)	Mains connection
Home charging	3.7 - 11 (AC)	3x25 A
Regular	11 - 22 (AC)	LV
Quick	Up to 43 kW (AC) 50-150 (DC)	MV. Often around 2 MW, but possibly higher in the future
Ultra-fast	150 - 350 (DC)	
Fast for trucks	350 - 500 (DC)	MV
Ultra-fast for Trucks	>1 MW (DC)	MV

For home and regular charging, the charger and inverter are in the vehicle (on-board charger) and for DC, the inverter and charger are in the charging station. The plugs and cables for fast charging are also different from those for regular charging (ElaadNL, 2019).

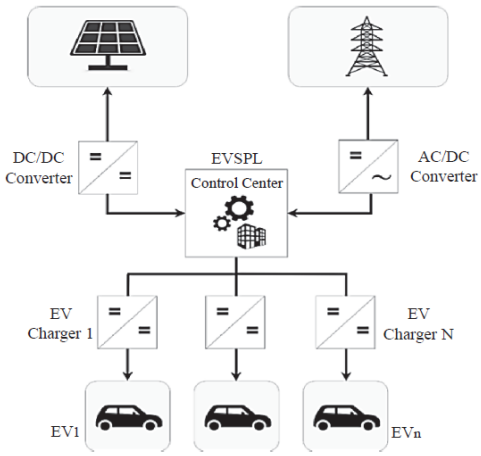

Figure 2.6 Integration of PV at a charging station

EVSPL: electric vehicle smart parking lot.

Source: Osorio et al., 2021.

The conversion efficiency of charging is the quotient of the energy that can be extracted from a charged battery and the energy required to charge the battery. In the charging process, energy is lost in the charging circuit, during the conversion from AC to DC, and as heat during charging. Losses also occur when discharging the battery while driving. Normally, the charging efficiency is around 80-90% (see Appendix C Electricity). If a charging station can be integrated with PV systems (see e.g. figure 2.6), two conversions, that from DC to AC and that from DC to AC, are not necessary and a 10% energy loss can be avoided (Osorio et al., 2021).

Charging at higher power gives a higher efficiency than at lower power, although more cooling is often needed to keep the battery from getting too hot. Charging becomes less efficient the more the battery is charged (Donkers, 2019). Charging at low temperatures can cause damage to the battery.

Space usage and costs of loading

Passenger cars
To supply electric passenger cars with electricity, different types of charging stations are available, which differ in charging time. Charging characteristics of passenger cars and delivery vans are similar in terms of technology and charging capacity (Municipality of Rotterdam, 2020). Besides the capacity for different types of charging stations (as indicated above), there are other factors that determine the charging speed.

First, the car itself, with many 1e generation EVs having 3.7kW on-board chargers and some models 7.4kW. Future models are expected to have 11kW. In addition, the power connection must be able to handle the power (ElaadNL, 2019). The number of cars charging at the same time is also relevant because there is a maximum to the total power supplied. At high loads, a smart charging system can distribute the peak by reducing the charging speed. This is especially true for slow charging. Possibilities for such flexibility exist in solitary charging points at home or at work and in charging stations.

To be able to charge quickly, high charging capacities are needed. The share of fast charging in the total electricity demand of an EV is often assumed to be around 10-15% (see e.g. Berveling et al., 2020 based on ANWB and TNO, 2019 in MRA-E, 2020). A fast charger will charge the battery of an average electric car to 80% in 15

to 30 minutes. Often, the charging speed is also reduced from 80% state-of-charge (or lower) to protect the battery and extend its life.

Possible lack of technicians: To meet the goals of the Klimaatakkoord, 1.8 million charge points (private and (semi-)public) are needed in 2030 (Climate Agreement), for about 2 million electric cars. To achieve this target, from 2025 onwards, more than 550 charge points must be installed per day. In 2030, a rate of more than 1,400 charge points per working day will even be required to meet demand, compared with approximately 217 public charge points per working day today (Dirks et al., 2020). A bottleneck here is the number of technicians needed to carry this out.

Land use

A large proportion of charging stations are in public spaces. Millions of charging points would be needed if we were all to drive electrically. Of the 1.8 million charge points required in 2030 in the Netherlands, around 0.4 million will be public[30,31], i.e. available 24 hours a day, and around 0.56 million will be semi-public (e.g. at a restaurant or shopping centre). About 10,000 fast chargers are needed (0.5%), and about 0.8 million on private property[32] (NAL, n.d.). Many public charging points have two charging points per pole.

Per charging station, the above-ground[33] space requirement is limited, up to about 1 m^2 but on the pavement every square metre counts, especially in cities. In addition, the charging cable also takes up space. In a report about obstacles on footpaths, charging stations are only mentioned as a side note (Molster et al., 2021). Others see them as something that should be looked at (Wolbertus et al., 2020), with wireless charging as a possible solution. 1.4 million (semi-)public charging stations (required for 9 million EVs in 2050 by ElaadNL (2021)) would then occupy about 1 km^2.

Calculation example PV and EV: how many solar panels do you need to generate electricity for your EV?

With 9 PV panels of 360 Wp (1x1.65m) you can generate about 3000 kWh per year in the Netherlands, which is enough to drive 13,000 km, assuming 0.2 kWh/km. Due to the variable production in PV, storage of electricity in a house battery is necessary to actually drive on your own solar power.

Another illustration of PV and EV is that for 1 fast charger of 150 kW at maximum solar irradiation in the Netherlands, over 400 panels of 1x1.65 m are needed. However, this energy is not always available.

To save public space, the integration of public charging points in street furniture, such as street lamps, or in charging plazas is an option (NKL, 2021). A charging plaza is a form of clustered charging, where a number of parking spaces equipped with charging points can be found together.

On the one hand, the need to charge electric cars puts some pressure on public space. On the other hand, space becomes available again because petrol stations in the city will not be needed, or at least will be needed less.

[30] There are some 10 million public parking spaces in the Netherlands, out of a total of some 19 million (TNO, 2021). And 2.2 parking spaces in total per car (Zijlstra et al., 2022).
[31] Public charging stations are located in public spaces, but are not a public good. It is companies that operate this utility (Dirks et al., 2020).
[32] About 30% of the Dutch live far enough away to be able to charge their car at home (Voermans, 2022)
[33] Underground cabling will also occupy space, which may be limited in cities

Outside the city, fast chargers will be needed, especially along motorways and urban access roads. These can possibly be combined with other hub functions (including petrol stations) and/or charging plazas. By 2030, there will already be more fast-charging points needed than there are petrol filling stations today (Verbeek & Cuelenaere, 2019). Approximately 10-35 m^2 of above-ground space is required for a fast charging station. 30,000 fast chargers will then need a maximum of 1 km^2.

At some service stations along the main road network, more than 40 fast chargers will be needed, assuming 120 kW per fast charger (Verbeek & Cuelenaere, 2019). With higher capacities, fewer will be needed because cars can be charged faster. "The medium-voltage network to which fast chargers are connected is already spread throughout the country, but the efforts required to connect current service areas to it in a future-proof manner can be considerable" (Verbeek & Cuelenaere, 2019).

Costs
For a 22 kW charging station, NKL (2018) reports an investment of EUR 3270 in 2018 (including grid connection costs), with a further cost reduction of 15% possible. In addition, there are 510 euros in annually recurring costs. Berveling et al. (2020) estimate a 22 kW regular charge post (with smart charging) at 3000 - 6000 euros for the investment and installation. In addition, there are 550 euros per year in fixed maintenance costs. Fast chargers cost between 20,000 and 100,000 euros.

In March 2022, a charging station delivered an average of 500 kWh per charging point per month in 6 urban regions (www.evdata.nl). An increase of 50% is possible here (NKL, 2018).

This brings the cost of charging stations to about 0.07 €/kWh charged.

For fast charging, the costs for maintenance and operation are higher than with a regular charging network. At 300 euros per kW, the costs come to 0.09 €/kWh. These costs are factored into the charging price. In general, the costs to the end user for a fast charging session are on average a factor of 2 higher than charging at a regular publicly accessible charge point and a factor of 3 higher than charging at a home charge point (MRA-Electric, 2021). It is unclear whether this is due to the difference in maintenance and operating costs, or whether the profit margins are also higher.

Heavy duty vehicles

Here we consider long-distance transport by N3 category vehicles, i.e. vehicles heavier than 12 tonnes. These have a load capacity of up to 40 tonnes and come in both tractor-trailers and heavy duty trucks, of which respectively 81,000 and 63,000 were registered in the Netherlands in 2020 (Van Zyl et al., 2021), with a clear trend towards tractor-trailers over the past two decades (Ecorys, 2020). A tractor-trailer travels an average of 87,000 km/yr (Van Zyl et al., 2021). As this requires about 6 times as much energy per kilometre as a passenger car (see appendix B), the annual energy consumption of one truck is equivalent to 40 passenger cars. More frequent or longer charging, and with more power, will therefore be necessary.

On average, 80-90% of the electricity demand of a battery-electric truck can be met from company premises (depots), distribution centres or charging hubs[34], and 7%-20% with fast charging (opportunity charging) during short stops, especially along

[34] New locations can be developed specifically for electric charging, or existing locations can be opened up to other companies who can then charge their trucks there.

motorways at service areas and truck parks (ELaadNL, 2020a; T&E, 2021[35])[36]. Without fast charging during the day, i.e. only overnight charging, the potential for new sales of battery-electric tractor-trailers is limited to around 10% over the next two decades (Van Zyl et al., 2021).

The fast chargers at service stations will have a capacity of 350 to 1000 kW or higher, and it is expected that ultrafast chargers of more than 1 MW will be installed in the coming years (MRA-Electric, 2021). To illustrate: with a 1 MW charger, a battery of 800 kWh[37] can be charged to almost 80% in 45 minutes[38]. Slow charging at depots, for example, can be done with 50 kW, whereby a 400 kWh battery[39] is charged in 8 hours.

Supply points, of which there are 223 in the Netherlands, can have a peak demand of e.g. 4 MW, for example 2 x 1 MW loaders and 4 x 350 kW loaders. This requires a medium-voltage connection. Truck parking areas are mainly used at night, and there are 98 of these in the Netherlands. In principle, these can do with a smaller capacity. To enable battery-electric trucks to travel long distances, a network of fast chargers is needed. In a growth scenario for battery-electric trucks to about 50,000 by 2035 (battery-electric share in new sales is about 60%), the following numbers of charging points will be required (table 2.5) as well as a grid connection capacity of 3 GW (ElaadNL, 2020). Part of this will be new or upgraded connections.

Table 2.5 Projected number of charging points and demanded capacity in ElaadNL mid-scenario for 50,000 electric trucks in 2035

Locatie:	Prognose totaal aantal laadpunten (midden scenario)			Gem. aansluit-vermogen per laadpunt (kW)	Verwachte gevraagd vermogen in MW (midden scenario)		
	2025	2030	2035		2025	2030	2035
Depot laadpunten	1.362	11.707	38.862	50	68	585	1.943
Gedeelde laadhubs	60	1.208	6.519	50	3	60	326
Truck parkings	45	403	1.397	70	3	28	98
Verzorgingsplaatsen	28	253	878	650	18	164	570
Totaal:	**1.495**	**13.571**	**47.656**	-	**93**	**838**	**2.937**

Source: ELaadNL, 2020.

A concern is how to realise the grid upgrades and the lead time and costs involved (Al Hanahi et al., 2021). Realising a grid connection for charging infrastructure can take 2 to 10 years (Ran et al., 2021). It is possible that many companies will apply for grid upgrades in fairly quick succession (ElaadNL, 2020). Smart-charging strategies can help reduce peak demand in an area, and distribute electricity demand over the time that trucks are parked.

Investment costs for depot and HPC chargers are estimated at 400 and 500 €/kW respectively (T&E, 2021), with a cost reduction of 1.5% per year for the next

[35] It was assumed that 40% of the total energy consumed by electric trucks would be charged at public chargers, of which 20% will be public opportunity (HPC) chargers and 20% public overnight. The rest is expected to be covered by depot chargers (45%) and destination chargers (15%).

[36] In an analysis of stop locations of regional and long-haul trucks in Europe, 60% of the stops are shorter than 3 hours, and 1/3 longer than 8 hours. The 10% busiest locations comprise more than 50% of the stops (Plötz & Speth, 2020).

[37] A truck with an 800 kWh battery has a range of 400-700 km, comparable to a diesel truck with a 250 L tank and 30-40 L/km efficiency.

[38] This is the break time that drivers must take every 4.5 hours (T&E, 2021: Regulation (EU) 561/2006). Although it also says: "This break may be replaced by a break of at least 15 minutes followed by a break of at least 30 minutes each distributed over the period in such a way as to comply with the provisions of the first paragraph".

[39] Most electric trucks currently on the market fall within this capacity, but for example the forthcoming Tesla Semi has a capacity of 600-1000 kWh (Al Hanahi et al., 2021).

decade. With utilisation rates of 20% and 10% respectively (ElaadNL, 2020) and 10% annual costs (compared to investment costs), the charging costs for depot and fast charging come to 0.04 and 0.10 €/kWh.

Electric Road Systems[40]

An alternative to charging at charging stations is dynamic charging on the road, i.e. while driving. Electric road systems (ERS) enable trucks to charge their batteries while driving by means of a pantograph with electricity from overhead wires. This technology is still in a start-up phase, and there are pilots on a few kilometres of motorway in Germany and Sweden.

The advantages of this technique are 1) time savings because there is no need to stop to charge, 2) considerable smaller battery (needed only for the distance on roads outside the ERS network) needed compared to BEVs so more charging capacity and less use of critical materials, 3) possible lower peak demand on the electricity network compared to fast charging stations, and 4) no investment needed from transporters themselves in charging stations, apart from pantograph technology for the chargers.

A recent study (Van Ommeren et al., 2022) concludes that ERS might be economically interesting compared to alternatives like BEV and hydrogen fuel cells, although the uncertainties are large. However, a network of at least 1000 km of highways will have to be equipped with ERS in the Netherlands. The investment costs for the infrastructure amount to 3.3 million €/km (excluding any electricity network adaptation costs). A German study assumes 4.1 million €/km (Wietschel et al., 2017 in Breuer et al.). The utilisation rate of the ERS network is, of course, of key importance in the cost-benefit ratio. At a usage of two vehicles per minute, a 0.20 EUR/kWh price can make ERS cost-effective (including electricity). The study assumes about 100 km to be driven on the battery to reach final destinations outside the ERS network. This compares to 400-800 km for BEVs. So the battery capacity can also be substantially lower.

Further points of interest are the following. A large amount of copper is needed for the overhead lines. With intensive use, wear will also be high and it is estimated that over the 35-year lifetime of ERS, 1000 kg of copper per km of ERS is released into the environment (this is much higher than for train wires due to more intensive use). On the other hand, there is of course a saving in critical raw materials for the battery (and associated environmental impacts) such as cobalt, lithium, nickel and rare earths compared to BEV.

It will take time to build a network of ERS infrastructure, and it will take time to increase the share of pantograph trucks in the fleet. The transition to other CO_2 neutral solutions may be faster and by then large investments in these alternatives will have been made, making ERS less interesting.

Safety risks such as motorists driving into a pole or being distracted by the overhead line, or wire breakage, are all estimated to be relatively low and manageable.

Landscape effects must be carefully considered. For the motorist, the overhead wires will create a more restless image. And the spatial quality, especially in open areas, will also be reduced.

Inland navigation

Inland navigation is in an even earlier phase of electrification than heavy road transport (NKL, 2020). The 'Greendeal zeevaart, binnenvaart en havens' has set the goal of having at least 150 emission-free inland navigation vessels in operation by

[40] Source: Van Ommeren et al. (2022) unless otherwise stated.

2030, out of a total of 5,000 inland navigation vessels. The share of electric is not specified, but charging infrastructure will be needed. If all 150 are electric, 20 charging stations for battery containers will be required (NKL, 2020).

One possibility for electrifying inland navigation is to use a battery swaping system with battery containers (energy as a service). The empty battery is exchanged for a full one at charging points and recharged ashore. This is particularly suitable for container ships, which in total account for some 10-15% of inland navigation tonne-km (ELaadNL, 2020c), but a battery container can also be placed on deck for bulk carriers. One such container ship is now sailing electrically in the Netherlands (Figure 8). In Norway, a larger fully-electric container ship with a battery capacity of 7 MWh and a carrying capacity of 120 containers is sailing (Manthey, 2021).

Picture 2.2 **The first electric inland vessel in the Netherlands, sailing since 2021**

Source: Lewis, 2021.

There is currently 1 charging point for exchanging and charging batteries: CCT terminal in Alphen. The ZESpack charging station delivers 2 MW, with which two ZESpacks (each with a capacity of 2 MWh) can be charged simultaneously in 2 hours. Depending on the load profile, the demand of a container ship is between 0.5 and 1 MW. So with the 2 ZESpacks they can sail for 4 to 8 hours. There are also other concepts, but little recent news about actual implementation.

The total electricity demand of inland navigation at 100% electrification will be about 2 TWh per year (see 2.1), where container shipping is about 0.2 TWh, and the rest bulk and small dry cargo.

2.5 Use in vehicle

Battery-electric vehicles are strongly on the rise for road transport with currently 3% of the car fleet fully electric in the Netherlands (RVO, 2022), but are also gaining increasing attention in shipping (especially inland shipping). The electric drivetrain is characterised by a very high efficiency and the possibility of using energy generated from very different sources, including a wide range of renewable energy sources. Bottlenecks for heavier transport are mainly the limited energy content of battery systems, as well as the infrastructure and time needed for charging.

An electric vehicle has a battery instead of a fuel tank to store energy. And an electric motor instead of a combustion engine to convert the electrical energy into kinetic energy. In addition there is a charger, a DC-DC converter (for auxiliary applications) and a cooling system to keep the battery from overheating (see section 2.4 on charging). Figure 2.7 shows this for a passenger car.

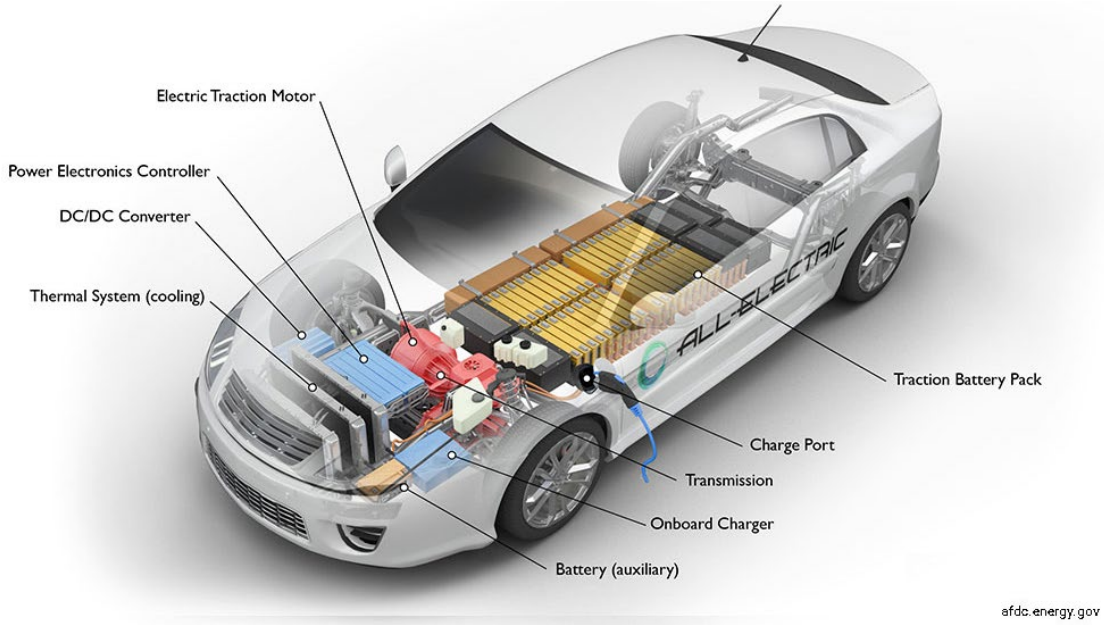

Figure 2.7 Components of an electric car

Source: https://afdc. energy.gov/vehicles/how-do-all-electric-cars-work

A lithium-ion battery consists of an anode and cathode, separated internally by a separator and an electrolyte in which the ions can move. When charging, the current flows from the anode (negative electrode) to the cathode (positive electrode) and the ions from the cathode to the anode. When discharging, it is the other way round (figure 2.8).

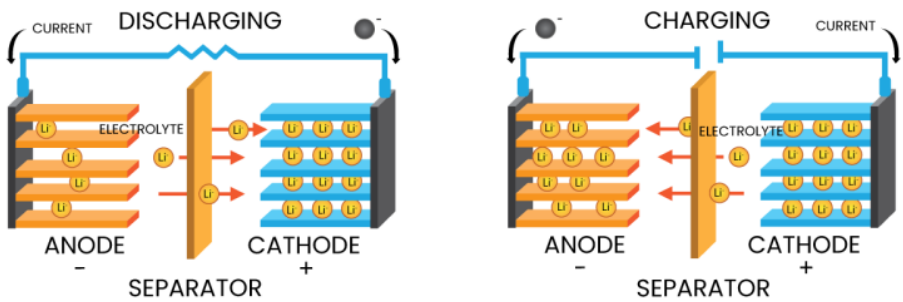

Figure 2.8 Principle of charging and discharging a lithium-ion battery

Source: https://sinovoltaics.com/energy-storage/batteries/materials-for-lithium-ion-battery-safety/

Of key importance for the development of electric vehicles is the energy density of the batteries, usually expressed in Wh/kg battery cell. At present, lithium-ion batteries are mainly used because of their relatively good energy density and cost per kWh. These are also called NMC (nickel - manganese - cobalt) batteries. The energy density has increased steadily in recent years and is usually above 200 Wh/kg. That means that a 50 kWh battery has 250 kg of battery cells (the battery itself weighs a little more because of the casing and electronics), and an 800 kWh battery about 4 tonnes. Cobalt-free batteries such as LFP (lithium iron phosphorus) have a lower energy density, but are used increasingly for personal cars. Higher-density batteries are under development, for example solid-state batteries with silicon (figure 2.9).

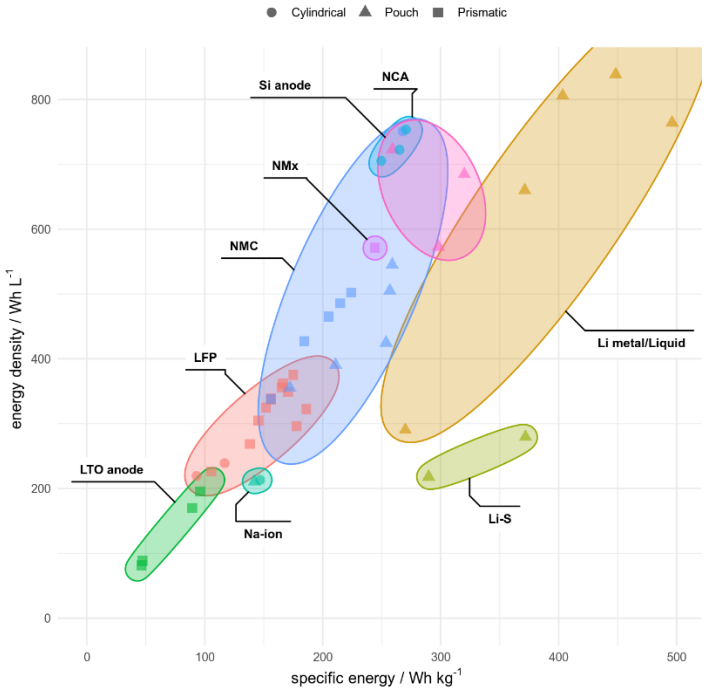

Figure 2.9 **Energy density of various types of batteries**

Source: Lacey, 2022.

Efficiency of electric vehicles

For electric vehicles, the proportion of kilometres driven on motorways, where the vehicle's energy demand is greatest, has a major influence on energy consumption. On average, light road vehicles drive more kilometres in the city than heavy road vehicles. In the city, vehicles are used more dynamically (more acceleration and braking). For short distances and dynamic use, electric vehicles can derive additional benefit from reclaiming braking energy compared to conventional vehicles.

In addition, the weather can affect the energy consumption of passenger cars. A battery works best at about 21ºC. At lower temperatures, both efficiency and usable battery capacity decrease, so heating is needed to keep it at the right temperature - or cooling at higher outdoor temperatures. In addition, the driver will probably want to heat or cool the car, which is done with energy from the battery, reducing the proportion of energy going to the wheels[41].

In the future, this consumption could increase, as new cars become ever larger and heavier (apart from the weight increase due to batteries). Since 2010, this has increased by about 24 kg per year in the Netherlands (Zijlstra et al., 2022). In contrast to petrol cars, there is a strong correlation between vehicle mass and energy consumption with EVs (see figure 2.10), while the efficiency of new EVs has improved only slightly in recent years (Weiss et al., 2020).

[41] https://www.anwb.nl/auto/elektrisch-rijden/waarom-het-weer-van-invloed-is-op-je-actieradius

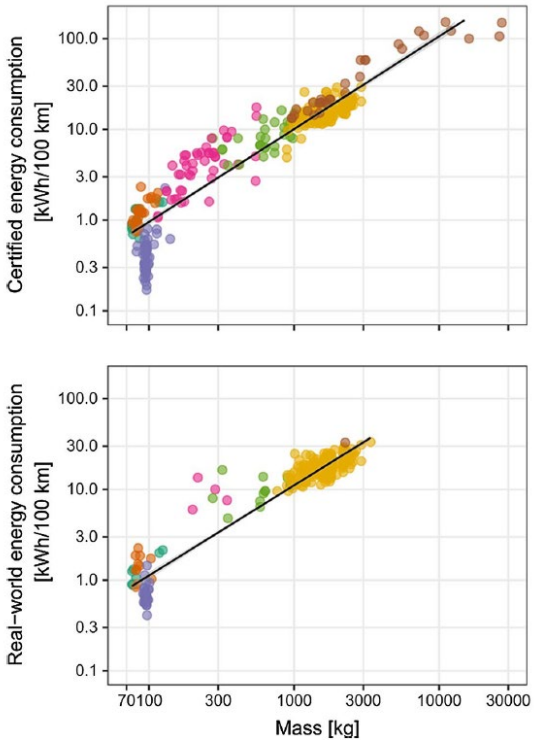

Figure 2.10 Energy consumption by electric vehicle mass on a log-log scale

In yellow passenger cars and in green light electric four-wheelers, other colours are two-wheelers.

Source: Weiss et al., 2020.

Cost of vehicles

The cost of the battery is a key factor in the total cost of an electric vehicle. The cost of the Li-ion battery has fallen significantly in recent years, by a factor of 5 between 2013 and 2020 (figure 2.8) (Bloomberg NEF, 2020). A price of USD 137 per kWh means that a 50 kWh battery costs just under USD 7,000 (about € 6,000). It is expected that the decline in costs will continue in the coming years. However, these are the production costs: for the consumer this amount is significantly higher, possibly double (AD, 2022).

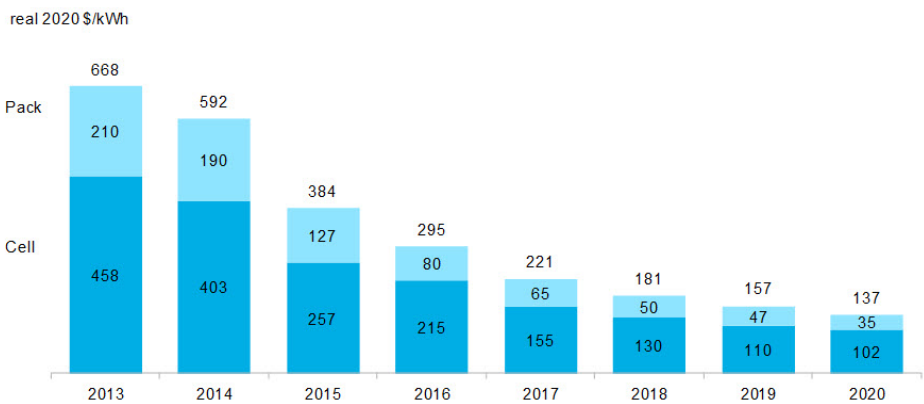

Figure 2.11 Development of battery and accumulator prices per kWh

Source: BloombergNEF, 2020.

Battery-electric trucks are still more than twice as expensive as a comparable diesel vehicle. Much has happened in this market in recent years, including in the heaviest

segment. Based on the STRIVE project, a cost reduction to €132,000 is expected in 2030, compared to €256,000 in 2020 (see Appendix A Costs), for a truck with 400 kWh battery capacity.

For inland navigation, the market is still at a too early stage to say anything about cost expectations. Investment in an electric battery to drive the motor is not yet financially attractive. However, in recent years dozens of ships have installed an electric motor drive, which is then fed by a diesel engine.

Barriers and uncertainties

Availability of scarce and critical raw materials is a point of concern (see also section 2.1). It cannot be ruled out that lithium, cobalt, nickel and rare earth metals for batteries will become scarce. In addition, the extraction of these materials involves social and ecological impacts. The Dutch Battery Strategy therefore aims to promote responsible extraction (IenW, 2021).

Recycling of batteries is still in its infancy. It is difficult to recover all the raw materials from discarded batteries, which may be an obstacle to a circular economy. Recycling is one of the pillars of the Dutch Battery Strategy and the proposal for a European Battery Strategy.

In terms of safety, an extensive report by CE Delft (Hilster et al., 2020) concludes that the safety risks of electric passenger cars do not differ much from those of conventional cars. The main concerns are overheating of batteries and fires in car parks. Current knowledge indicates that there is no indication that both the probability and the effect of overheating are high. However, it is important to have management systems in place should such an incident occur. Other risks, such as collisions with EVs, absence of engine noise, overturning and those from charging stations are similar to conventional cars and can be reduced by regulations and technology. At present EVs still have a higher weight than conventional cars, but it is difficult to determine to what extent this will affect the safety of other road users.

Non-exhaust emissions come from wear and tear on tyres, brakes and the road surface, as well as dust blowing up onto the road. The extra weight and high torque during acceleration causes a little more wear for an EV, but there is a strong advantage for the brakes, which are used less because the braking energy is used to charge the battery. Here the EV does not seem to have any disadvantage compared to diesel vehicles when it comes to PM10, although for PM2.5 in heavier vehicles emissions could be a few percent higher (OECD, 2020).

2.6 Total efficiency in the electricity chain

Efficiency

Figure 14 shows the median estimates of the efficiencies in each chain step. The chain efficiencies for the three generation scenarios are then 77%, 71% and 63% for wind, solar and solar-import respectively. Note that the efficiency of solar electricity imports does not take into account the fact that the generation efficiency per panel is much higher in North Africa (this difference is reflected in the land use). The efficiency of electricity storage is not included.

This is in reasonable agreement with estimates in the literature of 69% (NAW-Leopoldina, 2017) and 70% (Haugen et al., 2021).

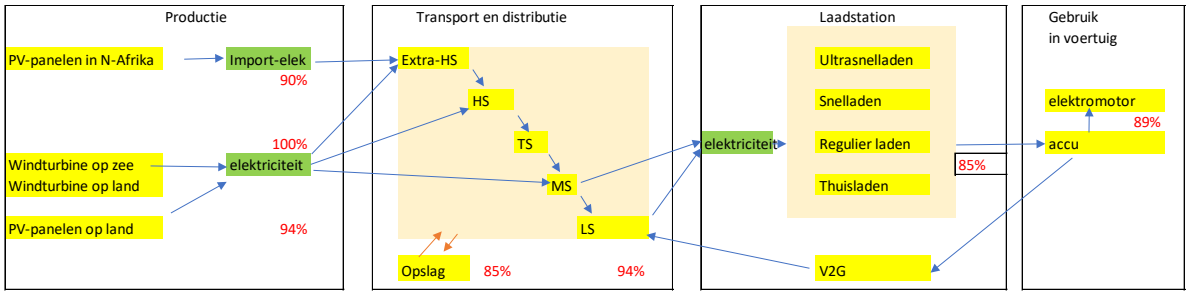

Figure 2.9 **Mid-range estimates of the returns per chain step**

In addition: this is about energy efficiency alone. For a fair comparison of energy use between energy carriers, the extra weight of electric vehicles compared to alternatives must be taken into account, which slightly reduces the energy advantage of EVs (as previously indicated in the case of energy efficiency of electric trucks).

Land use

To drive a passenger car for a year (assuming 13,000 km and 0.2 kWh/km), about 3 MWh is needed. Based on the space usage and chain efficiencies of the three generation scenarios, this will require about 7 m^2 for wind, 50 m^2 for solar in the Netherlands (of which about 4 m^2 for transport and the rest for generation), and 40 m^2 for imported solar electricity.

3 Hydrogen

Main points

- Hydrogen can be used in mobility as a fuel in a combustion engine or as a fuel supply for a fuel cell. For the latter, the H_2 must be extremely pure and requires cleaning steps.
- Producing hydrogen from electricity by electrolysis is a technology that has not been used a lot yet and is not yet fully developed on a global scale. It is expected to have an efficiency of around 67 (63-71) % in 2030.
- Making hydrogen from natural gas by steam reforming is a proven, mature technique. In combination with a capture installation that captures 90% of the CO_2 created, it has a similar efficiency (69%) as electrolysis, but the production is about half the price (assuming gas costs of 5-15 €/GJ and electricity costs of 50-100 €/MWh). Because not all CO_2 is captured, SMR-CCS requires part of the natural gas (10%) to be replaced by, for example, biogas in order to be carbon neutral. This increases production costs, but production remains cheaper when using electrolysis.
- The construction of electrolysis plants is still in its infancy in the Netherlands and worldwide, with a total capacity of less than 300 MW. The ambition in the Climate Accord (2019) of 3-4 GW of electrolysis capacity in the Netherlands by 2030, yields about 90 to 120 PJ of hydrogen per year. If all trucks in the Netherlands were to run entirely on hydrogen, they would use ½ to ¾ of this. If all trucks and all passenger cars were to run on hydrogen, a total of 8 GW of electrolysis capacity would be needed.
- Outside the Netherlands, the H_2 production costs of electrolysis may be somewhat lower, because electricity generation is cheaper in more southern regions (such as North Africa or the Middle East). In principle, larger hydrogen volumes are feasible than in the Netherlands, because logically the space for electricity generation is larger than in the Netherlands. In 2020 and 2021, the Netherlands signed letters of intent with various potential import countries. The lower production costs of imported hydrogen are often offset by higher transport costs (unless, for example, the Dutch electrolysis units are located far out in the North Sea). Both import and domestic production involve costs for storage, distribution and refuelling.
- Storage and transport of hydrogen can be in gaseous form under high pressure, liquid (cryogenic, -253ºC) or chemically bonded in the form of ammonia. Especially the conversion (to liquid hydrogen or ammonia), the reconversion of ammonia to gaseous hydrogen, and the storage at import and export terminals are expensive and energy intensive. A more experimental form is transport in the form of LOHCs (Liquid Organic Hydrogen Carriers), such as benzene and toluene; this has a low TRL and has the disadvantage of a return flow.
- Hydrogen can be transported by ship (liquid), pipeline (gas) and tankers (liquid and gas). Tank trucks are particularly suitable for short distances and smaller volumes (i.e. distribution). For longer distances and large volumes, pipe transport of gaseous H_2 is the cheapest option up to approximately 1,500 km. Above that distance, ships are more suitable: transport by ship is relatively cheap and not strongly dependent on distance, but conversion, reconversion and storage at the port terminals lead to high costs which only outweigh the costs of transport by tube over long distances.
- Liquefaction costs an amount of energy equal to approximately 30% of the energy content of the hydrogen, compression to high pressure levels (500-900 bar) costs approximately 10% energy. Conversion to ammonia and back to H_2

requires about 50% of the energy content of the hydrogen. During storage, the liquid hydrogen must remain permanently cooled.

- The costs of the chain steps transport (including any conversion and reconversion to liquid form or NH_3) + storage + distribution + refuelling are of the same order of magnitude, or greater, than the costs of the chain step production. In addition, the costs of refuelling depend very a lot on the modality in question: a refuelling station for road traffic is much more expensive than one for ships, which is called a bunker station. Also, a road filling station requires expensive fine-meshed distribution with either tank trucks or pipelines, whereas bunker stations will often be connected at a higher level in the transport network. Finally, the costs of a filling station depend strongly on the degree of utilisation and the scale of the filling station. The compressor at the filling station that brings the pressure up to 350-700 bar is a very costly installation (30-60%) and consumes a lot of energy (approximately 10% of the energy content of the hydrogen).
- Conversion of hydrogen into electricity with a fuel cell takes place in a road vehicle with an efficiency of 50-60%. The electric motor has an efficiency of 95%. Combustion of hydrogen in an internal combustion engine has a lower efficiency of 40-45% (comparable to a diesel engine).
- Hydrogen has a larger volume and, with the tank included, is heavier than petrol and diesel with the same energy content. This limits its use in vehicles, where space and weight are important factors.
- In a fuel cell vehicle, the fuel cell system also adds weight and space requirements. In the Toyota Mirai (1st generation) hydrogen passenger car with 5 kg of hydrogen, the fuel cell system weighs about 230 kg, and the empty tanks weigh 87 kg. So for 1 kg of H_2 in the tank, there is a mass of over 60 kg for the tank and the fuel cell system.
- For the same range, a truck with a fuel cell system is heavier than a truck with an internal combustion engine, but lighter than a battery-electric truck.
- Use in an internal combustion engine has the advantage of lower costs (no expensive fuel cell system needed) and fewer requirements on the purity of the hydrogen. On the other hand, the energy efficiency is lower and NO_x is emitted.
- Hydrogen as a fuel for long-distance sea shipping seems only suitable if there is the possibility of bunkering every few days. Hydrogen is better suited for ships sailing short and medium distances, preferably in the form of compressed gas to avoid cryogenic cooling.
- The application of hydrogen in an aircraft raises the question of whether it is physically and practically possible because of the large space requirement and the weight of the hydrogen and tank (and possibly the fuel cells). The TRL of flying on hydrogen fuel cells is 3. Water vapour has a (short-lived) greenhouse effect when emitted at high altitude.

Land use and other issues

The land use in the H_2 chain is entirely due to electricity consumption in this chain. This is highest in the electrolysis variant, where electricity is used for the production of H_2. In both the electrolysis and the SMR-CCS variants electricity is also used elsewhere in the chain, such as (possibly) liquefaction or conversion to NH_3 and compression at the filling station. The SMR plant and the electrolyser themselves take up only a small amount of land per unit of hydrogen supplied. Both plants are highly industrial, however, and therefore have a certain impact on the landscape. For the space requirements of the SMR-CCS route we have assumed that the 10% biogas needed to make the SMR-CCS process carbon neutral will be obtained from residual flows such as animal manure and sewage sludge, and will therefore not take up any (extra) land. This does mean dependence on natural gas and possible

acceptance issues for CO_2 storage. Sufficient availability of biogas may also be an issue.

3.1 Introduction

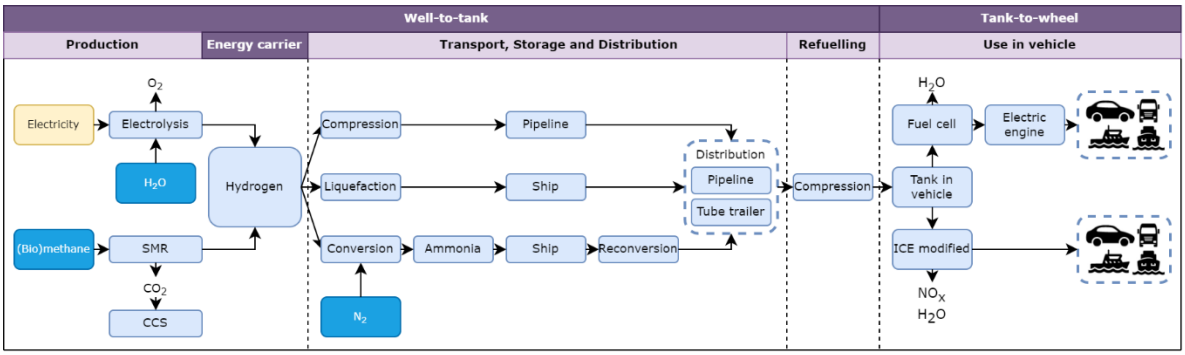

Figure 3.1 Overview of chain steps within this chapter

3.1.1 *Scope*

For our study, only carbon neutrally produced hydrogen is relevant. The terms 'grey', 'blue' and 'green' hydrogen are used in the literature. These terms stand for:

- Grey: produced from fossil fuels,
- Blue: produced from fossil fuels in combination with carbon capture and storage (CCS),
- Green: produced from renewable sources.

In the case of 'blue' hydrogen, the feedstock is usually natural gas (methane) and the hydrogen is made with a process called steam-methane-reforming (SMR), in combination with CCS. Blue hydrogen is not the same as carbon neutral hydrogen, because CCS only captures about 90% of CO_2. More capture is possible, but would lead to (too) high costs. Blue hydrogen can be made carbon neutral by replacing part of the natural gas with an alternative based on biomass (biomethane). If CCS captures 90% of the CO_2, then adding 10% biomethane to the mix would in principle be sufficient for carbon neutrality.

In this study we distinguish two "raw materials" and several production processes to make carbon neutral hydrogen, see table 3.1.

Table 3.1 Production process for grey, blue and green hydrogen. In this study we only include carbon neutral hydrogen (the last column)

"Raw material"	H_2 production process	H_2 -variants			This study
		Grey	Blue	Green	carbon neutral
Electricity	Electrolysis of water	Electricity from fossil sources	Power generation with CCS	Renewable electricity (e.g. from wind turbine or PV)	Renewable electricity (e.g. from wind turbine or PV)
(Bio) methane	Steam Methane Reforming (SMR)	Natural gas	CCS in the SMR process	SMR with 100% use of biomethane	SMR + CCS, with use of bio-methane for the uncaptured part of CO_2

Conversion table

Mass	Energy content (MJ)	Energy content (kWh)
1 kg H_2	120 MJ	33.3 kWh

3.2 Production

3.2.1 *Current state of affairs and plans towards 2030*

The current production of H_2 in NL is about 180 PJ (PwC, 2021), or 1.5 billion kg. The most common technique for producing the hydrogen is steam-methane-reforming (SMR) on the basis of natural gas. Production in electrolysers, i.e. with electricity as input, also occurs, particularly in the chlorine/alkali industry, but then the hydrogen is usually a by-product (IEA, 2019a). In the Netherlands, the split between hydrogen production from natural gas and electricity is approximately 3:1 (Weeda, 2016).

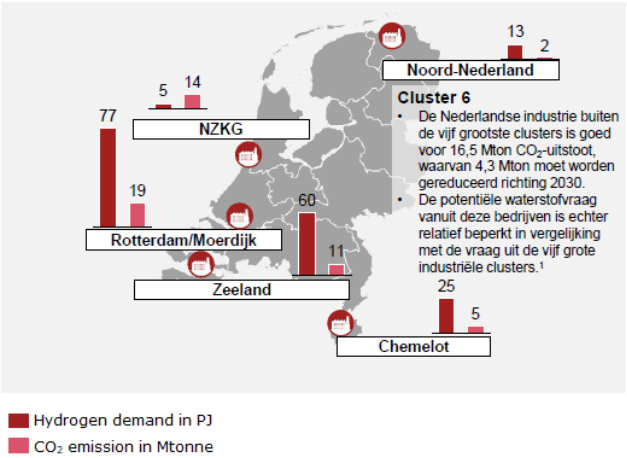

Figure 3.2 **Hydrogen production in the Netherlands**

Source: PwC, 2021.

Electrolysis

The goal in the climate agreement is the installation of 3-4 GW of electrolysis capacity by 2030. The only electrolyser in the Netherlands that makes green hydrogen is in Veendam and has a capacity of 1 MW.[42] There are concrete plans for green hydrogen electrolysis capacity of, for example, 200 MW at the Maasvlakte and 20 MW in Delfzijl (TKI Nieuw Gas, 2020). There are also plans for green hydrogen electrolysis facilities in IJmuiden (100 MW) and Rotterdam (250 MW), for the production of sustainable steel and for BP's refinery, respectively (Energeia, 2022). The lead time for the construction and connection to the electricity grid of a large electrolyser (>200 MW) is in the order of 6-10 years (Scholten et al., 2021). Part of this long duration is due to the connection to the electricity grid. A 200 MW electrolyser, for example, requires an electrical connection of approximately 300 MW, 1.5 times as much as the Aldel aluminium plant in Delfzijl, one of the largest electricity consumers in the country.[43]

[42] Hystock, a market test by Gasunie at Zuidwending near Veendam. Opened summer 2019. https://www.north2.eu/groene-waterstofketen/elektrolyse/?gclid=EAIaIQobChMIkLy984-r8gIVBnYYCh2tzwYoEAAYASAAEgIFPPD_BwE

[43] https://nos.nl/artikel/2408773-aluminiumfabriek-aldel-gered-maar-120-mensen-verliezen-hun-baan

The ambition of 3-4 GW in 2030 in the Netherlands in perspective

Electrolysers with a capacity of 3-4 GW produce 90-120 PJ of hydrogen annually when operating 95% of the time. Production requires an input of 36 to 48 TWh of electricity.[44] This is more than the current production of renewable electricity through solar and wind in the Netherlands, which amounts to 30 TWh per year (CBS, 2022). The space required by 3-4 GW of electrolysis units is 40-55 hectares.[45] If all trucks that drive in the Netherlands would do so on hydrogen by using a fuel cell, they will use ½ to ¾ of this hydrogen production; to run all trucks and all passenger cars on hydrogen would require a total of 8 GW of electrolysis capacity.[46]

Use of green hydrogen in the wider economy and in transport

In its *Fit for 55 package,* the European Commission proposed in July 2021 a binding obligation to use at least 50% green hydrogen in industry's hydrogen consumption by 2030 (EC, 2021). For the Netherlands this would mean a production of approximately 55-60 PJ green hydrogen in 2030 (PBL, 2021). The EC proposal also requires a 2,6% share of green hydrogen in road traffic in 2030 (on an energy basis). Together, this means a required quantity of approximately 70 PJ in 2030, according to PBL (PBL, 2021) (KiM supplement: and an electrolysis capacity of approximately 2,3 GW to produce this).

Ambition number of hydrogen vehicles

The Klimaatakkoord (Dutch Climate Agreement) states the ambition of 300.000 hydrogen-powered vehicles by 2030. At the end of 2020, there were 390 passenger cars, 13 delivery vans, 6 buses and 9 trucks in the Netherlands running on hydrogen by using a fuel cell (RVO, 2021; NederlandElektrisch, 2021). There are no vehicles in the Netherlands that use hydrogen in a combustion engine yet, but there are developments in this direction.

Developments with petrol stations

The *Fit for 55 package* proposal also includes a strengthening of the targets for the deployment of the Alternative Fuels Infrastructure Regulation (*AFIR*). For hydrogen, the Commission sets the objective to install hydrogen refilling points, accessible to both light and heavy duty vehicles, every (maximally) 150 km of the TEN-T core network and in each urban node. In addition, the proposal includes the obligation to install liquid hydrogen filling stations every 450 km of the TEN-T core network and at each freight terminal. Liquid hydrogen has the advantage that only about half the volume of gaseous hydrogen (at 700 bar) is needed per unit of energy; a disadvantage is boil-off of part of the fuel (unless it can be reused). At the end of 2021 there were about 13 hydrogen filling points in the Netherlands (see the section on refuelling and bunkering).

Import of hydrogen

In 2020 and 2021, the Netherlands has signed letters of intent with Portugal, Chile, Namibia and Uruguay, and talks are underway with Canada (Energeia, 2021). The declarations of intent deal with the 'construction of an international market, the development of technologies, the rollout of infrastructure and the establishment of export-import corridors for green hydrogen' between these other countries and the Netherlands. Dutch ports are also making contacts. The Port of Rotterdam Authority

[44] An electrolysis efficiency of 69% has been assumed (IEA, 2019a).
[45] Calculation based on IEA (2019a).
[46] Based on the distance travelled by trucks and passenger cars in 2020 (CBS) and a hydrogen consumption of 8.7 MJ/km for trucks and 1.5 MJ/km for passenger cars (see Appendix B).

has started exploratory talks with: Iceland, Portugal, Morocco, Oman, South Africa, Uruguay, Chile, Brazil, Australia and Canada.

3.2.2 *Production of hydrogen with electrolysis*

Electrolysis has several variants, which differ in the type of electrolytic cell used; in the electrolyser itself, the cells are stacked in stacks. We distinguish 3 types of electrolysis (IEA, 2019a):

- **Alkaline electrolysis (AEL)**: Electrolysers with alkaline electrolytic cells have the highest TRL (9). AEL has been in use since the 1920s, particularly in the fertiliser and chlorine industries (with hydrogen as a by-product).
- **Polymer Electrolyte Membrane (PEM) electrolysis**: Another well-known method is polymer electrolyte membrane (PEM) electrolysis. PEM electrolysis has a TRL of 8 and was developed in the 1960s to overcome some of the operational disadvantages of AEL. For example, no recovery and recycling of the electrolyte solution is required because PEM uses pure water and not potassium hydroxide as in AEL.
- **Solid Oxide Electrolysis (SOE)**: A third variant is solid oxide electrolysis (SOE). SOE achieves higher conversion efficiencies than PEM and AEL, operates at high temperatures and uses ceramics as electrolyte and therefore has low material costs. However, due to the short lifespan of the cells, the system is more expensive than AEL and PEM.

By the end of 2020, there was almost 300 MW of electrolysis capacity worldwide, of which about 2/3 are AEL cells and 1/3 PEM cells, see figure 3.3. In Europe, just over 100 MW has been installed (IEA, 2021). The average capacity of electrolysers is less than 1 MW (IEA, 2019a). Annex D, section 'Electrolysers' provides more information on the different cell types.

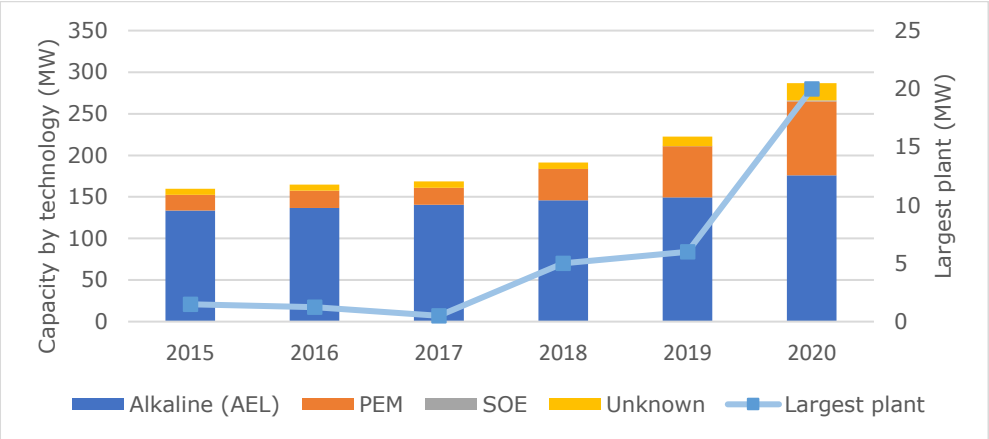

Figure 3.3 **Worldwide electrolysis capacity development by cell type, 2015-2020**

Source: IEA, 2021a.

General characteristics

Table 3.2 shows some important characteristics of the 3 types of electrolysers (AEL, PEM and SOE), such as energy efficiency, operating conditions, CAPEX and space requirements.

Table 3.2 Some characteristics of AEL, PEM and SOE electrolysers, both at present and projected for 2030 and the longer term (LT)

	AEL			PEM			SOE			
	Current	**2030**	**LT**	**Current**	**2030**	**LT**	**Current**	**2030**	**LT**	**Source**
TRL	9			8			6	9		1,2,3
LHV energy efficiency (%)	63-70	65-71	70-80	56-60	63-68	67-74	74-81*	77-84*	77-90*	4
Pressure (bar)	1-30			30-80			1			4
Temp (°C)	60-80			50-80			650-1000			4
Operating hours stack (x 1000)	60-90	90-100	100-150	30-90	60-90	100-150	10-30	40-60	75-100	4
Service life (years)	10			7			?			5
CAPEX ($/kW$_e$)	500-1400	400-850	200-700	1100-1800	650-1500	200-900	2800-5600	800-2800	500-1000	4
Land use (m^2/MW$_e$)	95			48			?			4
Land use (m^2/MW-H_2)	140-150			80-90			?			

* For SOE, the energy efficiency does not include the energy required for the production of steam.

Source**:** 1: Marsidi (2018), 2: Marsidi (2019), 3: Koirala (2020), 4: IEA (2019a), 5: Wieclavska and Gavrilova (2021).

Cost per unit of hydrogen

In the case of electrolysis, the cost per unit of hydrogen (€/kg) mainly depends on the following factors:

- The cost of electricity (in €/kWh);
- The energy efficiency with which electricity is converted into hydrogen;
- The installation costs of the electrolyser (the CAPEX, in €/kW);
- The operating time of the electrolyser (the number of full load hours per year);
- The service life of the electrolyser;
- The discount rate used to calculate the installation costs.

Figure 3.4 below shows the H_2 unit costs for an AEL electrolyser ranging from 400 to 850 €/kW (the same range as those in Table 3.2), an efficiency of 68% and electricity costs of 50 and 100 €/MWh. For a substantiation of this choice, see chapter Electricity.

For comparison, the unit costs corresponding to just the electricity costs (CAPEX 0 €/kW) are also shown (the dotted lines in the figure).

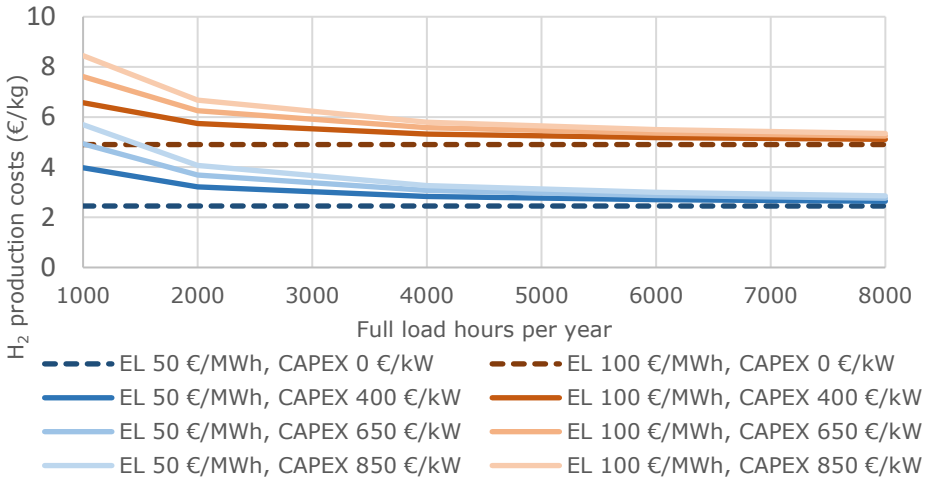

Figure 3.4 **Hydrogen production cost (€/kg) in 2030 with an AEL electrolyser (efficiency 68%) at various capital costs (CAPEX), operating time from 0 to 8000 hours, electricity cost of 50 and 100 €/MWh and discount rate of 2,25%**

Two things become apparent from the figure:

1. The longer the operating time of the electrolyser (in hours per year), the lower the production costs per unit of hydrogen. This is logically explained by the fact that the capital costs (CAPEX) of the electrolyser are spread over a larger rumtime when operating time is longer.
2. With long operating times, the unit costs (the solid lines) are barely higher than the costs for just the "input" electricity (the dotted lines in the figure). Thus, the investment costs of the electrolyser are of minor importance at long operating times: the electricity costs are decisive.

In the rest of this study, we calculate the production costs of H_2 from electrolysis at €4,15 (2,64-5,80)/kg, or €34,6 (22.0-48.4)/GJ. These amounts are based on:

- The average efficiency of AEL and PEM electrolysers in 2030 (table 3.2),
- The bandwidth in the CAPEX of AEL and PEM in 2030 (table 3.2),
- 8000 operating hours per year,
- Electricity costs of 75 (50-100) €/MWh.

Land use

The land required for hydrogen production with electrolysis consists of two components: the land for the electrolyser (as an installation) and the land for electricity production as 'input' for the electrolyser. The second component is by far the largest per unit of hydrogen production, see table below.

Table 3.3 **Space requirements for hydrogen production from electrolysis**

	Land use (m^2/GJ H_2)	**Assumptions**
Electrolyser	0.005	AEL electrolyser, efficiency 67%, 8,000 operating hours per year, land use 95 m^2/MW_e
Electricity production from renewable sources (solar and wind) as input for the electrolyser	1.56	Land use of electricity mix (solar/wind): 3.77 m^2/MWh (see chapter Electricity)

The picture below shows a 10 MW PEM electrolyser, currently the largest electrolyser in Europe. It produces 1,300 tonnes of green H_2 annually. This picture does not show the exact land use, but according to IEA (2019b) the land take of a 10 MW PEM electrolyser would be around 480 m^2.

Figure 3.1 Largest European PEM hydrolyser (10 MW) in Wesseling, Germany.

Source: Shell (https://www.refhyne.eu/shell-starts-up-europes-largest-pem-green-hydrogen-electrolyser/)

Bottlenecks and uncertainties

We see two potential bottlenecks with hydrogen from electrolysis:

1. Scarce raw materials for the electrolyser. This is particularly the case with AEL and PEM electrolysers. SOE electrolysers do not suffer from this, as they use ceramics and few rare metals (which is an important advantage of SOE over the other two types).
2. Water use.

Scarce raw materials for the electrolyser. AEL and especially PEM electrolysers make a claim on a number of scarce materials, in particular **platinum** (for PEM and AEL) and **iridium** (for PEM) for the catalysts of the electrolysers. Platinum and iridium are on the European list of *critical raw materials (CRM)*, both as part of the *platinum group metals (PGM)* (EC, 2020a). Most iridium (92%) and platinum (71%) comes from South Africa (EC, 2020a).[47]

Critical point: even a PEM electrolysis capacity of around 110 GW[48] would require as much **iridium** annually as is currently being produced. This is due to the limited lifespan of electrolysis cells, which means that they have to be replaced continuously. In its *World Energy Outlook 2021,* the IEA expects global electrolysis capacity to reach 90 GW by 2030, that is, if all the announced plans are implemented (IEA, 2021c). This is pretty close to the critical limit. Increasing the annual production of iridium is possible, but takes time, because new extraction sites have to be started up (EASAC, 2019). Recycling iridium from discarded cells is also a possibility.

The limit on the use of **platinum** is less urgent: only when the combined capacity of PEM and AEL electrolysers is about 8,000 GW is the full annual amount of platinum used.[49]

[47] Iridium is currently used in electronics (43%), electrochemistry (22%) and the chemical industry (7%). Platinum is widely used as a car catalyst (80%), for jewellery (10%) and in the chemical industry (5%) (Wieclavska and Gavrilova, 2021).

[48] KiM calculation based on Wieclavska and Gavrilova (2021), who indicate that with an annual production of 4050 PJ with PEM electrolysers, 122% of the current worldwide annual production of iridium is needed. We have taken into account an operating time of 95%.

[49] According to Wieclavska and Gavrilova (2021), production of 8100 PJ H_2 with 50% AEL and 50% PEM electrolysers requires 25% of annual global platinum production.

N.B. Platinum also plays a role at the end of the hydrogen chain, in the application in vehicles. It is used in the fuel cells that convert the hydrogen in the vehicle into electricity; see section 'Fuel cell or combustion in vehicle'. This increases the platinum scarcity through the use of hydrogen even further.

Water consumption. The production of 1 kg of hydrogen requires 9 kg of water.[50] This can be problematic when the electrolyser is located in areas where fresh water is scarce. This often affects sunny regions with low production costs for electricity from renewable sources. Desalinating water from seas and oceans is a technical possibility, but is capital-intensive and costs energy: about 0.05 kWh_e per kg H_2 (HZ Water Technology, 2021), about 0.15% of the energy content of the hydrogen. More than 0.3 kg of salt per kg H_2 remains; if this cannot be put to good use, the obvious course of action is to dump it back into the sea.

In addition, there are uncertainties regarding the operating time and electricity costs for the electrolyser.

Uncertainties in the operation of the electrolyser

Operating time: The question is whether electrolysers will achieve maximum operating time in practice. This is certainly the question when the required electricity must come from renewable sources, the requirement for the produced hydrogen to be carbon neutral. Renewable sources are generally (seasonally) variable sources (such as wind and sun, see 2.1), which do not always deliver (or which must be obtained from far away, thus at high cost). This could mean that hydrogen costs will not be at their lowest possible level in practice. To illustrate, in figure 3.4 hydrogen costs would rise by approximately 15% to 20% if the operating time fell from 8,000 to 4,000 hours.

Electricity costs: Another point is that not only the supply of electricity from renewable sources is variable, but also its price. This price is dependent on the market, because demand for electricity is also variable. In practice, renewable electricity is available at low cost for some of the time (because the demand for electricity from other users is low at that time, or because there is a large supply from the seasonally variable sources) and at higher cost for another part of the time. A short operating time with low electricity costs can result in hydrogen costs comparable to those of an electrolyser that achieves more operating hours but faces higher electricity costs.

Switching off the electrolyser when electricity costs are high must be weighed against keeping it in operation when electricity costs are high, but with a lower CAPEX. See Appendix D, 'Electrolysers' section.

Proximity to cheap sources of renewable electricity. Another type of consideration is where the electrolyser is optimally located from a cost point of view. In the vicinity of the sales markets in the Netherlands? Or rather in a region where cheap renewable electricity is available, such as the Middle East or North Africa? In the latter case, there are the additional costs of transporting the hydrogen to the Netherlands, but these additional costs may outweigh the avoided costs of hydrogen production. The region with the lowest costs of electricity generation from renewable sources is cheaper by a factor of 3 to 4 than the most expensive, according to IEA (2019a). In section 3.3 we look in more detail at the costs of long-distance hydrogen transport.

[50] This must be deionised and a cooling system must be in place so that the electrolysis temperature does not exceed 100°C (Apostoulou and Xydis, 2019).

3.2.3 *Production of hydrogen using SMR-CCS*

Worldwide, three quarters of all hydrogen is produced from methane (IEA, 2019a). The most widely used technology is steam-methane reforming (SMR), because hydrogen can be produced cheaply through it.

Figure 3.2 **SMR installation of Air Liquide**

Source: https://www.engineering-airliquide.com/focus-steam-methane-reformers-gasworld

The SMR process is not carbon neutral. The production of 1 kg of H_2 with SMR generates 8.9 kg of CO_2. However, it is technically possible to capture the CO_2 and subsequently store this CO_2.

CO_2 capture at SMR plants is already happening on a large scale. It is an existing commercial operation and one of the main sources of CO_2 for industry and food processing in the global market (IEAGHG, 2017). In practice, up to about 90% capture is achieved; more is possible, but the costs then increase significantly. At 90% CO_2 capture, the energy efficiency of hydrogen production with SMR decreases by 7% points (from 76% to 69%: see table 3.3). As not all CO_2 is captured, additional measures are needed to neutralise the remaining CO_2. One option is to feed the SMR plant with a mixture of fossil methane (natural gas) and biomethane. Biomethane causes CO_2 within the short carbon cycle (because the carbon was only recently absorbed from the air during the biomass growth process). At 90% capture, blending 10% biomethane is sufficient for carbon neutrality. Of course, it is also possible to use more than 10% biomethane, in which case the process even becomes a carbon sink. Biomethane as a raw material for H_2 production currently does lead to higher costs than natural gas; see the chapter on biofuels.

General characteristics

Table 3.4 summarises some key features of SMR, both with and without CO_2 capture. SMR with CO_2 capture is an advanced technique, with a TRL of 9. The catalyst is usually nickel, due to its low cost (Van Beurden, 2004). For the future, the IEA does not expect any improvement in efficiency for SMR with CO_2 capture. The costs of SMR will remain at the same level. However, a cost reduction for the capture installation can still be expected. The combination of CO_2 capture, transport and storage is called CCS (*Carbon Capture and Storage*). Only limited experience has been gained with CCS worldwide. According to the IEA, transport and storage of CO_2 represent a relatively small cost item compared to CO_2 capture, although this will depend on the CO_2 volume flow, the availability of a storage site and the distance to the site.

Table 3.4. Efficiency, operating characteristics and costs of SMR and of SMR-CCS (with 90% capture)

	SMR without CO_2 capture			SMR with 90% CO_2 capture			
	Current	**2030**	**LT**	**Current**	**2030**	**LT**	Source
TRL	9			9			1
Return LHV (%)	76	76	76	69	69	69	2
Pressure (bar)	25-40						3
Temp (°C)	800-900						4
Service life (years)	25	25	25	25	25	25	2
Land use (m^2/MW-H_2)	50 (*)			60 (**)			5
$KgCO_2/kgH_2$	8.9	8.9	8.9	1.0	1.0	1.0	2
CAPEX ($/kWe)	910	910	910	1680	1360	1280	2
Costs of transport and storage CO_2 ($/ton CO_2)				20			2

CAPEX shows the system costs, including electronics, gas conditioning and balance-of-plant costs.

(*) According to RotoReform AS (2019), the land use for an SMR plant producing 100 kton H_2 annually is 20.000 m^2 . With an efficiency of 76% and an operating time of 95%, the plant has a capacity of 400 MW and a land use of 50 m^2 /MW of hydrogen production (KiM calculation).

(**) KiM estimate, see 'Land use'.

Source: 1: Janssen (2018), 2: IEA (2019b), 3: Weeda (2016), 4: IEAGHG (2017), 5: Rotoreform AS (2019).

Cost per unit of hydrogen

In SMR with CCS, the cost per unit of hydrogen (€/kg) depends mainly on the following factors:

- The cost of (bio)methane;
- The energy efficiency;
- The installation costs of the SMR installation with or without CO_2 capture (the CAPEX, in €/kW);
- The operating time of the installation (the number of full load hours per year);
- The costs of CO_2 transport and storage;
- The life span of the installation;
- The discount rate used to calculate the installation costs.

Figure 3.5 below shows the H_2 production costs of an SMR-CCS plant at different numbers of operating hours. To allow for uncertainty in the natural gas costs, we have calculated with 3 price levels: 5, 10 and 15 €/GJ (18, 36 and 54 €/MWh).[51] For comparison, the H_2 costs corresponding to just the costs of natural gas are also shown (the dotted lines in the figure).

At 8,000 operating hours, production costs vary between 1.3 and 3.0 €/kgH_2. More than 2/3 of the costs consist of the cost of natural gas.

The SMR plant, unlike the electrolyser, is not dependent on energy from seasonally variable sources. Natural gas can also be supplied from many parts of the world in the form of LNG. In principle, the cost of importing LNG is higher than that of natural gas from closer sources (mainly due to the cost of cooling and storage and to a lesser extent of transport), but nevertheless it is quite conceivable that the cost will remain within our range of 5-15 €/GJ.[52] Thus, long operating times will generally be

[51] In comparison, the WLO calculates for 2030-2050 gas prices varying between 5.2 and 12.9 €/GJ in the 2013 price level (WLO, 2015).

[52] A historical comparison shows that in the period 2010 through 2020, imported LNG in Asia cost an average of 9.7€/GJ (11.15$/MMBTU; FRED, 2022), compared to a wholesale price of natural gas in the Netherlands of 5.6 €/GJ on average in the same period (CBS Statline; delivery price). LNG was thus approximately 4€/GJ more expensive than natural gas.

feasible in practice. However, like the electricity for the electrolyser, the price of natural gas will also fluctuate. When the price of natural gas is high, it may be economically more feasible to temporarily shut down the installation.

Land use of SMR-CCS

Land use of SMR-CCS installations: We were unable to find much information on the land use of SMR installations. Based on one source, we assume that the land use of a SMR plant without CO_2 capture is 50 m^2/MW_{out} (RotoReform AS, 2019).

Because of the lower energy efficiency, we estimate the land use of a SMR installation with CO_2 capture (90%) to be higher, at 55 m^2 per MW_{out}. In addition, the CO_2 capture installation takes up approximately 4 m^2 per MW_{out}.[53] CO_2 is generally transported and stored underground, so we have not allocated any land use to that. The total land use of the SMR plant with CCS therefor comes to about 60 m^2 per MW_{out}. This is less than the land use of an electrolyser (see table 3.3).

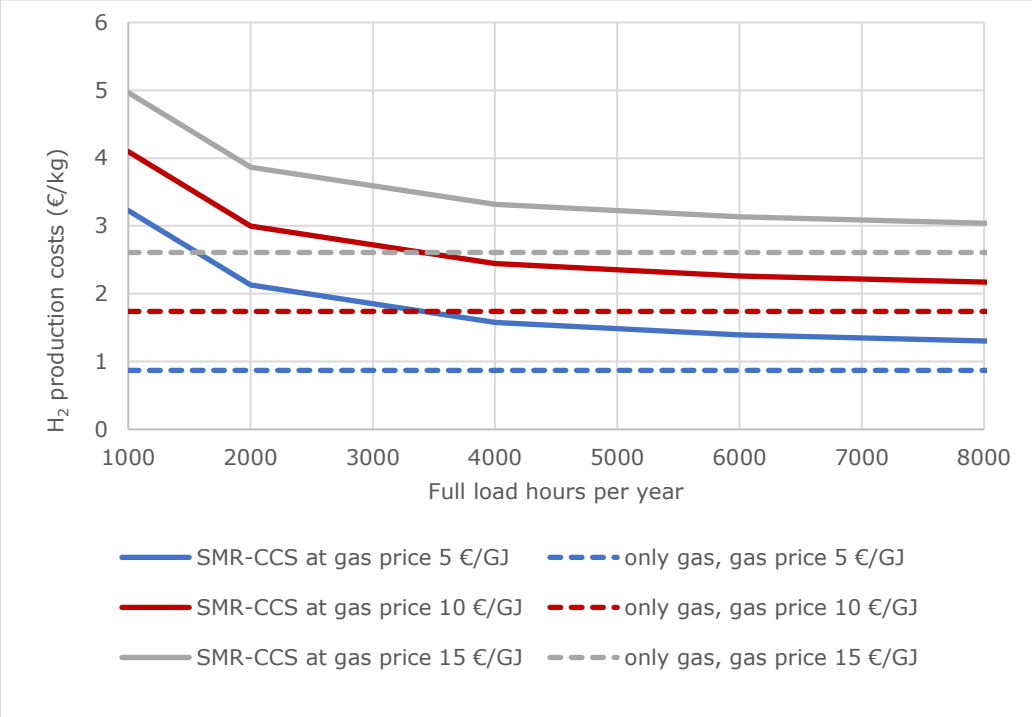

Figure 3.5 **Production cost of hydrogen from SMR-CCS**

At natural gas prices of 5, 10 and 15 €/GJ (18, 36 and 54 €/MWh), an operating time of up to 8322 hours per year (95%) and a discount rate of 2.25%. Installation lifetime 25 years, efficiency 69%, CAPEX 1360 $/kW-H2 (2030) (IEA, 2091b). For CO_2 transport and storage, 0.02 €/kg CO_2 was used (IEA, 2019b).

Bottlenecks and uncertainties

When producing SMR in combination with CCS, we see several potential bottlenecks.

Methane leakage (methane slip). Methane leakage can occur during the extraction of natural gas and its transport to the SMR plant via transport pipelines. Methane is a strong greenhouse gas (23 times stronger than CO_2). *Upstream,* about 1,7% of natural gas leaks worldwide (IEA, 2017). This problem can occur if the SMR plant is far away from the gas field and long-distance transport is required.

[53] The space required by the CO_2 capture plant is approximately 2,000 m^2 at a capture capacity of 1 Mton/year; see chapter 4 Synfuels.

Methane may also leak during biogas production - which is necessary because CO_2 capture at the SMR-CCS plant is not complete and therefore it is not carbon neutral, although there is uncertainty about the extent to which this occurs (IEA, 2021b). Many factors influence this leakage, including the type of facility, whether biogas production is a primary or secondary activity, and whether operators use open or closed storage tanks (IEA, 2021b). Biogas production can sometimes prevent methane leakage from feedstocks that would otherwise remain untreated. This is the case, for example, when biogas is produced from livestock manure and the organic fraction of sewage sludge (IEA, 2021b).

Availability of and public support for CO_2 storage: A relevant question is whether there is an (underground) CO_2 storage site at all in the vicinity of the production location, so that the captured CO_2 does not have to be transported over too great a distance. This is not a major issue in the Netherlands because there are various empty natural gas fields both onshore and offshore. Public support for CO_2 storage can be a problem, especially if the storage is close to residential areas (Barendrecht case). Underground CO_2 storage does not yet exist in the Netherlands and is currently only permitted under the sea.

Leakage of CO_2 from the storage site: In principle, CO_2 in former gas fields is well stored, just as natural gas was well stored in the porous rock. However, there is a slightly increased risk of leakage at the former boreholes.

Impurities in the hydrogen: The type of fuel cell most commonly used for mobility applications (i.e. the PEM fuel cell, see section 'Fuel cell and combustion in vehicle') requires hydrogen of extreme purity. If the hydrogen is produced from methane, this means that the process stream must at least be purified of sulphur (which is often added to methane) and carbon monoxide.[54] This creates the risk of economic damage (destruction or degradation of fuel cells) if fuel cell vehicles are supplied with hydrogen of insufficient purity, for example through a national hydrogen network.

Incidentally, the hydrogen from electrolysis also requires purification (Apostoulou and Xydis, 2017). A purification unit is often present at a filling station anyway, see appendix D, section 'Hydrogen filling station'.

3.3 Transport, storage and distribution

This section deals with the transport of the hydrogen from the production site (electrolyser or SMR-CCS plant) to the filling point: a refuelling station for road vehicles or a bunkering point for ships. Storage is also included, as it is inseparable from the transport of the hydrogen. For example, in the case of transport by pipeline or ship, the hydrogen is actually stored in the pipeline or ship. Additionally, before and after transport by ship or pipeline, there is often storage in tanks (terminals), such as in a port complex or at a distribution station.

Forms of hydrogen: liquid, gaseous or chemically bonded

Due to its very low energy density at atmospheric pressure[55] hydrogen is usually compressed or liquefied in order to be stored and transported. Another option is to

[54] The PEM fuel cell has a tolerance of less than 0.1 ppm for sulphur, less than 10-100 ppm for CO and no tolerance for ammonia (Staffell et al., 2019).

[55] At atmospheric pressure, 1 kg of hydrogen occupies a volume of 11 m^3, its energy content is equal to that of 3.8 m^3 natural gas. However, this weighs 3.2 kg.

chemically bond the hydrogen to another substance, which is easier to transport and store. We distinguish[56] :

- Compressed hydrogen (gaseous), GH2;
- Liquid hydrogen (cryogenic, -253°C), LH2;
- Hydrogen chemically bonded to another substance (liquid or solid), also called hydrogen carrier. Examples are ammonia (NH_3) (liquid), LOHCs (liquid) and metal hydrides (solid).

The text box below briefly discusses how the various forms are made.

Different ways to store and transport H_2

Compressed (GH2)

Compression requires energy in the form of electricity for the compressors; the higher the pressure to be achieved, the more energy is needed. For compression to pressures of 500-900 bar, the energy consumption is in the order of 7-10% of the energy content of the hydrogen.

Liquid (LH2)

Liquefaction takes place in a process called **liquefaction**. This is an energy-intensive process: an energy supply of 25-35% of the energy content of the hydrogen is needed. The hydrogen is cooled to -253°C, the boiling point of H_2 at atmospheric pressure. This deeply cooled hydrogen is also called 'cryogenic'. To remain liquid, the hydrogen must be stored in a very well insulated tank or (for long periods) permanently cooled.

Chemically bound

Hydrogen can, together with nitrogen from the air (the atmosphere contains 78% nitrogen), and under high pressure and temperature be converted into **ammonia (NH_3)**. Ammonia is a gas at normal temperature and pressure, but it can easily be liquefied at -33°C. Liquid ammonia has an energy density 50% higher than liquid hydrogen (IEA, 2019a, p.56 and further).

The efficiency of converting **electricity** into H_2 and then, with N_2, into NH_3 is, according to the IEA (2019b), currently around 49% and is expected to increase to 53% and 56% respectively in 2030 and 2050 (IEA, 2019b). Morlanés et al. (2021) estimate the efficiency of this process as well as the improvement potential to be slightly higher, from 55% today to 69% in 2050.

If **natural gas** is the starting point, conversion to NH_3 (in combination with CCS) occurs with an efficiency of about 49%. This is done in a direct process, so without the SMR that we have assumed so far. The required input is 38.3 GJ methane and 1.3 GJ electricity per tonne NH_3, and 0.1 tonne CO_2 per ton NH_3 is released (IEA, 2019b); to make this process carbon neutral, the use of a part of biomethane is therefore necessary again (as with SMR-CCS).

An overview of efficiencies and energy use per type of hydrogen storage and transport, taken from various literature sources, can be found in Appendix D, section 'Transport, storage and distribution: costs and efficiencies'.

[56] Appendix D 'Hydrogen: Storage forms and characteristics' gives a complete overview of the forms that hydrogen can take.

3.3.1 *Transport (long distances, large volumes)*

In this section we will discuss the different ways in which hydrogen can be transported, see table 3.5.

Gaseous hydrogen (compressed) can be transported by pipeline or by tanker. When transported by pipeline, pressure levels of less than 100 bar apply (IEA, 2019b; Staffell et al., 2019; Apostoulou and Xydis, 2017). Hydrogen supplied by SMR plants, PEM and AEL electrolysers already has a pressure level in the order of 15-80 bar[57] and therefore does not need to be pressurised first. However, a compressor station is needed every few 100 km to maintain the pressure in the pipe (Staffell et al., 2019). The compression energy required for this is about 2% of the energy content of the hydrogen per 1000 km (Wang et al., 2020). When hydrogen is transported from less than 100 km from the production site, no compressor station is needed in principle, if the hydrogen emerges from the production process with sufficient pressure.

Liquid hydrogen can be transported by ship and by tube trailer. Ship transport requires special ships (IEA, 2019a, p.77), of which only one currently exists (Koide, 2021), see Figure 3.3. Pipeline transport of cryogenic hydrogen is not realistic due to its extremely low temperature (-253°C). The energy consumption of a tanker transporting liquid hydrogen is approximately 0,08% of the energy content of the transported hydrogen per 1000 km.[58] Tube trailers for liquid hydrogen are suitable for distances of up to 4000 km, as the hydrogen heats up and causes a pressure increase in the tank (IEA, 2019a).

Table 3.5. Combinations of hydrogen (in various forms) and means of transport

	Pipeline	**Ship**	**Tube trailer**
Compressed H_2 (gas)	Yes, with a compressor station approximately every 100 km	No	Yes
Cryogenic H_2 (liquid)	No	Yes, in special ship similar to LNG tanker, of which only a single small one exists (75tH_2)	Yes
NH_3 (liquid)	Yes	Yes, in LPG tankers	Yes
LOHCs (liquid)	Yes, but separate return pipeline is required	Yes, in standard oil tankers	Yes

Ammonia is a gas, but it can be liquefied under pressure (8,5 bar at 20°C) or cooled (1 bar at -33°C). Thus, it can be transported by ship, by pipeline or by tube trailer. After transport, the ammonia can be converted back into hydrogen (cracking). The latter process has an efficiency of approximately 66% (Chatterjee et al., 2021). Ammonia can also be used directly as a fuel for mobility applications; see chapter Synfuels.

[57] See section "Production".
[58] Based on IEA (2019b): energy consumption tanker 1500 MJ/km and transport capacity 11 ktH_2.

Figure 3.3 The world's first ship capable of carrying liquid hydrogen was built in Japan in 2021 and can carry 75 tonnes of H_2 . It is an experimental ship

Source: Koide, 2021.

Transport distance plays a major role

For transport costs, the distance over which transport takes place is important. For relatively short distances, transport by pipeline is the cheapest option, while transport by ship is the cheapest option for longer distances. In transport by pipeline, the costs increase more strongly with distance than by ship. Not only are the costs higher with longer pipelines, but more compressor stations are also needed.[59] In the case of gaseous hydrogen, these are expensive pieces of equipment. In contrast, the costs of transport by ship increase little with distance. [60]

IEA (2019a) uses 1500 km as the tipping point: for distances shorter than 1500 km, transport by pipeline is cheaper, above that by ship. This classification is perhaps too rough. IRENA (2022) makes a more precise classification, in which besides distance, the transported volume is included as a factor as well, see figure 3.6. IRENA also distinguished between retrofitted and new pipelines. However, the analysis by IRENA (2022) does not differ from that of the IEA: the greater the distance, the more attractive transport by ship becomes, and the greater the volume, the longer the distance over which transport by pipeline remains attractive. For quantitative details, see Annex D, section 'Transport, storage and distribution: costs and efficiency'.

[59] If existing natural gas pipelines are reused, the existing compressor stations must be replaced because they are not suitable for compressing hydrogen (PwC, 2021). Incidentally, ammonia (in liquid form) can also be transported in pipelines. Ammonia only requires intermediate pumping stations to keep the liquid under pressure. These are a lot cheaper and more efficient than compression stations.

[60] With longer transport distances, only one ship is still needed, although this is of course longer occupied and the shipping company may need more ships to transport the same volumes in total. The fuel costs of a ship transporting liquid hydrogen are low: on the outward journey, in principle, there are no fuel costs because then the ship uses the boil-off of hydrogen on board, which has to take place anyway; this concerns 0.2% of the transported quantity of hydrogen every day (IEA, 2019b). Only on the (empty) return journey does the ship use fuel oil. The depreciation costs of the ship are relatively low compared to the costs of the export and import terminals.

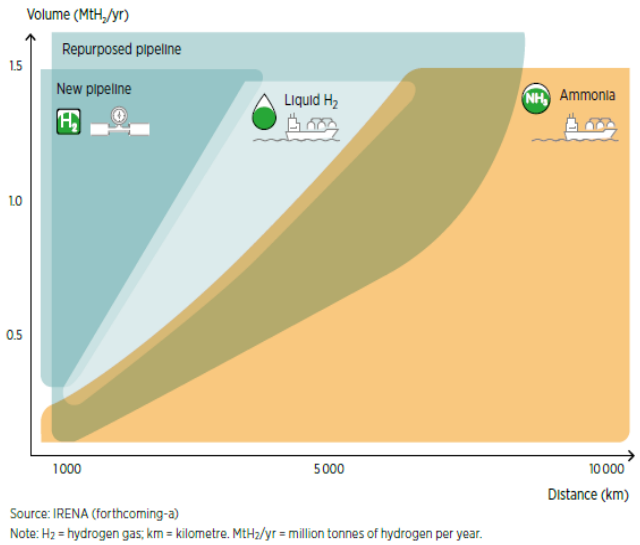

Figure 3.6 **Which transport is cost-effective depends on transport volumes and distance**

Source: IRENA (2022).

3.3.2 Storage

Many different forms of storage are possible. The most appropriate storage medium depends on the volume to be stored, the duration of storage, the desired speed of hydrogen retrieval and geographical availability. Geological storage, such as in salt caverns and empty gas fields, is the best option for large-scale and long-term storage, while tanks are more suitable for short-term and small-scale storage (IEA, 2019a).

Geological storage is also suitable if hydrogen is used as a long-term storage medium for electricity. This is beyond the scope of this chapter, but it is discussed in the Electricity chapter.

Long-term storage in salt caverns

Storage in salt caverns is cheap: it usually costs less than 0.6 $/kgH$_2$. Hydrogen losses are in the order of 2% and there is little risk of contamination (IEA, 2019a). The high pressure allows for rapid discharge, making storage in salt caverns attractive for industrial and power sector applications.

Salt caverns have been used by the chemical industry for hydrogen storage since the 1970s in the UK and since the 1980s in the US. The largest system currently in operation is in the US and can store approximately 10-20 ktH$_2$ (i.e. 30 days of hydrogen production from a nearby SMR plant). The UK has 3 salt caverns, each capable of storing 1 ktH$_2$.

In the Netherlands, Gasunie carried out a successful trial in 2021 to store hydrogen in a salt cavern at a pressure of 200 bar. This was in Zuidwending (municipality of Veendam), the same location where the only Dutch electrolyser (1 MW) for green hydrogen is now located. The first salt cavern in the Netherlands could be operational in 2026, with extension to 4 salt caverns by 2030.[61]

[61] https://allesoverwaterstof.nl/succesvolle-proef-met-waterstofopslag-in-zoutcavernes/

3.3.3 *Distribution (short distances, small volumes)*

Distribution refers to the finely-meshed transport to the hydrogen customers (filling stations). This is done with smaller volumes than transport of hydrogen. There is a choice between distribution by tube trailer or by pipeline. The latter will be chosen mainly for relatively larger volumes and shorter distances, so that investment costs in the pipeline are limited in relation to the volume transported. Pipelines for distribution have less capacity than those used for transport.

Energy efficiency: In the case of distribution by tube trailer, the energy consumption of the tube trailer determines its energy efficiency. Assuming a battery-electric tube trailer and a distribution distance to the filling station of 100 km, about 1 kWh/kgH_2 is needed.[62] This corresponds to 3% of the energy content of the hydrogen.

3.3.4 *Cost overview at hydrogen import from North Africa*

Transporting hydrogen over long distances entails costs and energy losses for transport, storage and (eventually) distribution. The costs and energy losses depend mainly on the mode of transport - by pipeline or by ship - and the form in which the hydrogen is transported - gaseous, liquid or chemically bound.

Figure 3.7 shows a cost structure for importing hydrogen from North Africa, in which both the form of the hydrogen and the method of transport vary. The starting point is gaseous hydrogen. For transport by ship it must be converted into a liquid, either liquid hydrogen (LH2) or ammonia (NH_3). Ships for the transport of liquid hydrogen are not yet common, ships for ammonia are. The final destination is a refuelling station in Europe, where the hydrogen arrives in gaseous form.

There are different costs on the import route:

- Production of gaseous hydrogen in North Africa,
- Conversion to LH2 or NH_3 (if required),
- Storage in a North African export terminal,
- Transport by pipeline or ship from North Africa to Europe,
- Storage at a European import terminal,
- Reconversion (if needed) of NH_3 to GH2, [63]
- Distribution (100 km) from the export terminal to a delivery location (e.g. filling station).

To put the costs into perspective, Figure 3.7 also includes production costs of hydrogen at 4.15 €/kg[64] .

[62] A tanker truck transports around 300 kg H_2 (Verbeek & Cuelenaere, 2019) and when electrically driven uses around 5.6 MJ_e /km, or 1.6 kWh_e /km (see heavy road transport in Appendix B Efficiency). If we assume that the tanker travels 2x100 km (Verbeek & Cuelenaere, 2019; IEA, 2019a), the electricity consumption of the tanker is 1.0 kWh per kg H_2 transported.

[63] According to IEA (2019a), we do not consider conversion of LH2 to gas form ('regasification') as a separate cost item from the import terminal costs. Regasification costs are low (Aziz et al., 2020, p.6), so no energy costs are incurred. Reconversion does release cold, which could be put to good use.

[64] See section 3.2 Production.

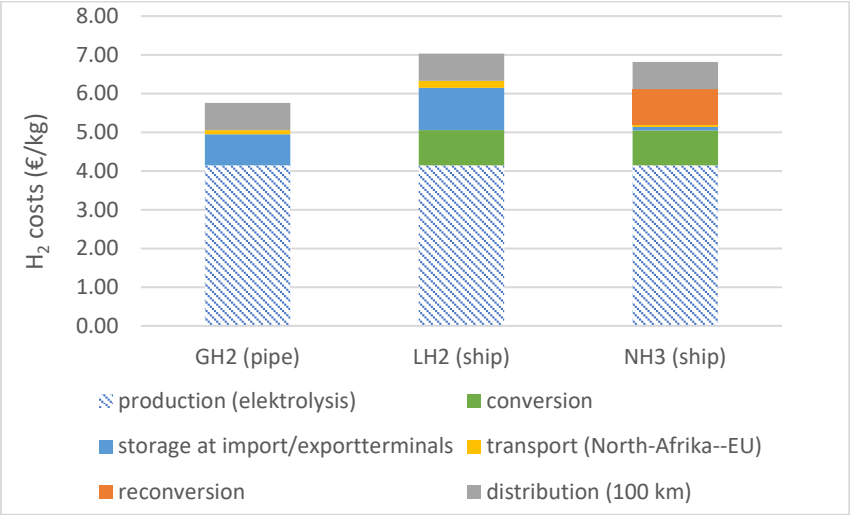

Figure 3.7 **Costs of transport, storage and distribution of hydrogen by pipeline and by ship**

In gas form (GH2) or liquid form (LH2 and NH_3). Distance travelled: LH2 and NH_3 from production site in North Africa to filling station in Europe; GH_2 by pipeline 1500 km. For comparison, H_2 production costs of €4.15/kg have been included.

Source: based on IEA (2019a), Cihlar et al. (2021) and Reuss et al. (2019).

An overview of the costs and the sources on which they are based can be found in Appendix D, section 'Transport, storage and distribution: costs and efficiency'. The costs of the filling station are not included; these are discussed in section 3.4.

Conclusion from figure 3.7:

As figure 3.7 shows, the transport of hydrogen in gaseous form by pipeline (over this distance) is the cheapest and the transport of liquid hydrogen by ship the most expensive. The costs of the means of transport (pipeline or ship) itself are relatively low, but with LH2 there are high costs of the liquefaction and (especially) the storage at the import and export terminals.

Transport in the form of ammonia costs slightly less than transport as LH2. The biggest costs for NH_3 are the conversion and reconversion; together this is twice as expensive as the liquefaction needed for LH2. However, for ammonia the storage terminals are much cheaper[65] than for liquid hydrogen, so all in all it is slightly cheaper to transport the hydrogen in this way.

It is also striking that the last part of the import route, the distribution of gaseous hydrogen over some 100 km from the import terminal (a large-scale storage facility) to the filling station, is a significant cost item.

[65] Storage tanks for ammonia generally consist of an inner tank made of metal and an outer tank made of metal or concrete (MinVROM, 1999).

3.4 Refuelling and bunkering

3.4.1 Refuelling road transport

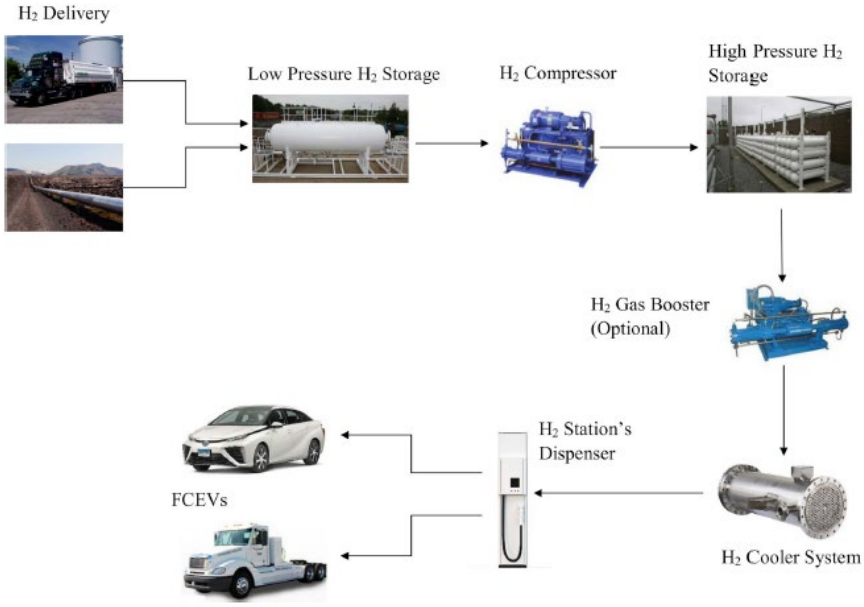

Figure 3.4 Overview of a typical H_2 filling station supplied by tankers or by pipeline

Source: Apostoulou and Xydis (2019).

For an overview of the components that make up a filling station, see the illustration above and Appendix D, section 'Hydrogen filling station'.

Service stations in the Netherlands

Currently, 15 public hydrogen filling stations are in operation in the Netherlands and dozens are planned or already under construction (see figure 3.5). Most of them supply hydrogen at a pressure of both 350 and 700 bar, some only at 350 or 700 bar. Hundreds of filling points would be needed in the Netherlands to meet the targets set out in the Climate Agreement (2019); see text box 'How many hydrogen filling points are needed to meet Climate Agreement targets (2019)'. A proposal for new European regulations in the area of energy infrastructure (*AFIR, Alternative Fuel Infrastructure Regulation*) requires that, by 2030, gaseous hydrogen (700 bar) can be refuelled every 150 km on the main road network and liquid hydrogen every 450 km (EC, 2021a).

The filling stations in Delfzijl and Rhoon are already connected to existing hydrogen pipelines (Verbeek and Cuelenaere, 2019). The other stations are expected to be supplied for the time being with tube trailers. A tube trailer can carry approximately 300 kg of gaseous hydrogen at a pressure of 200 bar (IEA, 2014).

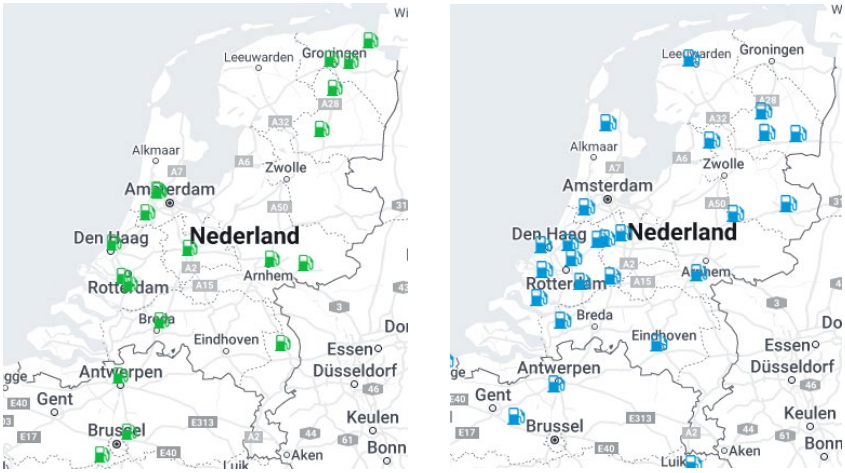

Figure 3.5 **Number of hydrogen filling stations in the Netherlands: operational (left) and planned for the next 2 years (right)**

Source: H_2rijders (2022), status 1 June 2022. 15 stations are operational, and 1 (Eindhoven) is out of service because of a move to Veldhoven. 2 filling stations are not formally public: Groningen and Delfzijl.

How many hydrogen refuelling points are needed to meet the Dutch Klimaatakkoord (Climate Agreement) targets (2019)?

Verbeek and Cuelenaere (2019) calculated that for 300.000 vehicles running on hydrogen (the target number in 2030 according to the Climate Agreement), 360 hydrogen filling points would be needed in the Netherlands to meet the total H_2 requirement of 141 million kg per year. This means that each filling point supplies almost 400 tonnes of H_2 annually, or more than 1 tonne per filling point per day. If an average passenger car fills up with 5 kg of H_2, this means approximately 200 refuelling sessions for passenger cars per filling point per day. Assuming supply by tube trailers that each carry 300 kg of H_2, each filling point would have to be supplied at least three times a day.

Energy efficiency

The main energy item of a filling station is the compression to 350 or 700 bar for use in the vehicle. This takes a great deal of energy, in the order of 10% of the energy content of the hydrogen (2-5 kWh/kgH_2). Another energy item is the purification of the hydrogen. This purification is necessary for both hydrogen derived from electrolysis and hydrogen derived from SMR, and uses energy in the order of 1.5 kWh/kgH_2. For more details see Annex D, section 'Hydrogen refuelling station'.

Costs

A hydrogen filling station is expensive. The largest single cost item is the compressor that brings the hydrogen to pressure levels of 350-700 bar: calculations in the literature vary from 30% to as much as 60% of the total cost of the filling station (IEA, 2019a; Apostoulou and Xydis, 2019). The cost per quantity of hydrogen refuelled depends strongly on the utilisation rate of the refuelling station and the scale. IEA (2019a) calculates refuelling costs of around 2 €/kg for passenger cars and trucks at high utilisation rates. At lower utilisation rates the costs are a multiple of this. The table below shows the refuelling costs according to a number of sources.

Table 3.6. Cost of refuelling according to different sources

Type of service station	Cost (€/kg H_2)	Note	Source
Not specified	2.2		IEA (2019a), Fig 32
Large	1.1	750 kg/day, service life 20 years	Cihlar et al. (2021), table 2-H
Small	2.1	300 kg/day, service life 20 years	Cihlar et al. (2021), table 2-H
Delivered by tube trailer	2.5 (2.1-2.9)	Of which 55% for the compressor (1.35 €/kg)	NREL (2014), Fig 3
Delivered by pipeline	2.2 (1.8-2.5)	Of which 65% for the compressor (1.40 €/kg)	NREL (2014), Fig 2

In the analyses in this study, we do our calculations using 1.6 (1.1-2.1) €/kg, according to Cihlar et al.

Land use

Direct land use. The hydrogen station at Rhoon along the A15 motorway is 1250 m^2 (50 m x 25 m) (www.ruimtevoorenergie.nl). It is connected to a pipeline (the Air Liquide pipelines connecting the ports of Antwerp and Rotterdam run underground here). The storage tank at the filling station has a volume of 2800 litres (at a pressure of 700 bar it would be about 1200 kg H_2), storage takes place at 450/950 bar, there are 2 compressors, a pre-cooler and 3 connections (Honselaar et al., 2018).

Indirect land use. For the site-bound risk, the distance is (Informatiepunt Leefomgeving, 2021):

- 30 m from the intermediate storage, in so far as hydrogen is supplied through a pipeline or produced on-site; and
- 35 m from the filling point if the hydrogen is supplied by tanks.

Bottlenecks and uncertainties

There are several bottlenecks and uncertainties in the refuelling chain step.

Leaking hydrogen?
Hydrogen itself is not a greenhouse gas, but it does enhance the greenhouse effect of methane (Kurmayer, 2021). It is therefore important to prevent hydrogen leakage. Another reason is that hydrogen is explosive (see next point).
A possible leakage of hydrogen occurs during the "boil-off". Boil-off is necessary when hydrogen is stored in liquid form (cryogenically). This is because the temperature difference with the environment causes some of the liquid hydrogen to evaporate, which in turn builds up pressure in the storage tank. Boil-off is necessary to reduce the pressure again and thus prevent leaks in the tank and potential ignition in the presence of static electricity or condensed air (Genovese et al., 2020). At a liquid hydrogen filling station, hydrogen loss through boil-off is of the order of 1% per day (Genovese et al., 2020).

Safety and malfunctions when refuelling
Hydrogen is odourless and burns with an invisible flame. An odourant and a colouring agent must be added. The odourant cannot be sulphur, as in the case of methane, as this is extremely harmful to the fuel cell (Staffell et al., 2019). By way

of comparison: in the case of natural gas, the addition of the odorant to natural gas takes place at the measuring and control stations, which are located between the high-pressure network (66-80 bar) and the regional transport pipelines (40 bar) (Gasunie, 2015).

Sakamoto et al (2016) analysed safety incidents involving hydrogen refuelling stations in Japan and the US in the period 2005-2014 (Sakamoto et al., 2016). As safety issues surrounding hydrogen refuelling stations, they mention:

1) Very high hydrogen pressure is used (in Japan 720 bar).
2) Explosions and fires are likely because of the inherent characteristics of hydrogen: it can leak because it is small molecule, it is highly flammable[66] and its ignition energy is low (10 times lower than that of natural gas).

In addition, hydrogen embrittlement can be a problem for the service life of components (Sakamoto et al., 2016).[67] Hydrogen embrittlement occurs when hydrogen molecules become trapped in capillaries of the material.

3.4.2 *Bunkering maritime and inland navigation*

There are plans for bunkering stations for ocean-going vessels in the Netherlands at Den Helder and Vlissingen, almost all the Wadden Sea ports, Delfzijl, Harlingen, Den Helder, Scheveningen, Yrseke and Medemblik. Deliveries are also made by bunker ships. An estimate of the costs is shown in the following table.

Table 3.7 Bunker vessel costs expressed in cost per kg H_2

	Cost (€/kg)	Details
Bunker ship for inland shipping	0.25	Transports 3 tonnes H_2, makes 4 deliveries per day; vessel costs 3 k€/day
Bunker ship for sea shipping	0.1	Carries 50 tonnes H_2, makes 3 deliveries per day; vessel costs 15 k€/day

Source: TNO (2020).

3.5 For which vehicles is hydrogen suitable?

This section discusses the suitability of hydrogen for different vehicles. The hydrogen can be used in either a *fuel cell (FC)* or an *internal combustion engine* (*ICE*). In the vehicle the hydrogen can be in a cryogenic, a liquid or a high-pressurised gas form.

In **heavy and light road traffic** (passenger cars, vans, trucks, buses) hydrogen is already being used, albeit sporadically (see section 3.1 Introduction). It is always applied in a fuel cell and with hydrogen in gas form. In **shipping and aviation**, hydrogen is still in its infancy, as the TRLs in table 3.8 show.

[66] A gas or vapour is highly flammable if its flash point is below 0° C. The flash point is the temperature at which the gas or vapour can be ignited by an external ignition source to produce self-sustaining combustion. The flash point is a characteristic of the probability that a spark or a glowing object will cause a fire.

[67] In the period 2005-2014, there were a total of 43 incidents, 20 of which involved the leakage of flanges, valves and seals. Most incidents were due to design flaws, particularly material fatigue. In the US, there were two fires at hydrogen filling stations. One occurred after leakage of 300 kg H_2 over a period of 2,5 hours. This incident is extensively analysed in Harris and San Marchi (2012). There were no personal accidents.

Table 3.8 **TRL of application of pure hydrogen in shipping and aviation and concrete examples**

Technology	TRL*	Examples of intentions and plans
Deep-sea shipping		
H_2 + ICE	4-5	Hyundai Heavy Industries has developed a plan to develop a large ICE on H_2 by 2022. Japan has a Roadmap for Zero Emission in the Marine Sector and aims to commercialise H_2-ICEs in large ships by 2030 (IEA, 2021).
Short and medium range vessels		
H_2 + FC	7	Several large prototypes of FC vessels have been tested. Horizon2020 FLAGSHIP is testing the feasibility on 2 smaller vessels (IEA, 2021). In the Netherlands, there is a 24 mln subsidy from the R&D Mobility Fund for a consortium (SH2IPDRIVE) investigating FC vessels.[68]
H_2 + ICE	8	Since 2017, the ship Hydroville has run on both hydrogen and diesel (IEA, 2021). BeHydro develops dual-fuel and mono-fuel H_2 -ICEs with a capacity of over 1 MW with various applications.[69] A first is a dual-fuel (2x2 MW) hydrogen-powered tugboat.[70] TNO is investing in a 1-cylinder research platform for H_2 -ICE for shipping.
Aviation		
H_2 + FC	3	DLR tested a 4-seat motor glider (HY4) with FC in 2016. Boeing tested an FC electric prototype in 2008. There are no announced plans for larger aircraft. Airbus (2021) has developed a vision but will not decide until 2025 whether to continue with H_2 and in what form (synfuels or pure hydrogen) (n.d.) ZeroAvia has made a flight with FCs in a 6-seater aircraft in 2020. By 2023, it aims to fly more than 1.000 miles in aircraft with more than 100 seats.[71]

* Source: (IEA, 2021)

Factors that play a role in suitability

In theory, the suitability of hydrogen, either pressurised or cryogenic, for a vehicle type depends on a large number of factors related to the vehicle. These include:

- The **space available** in the vehicle for a hydrogen tank and propulsion technology (fuel cell system with electric motor or combustion engine).

[68] See for example https://www.innovationquarter.nl/e242-mln-voor-project-sh2ipdrive-voor-onderzoek-naar-varen-op-waterstof/
[69] https://www.abc-engines.com/nl/news/behydro-hydrogen-dual-fual-engine-launched-in-ghent
[70] https://cmb.tech/nl/hydrotug-project
[71] https://www.thenationalnews.com/business/aviation/british-airways-teams-up-with-zeroavia-for-hydrogen-powered-flights-1.1127801

- The **weight** of the tank with its contents and the propulsion system. This is an important criterion for aircraft, for example.
- The **distance** that a vehicle must be able to travel on a full tank. If refuelling is possible within a short distance (and time!), a tank with a small volume is sufficient. Similarly, if the vehicle runs on liquid hydrogen, a smaller (but better insulated) tank is needed than for pressurised hydrogen (which above all needs to be very robust) to cover the same distance.
- Practical matters such as **how much the tank may cost**. The cost of the tank is determined by the materials used and the required strength. A tank for storing gaseous hydrogen must be much sturdier than a tank for liquid hydrogen, and a tank for liquid hydrogen must above all be extremely well insulated.
- **Safety requirements**. Hydrogen is explosive; care is required at all stages of the hydrogen chain. Where leaks can occur, a combination of oxygen and/or air and sparks is taboo.

Hydrogen is not considered suitable for aviation in some studies. Limitations are also seen in maritime shipping. The factors mentioned above also play a role here. For example, in a modelling study ICCT (2022) calculates for various types of ships whether they can travel a certain minimum distance with a tank of hydrogen on board and how much cargo space can be sacrificed for fuel storage.

The most suitable form of hydrogen - gaseous under high pressure or cryogenic - also varies according to the type of vehicle. This depends not only on the space that can be made available for the storage tank (liquid, cryogenic hydrogen requires less space than gaseous), but also on technical possibilities (e.g. cooling) and certainly on costs (affordability).

A number of studies address suitability in more detail (Van Kranenburg et al., 2019; IEA, 2021b; ICCT, 2022); see table below.

Table 3.9 **Suitable form of H_2 by vehicle type**

Mode	Van Kranenburg et al (2019)	IEA (2021b)	ICCT (2022)
Truck	Compressed gas or cryogenic	Outside the scope of the study	Outside the scope of the study
Inland shipping	Compressed gas or cryogenic	Outside the scope of the study	Outside the scope of the study
Short-sea shipping	Cryogenic	Cryogenic or compressed gas	Cryogenic more often suitable than compressed, depending on distance
Deep-sea shipping	Not suitable unless hydrogen is bunkered every one to three days	Cryogenic, probably only on routes where frequent bunkering is possible	
Aviation	Not suitable	Does not comment on. Low TRL (3)	Outside the scope of the study

Source: Van Kranenburg et al. (2019), IEA (2021b) and ICCT (2022)

For the volume and weight of hydrogen with tank, see section 3.5.1. The costs and efficiency of using hydrogen in a vehicle are discussed in section 3.6.

Volume and mass of hydrogen storage (relative to fuel tank and battery)

Volume: Hydrogen occupies more volume than diesel for the same energy content. For gaseous hydrogen (700 bar) the volume is 6 times larger, for liquid hydrogen almost 4 times larger than for diesel. Including storage tanks, the difference with diesel is even greater: a tank of gaseous hydrogen has a volume 16 times that of a

diesel tank (with the same energy content), a tank of liquid hydrogen has a volume 8 times that of diesel.

Compared to a **battery** for electricity storage, hydrogen does have an advantage: a tank of liquid hydrogen takes up 12 times less volume than a battery with the same energy content, a tank of gaseous hydrogen (700 bar) 6 times less volume than a battery. See Annex D, section 'Hydrogen: storage types and characteristics'.

Mass: Hydrogen is lighter than diesel. The mass (kg) of hydrogen is almost 3 times smaller than that of diesel (or petrol and kerosene) with the same energy content. The H_2 storage tank does represent a significant mass, which is a multiple of the H_2 mass in the tank. For example, the 5 kg hydrogen tank of a Toyota Mirai has an empty weight of 87 kg.

How big and heavy are hydrogen tanks in vehicles?

Passenger car: At the moment, a passenger car with a hydrogen fuel cell refuels about 5 to 8 kg H_2 at a time, at a pressure of 350 or 700 bar. 1 kg of hydrogen is enough for a car to cover about 100 km. The 5 kg tank of a Toyota Mirai has an empty weight of about 87 kg.[72] The ratio between the mass of hydrogen in the tank and that of the tank is therefore approximately 1:18. The tank is 3-layer and made of, among other things, plastic (nylon-6) reinforced with carbon fibre. An American source (Sirosh, 2002) reports for both liquid and gaseous hydrogen (at 700 bar) a tank mass to hydrogen mass ratio of 1:10 (tank capacity maximum 10 kg H_2).

Truck: The few trucks with a fuel cell system that are currently on the road fill up with 350 bar and have a tank capacity of around 30 to 40 kg H_2. The announced GenH2 truck from Mercedes-Benz has two tanks of 40 kg H_2 each.[73] Per kg, a truck can travel approximately 14 km.

General: The mass of the tank in relation to the mass of its contents depends on the shape of the tank (round or cylindrical) and the material from which it is made. See the figure below from NASA (2002). A cylinder made of the lightest type of material, carbon fibre, with a potential content of 2000 kg H_2 at 700 bar, weighs 11,000 kg; a ratio of approximately 1:5.5. A cylindrical titanium tank that can hold 2,000 kg of gaseous H_2 weighs about 70,000 kg. A ratio of 1:35.

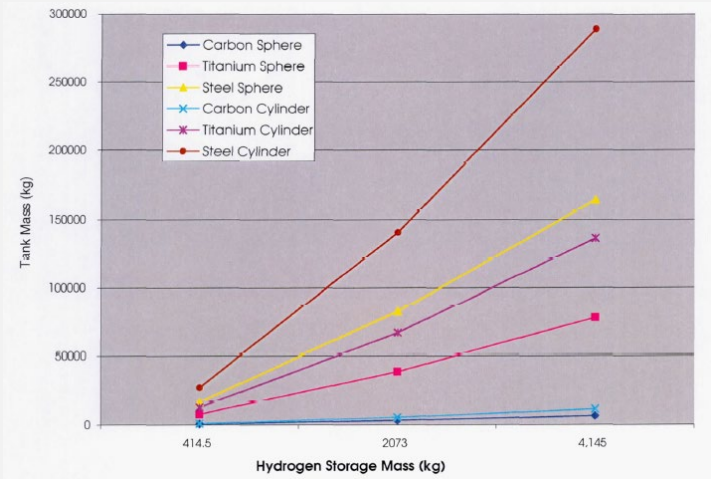

Figure 3.8. Relationship between weight (kg) stored H_2 (compressed) and empty weight (kg) of H_2 storage tank, for different materials and shape (cylinder/sphere)

Source: NASA, 2002.

[72] Wikipedia Toyota Mirai.
[73] https://www.autoweek.nl/autonieuws/artikel/mercedes-benz-genh2-truck-vrachtwagen-met-brandstofcel/

3.6 Fuel cell or combustion in vehicle

There are 2 options for using hydrogen in the vehicle:

- **Fuel cell (FC) + electric motor**: The fuel cell converts hydrogen with oxygen from the air into electricity, via the reverse process of an electrolyser. The electricity powers an electric motor.[74] There is also a small battery.
- **Combustion engine**: The hydrogen goes directly into an internal combustion engine as fuel. The advantage is that the hydrogen does not have to be as pure as when used in a fuel cell. The disadvantage is that NO_x is created in the combustion process; how much depends on the engine configuration (combustion temperature, post-treatment of flue gases).

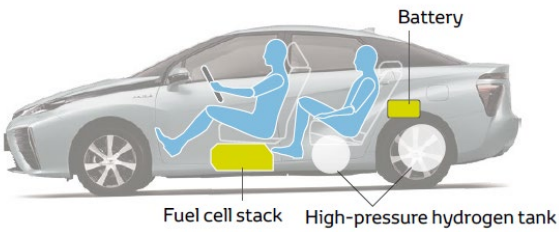

Figure 3.6 Passenger car with fuel cells and small battery

Source: Toyota.

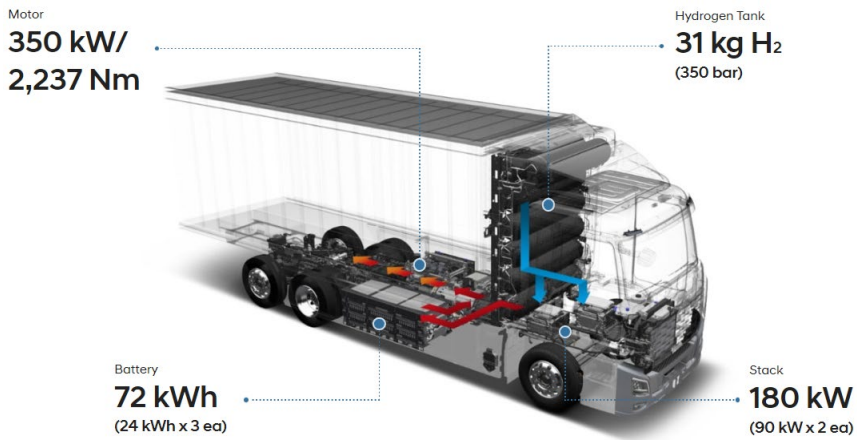

Figure 3.7 Example of truck (Hyundai XCIENT) with 7 hydrogen tanks of 5 kg each, visible as black cylinders behind the driver's cabin

Source: https://trucknbus.hyundai.com/hydrogen/en/hydrogen-vehicles/xcient-fuel-cell.

3.6.1 Fuel cell

A single fuel cell consists of an anode, cathode, electrolyte and catalyst. The fuel cells are stacked in a so-called stack. For example, the first generation Toyota Mirai had 6 stacks of 370 cells each, with a total power of 114 kW (Wikipedia, 2022). From the fuel cell stacks, a fuel cell system is created using the balance-of-plant. There are different types of fuel cells. For mobile applications under dynamic conditions, such as passenger cars, a PEM cell is used. SO-FC is still more experimental. For more details, see the 'Fuel cell types' text box. In the following, we will only discuss PEM.

[74] Aircraft require the combination of an electric motor with a propeller (instead of a jet engine).

Types of fuel cells

PEM-FC (*Protone Exchange Membrane Fuel Cell*): this has a polymer electrolyte and platinum as the catalyst. Its operating temperature is around 100ºC. For application in a road vehicle, this fuel cell is the most suitable because of its low operating temperature (JRC, 2020). It also works better under dynamic conditions (braking, acceleration). Of all fuel cells, the PEM-FC is the most sensitive to pollution. Its tolerance for sulphur is less than 0.1 ppm, that for carbon monoxide less than 10 ppm, ammonia is destructive for the fuel cell (Staffell et al., 2019).

SO-FC (*solid oxide fuel cells*): these have ceramic as electrolyte and nickel as catalyst. The operating temperature is 900-1000ºC. This high operating temperature creates challenges in terms of construction and lifespan of the fuel cell and means a long start-up time for the fuel cell. This cell can be applied in vehicles such as shipping and long-haul freight transport, where frequent switch-on/switch-off cycles or rapid start-up are not necessary, unlike vehicles operating in dynamic conditions (cars, motorbikes, vans, taxis and buses). The TRL of the SO-FC is still low. A tender by the European Commission is trying to raise the TRL from 2 to 4.[75]

Energy efficiency

According to various sources, the efficiency of the PEM fuel cell stack is in the range of 45-60%, see the table below. The US Department of Energy (DoE) has a long-term target ('ultimate target') of 70% efficiency (DoE, n.d.). DoE's target values are seen as a good indication of potential future improvement (Rivard et al., 2019).

Table 3.10 Efficiency of the PEM fuel cell stack according to different sources

Efficiency PEM	Source
49% at 50% load; 45% at 100% load	Van Kranenburg et al. (2019)
60%	IEA (2019a)
60%	EASAC (2019)
70%	DoE target

For the chain calculation, we assume the range 50-60% (see Appendix B Efficiency).

Costs

Stack (PEM): For passenger cars, the cost of just the fuel cell stack is currently around $70/kW and there is the prospect of it decreasingto $20/kW by 2035, according to the UK Propulsion Centre (Apcuk, 2021). The costs have already decreased significantly in recent decades. In 2005, for example, a stack cost 125 $/kW (Pollet et al., 2019).

The platinum catalyst is the most expensive element of the PEM fuel cell stack. The required platinum currently constitutes more than 40% of the cost (Pollet et al., 2019). To illustrate, the fuel cell system of a Totoya Mirai passenger car contains about 30 g of platinum (Onsted, 2019). The market price for platinum is approximately 30 €/g (https://www.goldrepublic.nl/platinaprijs).

System: For application in a vehicle, auxiliary equipment and system balance are required in addition to the stack. A complete fuel cell system cost around $112/kW

[75] https://www.fch.europa.eu/project/next-generation-solid-oxide-fuel-cell-and-electrolysis-technology

in 2020 (Apcuk, 2021). At a capacity of 100 kW[76] per fuel cell car, this is $11 k. There is the prospect of costs decreasing to $40/kW by 2035 (Apcuk, 2021).

Further cost reductions are possible if the amount of platinum is reduced[77] and if production is applied on a larger scale. The British Propulsion Centre (Apcuk, 2021) expects the cost of the fuel cell system to drop to $40/kW by 2030 if mass production takes place.

Hydrogen tank: The hydrogen tank also represents a significant cost (with potential for future cost reduction): in 2020 the cost was $470/kg$H_2$ storage; the future projection is a decrease to $200/kg$H_2$ storage (Apcuk, 2021). To illustrate: For a passenger car with a 5 kg hydrogen tank, the cost of the hydrogen tank in 2020 is $2350. This is comparable to ¼ of the cost of the fuel cell system (see above). Apcuk projects the cost of a 5kg tank dropping to $1000 in 2035.

Fuel cell system weight

The fuel cell system in the first generation Toyota Mirai weighed approximately 230 kg at 114 kW (https://en.wikipedia.org/wiki/Toyota_Mirai). For the weight of the tank, see section 3.5.1.

Vehicle weight (truck)

ATRI (2022) compared the weight of trucks with an internal combustion engine (ICEV), a fuel cell system (FCEV) and a battery-electric system (BEV). Assuming the trucks have a full tank or battery on board, the FCEV truck is 10% heavier than the ICEV truck, but 50% lighter than a BEV truck. However, the range of the 3 truck types is not the same. If we convert the vehicle masses into a mass per unit of range, the FCEV is almost 3 times as heavy and a BEV 5 times as heavy as an ICEV. The FCEV is 40% lighter than the BEV. See Appendix D, section 'Empty weight of ICEV, BEV and FCEV truck' for more details.

Bottlenecks and uncertainties

Degradation of cells: The efficiency loss during the lifetime of fuel cells is about 10%. See Appendix B Efficiency. If the hydrogen contains impurities, degradation is faster.

Greenhouse effect of water vapour at high altitude: Water is released from a fuel cell. This is normally not a problem. Only when hydrogen is used as jet fuel is it released at high altitude, where it has a (short-term) greenhouse effect; the amount of water vapour is 1.5 to 2 times greater than for kerosene (Staffell et al, 2019; Clean Sky 2 JU, 2020), so the greenhouse effect of the water vapour is also twice as great. The effect is 10 times smaller than of the avoided CO_2 emissions (Clean Sky 2 JU, 2020).

3.6.2 *Combustion engine*

Hydrogen can also be used directly in a combustion engine. The advantage is that less purity of the hydrogen is needed.

Developments in this direction are furthest along in trucks. The most relevant and quickly implementable engine variants for trucks are H_2 lean-burn combustion (mono-fuel with spark ignition) and H_2 dual-fuel (mix of H_2 with a small amount

[76] The power of the average fuel cell passenger car is 100 kW (Pollet et al., 2019).

[77] There are several initiatives for this. The next generation of the Toyota Mirai, for example, would use only 10 g of Pt, a 2/3 reduction compared to the current amount (Onstad, 2019). Siemens, TUDelft and TUEindhoven are also working on platinum reduction in fuel cells; see among others Wassink (2019) and De Ingenieur (2019).

(<5%) of diesel for ignition). The efficiency of these modified engine types (H_2-ICE) is very similar to that of the standard diesel engine.

Energy efficiency

The engine efficiency of a H_2-ICE for road vehicles is 40-45%; see Appendix B Efficiency.

3.7 Total efficiency in hydrogen chain (WTT, TTW, WTW)

Table 3.11 shows the chain efficiency when hydrogen is used in a road vehicle. The 'transport' column shows the form the hydrogen took on the route from the production site to the distribution network to which the filling station is connected. The distribution distance to the filling station is in the order of 100 km and distribution is by tube trailer or pipeline. The hydrogen is produced with either electrolysis of water or SMR-CCS. Figure 3.9 shows the energy efficiency and energy input per chain step.

Table 3.11 WTT, TTW and total chain efficiencies of the electrolysis and SMR-CCS sub-routes applied to a fuel cell electric passenger car (FCEV) and an internal combustion engine car (H_2 -ICE)

Subroute	Transport	WTT (%)	TTW (%)	Total FCEV (%)	Total H_2 - ICE (%)
Electrolysis	1: liquid	48 (42-54)	FCEV: 50-60 ICE: 40-45	25 (20-31)	21 (17-24)
	2: ammonia	34 (32-35)		18 (15-20)	14 (13-16)
	3: gaseous	59 (54-64)		31 (25-37)	25 (21-29)
SMR-CCS	1: liquid	49 (45-53)		26 (21-30)	21 18-24)
	2: ammonia	31 (30-31)		16 (14-18)	13 (12-14)
	3: gaseous	61 (58-64)		32 (27-36)	26 (23-29)

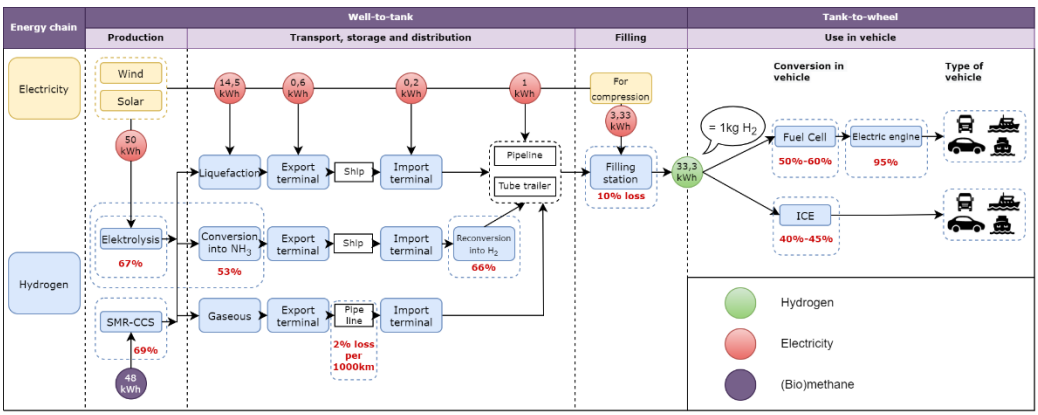

Figure 3.9 Energy consumption and energy efficiency in the steps of the hydrogen chain

4 Synfuels

Main points

- There are many different types of synfuels, each with its own advantages and disadvantages. In this study we look at ammonia, methanol and drop-in fuels (in the form of Fisher-Tropsch (FT) synfuels). Ammonia is only considered an option for the maritime sector in this study. Methanol is an option for the maritime sector and for light and heavy road transport. FT synfuels can be used for all modes.
- Synfuels are made from hydrogen produced by electrolysis with sustainably produced electricity (which is why synfuels are also called e-fuels). In addition, nitrogen (N_2) or CO_2 is required. The CO_2 can be captured from the air, or at large-scale point sources if the CO_2 would otherwise end up in the atmosphere. However, this CO_2 capture at point sources should not count as CO_2 storage, because the CO_2 is still emitted when the synfuel is burned.
- Synfuels are sometimes seen as an option for storing surplus sustainable electricity. It is very questionable whether the synfuel production process can cope with variable electricity supply.
- Compared to hydrogen and electricity, synfuels are easy to transport and store. At atmospheric pressure and room temperature they are liquid, only ammonia has to be cooled slightly (-33ºC).
- Ammonia and methanol are volatile and toxic substances, requiring additional safety measures during storage, bunkering and on board the vehicle. With additional measures, the risks are comparable to those of fossil fuels.
- For safety reasons, the transport of the toxic ammonia by tankers and trains is socially sensitive and therefore regulated and discouraged. So far, there seems to be no social resistance in the Netherlands to the transport of ammonia by ships and the storage of ammonia in harbours. Whether this will remain the case when ammonia is transported on a large scale by inland navigation vessels and stored near inland navigation vessel transhipment points is uncertain.
- The synfuels containing carbon - such as FT synfuels and methanol - emit CO_2 when burnt. Nevertheless, they be compatible withcarbon neutral mobility because the CO_2 has first been removed from the atmosphere. The CO_2 used must then be captured from the air using sustainably produced electricity or be a residual product that would otherwise be emitted.
- A disadvantage is that NO_X is released during the combustion of synfuels. With methanol, this is 60% less than with regular diesel engines due to a lower combustion temperature.
- If ammonia or FT synfuels are used as fuel in a ship, a catalyst must be installed to reduce NO_x emissions. This catalyst may emit a small amount of N_2O (nitrous oxide). N_2O is a strong greenhouse gas. The amount of N_2O emitted seems to be similar or slightly lower than what diesel engines emit.
- FT synfuels can be used in existing combustion engines without modification.
- For ammonia and methanol, the combustion engines have to be slightly modified. Both ammonia and methanol require a second fuel, such as biodiesel or hydrogen, in a diesel engine. This second fuel must now be refuelled separately, which means that two fuel tanks are needed in the vehicle, or the hydrogen must be produced on board from the synfuel. Another option for methanol is to base it on spark ignition (the principle of a petrol engine), but this sacrifices efficiency.
- The chain efficiency for all three synfuels is below 20%.
- The raw materials (mainly H_2 but also CO_2) are the biggest cost item of synfuels.

- The unit costs (€/GJ) of ammonia, methanol and FT synfuels are close to each other. The costs are between 50-65 €/GJ for all three synfuels, provided CO_2 can be captured at point sources. If these CO_2 point sources no longer exist (because all sectors have switched to hydrogen and electricity), methanol and FT synfuels become 15-20 €/GJ more expensive. However, the uncertainties in the latter cost estimates are large because CO_2 extraction from air (Direct Air Capture, DAC) is a technology still under development (with a TRL of 6) and it is unclear to what extent large cost reductions can be achieved.
- Synfuels are relatively new products, so costs may improve as a result of learning-by-doing. However, the potential for cost reduction should not be overestimated, because many sub-processes are already being used in the chemical industry, so that they are already reasonably mature.
- The space required by synfuels is mainly due to the raw materials, namely hydrogen and, in the case of methanol and FT synfuels, also CO_2 (if captured from the air; in the case of CO_2 point sources the space requirement is zero).

4.1 Introduction

Synthetic fuels, or synfuels, are made in a factory. The main advantage of synfuels is that they are easier to transport and store than, for example, hydrogen or electricity. The raw materials are diverse and can include natural gas, coal, biomass, hydrogen and nitrogen or CO_2 from the air. If natural gas or coal are used, the fuel is not carbon neutral and therefore these feedstocks are beyond the scope of this study. If the feedstock is biomass, the product is called a biofuel in this study (see also Chapter 5). In table 4.1 The main characteristics of different types of synthetic fuel can be found in the following table. It is important to distinguish between them:

1) Drop-in fuels (synthetic gasoline, diesel or kerosene) that are very similar in chemical structure and physical properties to their fossil counterparts diesel, gasoline and kerosene
2) Other types of synfuels, such as ammonia and methanol. These types of synfuels require other types of engines.

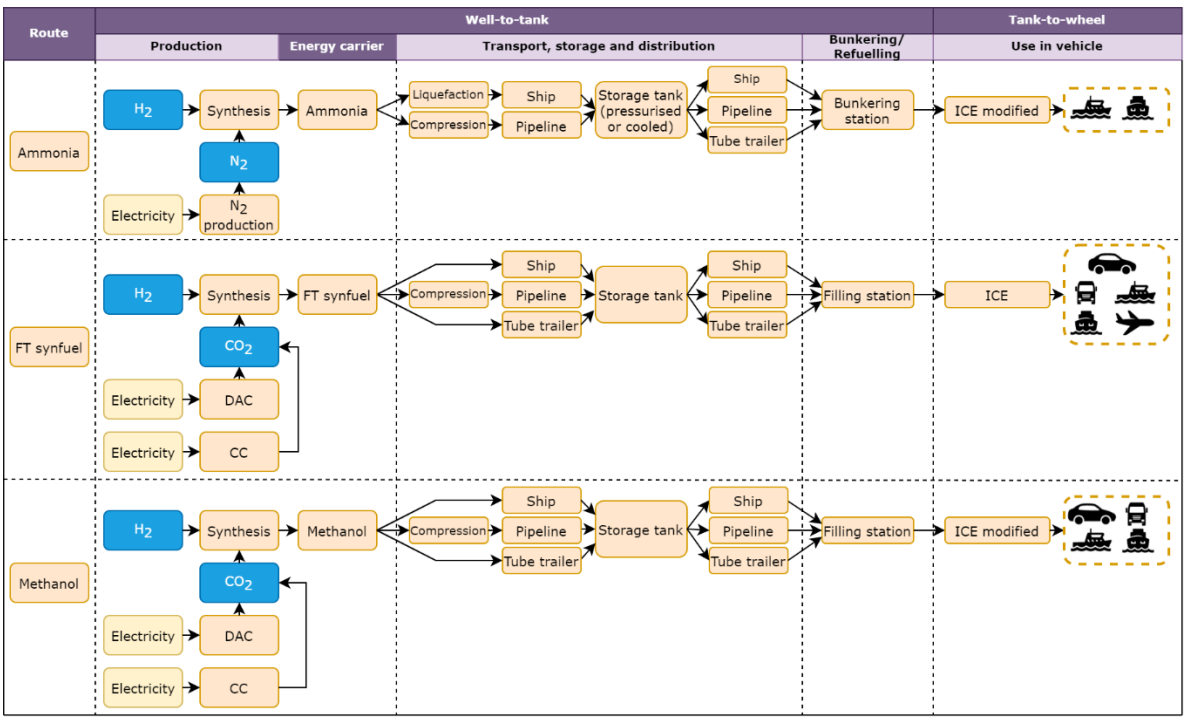

Figure 4.1 Synthetic fuel production chain steps

In this study, we only look at the use of ammonia for the maritime sector, as there are safety issues related to its use in light and heavy duty vehicles. For methanol, we look at the maritime sector and light and heavy road transport. Ammonia and methanol are not suitable options for aviation. For FT synfuels we look at all transport modes, see also table 1.2 in chapter 1 Introduction.

Table 4.1 Overview of specific characteristics of different synthetic fuels

	Gaseous[a]	Drop-in fuel	Combustion value (LHV)	
			MJ/kg	MJ/l[a]
Ammonia	Yes	No	18,6	14,1
Methanol	No	No	19,9	15,8
Synthetic petrol[b]	No	Yes	41,5	31,0
Synthetic diesel[b]	No	Yes	44,0	34,3
Synthetic kerosene[b]	No	Yes	44,1	33,3

a. At atmospheric pressure and room temperature.
b. The combustion values are based on those of fossil diesel, petrol and kerosene, each of which consists of a mixture of different hydrocarbons. These could differ slightly in a synthetic variant due to a slightly different composition of the mixtures.
Source: (Yugo & Soler, 2019).

4.1.1 *Drop-in fuels*

Drop-in fuels are a well-known type of synfuels. Drop-in fuels are not chemically different from synthetic diesel, petrol or kerosene and therefore do not require any changes in storage facilities near ports, refuelling infrastructure or the engines of aircraft or ships, for example. Because they are physically the same as fossil fuels, they contain carbon. They are therefore carbon neutral only if they recycle CO_2 from the air or use a CO_2 waste stream (which would otherwise end up in the atmosphere).

In this study we look at drop-in fuels produced using the Fischer-Tropsch (FT) process. The FT process has a high TRL and is frequently mentioned in studies as a possible option for synthetic fuels. This process can make petrol, diesel and kerosene, see section 4.4.

Drop-in fuels are by definition suitable for all current modalities. However, for many applications they are more expensive per unit of energy at the fuel station than, for example, electricity, biofuels and hydrogen. Only for modes that are difficult to decarbonise, such as aviation and shipping, they are often seen as attractive alternatives because cheaper options like hydrogen and electricity are not realistic for long-distance travel (Brynolf et al., 2018; Dieterich et al., 2020; Malins, 2017), see also section 1.3.

To ensure the development of sustainable aviation fuels, the European Commission proposed a subtarget in 2021 that 0.7% of all kerosene tanked in the EU should be synthetic kerosene by 2030 (SkyNRG, 2022). This share will increase to 28% in 2050. For other sectors, there is no subtarget for synfuels.

4.1.2 *Synfuels that are not drop-in fuel*

Besides drop-in fuels, there are other types of synfuels. These include, for example, ammonia (NH_3), methanol (CH_3OH) and dimethylether, DME (CH_3OCH_3). Hydrogen is also an essential material input for these synfuels.[78] The production of hydrogen is discussed in chapter 3.

Unlike the drop-in fuels, the other types of synfuels require a different infrastructure for transport and storage. In addition, the combustion engine in vehicles must be

[78] In principle, hydrogen is also a synfuel that is not a drop-in fuel. Since hydrogen is of great interest, it is treated separately in this study.

adapted, designed differently or replaced by a fuel cell in combination with an electric motor. An advantage of other types of synfuels is that they are relatively simple molecules, making them easier to produce than synthetic petrol and diesel, for example. In addition, they can also serve as input for the chemical industry.

As the first other type of synfuel, we look at ammonia in this study. Ammonia is seen as a promising fuel for the maritime sector (Ash & Scarbrough, 2019; Morlanés et al., 2021; Yugo & Soler, 2019; Zincir, 2020). For heavy duty trucks, ammonia is not recommended because of its toxicity and related safety issues (Arcadis & Berenschot, 2021; Duijm et al., 2005). Ammonia has the advantage that it is a carbon-free fuel, so it fits perfectly in a carbonfree energy supply. Another major advantage of ammonia is that it is already produced on a large scale (e.g. as a raw material for artificial fertiliser) and therefore a transport and storage infrastructure already exists.

As a second alternative fuel, we look at methanol, which is an alternative to ammonia for the maritime sector (Horvath et al., 2018; Liu et al., 2019; van Lieshout et al., 2020; Yugo & Soler, 2019). Recently, the Dutch government awarded over 24 million euros to the project "Methanol as an Energy Step Towards Emission-Free Dutch Shipping" (MENENS). The project partners see methanol as the most feasible fuel option that can achieve CO_2 emission reductions in the short and medium term for the international maritime sector.[79] In addition, methanol can be used for road transport (Hobson & Márquez, 2018). Methanol has a slightly higher calorific value compared to ammonia (i.e. 15.8 MJ/l versus 14.1 MJ/l), which leads to smaller storage volumes and a greater range per full tank (assuming constant tank capacity in the vehicle). Nevertheless, even for methanol the calorific value is considerably lower than for (synthetic) diesel, with a calorific value of 34.3 MJ/l.

[79] See this letter to the Dutch Parliament: https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2021Z21880&did=2021D46655

Policy context synfuels

The European Commission's "Fit for 55" package (July 2021) contains concrete proposals for the share of synthetic fuels in aviation. No concrete targets have been set for other sectors. There is, however, a general target for the transport sector in 2030 of a 2.6% share to be based on 'renewable fuels of non-biological origin (RFNBO)'. RFNBOs can be e-fuels, but also hydrogen produced from renewable electricity. In the Dutch context synthetic fuels are mentioned in the Climate Agreement, but no specific targets are given.

Aviation

For aviation, the European Commission proposes that all aviation fuel in Europe contains 2% sustainable fuel by 2025, whereby sustainable paraffin can consist of bio kerosene (made from biomass or residual flows) or synthetic kerosene (from green H_2 and CO_2 from the air). The share of sustainable aviation fuels (SAF) is being increased over time to 5% in 2030, 32% in 2040 and 63% in 2050. In addition, there is a sub-target for synthetic kerosene to provide market certainty for manufacturers of synfuels. The sub-target is for a share of synthetic kerosene of 0.7% in 2030, 8% in 2040 and 28% in 2050 (SkyNRG, 2022). In the Netherlands, the government would also like to see a European mandatory blending requirement for aviation; if this does not materialise in time, a national mandatory blending requirement will be introduced for sustainable kerosene from 2023. The aim is to blend 14% sustainable aviation fuel (SAF) in 2030. This sustainable aviation fuel can consist of bio or synthetic kerosene (MinIenW, 2020 - Aviation blending obligation and other developments of sustainable fuels).

Other transport sectors

The European Commission has not proposed any sub-targets for synthetic fuels for the other transport sectors. In the case of the maritime sector, however, the importance of ammonia, for example, has been recognised. The CO_2 intensity of fuels in the maritime sector must fall by 2% per MJ in 2020, 6% in 2030, 26% in 2040 and 75% in 2060 (all relative to 2020). Although this can also be achieved with biofuels or the use of electrically powered vessels, it is quite possible that synthetic fuels will also play a role.

The European Commission has further proposed that, by 1 January 2024, each Member State should draw up a national policy framework for the development of the alternative fuels market in the transport sector and the deployment of the relevant infrastructure (European Commission, 2021). This policy framework must in any case also devise a plan to realise the roll-out of transport and refuelling infrastructure for alternative fuels (e.g. ammonia) in seaports. The Dutch Climate Agreement of 2019 mentions synthetic fuels as a temporary solution in the period up to 2030 for heavy duty vehicles, until zero-emission energy carriers become available. Synthetic fuels are also likely to be needed as a hybrid standard in the period after 2030-2050. The climate agreement is not specific about how much and which synthetic fuels are needed for the various modes of transport.

4.2 Energy chain steps of synfuels

Figure 4.1 shows the chain steps of synthetic fuel production, namely production, storage/transport/distribution and refuelling. All synthetic fuels require electricity as an input at almost every stage in the chain.

4.2.1 *Production*

H_2 production: All synthetic fuels need hydrogen as a input, see chapter 3. We assume that the hydrogen is produced in the vicinity of the synfuel production facility (via electrolysis), as this offers major (cost) advantages in terms of transport. In addition, we assume that all hydrogen for synfuels is produced by electrolysis. The other way of producing carbon neutral hydrogen, namely via SMR with CCS from natural gas with some biomethane, is cheaper than producing hydrogen via electrolysis, but has other drawbacks and objections, such as the dependence on natural gas, the question of whether there is sufficient availability of biomethane and the proximity of suitable CO_2 storage sites.[80]

CO_2 production: Apart from hydrogen, all synthetic fuels except ammonia need CO_2 as an input. This can be captured from the air or from so-called point sources such as power stations and large-scale industry. The advantage of capturing CO_2 from point sources is that the CO_2 concentration is much higher (up to 27%) than CO_2 capture from the air (400 ppm or 0.04%), making the costs much lower. For the fuel to be carbon neutral, the CO_2 must be a by-product that would otherwise end up in the atmosphere (see section 1.3 for a discussion on this point). You take the CO_2 out of the air at the exit of the chimney, as it were, instead of letting the same CO_2 spread in the air first and then take it out with much more effort.

If CO_2 from point sources is not or no longer available, CO_2 must be captured from the air. This is a technology that is not yet commercially available. As a result, cost estimates vary widely. However, it is clear that capturing CO_2 from the air costs about a factor of 10 more than CO_2 capture from point sources. Because the CO_2 concentration is so low, a lot of air volume is needed to capture a reasonable amount of CO_2. This means that a plant that extracts CO_2 from the air also takes up a relatively large amount of space (see later in this chapter). Part of this space can, however, be used for other purposes, as is the case with wind turbines.

Nitrogen and ammonia production: Ammonia does not need CO_2 but nitrogen (N_2) in addition to hydrogen. The concentration of nitrogen in the air is relatively high (78%), making N_2 capture much less energy-intensive and cheaper than CO_2 capture. In addition, this is already a technique that is used commercially. The various raw materials (hydrogen and CO_2 or nitrogen) are then converted into a synthetic fuel in a factory using sustainably produced electricity.

4.2.2 *Storage/transport/distribution and refuelling*

The synfuel is then stored, transported and distributed to end users (filling stations). FT synfuels and methanol are liquid under normal conditions (temperature of 20°C and atmospheric pressure). Ammonia, on the other hand, must be slightly cooled or pressurised to liquefy and be easily transported or stored. Because these synthetic fuels are liquid without being highly cooled, they are relatively easy to transport, store, distribute and refuel compared to pure hydrogen.

Appendix E includes more technical details of all the production steps. In this chapter we focus on the most important aspects per synfuel. Section 4.3 is about ammonia, section 4.4 about FT synfuels and section 4.5 about methanol.

4.3 Ammonia

Ammonia is already produced on a large scale with a global production of about 180 million tonnes per year, mainly as input for fertiliser production (Cardoso et al.,

[80] Note that the CO_2 released from SMR cannot be used as feedstock for the synfuels, because then the synfuel would not be carbon neutral. If carbon neutrality is not a requirement (which it is in this study), it is much more efficient to produce the synfuels directly from natural gas than via the hydrogen route.

2021). This ammonia production would be approximately enough to fuel 30% of maritime shipping if we assume that an ammonia-powered ship is as energy-efficient as today's vessels (Hansson et al., 2020). However, ammonia is now mainly produced from fossil fuels (natural gas). This results in substantial CO_2 emissions, as the combination with CCS is not common. Ammonia production accounts for 2% of global primary energy consumption (Cardoso et al., 2021). If all ships were to run on ammonia, ammonia production would therefore have to be expanded and made greener.

Figure 4.2 gives an overview of the chain steps of ammonia production. In the following paragraphs, we briefly discuss the various aspects of ammonia production. For a more detailed discussion, please refer to Appendix E.

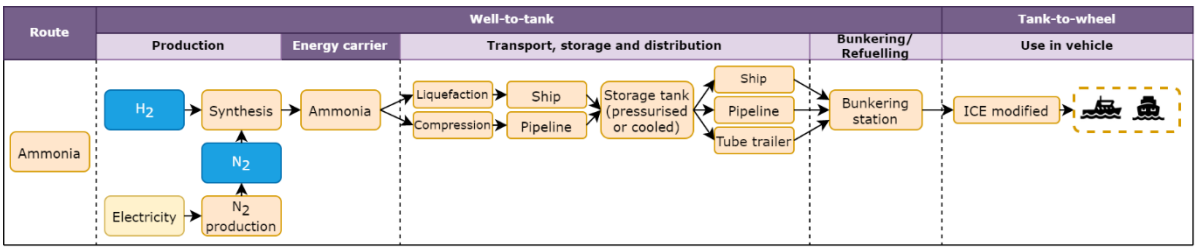

Figure 4.2 **Overview of ammonia production chain steps**

4.3.1 *Current technology*

Production: Currently, ammonia is mainly produced via the Haber-Bosch process, known for more than 100 years, in which N_2 (captured from the air) reacts with hydrogen extracted from natural gas. It is an energy-intensive process as it requires both high pressure (150-300 bar) and high temperature (350-500°C) to make N_2 react with hydrogen (Elishav et al., 2020; Royal Society, 2020). It is also possible to replace the natural gas with pure hydrogen. Figure 4.3 shows a schematic overview of this production process with hydrogen instead of natural gas.

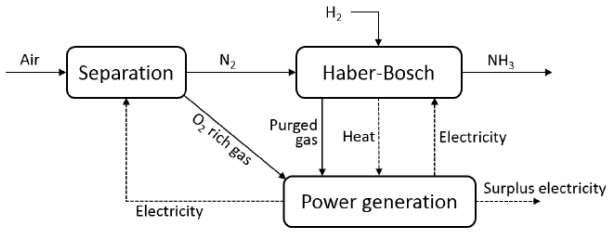

Figure 4.3 **Schematic overview of N_2 production and ammonia production in an integrated system**

Source: Aziz et al., 2018.

Transport/distribution: The ammonia has to be transported to the users, or it has to be produced in the port near the users. Since considerable quantities of ammonia are already produced, a transport infrastructure is already in place. This will need to be expanded if ammonia is to become the standard fuel throughout the maritime sector. Certainly if inland navigation vessels also start using ammonia, the transport infrastructure will have to be made more finely-meshed. Large-scale ammonia transport currently takes place via ocean-going vessels and pipelines.[81] In addition, ammonia is transported by inland navigation vessels, trains and trucks. These last two modalities, however, are not preferable in terms of safety risks (Arcadis & Berenschot, 2021; Duijm et al., 2005).

[81] Examples of existing ammonia pipelines are the NuStar pipeline in the United States of 3000 km that transports 2.9 million tonnes of ammonia annually and the ammonia pipeline between Russia and the Black Sea of 2400 km that transports 3 million tonnes of ammonia annually (Nayak-Luke et al., 2021).

To transport and store ammonia cost-effectively, it has to be liquefied. At normal conditions (1 bar; 20°C), ammonia is gaseous and to liquefy it, the ammonia can be pressurised (to around 10 bar), cooled (< -33ºC) or a combination of both (Nayak-Luke et al., 2021). Which way is most convenient, depends on the modality and what it will be used for afterwards (long-term versus short-term storage or direct use). Large-scale storage usually takes place under cooled atmospheric pressure. For transport, the ammonia is generally pressurised for road, rail and pipeline transport and cooled for ship transport.

Use in a vessel: Ammonia is also stored in a refrigerated vessel. In this form, ammonia still has twice the energy content of diesel. This means that a vessel with a 2,700 m tank^3 can store enough diesel for a journey of around 13,000 km, whereas the same tank is only enough for around half this distance (around 6,500 km) for ammonia assuming the engine has the same efficiency for both diesel and ammonia (McKinlay et al., 2021). In short, a vessel using ammonia as fuel would have to refuel twice as often or double its tank capacity, to the detriment of its cargo capacity. It is expected that, at least for deep sea shipping, the latter option will be chosen in order to ensure that the usual range (of 60 days) is achieved.

Short sea shipping and inland vessels have a smaller tank capacity and range than deep sea shipping. For these ships, the choice between refuelling more often, increasing tank capacity or a combination of the two will depend on the distances normally travelled and the costs involved in increasing tank capacity.

In addition to ammonia, a second fuel, such as biodiesel or hydrogen, is needed to burn the ammonia in an engine. This second fuel serves as a starter fuel to get the combustion of ammonia going and to keep it going.[82] This second fuel can be refuelled separately, so two fuel tanks are needed in the vehicle. Another option is to convert a small part of the ammonia in the vehicle into hydrogen and to use that hydrogen as "fuel". Both options take up space on board the vehicle and involve additional complexity. No data could be found on the exact amount of space required.

Another possibility is to make blends with ammonia (Cardoso et al., 2021), but this technology is still in its infancy with a TRL of 4-5 (IEA, 2020 - ETP).

Refuelling: Ammonia can be refuelled from bunker ships just like regular diesel, but these ships need to keep the ammonia cool. For inland navigation vessels, the ammonia could also be stored and refuelled at higher pressure (10 bar) and room temperature. Storing ammonia at 10 bar pressure, however, takes up almost twice as much space as refrigerated ammonia (Kranenburg et al., 2020). When refuelling or bunkering, extra attention must be paid to any leaks, as ammonia is toxic (Duijm et al., 2005). This probably means that the safety distances of bunkering stations must be increased.[83]

4.3.2 *Spatial aspects*

Looking at bunker fuels for ships in the Netherlands, almost 500 PJ of fuel was sold in 2020 (CBS, 2021).[84] This is slightly more than in the pre-corona year 2019, when

[82] This is necessary since ammonia has a very low cetane number which leads to very low flammability. Successful experiments with (modified) diesel engines have been conducted with 95% ammonia and 5% diesel and 70% ammonia and 30% hydrogen (Cardoso et al., 2021).

[83] Currently the minimum distance is 20 metres between the delivery point (or filling point) and vulnerable objects for bunker stations (https://www.infomil.nl/onderwerpen/veiligheid/activiteitenbesluit/afleveren-brandstof/afleveren-brandstof/).

[84] Shipping includes all transport of people and goods via waterways, such as inland, maritime and coastal navigation. Fishing is not included.

484 PJ was sold. If 500 PJ is replaced one-on-one with ammonia, this amounts to 27 Mt ammonia per year. Table 4.2 gives an overview of the space requirements for ammonia per chain step. Whether space is a potential constraint depends very much on where the ammonia and the required hydrogen are produced. If production takes place in ports close to end users, space may be a problem, whereas if ammonia is imported, land use may be less of an issue.

Table 4.2 Ammonia chain land use

Energy chain step	Land take (m^2 per GJ ammonia per year)	Land take (km^2) if all ships bunkering in the Netherlands sail on ammonia	Notes	Sources
Hydrogen production	2.0	$9.8*10^2$	Largest space requirement for electricity production for the electrolyser	See chapter 3 for space requirements of hydrogen production per GJ H_2
Ammonia production (including nitrogen production)	< 0.04	20	Upper limit	Pellikaan, 2019[1]
Ammonia storage	$8 * 10^{-5}$ - $5 * 10^{-3}$	0.04-2.0	Large economies of scale	(Morgan, 2013; The Royal Society, 2020)
Ammonia transport	-	-	Similar land use for infrastructure as now, perhaps twice the safety distances	(Duijm et al., 2005)
Refuelling infrastructure	-	-		
Total	2.0	$1.0*10^3$		

[1] Based on an industrial complex in Sluiskil with a surface area of 135 hectares where 1.8 Mt of ammonia is produced per year and then processed into fertiliser. Although this process does not run on H_2 or fossil fuels, it does give an indication of the area. In addition to three ammonia factories, the complex contains four CO_2 factories, two nitric acid factories, three urea factories and two nitrate granulation factories. Hence, the surface area indicated is an upper limit.

Land area requirements for production: In the ammonia chain, the production of ammonia takes up relatively little space compared to the space required to produce the hydrogen. This is due mainly to the space required to produce the required wind and solar power. The space requirements for electricity and hydrogen production were discussed in chapters 2 and 3, respectively.

Land take for transport, storage and refuelling: No sources of land take were identified for the transport and refuelling infrastructure steps. Transport is mainly by ship, making the land take small. Refuelling takes place by means of bunker vessels, which may need to be slightly larger due to ammonia's lower energy density in order to accommodate the same amount of fuel, or may need to be refilled more frequently or be available in greater numbers.

An additional factor in the space required for both storage and refuelling infrastructure are the safety distances necessitated by the toxicity of ammonia. Duijm et al. (2005) In the case of a road traffic filling station, the safety distance is calculated to more than triple from 40 m for petrol and LPG to 150 m for an ammonia filling station. With additional safety measures this can be reduced to 70 m, almost twice as large as for LPG and petrol. In practice, this means that greater distances are required between filling stations and residential areas or other public areas (Duijm et al., 2005). Although, as far as we know, similar calculations have not yet been carried out for the fuelling infrastructure of ships, the calculations for

roadside refuelling stations do give an indication of the extra space used by bunker ships. This need not be a barrier since ports and related matters are usually not located close to residential areas. For each storage location and bunker ship of ammonia, it should be checked whether this indeed does not lead to unacceptable safety risks.

Total land take: For ammonia production and storage (without counting the areas used for electricity and hydrogen production), we arrive at a total land take of approximately 22 km^2 to meet the fuel requirements of all shipping in the Netherlands. A multiple of this (i.e. over 1200 km^2) is required to produce the required hydrogen. In total, this occupies a space equivalent to about 2-3% of the Dutch land area.

4.3.3 *Cost and efficiency*

An overview of the costs per ammonia chain step for the maritime sector can be found at table 4.3 shows an overview of the costs per lifecycle step of ammonia for the maritime sector. These costs are based on an extensive literature review, see Appendix E for the details per chain step. Based on the minimum costs of all chain steps a kind of lower bound of the ammonia price can be determined (the optimistic cost estimate). In addition, using the maximum costs found for the chain steps, a pessimistic cost estimate can be determined. Figure 4.4 gives an overview of the costs of ammonia at the end user. Hydrogen production is the largest cost item of ammonia, and also the chain step with a large range in costs. The costs depend on the process by which the hydrogen is produced and the cost of the required energy (electricity or methane); see chapter 3, Hydrogen.

Table 4.3 **Cost of ammonia chain for use in maritime sector in 2030**

Chain step	Costs (€ per GJ ammonia)	Main assumptions [1]	Sources
Hydrogen production	52 (33 - 73)	H_2 input of 176 kg/tNH_3	See chapter 3 Hydrogen
Ammonia production (including nitrogen production)	1,3 (0.1-2.8)	Service life: 20 years Capacity factor: 80%. Efficiency: 67 Electricity output: 1 kWh per GJ ammonia. CAPEX: 0.3-3.0 M€/MW OPEX: 4% of CAPEX	(Ash & Scarbrough, 2019; Morgan, 2013; Nayak-Luke et al., 2021; Ikäheimo et al., 2018)
Ammonia transport	2,2 (0.9-3.6)	Straight from the literature; average of range per ship	(Elishav et al., 2020; Ikäheimo et al., 2018; Nayak-Luke et al., 2021; SmartPort, 2020; ACIL Allen Consulting 2018)
Ammonia storage	1,6 (0.5-3.9)	Electricity consumption of 37.8 kWh/t NH_3 for cooling CAPEX: 0.46 - 3.6 M€/kt OPEX: 3% of CAPEX	(Morgan, 2013; Nayak-Luke et al., 2021; The Royal Society, 2020; Ikäheimo et al. 2018)
Distribution and refuelling infrastructure	0,8 (0,5-0,8)	Straight from the literature	(Korberg et al., 2021; SmartPort, 2020; Taljegard et al., 2014)
Total	58 (35 - 84)		

[1] A discount rate of 2.25% was used for all capital costs.

For ammonia synthesis (including nitrogen production) an efficiency of 67% is assumed for the reference, optimistic and pessimistic cost estimate. This efficiency is based on model runs of Aziz et al. (2018). The fact that we assume a fixed efficiency for ammonia synthesis does not mean that there is no uncertainty. Based on the data from Morgan (2013) a much higher efficiency of 79% can be determined[85] . This means that 'only' 176 kg instead of 232 kg of hydrogen would be needed for one tonne of NH_3. Since hydrogen is a major cost item (money, energy and space) for ammonia, a higher efficiency significantly affects the cost of ammonia. With a higher efficiency of 79%, NH_3 costs 12 €/GJ less at an average hydrogen price of 34.6 €/GJ. Furthermore, less renewable electricity (and space) is needed to make the required H_2.

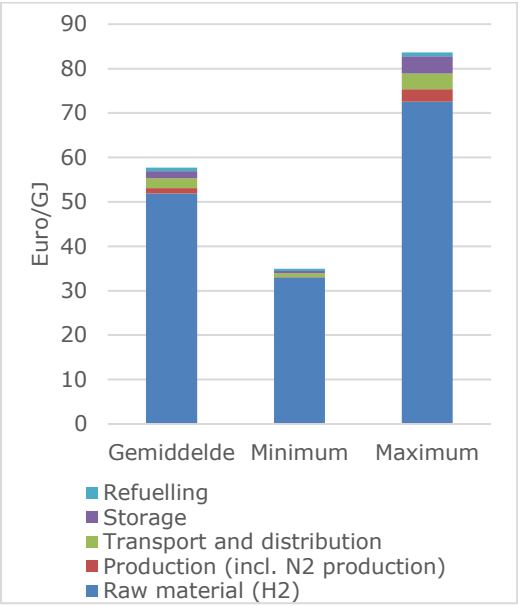

Figure 4.4 **Cost estimates for ammonia production**

The bandwidths are only due to uncertainties in costs and not to uncertainties in efficiency. The cost of hydrogen is 18 (13-24) €/GJ and 176 kg of hydrogen is needed per tNH_3. For other assumptions see table 4.3.

4.3.4 *Potential for improvement*

Ammonia production: Ammonia is a product that is already produced on a large scale today (180 Mt/year), but mainly with natural gas based on the Haber-Bosch process. For our study only the production of ammonia from Carbon neutral hydrogen, i.e. without CO_2 emissions, is relevant. Although the production process of ammonia with hydrogen and nitrogen is different, the principle is similar to the Haber-Bosch process. The Haber-Bosch process for ammonia production currently uses more energy (28-31 GJ/t) than the theoretical minimum (18-21 GJ/t). Therefore, there is still some room for improvement, although it is not specified where this improvement comes from. Morlanés et al. (2021) estimate that energy use for ammonia production (including hydrogen and nitrogen production) could fall from the current 10 MWh/t NH_3 to 8 MWh/t NH_3 in 2050, or from 36 GJ/t NH_3 to 29

[85] Efficiency of fuel production = fuel / input x 100% = ammonia / (hydrogen + electricity + nitrogen) = 1 t NH_3 / (0,64 MWh_e + 176 kg H_2 /tNH_3) x 100% = 1 t NH_3 * 18,6 GJ/t NH_3 / (0,64 MWh_e * 3,6 GJ/MWh_e + 176 kg H_2 /tNH_3 * 0,120 GJ/kg H_2) x 100% = 18,6 / 23,4 x 100% = 79%

GJ/ton NH_3.[86] The IEA is slightly less optimistic about the improvement potential; it estimates that energy consumption falls from the current 37.8 GJ/tNH_3 to 35.3 in 2030 and to 33.3 GJ/tNH_3 in the longer term (IEA, 2019).[87] This would mean that the costs of raw material and fuel production could decrease in the future.

New technologies to produce ammonia are also being developed in the laboratory, such as biological nitrogen fixation, non-thermal plasma, electrochemical and photocatalysis processes (Cardoso et al., 2021; Nayak-Luke et al., 2021). However, these processes have a very low TRL (1-3) and are therefore beyond the scope of this study.

Production of raw materials: There is also some potential for improvement in the production of nitrogen. In principle, N_2 can be produced with membranes, with distillation techniques or with a pressure differential absorption system (PSA). However, considering the high purity and quantity of N_2 needed for large-scale fuel production, nitrogen can currently only be produced with distillation techniques. (Morgan, 2013). Furthermore, nitrogen makes only a relatively small contribution to the total cost of ammonia. To achieve a large cost reduction, hydrogen in particular would have to be produced more cheaply.

Storage and transport: Since a lot of ammonia is already stored and transported commercially, and storage and transport are thus well-developed processes, it is not expected that there is much improvement potential in ammonia storage and transport. Under the influence of heat, only about 0.03% of the ammonia evaporates per day when stored. This ammonia is captured and recycled (Morgan, 2013).

4.3.5 *Barriers and uncertainties*

In the sections above, we discussed the technological, spatial and cost aspects of ammonia. In this section, we mention a number of aspects that are relevant, but that have not yet been given sufficient attention.

- Combustion of ammonia in an internal combustion engine, like other fuels, leads to NO_x emissions (McKinlay et al., 2021). Post-treatment of the exhaust gases using catalysts can reduce NO_x emissions, but this leads to higher energy costs and space requirements for the plant. Another disadvantage is that, as in the case of diesel engines, the catalyst forms N_2O (nitrous oxide), which is a strong greenhouse gas (McKinlay et al., 2021; Girard et al., 2007). The amount of N_2O emitted seems to be similar or slightly lower than with diesel engines (Ash and Scarbrough, 2019).
- Ammonia is toxic, so the safety distances around storage locations are greater than for storage locations for the same quantity of diesel. The transport of ammonia by tankers and trains through inhabited areas is sensitive for safety reasons in society and is therefore discouraged and regulated (e.g. via the Basisnet[88]). So far there seems to be no public resistance in the Netherlands to ammonia transport by ships and storage of ammonia in harbours. Whether this will remain the case when ammonia is transported on a large scale by inland navigation vessels and stored near inland navigation vessel transhipment points remains to be seen.
- Ammonia production works best as a continuous process. This makes it difficult to stop ammonia production if electricity from solar panels or wind turbines is temporarily unavailable. Another option is to keep hydrogen (and possibly nitrogen) in stock so that the synthesis process can run continuously. However,

[86] This amounts to an efficiency improvement from 55% to 69% for the joint chain steps of hydrogen production and ammonia synthesis.
[87] This is equivalent to an energy efficiency of 49% today, 53% in 2030 and 56% in the long term.
[88] https://www.infomil.nl/onderwerpen/veiligheid/basisnet/

this poses challenges to the storage capacity needed for the hydrogen (and possibly also nitrogen). In short, the consequences of variable power generation is a point of concern for ammonia production.

4.4 FT synfuels

There are not yet so many FT plants worldwide because FT synfuels are often not commercially attractive compared to fossil-based fuels. The FT plants that are operational often owe their existence to exceptional circumstances or are demonstration plants.[89] As far as we know there are no large-scale FT plants using hydrogen and CO_2 as feedstock.

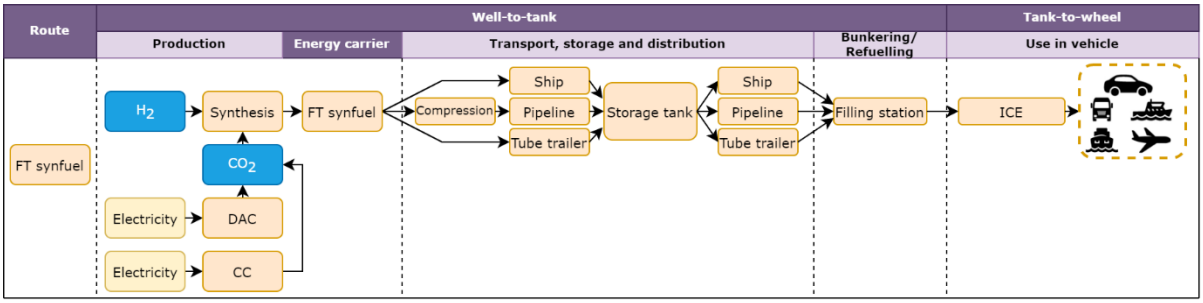

Figure 4.5 Overview of the chain steps of FT synfuels production from H_2 and CO_2

4.4.1 *Current technology*

Production: FT synfuels require CO and H_2 as raw materials. These two raw materials can come from gasification of biomass or from streams of pure H_2 and pure CO_2. This chapter only deals with FT synfuels derived from streams of pure H_2 and CO_2. Biomass based FT synfuels are covered in chapter 5. Chapter 5 also contains a detailed description of the FT process: see section 5.3.1.

About 12 kg H_2 and 80 kg CO_2 are needed per GJ of FT synfuel (Brynolf et al., 2018). For this study only H_2 produced in a carbon neutral way is relevant. The CO_2 is either captured directly from the air or at point sources.

Direct air capture (DAC) of CO_2 is a relatively new and innovative technology, which is not yet commercially available on a large scale. CO_2 capture from air consists of two steps, a capture step and a regeneration step. In the capture step the CO_2 is bound to a liquid solvent (or solid CO_2 absorber) and in the regeneration step the solvent (or CO_2 absorber) is recovered and a pure stream of CO_2 is produced. Synfuel production requires high CO_2 purity, above 99% (Fasihi et al., 2019). The process with a liquid solvent is the most developed and is currently one of the few available technologies that produces the required purity.

CO_2 capture from point sources: Most industrial sources currently emit CO_2, such as power plants, the chemical industry or the steel industry. The concentration of CO_2 in exhaust gases (3-27%) is significantly higher than the CO_2 concentration in air (0.04% = 400 ppm), so smaller volumes are needed. This makes CO_2 capture at these point sources more energy and cost efficient than capture from the air, although it is questionable to what extent there will still be large-scale CO_2 emitters in 2050 (see also section "Barriers and uncertainties"). There are various ways of obtaining a relatively pure CO_2 flow from industry. The CO_2 can be captured after the combustion process (post-combustion) or before combustion (pre-combustion).[90] A

[89] The large gas-to-liquids plant in Qatar, for example, was built primarily to do something useful with the gas that comes up during oil production, as flaring is not allowed. A second example is the coal-to-liquids plants in South Africa that date back to the time when oil was no longer delivered to South Africa as a sanction for the apartheid regime.

[90] The name pre-combustion may be confusing as the residual stream is often used for product formation (such as synfuels) rather than direct combustion. Pre-combustion means that the

third way is to burn the fuel with pure oxygen (oxyfuel), so that the exhaust gas stream consists only of CO_2, water and impurities (such as fine dust or SO_X). This flow must be dried and purified to form a pure CO_2 flow. In both pre- and post-combustion processes, there are various ways of obtaining a relatively pure CO_2 stream. Which of these technologies is most suitable depends, for example, on the concentration of CO_2, the amount of CO_2 needed and what other impurities are present in the exhaust gases. Currently, post-combustion processes are the most developed and are suitable for virtually all CO_2 streams from industry.

FT plant: Next, the FT synfuels are produced from CO_2 and H_2. As a first step, the CO_2 is converted to CO using the water gas shift reaction, which releases heat:

$CO_2 + H_2 \rightarrow CO + H_2O$ (ΔH_{298K} = - 41.2 kJ/mol)

The optimum ratio of CO to H_2 depends on the type of drop-in fuel being made and lies between 0.6 and 2.0. Next, this mixture is transported to an FT reactor, where it reacts under the influence of a catalyst to form various linear hydrocarbon chains.[91] The kind ofhydrocarbon chains that are formed depend, among other things, on the catalyst that is used (iron or cobalt), the composition of the syngas (more hydrogen produces more shorter hydrocarbon chains) and the temperature and pressure under which the process takes place. The longer hydrocarbon chains can be cracked to obtain shorter (more valuable) hydrocarbon chains. Although these parameters have some influence on which hydrocarbon chains are formed, the output remains a mix of hydrocarbon chains of different lengths. It is therefore not possible to produce, for example, only kerosene with this process. As a by-product, there will always be some shorter hydrocarbon chains, such as gaseous hydrocarbons and petrol. Should the market for short hydrocarbons disappear, because all cars have switched to electricity and all electricity production takes place using wind turbines, PV panels and hydroelectric power stations, then these products can be recycled in the process. However, this reduces the efficiency and increases the cost of the desired FT synfuels kerosene (and diesel).

Storage, transport, distribution, refuelling infrastructure and use invehicle: The main advantage of FT synfuels is that they have the same chemical structure as their fossil equivalents. This means that the same storage, transport, distribution and refuelling infrastructure can be used as for petrol, diesel and kerosene. In addition, they can be used in the same engines as fossil fuels. The fuel for barges, aeroplanes and sea-going vessels can often be supplied by pipeline or tankers as it involves larger quantities of fuel compared to petrol stations for cars and trucks. Roadside refuelling stations are usually supplied by road tankers, which are supplied from various storage and handling facilities. It is expected that FT synfuels will use the same storage, transport and refuelling infrastructure as fossil fuels today.

4.4.2 *Spatial aspects*

Tabel 4.4 provides an overview of the land take of FT synfuels per chain step. To put this land take into perspective, we can look at the aviation sector. The aviation sector has few alternatives to synthetically produced (bio)kerosene, see also Table 1.2. Pre-COVID in 2019 almost 168 PJ of fuel was sold in the total aviation sector in the Netherlands (CBS, 2021).[92] If this is replaced one-to-one by FT synfuels, the best estimate is that a total of 410-420 km^2 ofspace is needed. Most of this space

carbon atoms are removed before the rest of the stream (usually H_2) is used or burned, whereas post-combustion refers to a process that takes place after all other process steps have been completed.

[91] These include short gaseous hydrocarbon chains (e.g. methane and butane), liquid hydrocarbon chains (such as diesel, petrol and paraffin) and long hydrocarbon chains (C_{14} and longer).

[92] This includes all fuel that is refuelled in the Netherlands for the purpose of transporting people and goods by air.

will come from the electricity needed to produce the required hydrogen. This land take is equivalent to about 1% of the Netherlands' land area (although the electricity, hydrogen, CO_2 and synfuel need not be produced in the Netherlands).

Table 4.4 Net land use of the FT synergy chain

Chain step	Land take (m^2 per GJ per year FT synfuels)	Land area (km^2) if all aviation in the Netherlands refuels with FT synfuels	Notes	Sources
Hydrogen production	2.4	$4.1*10^2$	See chapter 3 for space requirements of hydrogen production per GJ H_2	
CO_2 capture at large scale sources (CC)	0.001	0.2	Post-combustion process. Question is whether there is enough room at existing CO_2 emitters.	(Berghout et al. , 2015)
CO_2 capture from air (DAC)	0.02 (0.003-2.0)	2.9 ($0.5-3.3*10^2$)	Calculated with 1.5 km^2 /Mt CO_2. The uncertainty margin is based on the very large range in the literature of 0.04-25 km^2/Mt CO_2.	(Johnston et al., 2003; Krekel et al., 2018; Socolow et al., 2011; Beuttler et al., 2019)
FT fuel production	0.03	4.2	Based on the Yinchuan FT plant (which runs on coal)	(Zhang, 2017)
Storage, transport and refuelling infrastructure	n.a.		Identical to the current situation; no problems expected.	
Total (based on CC)	2.5	$4.1*10^2$		
Total (based on DAC)	2.5 (2.5-4.4)	$4.2*10^2$ ($4.2*10^2$ - $7.4*10^2$)		

The same exercise can be performed for shipping and road transport.[93] The result is a land take equivalent to 3% of the Dutch land area for shipping and another 3% for road transport.

Space requirement of production

CO_2 capture industry (CC): A 1 Mt/year post-combustion CO_2 capture installation (with a capacity factor of 80%) occupies approximately 13,000 m^2. Based on 80 kg CO_2/GJ, this amounts to 1 m^2 per GJ. This is not much, but it is questionable to what extent space is available at existing plants. Berghout et al. (2015) conducted a study into the extent to which there is enough space for various CO_2 capture configurations at industrial plants in the Botlek industrial area in Rotterdam. The conclusion is that at many industrial plant locations there is no space to install individual CO_2 capture installations.

According to Berghout et al. (2015), there is often room at existing plants to clean the CO_2 and to install CO_2 compressors. This makes it possible to produce oxygen centrally, for example, and to have the factories operate on pure oxygen (oxyfuel

[93] 2020 is not a good reference year for aviation by COVID. In 2020, 'only' 94 PJ were sold in the aviation sector. In 2019, the energy demand for shipping and road transport was 484 PJ and 474 PJ respectively.

process). This creates a CO_2 stream that only needs to be dried and compressed, after which it can be stored. Another option would be to produce hydrogen centrally, with the CO_2 captured there. Both options would take up less space at the existing plants, about 2000 m^2 per Mt CO_2 per year or 0.1 m^2/GJ per year. However, extra space would then be needed elsewhere to produce oxygen or hydrogen. It is also questionable whether this is technically possible and whether it is an economically interesting option.

CO_2 capture from air (DAC): CO_2 capture from air occupies about 1.5 km^2 per Mt (Socolow et al., 2011). However, as with wind farms, there is much free space that can be used for other purposes (Keith et al., 2018); see also figure 4.6. As with solar and wind farms, there may be social resistance to CO_2 capture installations[94]. The question is to what extent the space between the capture units can be used for agriculture, for example, since the CO_2 concentration between the capture units is lower than normal, which may affect plants. Kiani et al. (2020) assume that about half of the CO_2 in the air can be captured. This means that the CO_2 concentration in the air coming out of the capture unit is around 200 ppm. Capturing a higher share of CO_2 reduces the efficiency of the capture process while a lower share of capture increases the amount of air that needs to be treated per unit mass of CO_2.

There is a relatively large degree of uncertainty in the estimate of the space required by units that capture CO_2 from the air. In the literature, the land take varies from as little as 0.04 km^2/Mt to as much as 25 km^2/Mt. The low estimate, however, is for a relatively small volume, so that the speed at which the air is refreshed plays less of a role. The very high estimates, on the other hand, are based on a very large volume of CO_2 and ignore the fact that CO_2 capture units can also be stacked on top of each other.

If all aircraft refuelling in the Netherlands were to use FT kerosene, approximately 13 Mt CO_2 would be required annually. Assuming a space requirement of 1.5 km^2 per Mt CO_2, the CO_2 capture installation would take up approximately 20 km^2. This is an area comparable to the second Maasvlakte industrial area near Rotterdam.

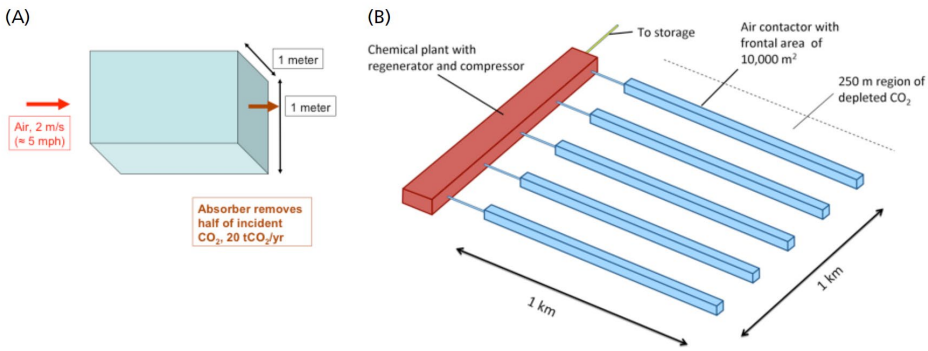

Figure 4.6 Schematic overview of (A) a small-scale CO_2 capture unit of 20 tCO_2/year and (B) a large-scale CO_2 capture unit of 1 $MtCO_2$/year

This large-scale plant has a land take of approximately 1.5 km^2 and consists of five units, each 10 m high and 1 km long. Between the buildings there is 250 m of 'empty' space. The drawing is not to scale.

Source: Socolow et al., 2011.

Space requirements for storage, transport, distribution and tank infrastructure

The infrastructure for storage, transport, distribution and refuelling of FT fuels is the same as that for fossil fuels, although locations and routes may be different, as

[94] This can include horizon pollution, although the units are a lot lower than a wind turbine.

there is no tie-in with current fossil fuel extraction sites. We expect the land take for storage, transport, distribution and refuelling infrastructure in the Netherlands to be identical to the current situation with fossil fuels, and no problems are expected here.

4.4.3 *Cost and efficiency*

Table 4.5 contains an overview of the costs of FT synfuels per chain step. The costs of capturing CO_2 via point sources (CC) and from the air (DAC) are included.[95] If CO_2 from point sources is not available and CO_2 has to be captured from the air instead, the costs of FT synfuels increase by about 15 €/GJ, although the uncertainties in these costs are rather large.

Distribution and refuelling infrastructure costs are needed to get FT synfuels to trucks, while transport costs are needed to get FT synfuels to ships and aircraft. Figure shows the average, optimistic and pessimistic cost estimates for FT synfuels for the small-scale end user such as heavy road transport. For the large-scale users, such as aviation and shipping, about 1-2 €/GJ is subtracted, due to the absence of distribution costs. It can be clearly seen in figure 4.7 that the raw material costs are the largest cost item for FT synfuels and involve the most cost uncertainty.

The cost ranges in table 4.5 and figure 4.7 only assume uncertainty in costs and not in efficiency. The required input of H_2 and CO_2 is kept constant at 12 kg H_2/GJ and 78 kg CO_2/GJ, (Brynolf et al., 2018), respectively, which leads to a synthesis efficiency of 69%. This does not mean that these inputs are not uncertain. For the input of hydrogen, for example, a range of 10 to 13 kg H_2/GJ is mentioned (Brynolf et al., 2018), which leads to an uncertainty in the synthesis efficiency of 64%-83%. This would lower the cost of FT synfuels in the average cost estimate by €8.3/GJ or raise it by €4.2/GJ respectively.

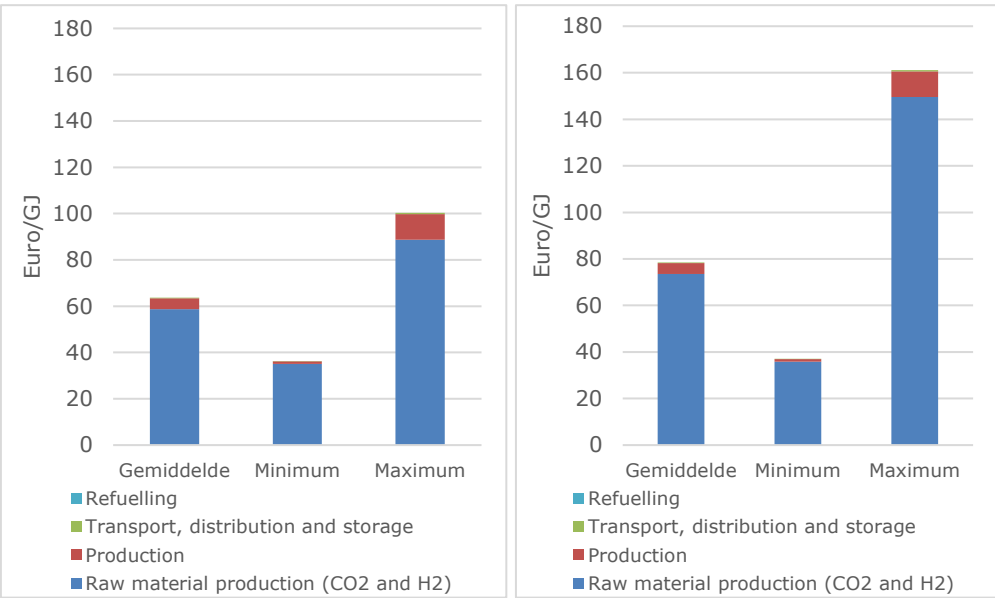

Figure 4.7 **Overview of costs of FT synfuels for large-scale end-users (shipping and aviation)**

Left based on CO_2 capture at industrial point sources (CC) and right based on CO_2 capture from air (DAC). The uncertainties are only due to uncertainties in costs and not to uncertainties in efficiency. The raw materials cost 18 (13-24) €/GJ for hydrogen and 60 (10-170) €/t for CO_2 from point sources and 250 (10-950) €/t for CO_2 from air. For other assumptions see table 4.5.

[95] Appendix E includes the details of each chain step.

Table 4.5 Costs of the FT fuel chain in 2030

Energy chain step	Cost (€ per GJ FT synfuels)	Main assumptions [1]	Sources
Hydrogen production	54 (34 -76)	Input of 11.7 kg H_2 /GJ	See chapter 3 for the cost estimate of hydrogen from electrolysis in €/GJ H_2 .
CO_2 capture at large scale point sources (CC)	4.7 (0.8 - 13)	Assuming 60 (10-170) €/t CO_2 Input of 78 kg CO_2 /GJ	(Brynolf et al., 2018; Dieterich et al., 2020)
CO_2 capture from air (DAC)	24 (1.6 -74)	Assuming 250 (10-950) €/t CO_2 Input of 78 kg CO_2/GJ	(Brynolf et al., 2018; Dieterich et al., 2020)
FT liquid production	4.8 (1.1-11)	Service life: 25 years OPEX: 4% of CAPEX Efficiency of 69	(Becker et al., 2012; Brynolf et al., 2018; Christensen & Petrenko, 2017; König et al., 2015; Smejkal et al., 2014; Tremel et al., 2015, IEA, 2019b)
FT liquid storage and bunkering	0.3 (0.15-0.5)	Uncertainty margin directly from literature	(Korberg et al., 2021; SmartPort, 2020; Taljegard et al., 2014)
FT liquid distribution	0.6 (0.5-1.1)	Based on 200 km distribution by trucks. The uncertainty range is based on distances of 100 and 500 km, respectively.	(SmartPort, 2020)
Road transport refuelling infrastructure	0.9	Straight from the literature; no uncertainty margins given.	(SmartPort, 2020)
Total for road traffic	65 (38 - 102)		
Total for other modes	64 (36 - 100)		
Additional costs for CO_2 capture from air	15 (0.8 -61)		

[1] A discount rate of 2.25% was used for all capital costs.

4.4.4 *Potential for improvement*

FT synfuel production: The current total installed FT synfuel capacity is low and there is room for cost reduction through learning-by-doing. However, the improvement potential should not be overestimated either, because many of the sub-technologies are already being used in chemical plants and are therefore reasonably mature. Based on both learning curves (top-down approach) and a technology inventory (bottom-up approach), the cost of synthetic fuel production (excluding the cost of the raw materials H_2 and CO_2) is expected to fall by about 30% in 2050 (Knoope et al., 2013). This leads to a reduction of about 1.5 (0.3-3) €/GJ.

CO_2 capture from air (DAC): CO_2 capture from air is still at an early stage of development. According to JEC, it has a TRL of 6 and a commercial readiness level (CRL) of 1 (JEC, 2020). Potential improvements include the development of more efficient solvents, use of more plastic instead of steel in various components and building capture facilities on a larger scale (Kiani et al., 2020). Keith and Heidel (2018) estimate that project costs decrease by about 30% between one of the first plants and when the technology has become standard (the Nth plant). Fasihi et al.

(2019) are much more optimistic about the cost reduction of CO_{2-} capture from air. Using learning curves, they estimate that the cost per tonne of CO_2 could drop by about 75% by 2050 compared to 2020. This assumes that 7.7 Gt of CO_2 is captured directly from the air each year worldwide in 2050.[96] This is a very large and ambitious task; for comparison: in the European Union 4.1 Gt CO_2-eq was emitted in 2019. For the total cost of FT synfuels this 75% cost reduction of CO_2 capture would mean a reduction of about 15 (1-56) €/GJ.

4.4.5 *Barriers and uncertainties*

CC-based FT synfuels are cheaper and take up less space than DAC-based FT synfuels. However, the question is to what extent there will still be large-scale CO_2 point sources in 2050. By 2050, the Dutch economy as a whole must be virtually carbon neutral. This means that the electricity sector, the chemical industry and other factories must have switched to carbonneutral alternatives. If this is biomass, then a relatively concentrated CO_2 flow will become available (as a residual product) that could be used for synthetic fuels.[97] A CO_2 stream based on fossil fuels does not fit into a carbon neutral society. There is a double counting if the CO_2 producer claims that the CO_2 is captured - and therefore his production process is carbon neutral - and the synthetic fuel producer claims that the CO_2 he uses is a residual flow, as the CO_2 ends up in the air after the fuel has been burned.

A disadvantage of FT synfuels compared to other energy chains considered in this study is that upon combustion they cause, among other things, particulate matter and NO_x emissions comparable to those of fossil fuels. With FT kerosene, however, it is possible to reduce the emission of soot particles compared to fossil kerosene by using fewer aromatics. The emission of water vapour is comparable to that of fossil kerosene: at high altitudes this has a (relatively short) greenhouse effect.

4.5 Methanol

Methanol is already used on a very limited scale as a fuel in the maritime sector and has been used in the past as a gasoline substitute for road transport (Hobson & Márquez, 2018). Most of the global production of about 85 Mt is used in the production of e.g. paints, carpets, building materials and in the pharmaceutical industry (McKinlay et al., 2021). This production capacity would need to be expanded significantly if the entire maritime sector were to run on methanol. McKinlay et al. (2021) estimate that approximately 815 Mt of methanol is required annually to power the global fleet of 50,000 merchant ships. This means that current production would have to increase tenfold.

Methanol is now mainly produced using natural gas and coal as raw materials. The production of methanol leads to CO_2 emissions of approximately 2.3 tCO_2 per t of methanol (IEA, 2019b). Methanol can be produced carbon free by using either biomass or sustainably produced hydrogen and CO_2 as feedstock. In the first case, we speak of bio-methanol. In this study we only look at the last option: production

[96] In this scenario, about 1.1 Gt is used for road transport fuels, 1.7 Gt for shipping fuels and 1.5 Gt for aviation fuels. Of these, approximately 417 million litres of diesel, 631 million litres of diesel and 617 million litres of kerosene can be made respectively. Besides CO_2 for transport fuels, CO_2 is also used in the chemical industry and the energy sector (power-to-gas and waste-to-energy). There are also 'insurmountable' CO_2 emissions that need to be compensated for. This is the conservative scenario from Fasihi et al. (2019). In the non-conservative scenario, twice as much CO_2 is captured from the air and that scenario is fully in line with the Paris Agreement.

[97] Several 1.5°C scenarios also make use of negative CO_2 emissions ('sinks'), for example by storing CO_2 emissions from biomass underground so that this CO_2 is not available for synthetic fuel production.

from H_2 and CO_2. Figure 4.8 gives an overview of the chain steps of methanol production from H_2 and CO_2.

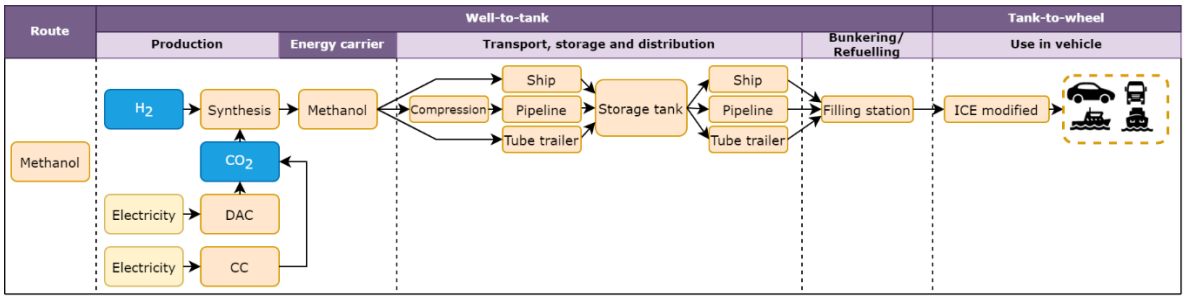

Figure 4.8 Methanol production chain steps based on CO_2 and H_2

DAC refers to CO_2 capture from air (derived from Direct Air Capture) and CC refers to CO_2 capture at point sources (derived from Carbon Capture).

4.5.1 *Current technology*

Production: Methanol production with H_2 and CO_2 is currently only taking place on a very small scale to demonstrate the technology. The process has a TRL of 6-7 (Pérez-Fortes et al., 2016). The production process consists of three steps. First, the pure streams H_2 and CO_2 are compressed to 50-100 bar and heated to 200-300°C (Rivarolo et al., 2016). Then, the streams are transferred to a reactor vessel where the H_2 and CO_2 react under the influence of a catalyst to form methanol and water. Distillation then takes place to separate the methanol and water. Figure 4.9 gives an overview of the production process.

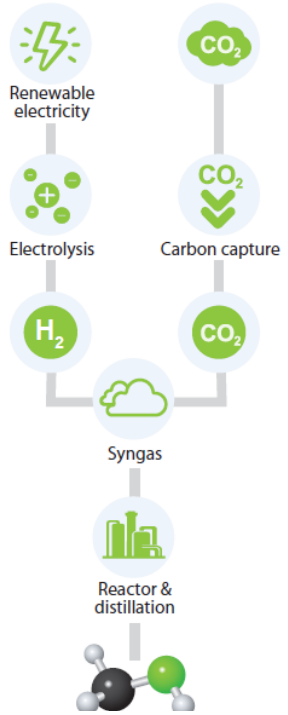

Figure 4.9 Methanol production from hydrogen and CO_2

Source: Hobson & Márquez (2018)

Transport/distribution: Methanol is liquid at atmospheric pressure and temperature. This makes methanol relatively easy to transport by tanker, ship or pipeline. It is also easy to store. Since methanol is already widely transported and stored, methanol and its infrastructure are already available in almost 90 of the world's 100 largest ports (Port of Rotterdam, 2021). If methanol is to become a standard fuel for seagoing and inland navigation vessels, the existing transport infrastructure will have to be made more dense. An advantage here is that with a few minor adjustments, the existing storage facilities for gasoline can be used (Svanberg et al., 2018).

Use in a vehicle: Combustion engines can be relatively easily adapted for methanol combustion (Hobson & Márquez, 2018). Methanol can be used in both a gasoline engine and a diesel engine (Liu et al, 2019).

Few modifications are required to use methanol in a gasoline engine (Svanberg et al., 2018). In California in 1997, there were a total of over 150,000 cars that could run on methanol or on both gasoline and methanol (in response to high gasoline prices). As the price of gasoline dropped, methanol was no longer an attractive alternative and disappeared. However, more than 300 million kilometres have been driven with methanol, which shows that methanol can be an alternative to fossil fuels. (Hobson & Márquez, 2018). In China, a methanol vehicle incentive programme

has been running since 2005. In total, these vehicles have covered more than 21 million kilometres in 3 years (Hobson & Márquez, 2018).

For methanol use in a diesel engine, more modifications are needed. Since methanol has a higher flammability temperature than diesel, methanol must be mixed with an ignition enhancer to burn it in a diesel engine (Lieshout et al., 2020). Another option is to mix methanol with a small proportion of diesel (2-20%) to make it suitable for use in a diesel engine[98] (Lieshout et al., 2020).

There are ships that currently already run on a combination of methanol and diesel. Some of these are retrofit and some are newly built (Svanberg et al., 2018). The main modification compared to a normal diesel ship is that additional tanks must be built for the methanol and a connection must be made from the methanol tanks to the engine in addition to the existing diesel supply (Wartsila, 2021). Methanol has an energy content of 19.9 MJ/kg (IEA, 2019b). This is a factor of two to three lower than the specific energy (MJ/kg) and energy density (MJ/m^3) of diesel (Lieshout et al., 2020).[99] This means that refuelling must be done more frequently or that the tank volume must be increased (Liu et al 2019). A ship with a 2700 m $tank^3$ can store enough diesel for a journey of 13,250 km, while the same tank can only store enough methanol for 8480 km, assuming the engine has the same efficiency for both diesel and methanol (McKinlay et al., 2021). This makes methanol a particularly interesting fuel for ships travelling medium distances (Lieshout et al., 2020).

Methanol is water soluble and biodegradable (IEA, 2019b; Wartsila, 2021). As a result, there is no environmental damage if methanol leaks from a ship after an accident. This is why methanol tanks (unlike diesel tanks) do not need to be double-walled and methanol can even be stored in ballast tanks (Wartsila, 2021). On the other hand, methanol fumes are toxic, and can therefore be dangerous for people on the ship.

Refuelling: Methanol can be refuelled relatively easily because it is liquid at atmospheric pressure. In California in 1997, there were more than 100 filling stations where methanol could be filled up, proving that it is technically possible.

The existing ships running on methanol are currently supplied from the shore by pipelines (Port of Rotterdam, 2021) or trucks (Svanberg et al., 2018). Last spring, the first methanol-fuelled ship was supplied via the ship-to-ship method (Port of Rotterdam, 2021). It is expected that this method will become dominant as the demand for methanol grows, as this is also the way in which bunkering is now mostly done (Lieshout et al., 2020). In principle, the same bunkering vessels and fuelling techniques can be used as for conventional fuels. Due to the low boiling point of methanol (< 60°C), flammable and toxic methanol vapours can arise relatively quickly (Lieshout et al., 2020). To make bunker ships suitable for methanol bunkering, the ships need to be slightly modified (Svanberg et al., 2018). After taking measures, the risk level for methanol bunkering is comparable to that of other conventional bunker fuels (Port of Rotterdam, 2021).

4.5.2 *Land use*

Methanol is an option for the shipping sector and for light and heavy road transport. In the total shipping sector in the Netherlands, almost 500 PJ of fuel was sold in

[98] A diesel engine works on the principle that the diesel ignites spontaneously due to the combination of high pressure and temperature. No spark is needed, as in a petrol engine.
[99] The energy density of methanol is 15.8 GJ/m^3 while that of diesel (heavy fuel oil) currently used in the maritime sector is 38-40 GJ/m^3.

2020 and 484 PJ in 2019 (CBS, 2021).[100] If 500 PJ is replaced one-on-one with methanol, this amounts to 25 Mt of methanol per year. Table 4.6 gives an overview of the land use of methanol per chain step.

Many of the chain steps correspond to FT synfuels, such as hydrogen and electricity production and CO_2 capture. The spatial consequences of these steps will not be described again here. The difference with FT synfuels lies in methanol synthesis, storage, transport and tank infrastructure. For each of these steps we have been able to find little information on the spatial impact. Based on a single source, the land take for methanol synthesis appears to be very small. We have found no estimates of land take for methanol storage, transport or refuelling infrastructure, but we expect these to be relatively small compared to the land take required for the production of the raw materials electricity, hydrogen and CO_2. As the energy density of fossil fuels is twice that of methanol, our initial estimate is that the land take for these three components will approximately double compared with the current situation. This does not take into account economies of scale (e.g. in storage) or a shift in production sites, which might make methanol supply chains shorter than those of fossil fuels. For current fossil fuels, too, we have no good indication of the space requirements per energy unit for transport, storage and refuelling infrastructure.

If all ships in the Netherlands run on methanol, the land requirement is approximately 1200 km^2, largely due to the electricity required for hydrogen production. This is a (slight) underestimate, as the space required for storage, transport and tank infrastructure has not been included. This land take is equivalent to about 3% of the Netherlands' land surface area. As road transport is almost as big as the maritime sector in terms of fuel use (474 PJ in 2019), an equivalent of 3% of the Dutch land area would be needed again, should road transport also start running on methanol.

Table 4.6 Methanol chain space requirements

Energy chain step	**Land take (m^2 per GJ methanol per year)**	**Land area (km^2) if all ships in the Netherlands sail on methanol**	**Notes**	**Sources**
Hydrogen production	2.2	$1.1*10^3$	See chapter 3 for space requirements of hydrogen production per GJ H_2	
CO_2 capture at large scale sources (CC)	0.001	0.6	Post-combustion process. Question is whether there is enough room at existing CO_2 emitters.	(Berghout et al., 2015)
CO_2 capture from air (DAC)	0.02 (0.004-2.4)	8.1 ($1.9-1.2*10^3$)	Unclear where the large range comes from	(Beuttler et al., 2019, Johnston et al., 2003; Krekel et al., 2018; Socolow et al., 2011)

[100] Shipping includes all transport of people and goods via waterways, such as inland, maritime and coastal navigation. Fishing is not included, but is a relatively small player with a consumption of 6.8 PJ in 2020 (CBS, 2022).

Methanol production	0.06	31	Based on demonstration plant in Iceland producing 4,000 tonnes of methanol on a plot of around 5,000 m^2	(CRI, 2022)
Methanol storage, transport and tank infrastructure	n.a.	n.a.	About twice as much space is needed than currently is needed for diesel, due to the lower energy density.	
Total (based on DAC)	2.3 (2.3-4.7)	$1.2*10^3$ ($1.2*10^3$ - $2.3*10^3$)		
Total (based on CC)	2.3	$1.2*10^3$		

4.5.3 *Cost and efficiency*

The figure 4.10 shows the costs of methanol per chain step. The main assumptions of these cost estimates are set out in table 4.7, further details are given in Appendix E. As with FT fuels, we distinguish between road and non-road methanol use. Due to distribution by truck and more expensive refuelling infrastructure, road methanol is approximately 3 €/GJ more expensive than for other modalities. We also distinguish between the costs of table 4.7 distinction between the costs of CO_2 capture at point sources and CO_2 capture from the air. If CO_2 is captured from the air rather than from point sources, methanol costs rise by 18 €/GJ, although the uncertainties in this cost increase are considerable. Figure 4.10 clearly shows that raw material costs are the largest cost item for methanol.

As with ammonia and FT synfuels, the ranges in Table 4.7 and Figure 4.7 assume only cost uncertainty. The required input of H_2 and CO_2 is kept constant at 10.8 kg H_2 /GJ and 94 kg CO_2 /GJ respectively, leading to a synthesis efficiency of 80% (Brynolf et al., 2018). This does not mean that this is not uncertain. For the input of hydrogen, for example, a range of 9.2 to 11.7 kg H_2 /GJ is quoted, leading to an uncertainty in the synthesis efficiency of 70%-89% (Brynolf et al., 2018). This would lower the cost of methanol in the average cost estimate by 6.9 €/GJ or increase it by 3.5 €/GJ, respectively.

Table 4.7 Costs of methanol synthesis in 2030

Energy chain step	Cost (€ per GJ methanol)	Key assumptions	Sources
Hydrogen production	45 (29 - 63)	Input of 10.8 kg H2/GJ	See chapter 3 for cost estimate of hydrogen from electrolysis in €/GJ H_2
CO_2 capture from point sources (CC)	5.7 (0.8-13)	Assuming 60 (10-170) €/t CO_2 Input of 94 kg CO2/GJ	(Brynolf et al., 2018; Dieterich et al., 2020)
CO_2 capture from air (DAC)	23.6 (1.9-90)	Assuming 250 (10-950) €/t CO_2 Input of 94 kg CO2/GJ	(Fasihi et al., 2019; Keith et al., 2018; Kiani et al., 2020; Krekel et al., 2018; Socolow et al., 2011)
Methanol synthesis	1.8 (1.1-3.7)	CAPEX: 0.5 (0.3-1.0) M€/MW OPEX: 4% of CAPEX Service life: 25 years Capacity factor: 80%. Efficiency: 80%	(Brynolf et al., 2018; Clausen et al., 2010; Nieminen et al., 2019; Rivarolo et al., 2016; IEA, 2019b)
Methanol transport	n.a.		
Methanol storage and bunkering	0.4 (0.2-0.6)		(Korberg et al., 2021; SmartPort, 2020; Taljegard et al., 2014)
Methanol distribution and refuelling infrastructure for road traffic	3.4	Distribution 200 km by truck	(SmartPort, 2020)
Total for road traffic	56 (34 - 87)		
Total for other modes	53 (31 - 83)		
Additional costs for CO_2 capture from air	(0.9 - 74)		

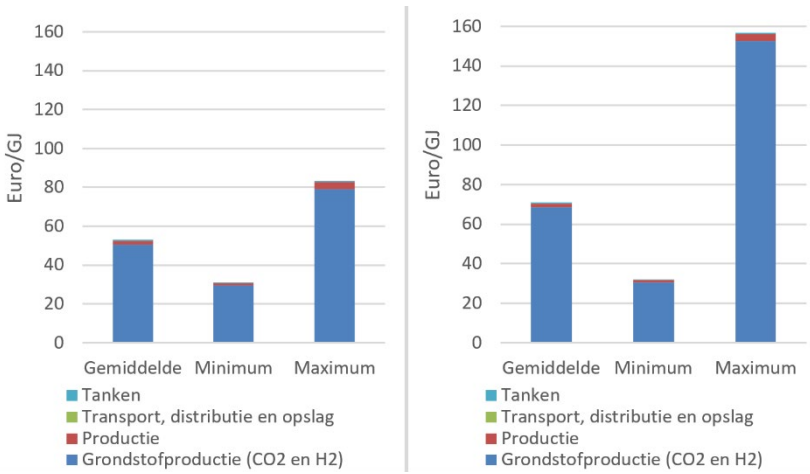

Figure 4.10 Methanol costs for the maritime sector, left based on CO_2 capture at industrial point sources (CC) and right based on CO_2 capture from air (DAC)

The ranges are only due to uncertainties in costs and not to uncertainties in efficiency. The raw materials cost 18 (13-24) €/GJ for hydrogen and 60 (10-170) €/t for CO_2 from point sources and 250 (10-950) €/t for CO_2 from air. For other assumptions see table 4.7.

4.5.4 *Potential for improvement*

Most of the costs of methanol consist of the costs of the raw materials CO_2 and hydrogen (which in its turn consists largely of electricity costs) as shown in figure 4.10. This makes it particularly interesting to improve the technologies for producing H_2 and CO_2, so that the costs of H_2 and CO_2 come down. The improvement options for CO_2 capture are described in section 4.4.4 and hydrogen production is discussed in chapter 3. In addition, it is also interesting to reduce the amount of H_2 and CO_2 needed. A number of other options have been mentioned in the literature that have the potential to reduce the cost of methanol:

- Separating methanol from the water formed and other impurities (such as esters and ketones) takes a lot of energy. Current methanol has a purity of above 99%. Diesel engines in the maritime sector do not need this high purity, and can also handle a mixture of 90% methanol and 10% water. This could reduce methanol production costs by up to approximately 15% (Carvalho et al., 2018; Svanberg et al., 2018). A disadvantage is that a separate distribution and storage system has to be set up for methanol of lower quality, since methanol of low quality is of limited or no use in the (chemical) industry. Furthermore, the ship's consumption will increase. Whether these additional costs outweigh the savings should be further investigated.
- Improving heat integration (Marlin et al., 2018). The CO_2 and H_2 need to be heated to around 200-300°C before being fed to the reactor vessel. Ideally, only residual heat would be used for this. Heat integration becomes extra important when CO_2 is captured from the air (Marlin et al., 2018) since waste heat is often present at industrial plants where CO_2 is captured.
- The current catalyst is optimised for a process with both CO and CO_2 as inputs. (Galindo Cifre & Badr, 2007; Marlin et al., 2018). Another catalyst optimised for CO only could lead to higher conversion efficiency and therefore lower costs.

4.5.5 *Barriers and uncertainties*

In the paragraphs above, we discussed the technological, spatial and cost aspects of methanol. In this section, we mention four aspects that are relevant, but that have not yet been addressed.

Firstly, the combustion of methanol produces NO_x. Compared to a normal diesel engine, a ship currently running on methanol emits 60% less NO_x than a comparable ship running on diesel. In addition, there are 99% fewer emissions of SO_x and 90% fewer of particulate matter (Wartsila, 2021). In theory, emissions of SO_x and particulate matter should be able to be completely eliminated if diesel is no longer used as the fuel for ignition (Hobson and Márquez, 2018). NO_x emissions can also be avoided if methanol is no longer used in a combustion engine but in a fuel cell (McKinlay et al., 2021). However, this technology still has a low TRL and we do not include it in this study.

Secondly, methanol vapours are toxic and have a risk of explosion. Due to the low boiling point of methanol, methanol fumes are released quickly (McKinlay et al., 2021). Methanol fumes are as toxic as fumes from current liquid transportation fuels, but have the advantage of not being carcinogenic (IEA, 2019b). People working with methanol or refuelling methanol should wear protective clothing, such as gloves and closed shoes, and protective glasses (Lieshout et al., 2020). In addition, additional safety requirements must be taken on board a ship that runs on methanol. These include detection of methanol as soon as there is a leak and extra ventilation to prevent methanol vapours building up. Furthermore, fire-fighting methods and protective clothing must be adapted, as they are currently not suitable for methanol fires (Lieshout et al., 2020).

Finally, it is important to note that synfuels are seen as a possible solution to absorb peaks in electricity supply. However, it is unclear at to what extent methanol

synthesis is suitable for this purpose. For example, Clausen et al. (2010) mention methanol synthesis as very suitable for this purpose, while Nieminen et al. (2019) emphasise that the methanol synthesis process must operate continuously and that hydrogen storage is necessary. Rivarolo et al. (2016) also point out that a fluctuating electricity supply can cause thermal stress in the methanol synthesis reactor. Nevertheless, the latter study assumes an operational duration of only 3000 hours per year due to the limited availability of renewable electricity (Rivarolo et al., 2016). This is considerably lower than the capacity factor of 80% (or 7008 hours per year) that we have assumed. With fewer operational hours, methanol costs increase. With an operational running time of 3000 hours instead of 7008 hours per year, we estimate that the cost of methanol synthesis increases by 2.5 €/GJ.

4.6 Chain efficiency of synthetic fuels

In this section we compare the total efficiency of a seagoing ship that runs on ammonia, methanol or FT synfuels. An overview can be found in table 4.8. Since ocean-going vessels do not require distribution of the fuels, we have not included this in the lifecycle efficiency. We have assumed that the efficiency of a seagoing ship with all three fuels is 45% (see also Appendix B Efficiency). The WTT-range for FT synfuels and methanol is due to the higher energy consumption of CO_2 capture from the air compared to CO_2 capture at point sources, with the lowest efficiency being a process based on CO_2 capture from the air and the highest for CO_2 capture at point sources. The overall chain efficiency for synfuels is between 15% and 18%.

Table 4.8 Overview of WTT- and TTW-based chain efficiencies of ammonia, FT synfuels and methanol based on CO_2 and H_2

Synfuel	WTT	TTW	Total ICE
1: ammonia	43%	ICE: 40-45%	18%
2: FT synfuels	38%-42%		16%-18%
3: methanol	40%-45%		17%-19%

5 Biofuels

Main points

The production processes for Fischer-Tropsch (FT)-biofuels and cellulosic ethanol based on fermentation are very energy-intensive. This has implications for the overall performance of the chains, as the production step is the most energy-intensive of the two value chains.

- *FT biofuels*. The production of FT biofuels from biomass, with an energy efficiency of between 45% and 73%, has significant losses, partly because part of the carbon content in the biomass is released in the form of CO_2.
- *Cellulosic ethanol*. The cellulosic ethanol process has an average efficiency of 30% on an energy basis. The low efficiency is mainly due to the low recovery and conversion of sugars from hemicellulose and to the fact that a significant part of the carbon content of the biomass is released in the form of CO_2 during the fermentation phase. The efficiency can be as high as 40%. The recovery of flows such as lignin and their valorisation is essential to improve the overall performance of the system.

For both FT biofuels and ethanol, there are still many uncertainties about conversion efficiency and biomass availability. This makes it uncertain what the cost price of these fuels will be, especially since the biomass is the dominant cost factor in most cases.

- FT biofuels. The cost of raw materials is one of the most important factors in the cost of FT biofuels from biomass. If cheap waste raw materials are used, FT biofuels may even become competitive with conventional fuels if further innovation achieves better efficiency.
- Cellulosic ethanol. Current cellulosic ethanol production has revealed significant technological and economic challenges for large-scale implementation. For example, cellulosic ethanol costs are higher due to relatively low efficiency and there are logistical challenges in scaling up biomass deployment. Many projects have not started or are at a standstill, which has significantly delayed the introduction of the technology. Improvements to reduce costs are very important to make cellulosic ethanol price competitive.

The use of FT biofuels (theoretically) requires no change in the vehicle fleet. In contrast, ethanol as a pure fuel or in high blend ratios might require drastic changes in car engines, and thus fleet adaptation. Currently, 10% ethanol is mixed with petrol (E10). With limited modifications to engine technology, this share can be easily increased to 85% or even 100%.

In terms of transport and storage, FT biofuels and ethanol can benefit greatly from already existing infrastructure. FT biofuels are drop-in fuels and have similar properties to fossil fuels, and current transport, distribution and storage infrastructure can be adopted. In the case of ethanol, the infrastructure for transport and storage has been available for decades, as (conventional) ethanol based on crops is mature. However, adjustments and thus investments are needed for distribution to the fuel station.

The main bottlenecks in the chains for FT biofuels and cellulosic ethanol are related to the supply of biomass and the conversion efficiency of the processes. The technologies are still in a pre-commercial phase, or, in the case of commercial plants already established, in an inactive mode. Future improvements are expected.

5.1 Introduction

Biofuels are traditionally produced from oil and starch-rich crops. These types of biofuels are referred to as first generation or conventional biofuels. Despite the "short-cycle"[101] character of the carbon in the biofuels themselves, many of these biofuels are far from being carbon neutral across their entire chain from feedstock to use. For example, fossil energy may be used in the production chain and greenhouse gas emissions are released during cultivation and as a result of land use changes.

The Renewable Energy Directive II (RED II)[102] regulates the use of biofuels in the transport sector (road transport, mobile equipment and, in the near future, inland navigation) in the EU. The European target for 2030 is to achieve a 14% share of sustainable energy carriers within final energy consumption in the transport sector. Renewable energy carriers include not only biofuels but also electricity, for example. The member states' targets for sustainable energy carriers may differ from this. The Netherlands has set itself the target of achieving a 28% share of renewable energy by 2030.[103]

In addition to the overall target for renewable energy, (sub) targets have also been implemented. The sub-target for advanced biofuels introduced in RED II aims to ensure that biofuels from waste and residual streams take up a higher share within biofuels. According to RED II, sales of advanced biofuels in transport (Annex IX A) must grow to a minimum of 7% by 2030 (see Figure 5.1). On the other hand, the share of conventional biofuels and biofuels based on used cooking oil (UCO) and tall oil (Annex IX B) is limited in 2030 to the maximum level of 2020, 1.4% and 10% respectively; see table 5.1.

Table 5.1. RED II 2030 targets for the transport sector based on implementation in the Netherlands including double counting

Category	Type/Feedstock	Energy share
Otherwise	Electricity, H_2, RFNBO	
Annex IX A	Biofuels from Part A feedstocks	Minimum 7%
Annex IX B	Biofuels from UCO and tall oil	Maximum 10%
Conventional	Biofuels from food crops	Maximum 1.4%

RNFBO: Renewable Fuel of Non-Biological Origin. For example, e-fuels. UCO: Used cooking oil.

As a result, the energy landscape of renewable fuels in mobility will change significantly in the coming years. RED II also has a direct impact on the sales of conventional and Annex IX B biofuels (mainly bio-naphtha, HVO, FAME and ethanol). These fuels are mainly made from used cooking oil and are currently responsible for over 90% of all biofuels in 2020.[104]

[101] Short-cycle means that the carbon has recently been absorbed by plants from the air.
[102] https://eur-lex.europa.eu/legal-content/nl/TXT/?uri=CELEX%3A32018L2001
[103] https://www.emissieautoriteit.nl/onderwerpen/algemeen-hernieuwbare-energie-voor-vervoer
[104] Including double counting, see: Energy Report for Transport in the Netherlands 2020 | Publication | Dutch Emissions Authority

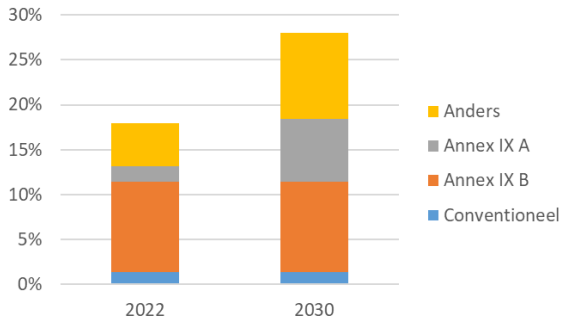

Figure 5.1 **Renewable energy shares based on RED II targets for the Netherlands (including double counting)**

5.1.1 *Biochemical and thermochemical routes*

For the production of biofuels from waste and residue streams, several conversion and synthesis routes are suitable. These can be roughly summarised in two groups:

- **Biochemical routes.** These convert ligno-cellulosic (woody) feedstocks into liquid biofuels, such as ethanol, in particular. In practice, this involves processes such as chemical hydrolysis and alcoholic fermentation.
- **Thermochemical routes.** These convert raw materials into biogas (biomethane/CNG/LNG), biocrude, petrol, diesel or kerosene. In practice, these include processes such as gasification and pyrolysis. Compared to the biochemical routes, production of biofuels via thermochemical routes generally has a lower technology readiness level (TRL).

An overview of these conversion and synthesis routes is shown in Figure 5.2. For a further description of the processes shown here, see Appendix F.

Figure 5.2 shows that biofuels can go through similar synthesis steps to synthetic (P2X) fuels. Such synthetic fuels are produced on the basis of a conversion of electricity to hydrocarbon via an intermediate step to hydrogen (from electrolysis) and the addition of CO_2 from, for example, flue gases (carbon capture and utilisation, CCU) or air (DAC). These hydrocarbons can then be converted to Fischer-Tropsch (FT) liquids, but also to methane; see the upper process flow in Figure 5.2. Biofuels are made from lignocellulosic (woody) biomass. In both cases the intermediate product is syngas that is converted to diesel or other products by FT synthesis.

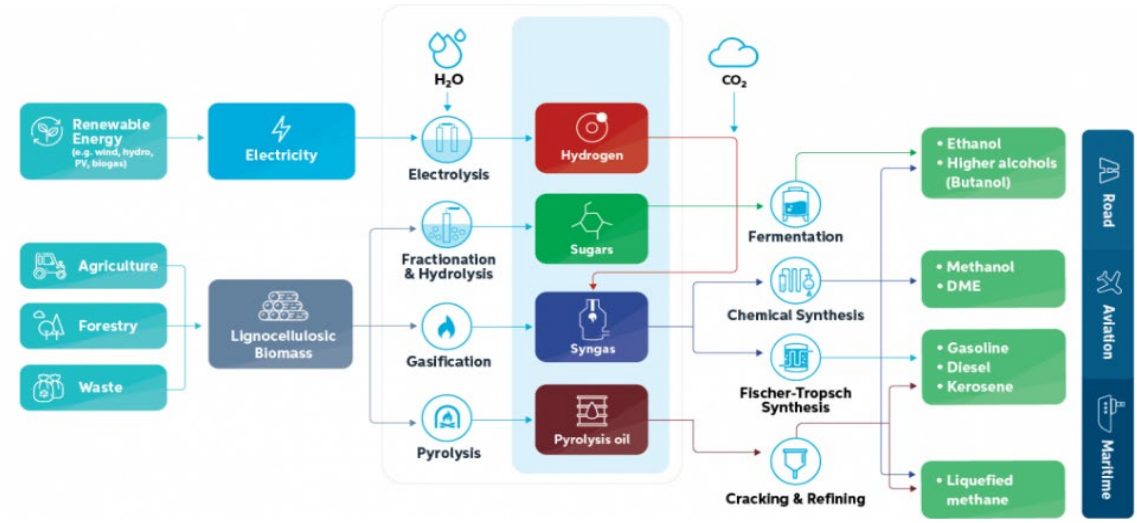

Figure 5.2 **Conversion and synthesis routes for bio and synthetic fuels**

Source: AdvanceFuel, 2020.

The production capacity of the conversion routes for advanced biofuels is still small today, but is expected to grow strongly in the coming years. Figure 5.3 gives an overview of the current and planned production capacity of advanced biofuels in Europe, or RED II Annex IX A biofuels.

Figure 5.3 shows that the current production capacity in Europe is around 300,000 tonnes/year. If all the facilities planned in Europe are actually built, production capacity will grow to more than 2 megatonnes per year by 2024, an increase of almost a factor 7. It is expected that some biofuels, such as synthetic diesel, will only be used in the transport sector, while other biofuels, such as ethanol or biogas, can also be used in other sectors. For example, ethanol can be used as a raw material in the chemical industry and biogas as a replacement for 'Gronings gas' in the energy sector.

The extent to which biofuels will be used in the future and competition between different sectors is very uncertain. It is also possible that competition for biofuel feedstock will arise (due to demand from production of bio-based materials), which could limit the supply of biofuels.

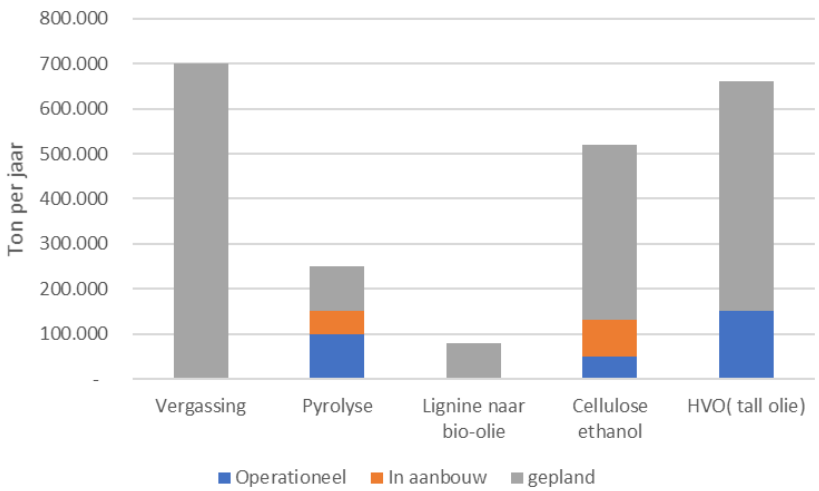

Figure 5.3 **Overview of current and planned production capacity of advanced biofuels in Europe**

Source: ETIP-Bioenergy, 2020.

5.1.2 Biofuel routes within the scope of this study

In the light of this study, we focus only on advanced biofuels, i.e. those biofuels listed in Annex IX A of RED II.

Advanced biofuels include fuels from algae, woody biomass, manure and various waste streams (e.g. industrial, municipal waste and sewage sludge). The full list of feedstocks from RED II Annex IX Part A is shown in the top half of Figure 5.4 below.

Annex IX	
Part A ("Advanced") targets: at least 0,2% in 2022, 1% in 2025 and 3,5% in 2030	
• Algae if cultivated on land in ponds or photobioreactors • Biomass fraction of mixed municipal waste but not separated household waste subject to recycling targets • Bio-waste as defined in Article 3(4) of Directive 2008/98/EC from private households subject to separate collection • Biomass fraction of industrial waste not fit for use in the food/feed chain, including material from retail/wholesale and the agro-food and fish and aquaculture industry, excluding feedstocks listed in part B. • Straw • Animal manure and sewage sludge • Palm oil mill effluent and empty palm fruit bunches • Tall oil pitch	• Crude glycerin • Bagasse • Grape marcs and wine lees • Nut shells • Husks • Cobs cleaned of kernels of corn • Biomass fraction of wastes and residues from forestry and forest-based industries, i.e. bark, branches, pre-commercial thinnings, leaves, needles, tree tops, saw dust, cutter shavings, black liquor, brown liquor, fiber sludge, lignin and tall oil • Other non-food cellulosic material • Other ligno-cellulosic material [...] except saw logs and veneer logs
Part B (not considered as "advanced") capped to 1,7 % but exemption possible	
• Used Cooking Oil (UCO)	• Animal fats classified as categories 1 and 2 in accordance with Regulation (EC) No 1069/2009

Figure 5.4 **Biofuels in RED II annex IX part A (top) and part B (bottom)**

The targets in the figure are European targets, Member States may deviate from them.

In doing so, we choose the options that are most relevant for future expansion of biofuel use. It is expected that in the future (2040/2050), biomass of woody origin will be the most important option.

To process this biomass of woody origin, we choose both a biochemical and a thermochemical route, both with a high Technology Readiness Level (TRL).

- The **biochemical** route involves production of ethanol based on hydrolysis and fermentation at a TRL of 8 (JRC, 2020). Ethanol serves primarily as a petrol substitute.
- The **thermochemical** route involves production of Fischer Tropsch (FT) liquids at a TRL of 8-9 (JRC 2020). The liquids are petrol, diesel and kerosene. There is no difference in the FT process for these liquids so they are treated together.

HVO from tall oil, which in Figure 5.3 has a large share of the expected future production capacity, is not discussed further in the rest of this chapter. Tall oil is a residual product from the paper industry. From a user and sustainability point of view, HVO from tall oil is an alternative to FT diesel from biomass. Like FT diesel, HVO from tall oil falls under the EN15940 regulation, which means that the two products are highly comparable.

Practical applicability

The use of FT fuels does not, in theory, require any engine modifications. Ethanol and other fuels, on the other hand, may require changes to car engines and thus fleet adaptations in order to be used. Currently, 10% ethanol is mixed with petrol (E10). With limited modifications to engine technology, this share can easily be increased to 85% or even 100%.

5.2 Raw materials

Advanced biofuels can be made from wastes and residues from energy crops. The wastes and residues can be divided into four separate categories. These categories are:

- Wastes, these are materials without any other useful purpose, which generally have to be treated in order to be disposed of.
- Processing residues and by-products which are part of an industrial process and are available at a certain location.
- Locally collectable residues from harvesting operations but which are generally dispersed.

- Internationally traded raw materials such as wood pellets.

In addition to waste and residues as feedstock for advanced fuels, energy crops can also be used as feedstock if they are part of a rotation scheme or through low-intensity cultivation on marginal lands or on lands that meet strict sustainability criteria (Saddler et al., 2020).

5.2.1 *Availability of raw materials*

Regarding the availability of biomass, several studies have estimated the potential supply of biomass as a raw material for bioenergy use. The estimates vary widely in order of magnitude, and are highly dependent on a number of assumptions made. The greatest uncertainties in the estimates stem from the question of what proportion of the residues can be used economically, while also meeting sustainability requirements. Estimates of the amount of land that can be used for energy crops can also vary widely, given the large uncertainties about future demand for food. The International Energy Agency (IEA) has estimated the long-term potential availability of biomass for bioenergy on a global scale, based on a selection of studies (Saddler et al., 2020). Table 5.2 summarises the main results on the potential availability of biomass for bioenergy in the world in 2060. It is important to note that the source used indicates a reasonable range given the varying estimates.

Table 5.2 Overview of global biomass availability up to 2060

Raw material type	Sustainability conditions	Expected availability (EJ)[105] in 2060
Household waste	Taking into account the waste management hierarchy, which favours waste prevention and minimisation as well as recycling, and evolution of waste management systems in economies as they develop	10-15
Agricultural waste, residues and processing residues from forestry and agro-industry	Taking into account the need to reserve part of the available resources for animal feed and to leave sufficient residues on the field for soil protection, and in accordance with other uses.	46-95
Residual products from timber harvesting	Used in the context of a sustainable forestry plan, which takes full account of carbon aspects and other characteristics to maintain the forest, including biodiversity.	15-30
Agriculture	Produced on land in a way that does not threaten food availability and whose use results in low emissions from land use change, and with a positive assessment for other sustainability indicators such as biodiversity and water availability and quality.	60-100
TOTAL		131 - 240

Source: Saddler et al., 2020.

[105] 1 EJ is about 278 TWh or 25 million tonnes of oil (TOE, tons of oil equivalent).

The worldwide potential availability of biomass[106] in 2060 is between 130 and 240 EJ per year, according to Saddler et al. (2020) between 130 and 240 EJ per year. This is more than the current energy demand of the transport sector, about 2500 MToe (or 105 EJ) according to IEA.

5.2.2 *Cost of raw materials*

Table 5.3 gives an overview of the typical costs of raw materials, in another section the costs of the final biomass product are specified. The costs given are current costs, if a market for these feedstocks develops in the future, the costs may increase.

- Processing residues can be collected at no or low cost if they have no further use. Low costs are attributed to the fact that the processors have already processed the raw materials and the processing costs are attributed to the main product of the process. However, in some cases, increasing use of these residues may result in higher costs due to increasing demand.
- Collectable residues are often scattered across fields and must be collected and transported to a central point for conversion into bioenergy. This poses logistical hurdles that ultimately affect the cost of these residues.
- Internationally traded biomass is compacted to reduce volume, but this also increases costs. Compacted biomass is suitable for long-distance transport to large conversion plants. The cost of densified biomass is higher than for residues. (Saddler et al., 2020).

Table 5.3 Typical biomass costs for advanced fuels

Type of raw material	Typical cost/price (€/GJ)
Processing residues	0 - 4
Collectable residues	4 - 8
Internationally traded solid biomass	8 - 13

Source: Saddler et al., 2020.

5.3 Production

5.3.1 *Production process FT biofuels*

In short, the Fischer-Tropsch (FT) process applied to biomass works as follows. The biomass is brought to a gasifier where, under the influence of high temperature (1500°C), the biomass breaks down into syngas consisting mainly of CO, CO_2, H_2 and H_2O. The required high temperature is achieved by burning part of the biomass. This combustion takes place with pure oxygen in order not to contaminate the syngas with nitrogen (see figure 5.5).

[106] This can be used for both bioenergy and biomaterials

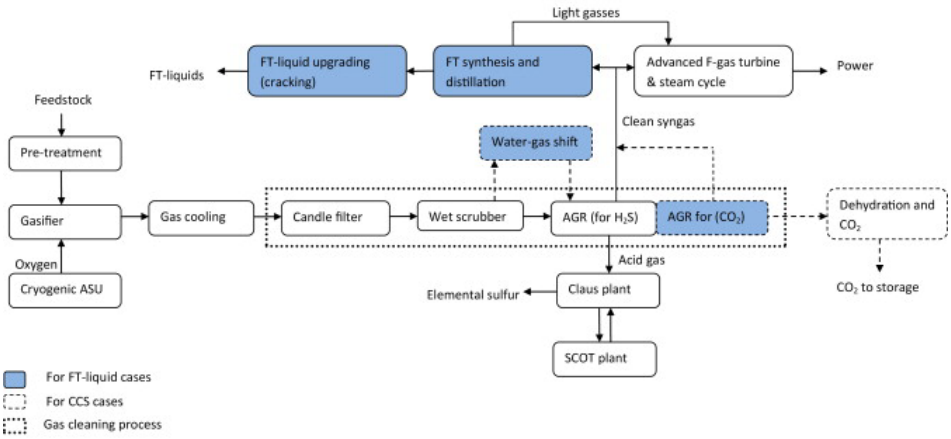

Figure 5.5 Overview of the production process of Fischer-Tropsch fuels

Source: Knoope et al., 2013.

The syngas formed contains impurities such as halogens, solid particles and sulphur components. These have to be removed with filters, scrubbers and solvents. After the syngas has been cleaned, the ratio $CO:H_2$ can be adjusted by means of steam supply and the 'water-gas shift' reaction: $CO + H_2O \rightarrow CO_2 + H_2$ ($\Delta H°_{298K}$ = -41.2 kJ/mol). The optimum $CO:H_2$ ratio for FT fluids is between 0.6 and 2.0 (and for methanol it is 1.3-1.4).

The mixture is then transported to an FT reactor where, under the influence of a catalyst, it reacts to form linear hydrocarbons. Hydrocarbon chains of varying lengths emerge from the FT reactor. The exact composition depends on various factors such as the catalyst used (iron or cobalt), the composition of the syngas (more hydrogen produces more short hydrocarbon chains) and the temperature and pressure under which the process takes place. The longer hydrocarbon chains can be cracked to obtain shorter (more valuable) hydrocarbon chains, or used in another industry.

Capacity and spatial considerations

There are several commercial FT plants, most of which use coal, natural gas or biomass as input. The largest known biomass FT plant is in Sweden with an input of 600 tonnes of biomass per day and a maximum daily output of 300 tonnes of methanol and 15 MW of electricity (NETL, 2020). It is unclear whether this is a commercial plant.

One of the largest production facilities is the Yinchuan plant which produces 100,000 barrels per day or 4 Mt per year of liquid FT fuels from coal (ICSC, 2017). This plant consists of 28 gasifiers, 12 units producing oxygen, 4 cleaning lines and 3 units to make fuels. The capacity of one gasifier is limited because heat transfer is crucial to convert the fuel into syngas. However, as the Yinchuan production facility demonstrates, several gasifiers can be placed in parallel. The Yinchuan plant covers a total area of 560 hectares (this includes a water treatment plant and a power plant). This seems reasonably comparable to an oil refinery with the same output. The land take of an FT facility is therefore no greater per unit of output than that of a refinery.

The largest FT plant is ten times smaller in capacity than the largest oil refinery, which produces over 1 million barrels per day (bbl/d) of liquid fuels. The Dutch refinery in Pernis also has a capacity four times larger (416,000 bbl/d) than the largest commercial FT plant. In the future, the capacity of FT plants could possibly be increased further. The question is whether this is desirable, given that a lot of

biomass input is also needed. Assuming a biomass FT plant of 100,000 bbl/d with an efficiency of 55%, it is estimated that 1.1 x 10^6 GJ wood pellets are needed daily. This is equivalent to about 1500 trucks or 1 sea tanker per day with wood pellets if we assume an energy value of 10 GJ/m^3 .[107]

Efficiency and costs (excluding biomass feedstock)

Various estimates of the efficiency of the FT process and the required investments in the FT installation can be found in the literature. An overview can be found in Appendix F. These estimates are based on the current state-of-the-art (SOTA) of technology. It is striking that the efficiency differs between the various sources (45%-73%), with a median of 60%. The efficiency is also determined by the type of feedstock used, the degree of heat integration applied, whether or not the CO_2 is stored and the mix of products coming out of the process.

Based on the cost range in Appendix F we arrive at an average cost of the FT process of 15.5 €/GJ biofuel with a wide range (1.2-47 €/GJ biofuel). Note that this does not include the cost of the biomass feedstock.

Improvement potential

There are not yet so many FT plants worldwide because they are often not commercially attractive compared to oil-based fuels. The number of FT plants running entirely on biomass is still much lower. The FT plants that are operational often owe their right to exist to exceptional circumstances or are demonstration plants. The large gas-to-liquids plant in Qatar, for instance, was built mainly to do something useful with the gas that is produced during oil production and because flaring is no longer allowed. The existing coal-to-liquids plants in South Africa date back to the time when oil was no longer supplied to South Africa during the apartheid regime. All this means that the total installed capacity is low and there is room for cost reduction through learning-by-doing. However, this potential should not be overestimated either, because many of the sub-technologies are also used in chemical plants, which means that the techniques are already fairly well developed.

According to Zhou et al. (2018) the cost improvement potential is mainly in the gasifier and the FT synthesis unit. Also the costs of oxygen production and CO_2 capture can decrease in the future (Knoope et al., 2013). In 2050, the capital costs of an FT plant with CCS are expected to decrease by about 10% and the efficiency to improve by about 5 percentage points when looking at the technology improvements per process step (bottom-up approach). Using learning curves (top-down approach), capital costs are expected to decrease by a greater 20-45% and efficiency increases by about 0-7% points, depending on assumptions on the development of production capacity (Knoope et al., 2013). With both methods, the costs of synthetic fuels fall by around 30%.

5.3.2 *Cellulosic ethanol production process*

The second biofuel route we consider is production of ethanol from lignocellulosic biomass based on the biochemical route via hydrolysis and fermentation. This second-generation ethanol generally performs better in terms of greenhouse gas emissions than first-generation ethanol (i.e. not from lignocellulosic material, but from crops containing mainly sugar and starch), see Padella et al. (2019).

Technically, there is no difference between ethanol from lignocellulose and ethanol from crops, only the production process of both variants. The production process of

[107] To make this calculation, we assume that a barrel of oil has an energy value of 6.1 GJ. In addition, we assume that an ocean-going tanker can transport approximately 100,000 m^3 and a truck 70 m^3.

ethanol from lignocellulose involves more steps than that of ethanol from crops. These steps can be summarised in four main stages: pretreatment, hydrolysis, fermentation and ethanol recovery.

Four production steps for cellulosic ethanol

1. **Pre-treatment.** The pre-treatment phase is important to change the structure of the lignocellulose so that it is more available for the hydrolysis phase (Quintero et al., 2013). There are several technologies for the pretreatment phase, but those involving steam explosion and dilute acid are the most widely used in the industry. In general, during the pre-treatment phase, the hemicellulose structure is hydrolysed into sugars that are later used for ethanol production during the fermentation phase.
2. **Hydrolysis.** The solid fraction remaining after the pretreatment phase is rich in cellulose and then goes to the hydrolysis phase where it is converted into C6 sugars with the help of enzymes (Moncada et al., 2018; Wei et al., 2017).
3. **Fermentation.** Both sugars from the pretreatment and from the hydrolysis are used as substrate in the fermentation phase. Fermentation is generally carried out with yeasts that can digest both haemicellulose and cellulose derived sugars.
4. **Ethanol recovery.** The downstream processing to recover ethanol from the fermentation broth is identical to that of first-generation ethanol production processes, where a distillation train is used to remove water and reach the azeotropic concentration of 95 wt%, and later a series of molecular sieves are used to dehydrate ethanol. This last step is necessary because ethanol is currently used for blending with petrol, and engines are not designed to allow water in the fuel mixture used.

In lignocellulosic ethanol production plants, a fraction of the biomass is obtained as a by-product, called lignin. Currently, there is no significant market for this by-product and, given the high energy consumption of the lignocellulosic ethanol process, lignin is therefore used as a fuel in on-site cogeneration plants that provide steam and electricity for the ethanol process. Generally, there is a surplus of electricity, which is sold to the grid (Quintero et al., 2013; Wei et al., 2017).

Commercial scale cellulose ethanol plants

There are several commercial-scale ethanol plants worldwide. Many of them are in operation or are being set up for full-scale operation. However, there are also plants that are inactive or on hold. This is usually due to cost effectiveness compared to fossil fuel production.

The table below gives an overview of cellulosic ethanol production in Europe. Globally, only a few lignocellulosic ethanol plants are operational, in Brazil and the US. The largest operational plant is in the US, owned by POET-DSM Advanced Biofuels and has a capacity of 75 kt per year. The two operational plants in Brazil have a capacity of 65 kt and 36 kt per year, respectively (E4tech, 2017; Padella et al., 2020).

Table 5.4. Overview of cellulosic ethanol projects in Europe via hydrolysis followed by fermentation

Project owner	Country	Raw material	Capacity (kt/y)	Status	Commissioning
Beta Renewables (acquired by Versalis) - IBP-Italian BioFuel	Italy	Lignocellulose crops	40	Currently inactive	2013
Beta Renewables - Energochemistry	Slovakia	Agricultural residues	55	Currently inactive	2017
Maabjerg Energy Concept Consortium - Flagship Integrated Biorefinery	Denmark	Plant dry matter	50	Currently inactive	2018
Clariant - Clariant Romania	Romania	Agricultural residues	50	Built	2020
St1 Biofuels Oy in cooperation with North European Bio Tech Oy - Cellunolix	Finland	Sawdust and recycled wood	40	Planned	2020
Enviral - Clariant Slovakia	Slovakia	Agricultural residues (wheat straw, maize stalk)	50	Planned	2021

Source: E4tech, 2017; Padella et al., 2020.

5.3.3 *Efficiency*

The first step in cellulosic ethanol production, pretreatment, requires a great deal of energy and contributes significantly to the total energy requirement of the production process (Wei et al., 2017).

As discussed above (see text box 'Four production steps for cellulosic ethanol'), steam explosion and dilute acid technologies are the most widely used in the industry. The table below summarises ethanol production efficiencies for wood-based systems using steam explosion, dilute acid and organosolv technologies respectively. A distinction is made between mass and energy efficiency.

- The **mass efficiency** (or biomass efficiency) describes the ratio of the mass of the final product to the mass of the input raw material flow.
- **Energy efficiency** describes the ratio of the energy content of the final product to the energy content of the raw material stream, including energy used to make the final product (ethanol has a calorific value of LHV 26.7 MJ/kg).

The mass efficiency for ethanol from woody biomass is directly linked to energy efficiency. In this case, mass efficiency is relevant because a relatively large amount of biomass is required for ethanol production. A significant part of the biomass is converted into CO_2 and a significant part of the biomass is not converted. At present, it is not yet common practice to capture and store (CCS) the CO_2 on an industrial scale. Sporadically, CO_2 is captured and traded as a raw material due to its high purity, and there are plans to apply this on a larger scale. The unconverted biomass is reused as process input.

Table 5.5 Mass and energy efficiency of ethanol production with different technologies

	Mass efficiency (%)	Biomass LHV (MJ/kg)	Energy efficiency (%)
Wet sugar beet (80 wt% moisture)*	8%	4.0	54%
Dry sugar beet (10 wt% moisture)*	30%	15.0	53%
Wood, dilute acid (10 wt% moisture)	21%	17.8	31%
Wood, steam explosion (10 wt% moisture)	19%	17.8	29%
Wood, organosolv (10 wt% moisture)	22%	17.8	32%

* Ethanol production from sugar beet biomass is based on a fermentation process

Source: based on Uslu et al. (2021).

For ethanol production, the following can be said about both concepts, mass efficiency and biomass efficiency:

- **Mass efficiency (or biomass efficiency)**. Ethanol production from woody (lignocellulosic) biomass ('wood') has a lower mass efficiency than ethanol from sugar beet ('sugar beet'); see table 5.5. This only applies to dry sugar beet with a low moisture content of about 10 wt%, not to wet sugar beet with a high moisture content of about 80 wt%. The mass efficiency of woody biomass is about 20%, for dry sugar beet it is 30%. This means that about 30% more biomass is needed to produce ethanol from woody biomass than from dry sugar beet. The mass efficiency of approximately 20% of the production from lignocellulose means that 20% of the biomass is converted into ethanol. By-products of ethanol production are mainly CO_2 and lignin. Per ton of ethanol, approximately 1.1 ton CO_2 is produced. A fraction of the biomass, mainly lignin, is not converted in the ethanol production process. This fraction can amount to up to 40% of the biomass mass (depending on the biomass type).
- **Energy efficiency:** For ethanol production from sugar beet, the JRC (Prussi et al., 2020) reports an energy efficiency of 53-54%. The energy efficiency of ethanol from lignocellulose (woody biomass) is lower, with about 30% of the energy in the biomass being converted to ethanol. The co-product lignin is not counted in the energy balance. Often, the co-product is (re)used as process input for the production of steam and electricity. In this case, the energy efficiency of the process will usually be higher (Uslu et al., 2021). The steam produced is entirely used internally, of the electricity produced only a fraction. The surplus electricity can be supplied to the grid. In practice, the surplus is about 11-13 MJ electricity per kg ethanol produced (Uslu et al., 2021).

5.3.4 *Costs (including biomass feedstock)*

Cellulosic ethanol is still under development. Several studies report that production costs are a limiting factor for the further development of cellulosic ethanol. In particular, the CAPEX and OPEX of production and the cost of raw materials and enzymes are very uncertain (Padella et al., 2019). Different studies therefore present different cost ranges, see Figure 5.6.

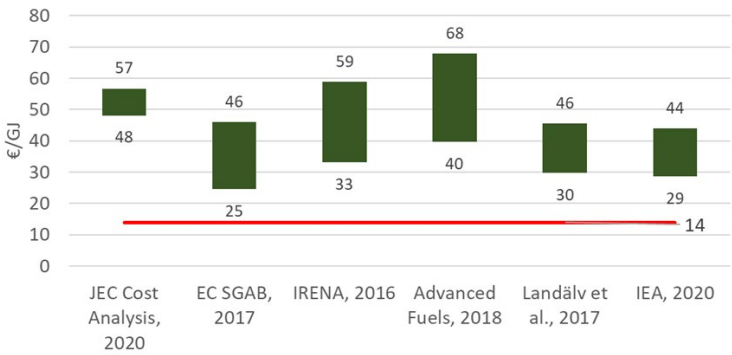

Figure 5.6 **Range of production costs (including feedstock costs) for cellulosic ethanol**

Sources: (Alberts, G.; Ayuso, M.; Bauen, A.; Boshell, F.; Chudziak, C.; Gebauer, J.P.; German, L.; Kaltschmitt and Nattrass, L.; Ripken, 2016; EC, 2017; I et al., 2017; Papadokonstantakis, 2018; Prussi et al., 2020; Saddler et al., 2020). The cost of fossil fuels (red line) is estimated at 0.45 €/l.

The investment in fixed assets (CAPEX) in the most expensive segment can amount to half of the production costs of the ethanol. The other half consists mainly of the cost of the raw materials, the biomass. The cost of this biomass depends on its accessibility (the difficulty of harvesting it), transport and distribution costs, and alternative uses of the biomass (Padella et al., 2019). According to the European Commission (EC, 2017) the cost of ethanol is, in the best case, 25 €/GJ (the lower bound in Figure 5.6). This is 70% higher than the cost of fossil fuel. Furthermore, the literature suggests that cellulosic ethanol production can benefit from the use of already produced first generation[108] ethanol assets, and thus significantly reduce CAPEX; see further under 'Improvement potential'.

In this study, we based the cost of ethanol production on Papadokonstantakis (2018)which distinguishes between a low, medium and high scenario, varying the CAPEX and OPEX of enzymes. This gives a range of 40-68 €/GJ for the cost of ethanol production, see table 5.6.[109]

Table 5.6. **Costs of ethanol production, including feedstock (biomass)**

Biomass input	**Low CAPEX[d]**	**Average CAPEX[d]**	**High CAPEX[d]**
TJ/y	6720	6720	6720
ktonnes/y	377	377	377
Ethanol production			
TJ/y [a]	2016	2016	2016
ktonnes/y	76	76	76
ML/y	96	96	96
Costs			
CAPEX - M€	173	265	487
OPEX biomass[b] - €/GJ	19	19	19
OPEX enzymes - €/GJ	4	6	8
OPEX other[c] - €/GJ	6	7	9
Total - €/GJ biofuel	**40**	**48**	**68**

[a] The conversion efficiency is estimated at 30% (energy) based on table 5.5.
[b] Biomass price assumed as 5.5 €/GJ biomass, based on Papadokonstantakis (2018).
[c] Assumed as 14% of total costs based on Papadokonstantakis (2018).
[d] Life span 20 years, discount rate 10%.
Source: based on Papadokonstantakis (2018) and updated to 2020 price level. Costs are harmonised on the basis of the CBS price index.

[109] The cost of 5.5 €/GJ biomass used by this author is higher than the cost range of 2.8 to 4.2 €/GJ biomass in an IEA study from 2020 (IEA, 2020). The latter cost range gives a range of 29 to 44 €/GJ ethanol at average CAPEX.

5.3.5 *Improvement potential*

In the Advancefuel project (AdvanceFuel, 2019) an estimate was made of possible CAPEX cost reductions of ethanol production plants due to learning effects. According to this source, future cost reductions could be as high as 10-25% for already realised plants and up to 40-50% for new plants around 2050.

Cellulosic ethanol production has revealed significant challenges for up-scaling. Many projects have not started or are at a standstill, which has significantly delayed the introduction of the technology. Improvements to reduce costs are very important to bring the price of cellulosic ethanol to a level that can compete with the price of fossil fuels.

5.3.6 *Cost overview production of FT liquids and cellulosic ethanol*

In this study, we calculate the following ranges for the production costs of FT liquids and cellulosic ethanol, see table 5.7. The costs in this table include the costs of the biomass feedstock.[110] For delivery to the fuel station, the costs of transport, distribution, storage and refuelling are added; see section 5.4.

Table 5.7 Bandwidth of production costs, including feedstock, of FT liquids and cellulosic ethanol used in this study

€/GJ biofuel	Middle	Low	High	Source
FT fluids	24	11	52	Plant costs: based on Table F.1 in Annex F; Feedstock costs (biomass: 5.5 €/GJ biomass based on Papadokonstantakis (2018)
Cellulose-ethanol	48	40	68	Table 5.6.

For comparison, Figure 5.7 gives an overview of the production costs of FT liquids and cellulosic ethanol compared to other advanced fuels, such as methanol, and also compared to current fossil fuel prices. The overview is taken from (Saddler et al., 2020).

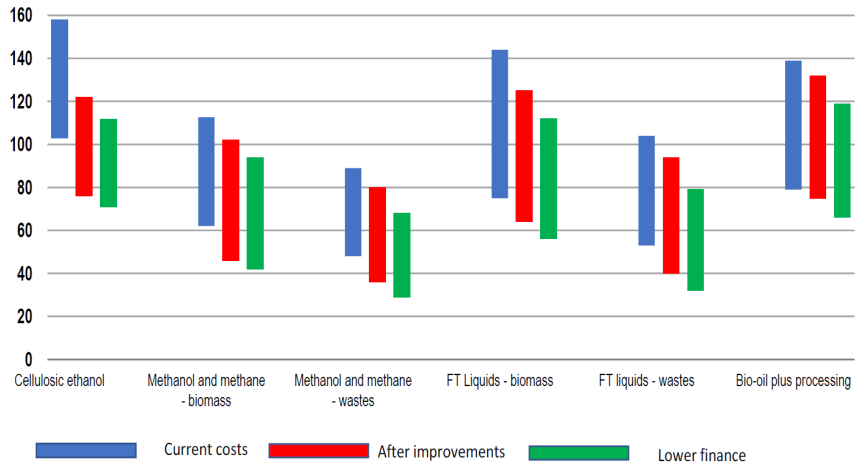

Figure 5.7 Overview of costs of FT fluids, cellulosic ethanol and various other advanced fuels compared to current fossil fuel prices

Source: Saddler et al., 2020.

The overview by Saddler et al. shows that of all the advanced biofuels, cellulosic ethanol is the most expensive. Even after improvements and assuming lower CAPEX financing costs[111] , it is projected to cost up to 50% more than fossil fuels. FT fuels

[110] For which we calculated 5.5 €/GJ based on Papadokonstantakis (2018).
[111] For 'Current costs' and 'After improvement', an interest rate of 10% and a project duration of 15 years were assumed. For 'Reduce financing', an interest rate of 8% and a project

can only compete on cost with fossil fuels if waste is used as a feedstock and if significant process improvements are made.

5.4 Transport, distribution and storage

5.4.1 *Transport of FT fluids*

In general, transport and distribution costs are a relatively small part of the total costs. The exact transport and distribution costs depend very much on various factors and the specific context.

Like ethanol, FT liquids can benefit from already existing infrastructure for transporting fossil equivalents. The maturity of this infrastructure can enable rapid penetration of these new transport fuels. Diesel is generally transported in ships and tankers.

In the context of the Power-2-Fuel cost analysis conducted by TNO (TNO, 2020), the costs of distributing various fuels were calculated in €/GJ fuel. In the same report typical vehicles and vessels were used, and estimates were made of daily costs. The cost estimates shown here for transport and distribution are therefore subject to uncertainty.

- For distribution via road transport, costs were calculated by estimating how much fuel a typical tanker can carry (see table 5.8).
- The calculated distribution costs for a distance of 200 km are shown in table 5.9.
- For inland and seagoing navigation, the estimated costs are given in table 5.10 and table 5.11. It has been assumed that fuel distribution takes place by means of bunker vessels.

Table 5.8. Typical volumes and energy contents of fuel carried by tankers

	Tanker truck		**Ratio of tank trucks with diesel reference**
	t	GJ	
FT diesel	16	683	1

Source: (TNO, 2020).

Table 5.9 Parameters for the distribution of different fuels for road transport at a distance of 200 km

	FT diesel
Tanker truck load [t]	16
Distance [km]	200
Truck transport [€/km]	1,1
Tank truck transport [€/kg]	0,026
Fuel station [€/kg]	0,04
Specific fuel energy [MJ/kg]	42,7
Transportation [€/GJ]	0,6
Fuel station [€/GJ]	0,9
Total [€/GJ]	1,6

Source: (TNO, 2020).

duration of 20 years was assumed. This is done with the idea that as the technology matures, the (technical) risks will also decrease (Saddler et al., 2020).

Table 5.10 Parameters for distribution of various fuels for inland navigation assuming distribution by bunker vessels

	FT diesel
Typical bunker quantity [t]	25
Typical bunker quantity [GJ]	1138
Bunker ship delivery [per day]	4
Bunker ship costs [€ per day]	2200
Distribution costs [€/t]	22
Distribution costs [€/GJ]	0,48

Source: (TNO, 2020).

Table 5.11 Parameters for the distribution of various marine fuels assuming distribution by bunker vessels.

	FT diesel
Typical bunker quantity [t]	500
Typical bunker quantity [GJ]	22750
Bunker ship delivery [per day]	3
Bunker ship costs [€ per day]	10000
Distribution costs [€/t]	7
Distribution costs [€/GJ]	0,15

Source: (TNO, 2020).

The cost of distribution by ship was estimated by assuming a typical transport volume (in tonnes), the charter cost for the ship per day including crew costs, depreciation and fuel costs, and the number of deliveries per day. In practice, many vessels are chartered, with charter rates varying considerably according to supply and demand and utility prices. To illustrate: the total daily throughput of an inland bunkering vessel is 100 tonnes. At a rate of 2200 €/day, the distribution cost is 22 €/tonne.

5.4.2 *Transport of ethanol*

Ethanol is currently typically shipped from Brazil to the US, Europe and the Far East (see figure 5.8). Brazilian ports are typically not suitable to load large tankers (loadings up to 55,000 DWT are used). There are only two terminals that can accept large crude oil tankers of the Suezmax and VLCC (Very Large Crude Carrier) size. In that case, the capacity varies between 130,000 and 300,000 DWT. The Dutch part of the infrastructure for the current trade in first generation ethanol can also be used to trade second generation ethanol. The current ethanol infrastructure has existed for decades, which will benefit cellulosic ethanol trade, should it take off. The existing infrastructure in, for example, Brazil will remain relevant if there is also a further switch to ethanol production from cellulose.

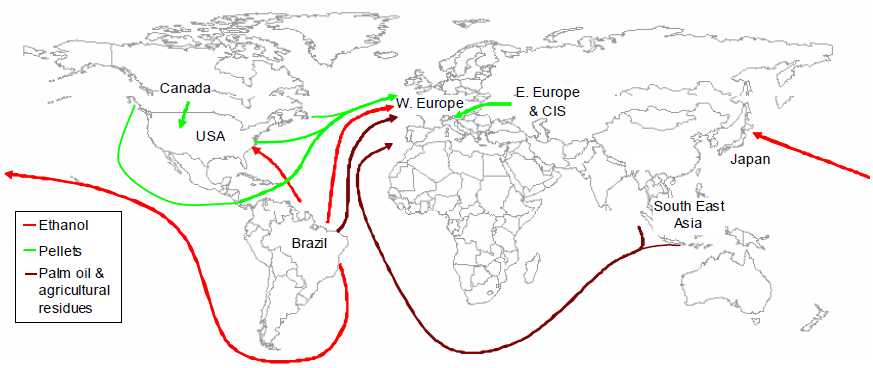

Figure 5.8 World biomass and ethanol transport

Source: (IEA, 2009).

The transport of bioethanol poses some risks to fuel quality. Additional measures are taken to reduce the risks. Ethanol is a 2-carbon alcohol (C_2H_5-OH). Due to the OH-group at the end of the chain, ethanol is hydrophilic (water attracting). This has consequences for fuel distribution. For example, tankers may encounter sediments that contaminate the fuel: water that dissolves in the fuel deteriorates its quality. When transported by water, there is a risk of water and salt contamination from the environment. Ethanol should therefore always be transported in tanks with a special coating, such as phenol-epoxy or zinc silicate.

Ethanol transport costs are well known from the US and Brazil, given the large production capacity and knowledge of ethanol trade around the world. As comparable cost indications for transport in Europe are not available, the costs of different modes of transport in the USA and Brazil have been taken as reference. These costs are highly dependent on the specific situation and should therefore be seen as indicative. Table 5.12 gives an overview of the transport costs for ethanol. Transport costs are highly dependent on charter rates, which can vary greatly. The costs are updated to 2020 using CBS price index figures.[112]

Table 5.12 Overview of ethanol transport costs

Mode of transport	Cost €/GJ*	
	US	Brazil
Water (including sea and river inland waterways)	0,4 - 1,2	0,5
Short distance freight transport (less than 300 km)	0,4 - 0,8	
Long-distance freight transport (over 300 km)	0,8 - 4,1	1,3
Track (more than 500 km)	0,8 - 2,0	0,8

* Ethanol has a calorific value of 22.8 MJ/l.

Source: based on (Rocha-Meneses et al., 2017) and updated to 2020 values.

For transport via water, transport costs are between €0.40 and €1.2 per GJ.

5.4.3 *Storage of FT fluids and ethanol*

FT fuels have a chemical composition similar to fossil fuels and can be used with existing storage infrastructure. The ethanol infrastructure has also developed in recent decades and cellulosic ethanol can benefit from this. The study by Cerny et al. (2021) shows the OPEX and CAPEX of storage tanks for ethanol and diesel. The OPEX and CAPEX are approximately the same for both liquids and are presented in Table 5.13.

Table 5.13. CAPEX and OPEX of storage tanks for diesel and ethanol

Tank capacity (m3)	CAPEX (€)	OPEX (€/y)
1.000	665,860	36,000
5.000	1,279,163	60,000
10.000	2,762,821	120,000

Source: (Cerny et al., 2021).

The annual storage costs were estimated using an annuity factor with a 5% discount rate and a lifetime of 20 years. Estimates of the costs at different tank capacities are presented in table 5.14 (Cerny et al., 2021). The values show that the storage of both diesel and ethanol has economies of scale. It is also important to note that storage costs are expressed in €/GJ per year as storage costs are entirely dependent

[112] Prices have been converted from €/m^3 to €/GJ based on a calorific value of 22.8 MT/L and are indexed to the HICP index.

on the buffer time (retention time) in the tank, which is related to the number of storage cycles per year and the injection and extraction rates.[113]

Table 5.14. Storage cost of ethanol and FT diesel at different tank capacities assuming an interest rate of 5% and a lifetime of 20 years for the tanks.

	Ethanol	FT Diesel
Tank capacity (m^3)	**Costs (€/GJ per year)**	**Costs (€/GJ per year)**
1.000	3.3	2.5
5.000	1.2	0.9
10.000	1.2	0.9

[113] A reasonable estimate of the storage cost per unit of fuel delivered can be determined by assuming that the share of storage cost here is equal to the share of storage cost in the fuel price.

6 Synthesis

This report describes the characteristics of the use of various energy carriers for a carbon neutral mobility in 2050. These are electricity, hydrogen, synfuel and biofuel. We have considered the use in five modes of transport that together are responsible for the bulk of current CO_2 emissions in mobility in the Netherlands, namely light and heavy road transport, inland navigation, maritime transport and aviation. For each of the relevant energy carrier-vehicle combinations, 4 characteristics were examined:

- Energy use: What are the energy efficiencies of the steps in the total energy chain from production of the energy carrier to use in the vehicle, or well-to-wheel? Which part of the total energy used in the entire chain remains as energy to be used in the vehicle?
- Land use: For which chain steps, from production of an energy carrier to its use in the vehicle, is land use important and how large is this land use per energy unit?
- Costs: What are the costs in the different steps of the energy chain?
- Barriers and uncertainties: Which barriers can be identified that could hinder the (large-scale) development of the 4 carbon neutral energy chains for mobility, such as the use of scarce materials? And what uncertainties do we see, the implications of which are not yet clear, but which are potentially important for future development?

Based on the findings, we present initial considerations for the use of energy carriers in the various modes of transport.

In the following sections, we answer these questions based on the analysis for the individual energy chains.

The reference year for efficiency, land use and costs is primarily 2030, as more reliable estimates are known for this than for 2050. In the underlying documents, we also provide a look ahead to how these three aspects might develop towards 2050.

6.1 Energy efficiency

Efficiency is one of the criteria on which the energy carrier-vehicle combinations were evaluated. This criterion is about the economical use of energy.

The energy efficiency of the entire (well-to-wheel) chain (R_{WTW}) is the product of the well-to-tank efficiency (R_{WTT}) and the tank-to-wheel efficiency (R_{TTW}).

Figure 6.1 shows R_{WTT}, the energy efficiency of the chain steps from production to fuelling or charging. Electricity has the highest energy efficiency of all chains studied, followed by the hydrogen chain in the variant that hydrogen is stored and transported in gaseous form (and not in liquid form or in the form of ammonia).

The fact that the electricity chain has a higher WTT efficiency than hydrogen made by electrolysis and than synfuels is logically explained by the fact that electricity is at the basis of both these other energy carriers. Namely, electricity is an input for hydrogen production by electrolysis and hydrogen in turn is a feedstock for synfuels. Due to losses in the respective production processes, to produce the same amount of energy for a vehicle more electricity is needed in the hydrogen chain than in the electricity chain and more electricity in the synfuels chain than in the hydrogen chain. In the case of hydrogen, compression, liquefaction or conversion to and from ammonia are also energy intensive.

The biofuel chain and the chain in which hydrogen is produced from (bio)methane are based on other inputs than electricity and are therefore not directly comparable.

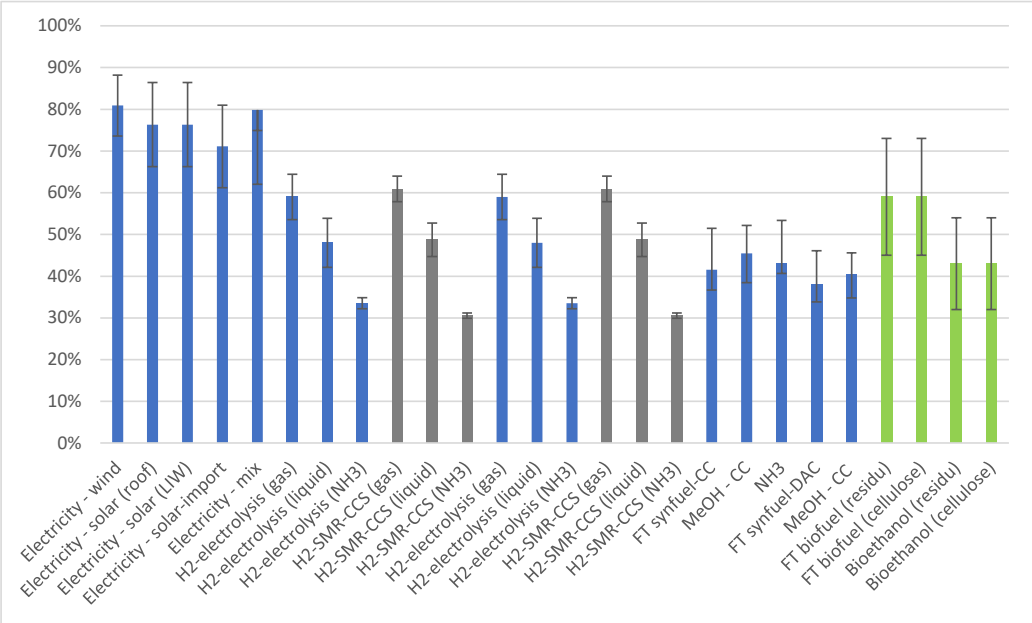

Figure 6.1 **Well-to-tank efficiency in 2030**

For biofuels and H_2 based on (bio)methane, the efficiency is relative to the energy content of the raw material, biomass or (bio)methane respectively. For the other chains, the efficiency is compared to electricity generation with a wind turbine. This difference in basis is indicated with the colours blue (electricity as basis), green (biomass as basis) and grey (methane as basis).

Figure 6.2 shows R_{TTW}, the efficiency of converting the energy charged or refuelled into energy used for propulstion of different drive trains.

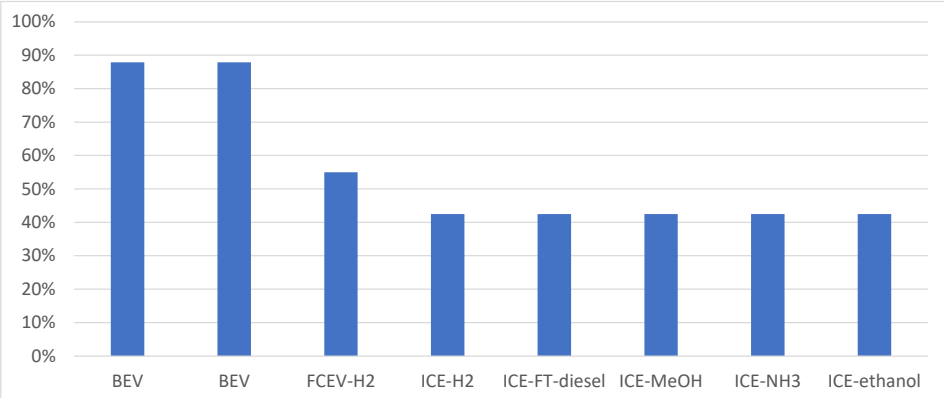

Figure 6.2 **Tank-to-wheel efficiency of different propulsion systems in 2030**

Results are reported for the efficiency under optimal conditions in terms of load and driving pattern (dynamic/non-dynamic). What constitutes the optimum conditions differs per powertrain type (Battery-electric Vehicle (BEV), Fuel Cell Electric Vehicle (FCEV) and Internal Combustion Engine (ICE)). The ICE efficiency (43%) refers to a large diesel engine, for example for a heavy duty vehicle or an inland waterway vessel. In general, the smaller the engine, the lower the efficiency. In this study the synfuel NH_3 is only an option for maritime shipping and inland navigation.

Figure 6.3 shows R_{WTW}, the chain efficiency when using the energy carriers from figure 6.1 with the various drive trains from figure 6.2. The reference year is again 2030. We see here that electricity achieves by far the highest efficiency across the entire chain compared with the other chains. This means that the energy input is converted most efficiently into vehicle propulsion. The difference with the other chains is even greater than for R_{WTT} (figure 6.1), because the powertrain for electric

driving or sailing (figure 6.2) is also more efficient than that for driving or sailing on hydrogen, synfuel and biofuel.

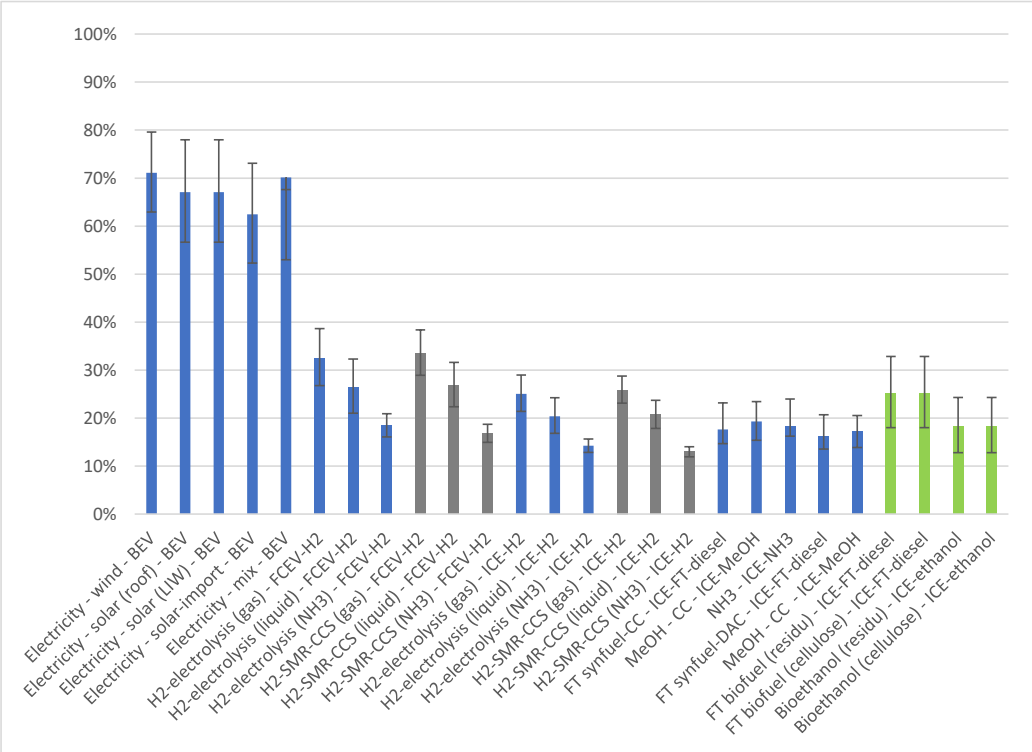

Figure 6.3 **The WTW efficiency, the combination of the WTT and TTW efficiencies from Figure 6.1 and 6.2**

In the sub-pathway "SMR-NH_3" methane is converted to ammonia and the ammonia is (later) converted to hydrogen; as this does not happen via SMR, the name is actually incorrect but for comparison with the other methane-based sub-pathways we have kept it this way.

Figure 6.4 shows the same differences as in figure 6.3, but in a different way, namely as energy use of the different energy chains compared to the most efficient one (electricity from wind for a battery-electric vehicle).

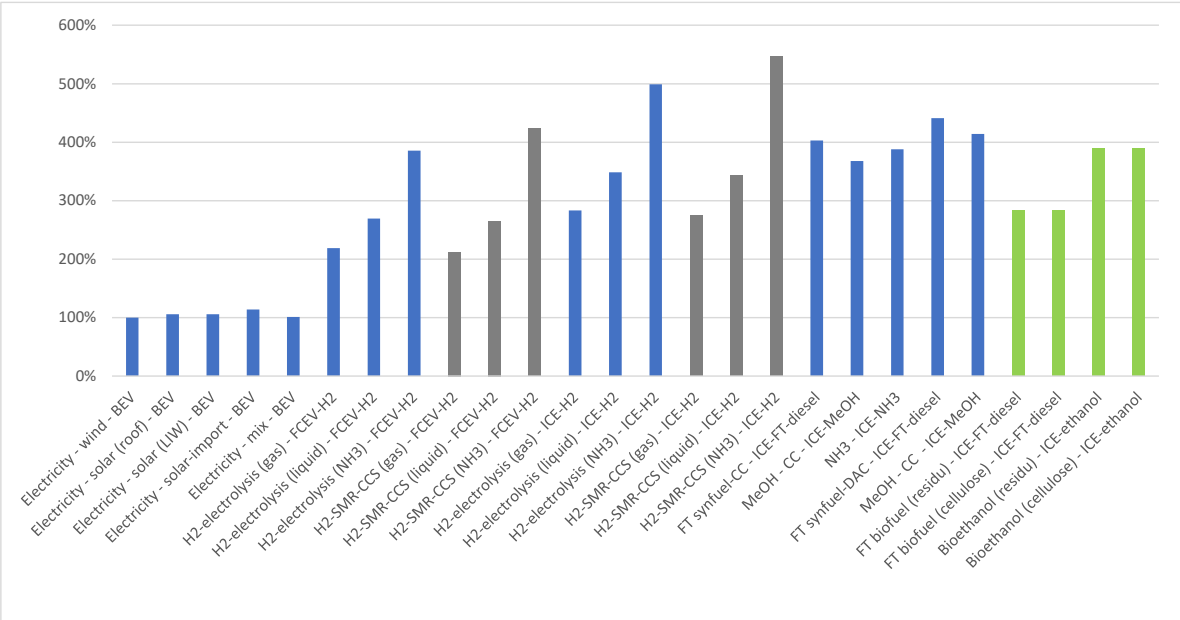

Figure 6.4 **Energy use in the entire energy chain (well-to-wheel) compared to wind energy in a BEV**

Overall conclusion from figures 6.1 to 6.4

The combination of wind energy with a battery-electric vehicle (BEV) uses by far the least energy over the entire chain (well-to-wheel), together with the other electrical sub-routes (domestic solar PV and imported solar PV), which are also energetically favourable. The electric routes have relatively low losses up to the charging point (well-to-tank) and the highest efficiency in the vehicle (tank-to-wheel).

The energy consumption of the combination of hydrogen with a fuel cell electric vehicle (FCEV H_2) is higher by a factor of 2 to 4, depending on the location where the hydrogen is produced, which may or may not require transport by ship or long pipeline. In the case of transport by ship, the conversion to liquid hydrogen and ammonia (NH_3) costs a relatively large amount of energy. In the case of NH_3 the step back to hydrogen is also energy-intensive. Furthermore, an internal combustion engine (H_2-ICE) has a lower efficiency than a fuel cell (FCEV H_2), so the energy consumption of that variant is slightly higher.

Synfuels are produced - with additional losses in the production process - from hydrogen and CO_2 or nitrogen. In addition, when synfuels are used in the vehicle, a lot of energy is lost in the form of heat. The synfuels chain therefore has a higher energy consumption than the hydrogen and electric chains.

All in all, a vehicle running on methanol, ammonia or FT synfuels needs about 4 times as much energy as a vehicle running on electricity. This means that four times as many wind turbines or solar panels are needed to generate the required energy.

The least efficient chain is the one with H_2 from SMR-CCS transported as ammonia and combusted in a vehicle with a combustion engine. The energy consumption here is more than 5 times higher than that of the most efficient chain.

6.2 Energy chain costs in 2030

In this study we look at the expected costs in 2030 over the entire chain of production, transport/storage/distribution, loading or refuelling of energy carriers and finally use in the vehicle. To facilitate comparison between the chains, we express the total costs as an amount per distance travelled.

We distinguish between energy costs, which are the costs at the loading or refuelling station (in €/GJ refuelled or loaded), and the costs of the vehicle with its specific power train to convert the refuelled or loaded energy carrier into motion (in €/km, taking into account the vehicle's lifetime). In the case of vehicle costs we only consider the purchase cost of the vehicle and not maintenance, insurance and taxes.

In formula:

Total cost (€/km) = vehicle purchase cost [with specific power train] [€/km] + energy cost [€/GJ] x energy needed in vehicle [GJ/km].

In principle, we are interested in the costs in 2050. However, this time horizon is too far away to make meaningful cost estimates. In any technology, learning effects may occur that reduce costs, while raw material and material costs may rise or fall depending on supply and demand. Even for 2030 there are large uncertainties, as the uncertainty margins in the figures below show. However, the optimistic cost estimates do reflect the optimistic expectations of the learning effects that may occur due to technological developments.

In this study we look at costs and not prices. To go from costs to prices, profit margins, taxes and possibly also subsidies and excise duties need to be taken into account. The latter three are policy levers to make one energy option more attractive than the alternative. Profit margins are difficult to estimate as they also depend on the amount of competition in the market and supply and demand. Although profit margins may differ between energy carriers, the cost ratios do give an idea of the price ratios (without government intervention) between the energy carriers.

As cost reduction is one of the most important criteria for individuals and companies to switch to a different type of energy carrier, the cost ratio between the energy carriers also gives an indication of how much excise duty should be levied on cheap fuel, or how much subsidy should be given on an expensive energy carrier, to make it comparable in cost to a cheaper alternative.

Figure 6.5 shows the energy costs of the various energy carriers for road transport and shipping. The costs include uncertainty margins, which are based only on uncertainty in capital and variable costs and not on uncertainty in efficiencies. The uncertainties in costs are not entirely independent of each other. For example, if the production costs of renewable electricity increase, the costs of hydrogen and synfuels will also increase as they use electricity as an input.

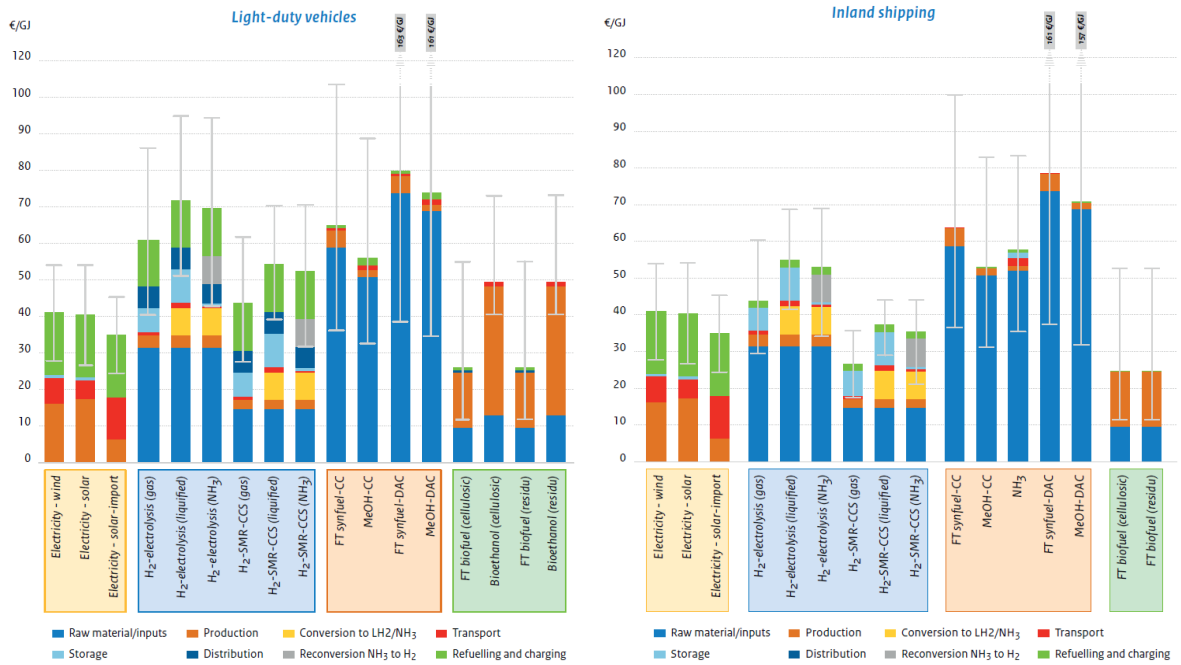

Figure 6.5 **Cost overview of the different energy carriers at fuel station or charging point for road transport (left) and shipping (right) in 2030**

The uncertainties reflect the uncertainty in fixed and variable costs, not the uncertainty in efficiencies. For synfuels, CO_2 can be captured directly from the air (DAC) or at point sources (CC). For the synfuels based on DAC in particular, the costs are very uncertain, up to a maximum of 165 €/GJ. For hydrogen we assume that the hydrogen is transported over a distance North-Africa-EU. For gaseous hydrogen with a pipeline of 1,500 km, for NH_3 and liquid hydrogen is transported by ship.

FT biofuels from woody crops (cellulosic) are the cheapest option per energy unit for both road transport and shipping. The cost uncertainty for this energy carrier is high, however, as the uncertainty bars show. This uncertainty exists in both the costs of woody biomass and the production costs, as it is a relatively new technology that is not yet widely used.

Electricity is also interesting for road transport. Although electricity is slightly more expensive per energy unit than FT-biofuels, the conversion in the vehicle is almost twice as efficient as for FT-biofuels, so that the total cost per vehicle is low (see also Figure 6.6 below). For electricity, 3 options were considered, of which the variant with 'solar import' (import of electricity generated by solar panels) is slightly cheaper than the one with electricity generated by wind turbines or solar panels in the Netherlands. If the electricity has to be imported over long distances, the transport costs increase but the production costs decrease, assuming that the electricity is imported from areas where production is cheaper, e.g. due to many hours of sunshine or favourable wind locations. Due to the large uncertainties in costs, for road transport it is not possible to say which option is the cheapest after FT biofuels and electricity.

For shipping, besides FT-biofuels from woody biomass and electricity, hydrogen from natural gas and biomethane (SMR-CCS) is also an interesting option in terms of unit cost (€/GJ). Hydrogen from electrolysis is approximately 18 €/GJ more expensive than hydrogen from natural gas and biomethane. We have taken into account natural gas costs of 10 (5-15) €/GJ and electricity costs of 75 (50-100) €/MWh. With these electricity and gas costs, about 30-60% of the costs in the hydrogen chain consist of production and raw material costs. The remaining costs are for transport, storage, distribution and refuelling. See the text box below for more details.

Transport, storage and distribution costs are in the order of 10-30%, and refuelling costs (in road traffic) are in the order of 20-30% of the unit cost. When the hydrogen is transported by ship, the additional costs for liquefying the hydrogen are in the order of 11-14% and those for converting to NH_3 and back are 22-29%. Conversion and reconversion for ammonia together are about as expensive as liquefaction, but storing liquid hydrogen is more expensive than storing ammonia. This makes hydrogen transported in liquid form slightly more expensive than hydrogen transported in the form of ammonia.

We have calculated a transport distance by ship from North Africa to the EU of about 1,500 km. For longer distances, the costs of transport by pipeline increase more than those of transport by ship. Whether it is a new pipeline or the re-use of an existing gas pipeline makes a difference to the costs.

For hydrogen in particular, there are large cost differences per energy unit between road transport and shipping. This is due in particular to the higher costs of fine-meshed distribution (by tanker or pipeline) and of refuelling infrastructure for road vehicles compared with bunkering for ships. Major cost items at road transport filling stations include the storage tanks and the compressor needed to bring the hydrogen to 350-700 bar; the cost per unit of hydrogen also depends strongly on the utilisation rate of the filling station.

For those synfuels that are based on H_2 and CO_2, methanol and FT-synfuels, the raw material costs are high. We distinguish between CO_2 captured directly from the air (DAC) and CO_2 captured from point sources (CC). The latter option is approximately 200 €/t CO_2 cheaper, or 15-20 €/$GJ_{synfuel}$, depending on the amount of CO_2 needed. It is likely that in 2050 CO_2 will have to be captured directly from the air because there are few or no large-scale point sources that still emit CO_2. In 2030, these will most likely still exist. However, the costs of DAC are very uncertain.

For biofuels, too, the raw material costs are substantial, although smaller than for synfuels. In this study we calculate with a biomass price of 5.5 €/GJ biomass for both woody biomass and residual flows, but the uncertainty in this assumption is high.

An advantage of both synfuels and biofuels is that the costs of transport, storage, distribution and refuelling are relatively low. For FT-synfuels and biofuels, all existing infrastructure can be used, and for the other biofuels and synfuels probably a large part of it (with some minor adjustments).

Total cost per vehicle

Figure 6.6 and figure 6.7 show the costs per distance travelled for the various vehicles when using the various energy carriers shown in Figure 6.1. The purchase costs of the vehicles (Appendix A Costs) are uncertain, but it is not possible to indicate how great the uncertainty is; for a battery-electric inland shipping vessel it is not even possible to give a cost indication. In Figures 6.6 and 6.7 no uncertainty bars are therefore shown.

Figure 6.6 shows that battery electric transport (BEV) is the cheapest option in €/km for heavy duty vehicles. This is mainly due to low energy costs, as the purchase costs for an electric truck are higher than for a truck with a fuel engine. In principle, this also applies to light duty vehicles, although there the cost per distance travelled for a FT-biofuels vehicle is still slightly lower than for a BEV. Costs for fossil fuel for ICE vehicles are included for reference, with the diesel price based on the average costs projected in PBL (2021) for the period 2020 to 2030: 0.62 €/L or 17 €/GJ (excluding taxes and duties).

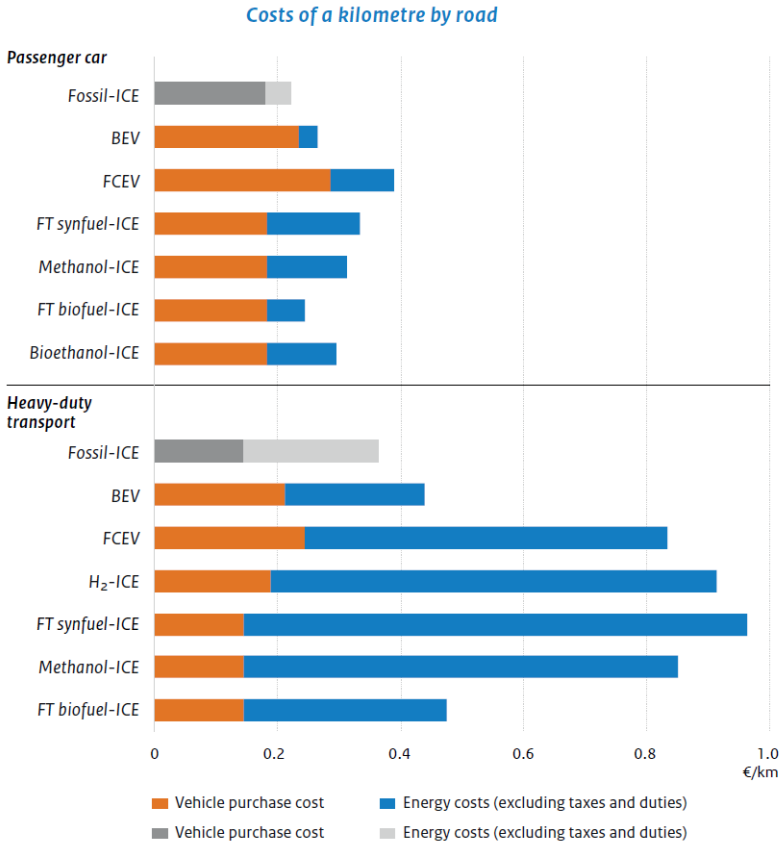

Figure 6.6 **Cost per distance travelled for heavy and light duty vehicles in 2030 with different energy carriers and power trains**

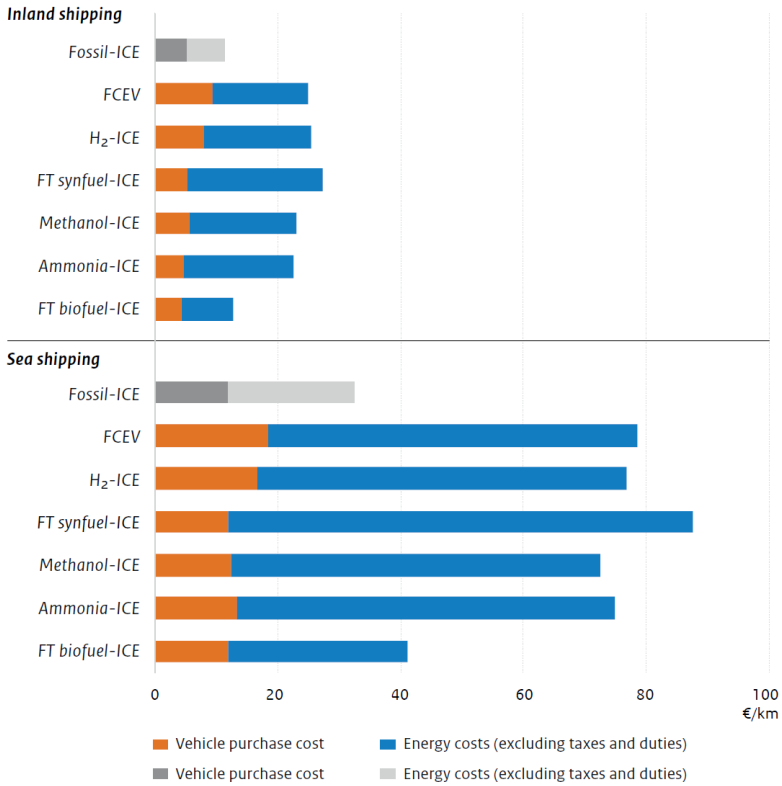

Figure 6.7 **Costs per distance travelled for inland and seagoing shipping in 2030 with different energy carriers and power trains**

For inland navigation and shipping, FT biofuel is the cheapest option. For both inland navigation and shipping, the cost differences are small for the other alternatives, consisting of various synfuels (ammonia, methanol and FT synfuels from CO_2 and H_2) supplemented by hydrogen-ICE and FCEV for inland navigation.

6.3 Land use

In our analyses of land use for the various chain stages, we look at the use of land from a quantitative point of view. Land use is expressed in terms of the land area required for energy supply to drive, sail or fly a vehicle. Land use refers to both the surface area on land as well as at sea.

6.3.1 Explanation of net and gross land use

We calculate the land use in two ways. The *net land use* is the above-ground land area that is used primarily (i.e. as the main purpose) for the production of energy, for example the piece of land or sea occupied by a wind turbine or used to erect solar panels, without taking into account the fact that wind turbines must be placed hundreds of metres away from each other so as not to affect each other. Animals may graze around the solar panels, which may also benefit from their shade, but the primary land use is for solar energy.

The *gross land use* indicates the total area required to produce a certain amount of energy. The space between the turbines, for example, also counts as space usage for energy production, even though it is or can be used for other purposes. However, this space between turbines must be present in order to be able to place the turbines at a distance from each other and is therefore indispensable. This gross measure is useful to determine what the spatial possibilities and limitations are to produce a certain amount (or certain capacity) of energy. Combinations of energy production can also take place on the same surface, for example biomass cultivation between the turbines of a wind farm, but this will not be considered here.

Table 6.1 shows what is and what is not included in the land use for the production of electricity and biomass (as a raw material for biofuels). A general assumption here is that for the net land area, the primary purpose of the land area is leading, and that when energy production is a secondary purpose of the land area used, the net use is zero. The latter applies to solar energy on building roofs and biomass from agricultural residues.

For wind energy, the net space usage is the 'built-up' area. On land, this surface is approximately 0.5% of the total surface area of a wind farm. This means that 0.5% of the space needed by the wind turbine to accommodate its wind energy is allocated to net space usage. At sea, the built-up area covers the space within a radius of up to 50m around a wind turbine, and 500m around a platform at sea for a transformer station (see appendix C Electricity). The area that can be used for other purposes is therefore not allocated to the wind turbine. This does mean, however, that - even though the required built-up area is still relatively small - the gross space usage can be large; see also the Electricity chapter.

In the case of PV, the surface area on roofs or (road) infrastructure applies, or the total surface area of solar farm. Note that PV on roofs leaves open the possibility of using the space under those roofs, and is therefore not included in net land use. This is not the case, or is very limited, when panels are placed in natural or agricultural areas (solar farm). The space between rows of solar panels can hardly be used for agriculture, so we have allocated it to the solar farm.

In the case of biofuels, we take the land area needed for the production of biomass. In the case of the use of agricultural crop residues (e.g. organic waste from maize cultivation), we do not assign any land use to this residue. This only applies to waste

streams from production that is already taking place anyway, so the assumption is that no *additional* agricultural production takes place through the market for biomass feedstock from residues.

Table 6.1. Definition of net and gross land use by the production of energy carriers

	Net land use	Gross land use
Wind energy	Land or sea area for turbines + any additional infrastructure (access roads, transformer platform at sea)	Surface of wind farm
PV (on roofs)	No use of space	The roof area used
PV (in landscape, on infrastructure and on water, LIW)	Surface area of solar panels + space between panels	Equal to net land use
Biofuels (energy crops)	Land area required to produce woody biomass	Equal to net land use
Biofuels (residues)	No land use	Surface area of land from which the residue is extracted
Hydrogen from electrolysis	Net area required for production electricity for electrolysis	Gross area of electricity required
Hydrogen from SMR with CCS and 10% biomethane	Net area required for SMR and CCS and natural gas transmission	Equal to net land use
Synfuels	Net area required for hydrogen production from electrolysis + DAC	Gross area of electricity requirement + DAC

Storage of CO_2 and transport of natural gas take place underground and as such do not require any land use. The required biomethane can be extracted from waste (sewage sludge) or residual flows from agriculture or livestock and therefore we do not count on land use either.

For the production of synfuels, in addition to hydrogen, CO_2 from the air is needed. The direct air capture (DAC) installations for this have a limited use of space but are included in the calculation.

For the transmission and distribution of electricity, we take the above-ground surface area of the entire electricity network: above-ground high-voltage cables and transformer stations. We allocate that to all the electricity supplied. In other words, every kilowatt hour is equal, and no distinction is made between different end-user sectors. For the production of hydrogen, we do not allocate land use to the transport and distribution of electricity, under the assumption that the electrolyser can be

connected relatively close to the electricity production site (wind turbines and solar panels).

6.3.2 *Net land use*

Figures 6.8 and 6.9 show the net land use of an inland navigation vessel (assuming 4,500 operating hours per year based on Jonkeren et al., 2020) and a passenger car (13,000 km per year, CBS (2021)), respectively, in the various energy chains.

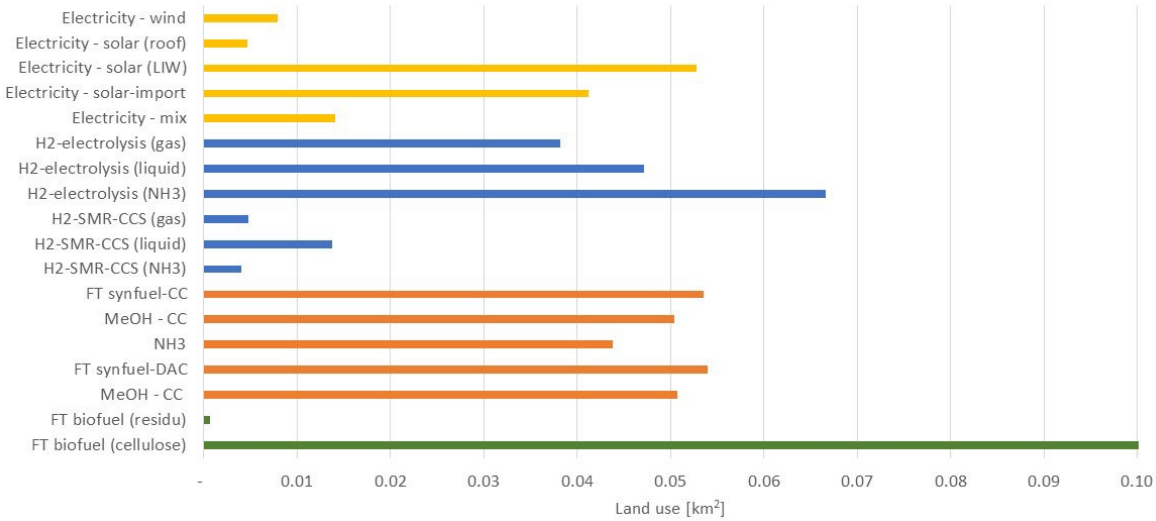

Figure 6.8 Net land use for energy supply for one inland navigation vessel

H_2 electrolysis is based on electricity from a mix of 76% wind and 24% solar PV. Space requirements for synfuels were calculated on the basis of space requirements for hydrogen from electrolysis. For biofuels from residues it has been assumed that this will not take up any additional land compared to the land required for growing the primary product.

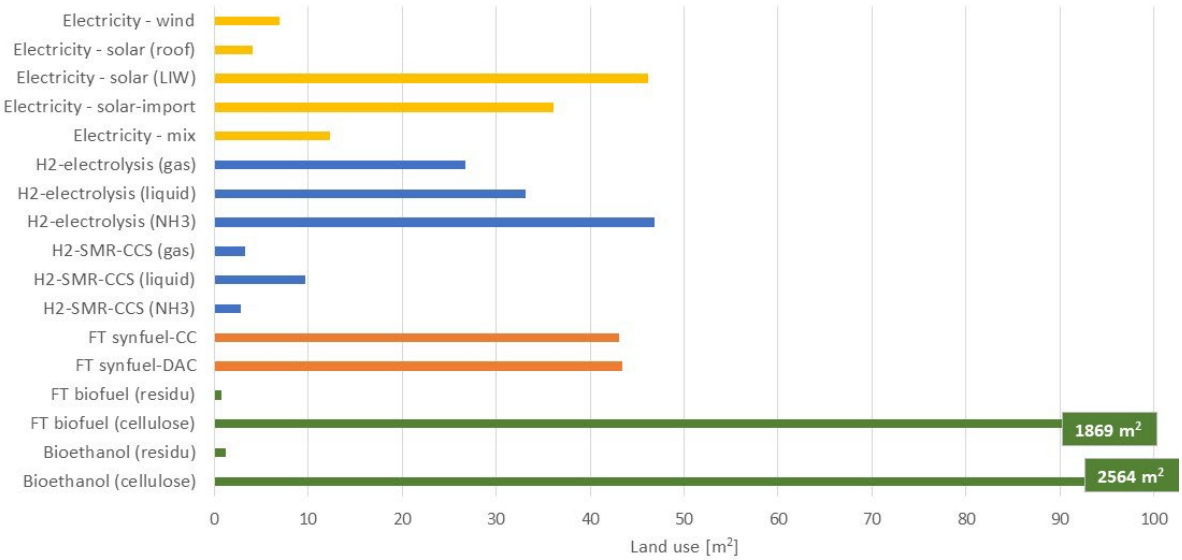

Figure 6.9 Land use for energy supply for 1 passenger car

For electricity (mix NL) and the electricity needed for electrolysis, a share of 76% wind and 24% solar applies. H_2-SMR-CCS: no land use attributed to biomethane use. No land use attributed to biomass feedstock from residues.

In interpreting this, we note the following. As mentioned, no distinction has been made in the figures between use of space on land or at sea, in urban or rural areas,

and in the Netherlands or abroad. In practice, space is more scarce in one country than another, depending for example on population density. Thus 1m^2 used for biofuel production in Sweden is not necessarily comparable with 1m^2 used for onshore wind in the Netherlands. Similarly, hydrogen generated close to solar panels in North Africa has a qualitatively different use of space than wind turbines in the Netherlands. Nevertheless, the figures below give an impression of the difference in space requirements for the various chains.

Hydrogen from natural gas with CCS (of which 10% biomethane) has a relatively low land use, caused by the electricity consumption in this chain (for compression and purification of the hydrogen and possibly liquefaction). Wind energy (both onshore and offshore) has the lowest net land use.

Land use in the hydrogen from electrolysis and synfuels chains is determined by the use of electricity in these chains.[114] Because the use of electricity in the electricity chain is lower than in the hydrogen and synfuels chain, and because the conversion efficiency in a BEV is higher than in an FCEV and an ICEV, the land use per distance travelled is higher for the hydrogen and synfuels chains than for those of electricity.

The use of land by biofuels from energy crops is greater by a factor of 100 than by the other chains, and therefore exceed the scale of the axis in the graph. If all the fuel currently bunkered in the Netherlands by air and sea transport were biofuel from energy crops (non-residues), this would require a land area 1 to 3 times that of the Netherlands (see appendix F). In the case of biomass from residues, there would be no additional land requirements. It is likely that in the longer term both energy crops and residues will be needed to meet the demand for biomass (see table 5.2 and Hanssen et al., 2020[115]).

6.3.3 *Land use of energy for the transport sector*

If all road mobility in the Netherlands had been electric in 2019, it is estimated that this would have taken 40 TWh of electricity, with a net land take of about 250 km^2. For comparison, this corresponds to about 1/5 of the existing surface for road infrastructure and (outdoor) parking.

A wind farm the size of the province of Utrecht is needed to power all road vehicles in the Netherlands. This is the gross land take, including the space between the wind turbines.

Wind farms with a surface area of 9 times the province of Utrecht, or one-quarter of the Dutch continental shelf (NCP) are needed to make synfuels for the aircraft and sea-going vessels currently bunkering in the Netherlands. Again, this is the gross surface area. Realising such an area of wind farms would be a major challenge, because other sectors also need electricity and the potential space for wind farms is limited to approximately one-third of the NCP.

The transmission and distribution of electricity from renewable sources will require the expansion and reinforcement of the electricity grid (see section 2.2). In climate-

[114] Only if H_2 and synfuels were produced only from temporary surpluses of wind/solar power (at times of greater electricity supply than demand) would there be no effect on space. But the question is how many of those surpluses there are and whether there are parties willing to invest in an electrolyser or synfuels plant that is idle for large parts of the year, and what the H_2 demand by other sectors is.

[115] Hanssen et al. (2020) conclude in a meta-study that residues from agriculture and forestry could cover 7-50% of global biomass demand in 2050. Moreover, the residue availability estimates analysed in this study do not include possible bottlenecks in logistics and biomass quality.

neutral scenarios, the use of space for the entire electricity grid may increase by about one-third, which may create problems in terms of spatial planning. It is not clear what importing electricity would mean in terms of the grid reinforcements required. Importing electricity saves a lot of space in the Netherlands. In Africa, for example, production of solar energy requires about half the amount of space as in the Netherlands.

Hydrogen from SMR-CCS takes up less space than hydrogen from electrolysis and therefore fits better in the Netherlands. The installations for hydrogen production, the SMR installation and the electrolyser, both take up little space. In the case of electrolysis, however, a lot of space is needed to generate the renewable electricity from solar and wind that the electrolyser needs. The other steps in the hydrogen chain also use electricity (for compression and the like) and therefore take up land area.

For the land use of the SMR-CCS route we have assumed that the 10% biomethane required to make the SMR-CCS process carbon neutral will be obtained from residual flows such as animal manure and sewage sludge, and will therefore not take up any (extra) land. SMR-CCS (with 90% natural gas and 10% biomethane) does mean dependence on natural gas and possible political and social discussions on the acceptance of CO_2 storage. Sufficient availability of biomethane may also prove a problem.

Importing hydrogen or synfuels may limit the land take in the Netherlands for the energy chains for mobility, but in fact the land take is then shifted to other countries.

6.4 Discussion on the basis of efficiency, land use and cost

The advantage of the electricity chain is that, while the need for renewable electricity from solar-PV and wind is great, that need is even greater in the hydrogen (from electrolysis) and synfuel chains. This also largely explains why the land use and the costs of this chain are relatively low: less space is needed for solar and wind farms and less needs to be invested in them. Only biofuels and hydrogen from (bio)methane do not consume electricity on a large scale. A choice between the various routes therefore has major consequences for the required pace of scaling up solar and wind farms and electricity imports.

However, the fact that the electricity chain scores best on all aspects - efficiency, space and chain costs - does not mean that policy should choose to focus only on this.

It may be a good strategy to use the other chains as well. Hydrogen, synfuels and biofuels can help create more flexibility in the total energy system for mobility, both in time and in place.

- **Time**: the use of hydrogen, synfuels and biofuels can help ensure that mobility does not contribute to peaks in electricity demand. The biofuel chain uses little or no electricity anyway. Hydrogen and synfuels do require electricity - because they have electricity as an input - but this is an indirect electricity demand that takes place at different times from the direct electricity demand of electric vehicles, which only provide some delay between demand and use via their (small) battery. Hydrogen and synfuels have a very different time dependence than electricity. For example, they are easier to store than electricity and buffers can be built up.
- **Location**: the production locations of hydrogen, synfuels and biofuels can be very different from those of electricity. Hydrogen, synfuels and biofuels can be

produced in any part of the world (using locally produced electricity and biomass) and brought to the Netherlands by ship. For electricity itself, transport over such long distances is not an option due to the large energy losses.

Other arguments also play a role. Efficiency, space and costs are ultimately 'only' 3 characteristics, while other matters are also important, such as diversification of resources and raw materials (not being dependent on one source or supplier), security of supply (can be delivered at the desired time and place) and ease of use. To achieve carbon neutral mobility by 2050, it is crucial that there is sufficient availability of raw materials and production facilities and that a rapid upscaling and transition takes place. Is such a rapid switch possible with electricity, both in terms of energy supply and vehicles? That is the question. Investing in multiple energy carriers spreads the chances of achieving targets and a rapid upscaling and transition. In this study, diversification, timely up-scaling and availability were not considered, except where we clearly saw an uncertainty or bottleneck. But they are certainly relevant for the path to 2050.

And finally, other characteristics, such as sustainability and public acceptance (see Section 6.5), are important in addition to the three main criteria of this study. Caution is therefore called for in drawing conclusions based on efficiency, costs and land take alone. These criteria can, however, be useful in revealing certain differences and in weighing up the pros and cons.

6.5 Other features

In addition to the above discussion for the 3 main characteristics (efficiency, cost and space utilisation), other characteristics are important in the 4 energy chains, as discussed in the respective chapters. The tables below give a summary overview of these for the well-to-tank and the tank-to-wheel part of the chains respectively.

Table 6.2 Summary of other characteristics for the well-to-tank steps

	Electricity	Hydrogen	Synthetic fuels			Biofuels
			Ammonia	Methanol (gasoline substitute)	FT-synfuels (diesel or kerosene substitute)	FT biofuels and cellulosic ethanol
Bottlenecks in availability	With a large increase in demand for electricity, available land will become a bottleneck; the number of available technicians can also be a bottleneck (but also: more employment per unit of energy).	Sufficient electricity for electrolysis. Water can be a bottleneck if the H_2 is produced by electrolysis in dry areas. Availability of biomethane (to replace part of the natural gas in SMR-CCS)	Availability of hydrogen is a prerequisite.	If CO_2 from point sources is not available, costs increase as CO_2 has to be captured from the air.	Availability of raw materials (biomass) may be a bottleneck for large-scale application	Can meet the current world demand for mobility but there is limited availability for other sectors.
Implications for refuelling and charging infrastructure	Spatial integration of charging infrastructure is challenging; Charging stations in ports: combination with shore power possible?	Refuelling often takes place at high pressure levels (350-700 bar). This costs energy at the filling station. A purification step may also be necessary (in the case of hydrogen from a large-scale hydrogen network) because of the vulnerability of fuel cells.	Same locations can be used, but larger safety zones are needed	Same locations can be used but different refuelling infrastructure is needed	None; same infrastructure can be used.	None; same infrastructure can be used.
Storage	Short-term and long-term storage of electricity will become important. The question is how this will be realised, and what role stationary batteries and batteries in vehicles will play in this, alongside, for example, hydrogen.	At atmospheric pressure, hydrogen has a low energy density; it is stored after compression or liquefaction. Liquefaction in particular requires a relatively large amount of energy. Furthermore, the storage tanks must be very robust.	Ammonia is relatively easy to liquefy, which makes it easy to store. Due to lower energy density (than fossil fuel), larger storage tanks are needed.	Methanol is liquid and easy to store. Due to lower energy density (than fossil fuel), larger storage tanks are required.		The same storage tanks can be used as with fossil fuels.

Implications for transport and distribution network	Distribution network and high-voltage grid need to be extended, which may create spatial bottlenecks, e.g. for transformer houses and distribution stations in/around the city	Supplying petrol stations leads to many transport movements with tankers. Pipeline only profitable with longer transport distances and large volumes.	Already extensive transport network. Needs to be expanded; and to become more finely meshed if barges are to run on ammonia	None; same infrastructure can be used.		None; same infrastructure can be used.
Safety		Safety zones around petrol stations and pipelines.	Ammonia is toxic and therefore requires larger safety zones around tank and storage sites than petrol. Use in trucks is not recommended due to safety issues.		Same safety risks as with fossil petrol, diesel and paraffin: especially fire and explosion risks.	
Scarce/critical materials	Wind turbines/PV panels require some scarce metals such as nickel, cobalt and scarce earths; ERS has high copper consumption	The most commonly used types of electrolysers use platinum group metals. The current production volumes of these metals combined with the large-scale use of electrolysers create a bottleneck.				
(Visibility) nuisance for the surroundings	Nuisance from wind turbines/PV panels and ERS overhead wire; charging stations on pavement reduce space for pedestrians; ERS has effect on landscape quality		Visual disturbance when capturing CO_2			Assumption that sustainability guidelines minimise environmental impact
Water use	Indirectly for production materials	For 1 kg of hydrogen from water electrolysis, 9 kg of water is needed. This can be	See hydrogen.	See hydrogen.	See hydrogen.	Depending on the crop, it is certainly not negligible.

		a barrier for production in dry areas such as North Africa. With desalination plants and water pipelines, this can be solved with possible side benefits for making these areas fertile.				
Other environmental effects (noise, emissions of harmful substances)	Noise from onshore wind turbines	Hydrogen from natural gas (SMR) risk of methane leakage into the natural gas chain; Hydrogen leakage (hydrogen enhances the greenhouse effect of methane)				Assumption that sustainability guidelines minimise environmental impact
Social effects and acceptance	Onshore wind and solar farms sometimes have limited support	In the case of hydrogen from SMR + CCS, there may be limited support for underground CO_2 storage near residential areas.				Assumption that sustainability guidelines minimise potential impacts on farming practices

Table 6.3 Other characteristics tank-to-wheel: use in vehicles (as applicable)

	Electricity	Hydrogen	Ammonia	Methanol	FT-synfuels	Biofuels
Space	Battery takes up a lot of space and is heavy, especially for heavy duty vehicles. Can be at the expense of cargo space	H_2 tank takes up a lot of space and is heavy (many times heavier than the hydrogen it contains). Fuel cell system is heavy.				
Safety	Road vehicles: (limited) fire risk in parking garages. Increased weight can affect road safety.	Road vehicles: Fire hazard in parking garages	Toxic: dangerous if ammonia is released (in an accident)			
Scarce/critical materials	Cobalt, nickel, lithium and rare earths	Platinum for the fuel cell (is scarce, but also a big cost item)				
Climate impact of aviation (non-CO_2)		When used in aircraft, more water vapour than (synthetic) paraffin; this gives a (relatively short) greenhouse effect at high altitude (total climate impact 10 times less than CO_2 emissions). Hydrogen leakage enhances climate effect of methane and ozone. No or less soot particles.			FT-fuels: less soot particles due to fewer aromatics. Water vapour emissions are similar to those of fossil paraffin: at high altitudes this has a (relatively short) greenhouse effect.	
Air pollution	For road vehicles: marginal effect (positive or negative) on particulates compared to diesel	Half less NO_x emissions in combustion.	NO_x emissions during combustion.	Still fine dust and NO_x on combustion.		
Social justice	Point of attention for extraction of some materials (cobalt, lithium, nickel)					
Circular economy	Recycling of batteries still in its infancy					
Other effects	Increase in vehicle weight due to battery: some additional damage to roads	Increase in vehicle weight due to hydrogen tank and possibly fuel cell system.	Additional kindling fuel needed, so 2 tanks or conversion process in the			High ethanol blending requires

	low maintenance of vehicle/vessel engine	When hydrogen is used in a (PEM) fuel cell, the hydrogen must be extremely pure, otherwise the fuel cell will be damaged; especially extreme intolerance to sulphur and ammonia.	vehicle. Both take up space on the vehicle. Lower energy density so more frequent refuelling or larger tanks		engine modification

6.6 Discussion from the perspective of each transport mode

What does the previous analysis mean for the applicability of energy carriers for the different modalities? In this section, we briefly discuss the advantages and disadvantages and points for attention for the energy chains for each of the five transport modes.

Passenger cars

For light road transport, there are many possibilities for carbon neutrality by 2050. In this study we examined five options: battery-electric driving, driving on hydrogen (with a combustion engine or fuel cell system), drop-in synthetic fuel, methanol and biofuel (both drop-in and ethanol). We excluded ammonia as the only fuel for safety reasons.

Electric driving has overall advantages compared to driving on hydrogen: the costs in the chain are lower and the efficiency along the chain is 2 to 5 times higher than for hydrogen (the range is mainly due to the way the hydrogen is transported: as compressed gas, liquid or in NH_3). Compared to hydrogen from electrolysis, electric driving also uses less land in the energy chain. This is because hydrogen is produced from electricity, and due to higher energy losses compared to a battery electric car. The compression of hydrogen at the filling station also requires a relatively large amount of (electric) energy.

Battery electric driving also has the advantage of enabling 'smart charging' and 'vehicle-to-grid (V2G) systems'. Smart charging varies the charging speed to optimise the load on the grid. V2G systems temporarily store electricity in the vehicle battery and return it to the grid at another convenient time. Both strategies can play an important role in the future electricity system, especially to reduce the need for reinforcement of the medium and low voltage grid. The safety risks of battery electric driving compared to petrol and diesel driving seem limited and, moreover, can be mitigated through regulation and management systems. BEVs produce no combustion particulates and a similar amount of wear and tear particulates as diesel cars: slightly more tyre wear due to the extra weight of the battery, but less particulates from braking.

Hydrogen-based vehicles have advantages in terms of refuelling time (compared to charging time), range and space requirements on board the vehicle. A battery takes up 6 to 12 times more space per unit of energy than a hydrogen tank. Hydrogen itself weighs little per unit of energy (about 3 times less than petrol and diesel). However, the hydrogen tank and fuel cell system add a lot of weight.

Hydrogen can be used not only in a fuel cell but also in an internal combustion engine. This has the advantage of lower costs (no expensive fuel cell system is needed) and fewer demands on the purity of the hydrogen. On the other hand, the energy efficiency is lower and NO_x is created (how much depends on the combustion temperature and after-treatment techniques, as is the case for all engines).

The drop-in fuels based on the Fischer-Tropsch process, the FT-biofuels and FT-synfuels, have the advantage that the energy density of the fuel is high and the vehicle does not need to be modified. On the other hand, a major disadvantage is that the energy costs (in €/GJ at the pump) are much higher than for the electric and hydrogen options. The total cost of vehicle and energy is thereby higher. In the case of biofuel, the availability of sufficient sustainable and advanced biomass, due to the land requirements, can also be a problem (see further under Aviation).

Heavy duty vehicles

For the heaviest category of road transport (tractor-trailer combination), battery electric driving scores favourably on all three criteria, compared to driving on the other energy carriers considered. However, a specific energy carrier can score as well as or better than battery electric on a specific criteria. For example, FT biofuels may have a cost advantage over battery electric and, if made from residues, require less space. The chain with hydrogen from SMR-CCS is more expensive and less energy-efficient than battery-electric, but it takes less land.

Yet battery electric has potential bottlenecks that the other energy carriers do not have, or have less of. Electric long-range trucks are being developed but the batteries are heavy (about 4 tonnes for 800 kWh and a range of 400-600 km) and large, which reduces loading capacity. A battery is heavier than a fuel cell and hydrogen tank system that can cover the same distance. Also, (ultra) fast charging is still needed with stops of 30-45 minutes at a time (this time corresponds to the break a driver needs to take every 4.5 hours). Charging infrastructure is needed at transport company depots and along motorways. The electricity demand, both for fast and regular charging, requires adjustments in the electricity grid.

These 2 trucks have the same range:

BEV	800 kWh battery	Efficiency 88%	Weight of battery 4 tonnes
FCEV	38 kg H_{2-} tank	Efficiency 55%	Weight FC+tank 2.3 tonnes

Weight FC+tank is calculated with the ratio 1:60 of Toyota Mirai (see passenger car). Fuel cell stacks and H_2 tanks are used in trucks in a modular way. NB: BEV and FCEV do not need an internal combustion engine, which results in a weight saving of 1 to 1.5 tonnes. Weights should be considered in the context of the total truck weight (including payload) of 40 tonnes.

Running on bio- and synthetic FT-diesel is possible in the existing trucks and using the existing transport and refuelling infrastructure. Running on methanol and hydrogen requires trucks with different engines. Especially when hydrogen is used in a fuel cell, the adjustments to the truck are considerable: both the FC system and the hydrogen tank take up a lot of space and add weight. Hydrogen in a fuel cell has the advantage of higher chain efficiency and lower costs than in an internal combustion engine (if both powertrains have their optimal driving dynamics and load).

Hydrogen and, to a lesser extent, methanol require a different kind of refuelling station. Hydrogen is gaseous or liquid and needs to be highly compressed or cooled.

BEV trucks make a claim on some scarce materials. Availability of lithium, nickel, cobalt and rare earths is uncertain for the longer term.

An electric road system that supplies electricity to trucks while they are on the road overcomes some of the disadvantages of BEVs: a smaller battery suffices and there is no need for charging stops. However, there are high investment costs and it takes time to plan and build the infrastructure, and there are environmental drawbacks such as copper wear and tear and adverse effects on the quality of the landscape.

Inland shipping

With approximately 5000 inland navigation vessels in the Netherlands, this is a relatively small market for developing carbon neutral options. The fleet in the Netherlands is relatively old, except for wet-bulk shipping. Ships are often also a home for ship owners, who are often self-employed. Ship engines are replaced after 20-40 years of use.

The transition in the sector towards carbon neutral shipping in an earlier stage than in road transport, and depends on developments in the much larger maritime sector and in mobile equipment. All options - electric, hydrogen-FC or -ICE, drop-in fuels, methanol and ammonia - are still open. Each option has its advantages and disadvantages, in terms of chain costs, energy efficiency, space requirements, and business and socio-economic aspects.

Bio and synthetic FT diesel has practical advantages: the propulsion technology in the ships can remain the same and the tank infrastructure is already in place. When running on hydrogen, ammonia and methanol, a separate distribution and refuelling infrastructure is needed.

Ammonia and methanol also require modifications to the vessel: ammonia must be stored in a at low temperature and, due to its toxicity, there is a large safety zone. This complicates the design of smaller vessels, such as inland navigation vessels. For methanol, seals must be reinforced because of its volatility. These options are less favourable from the point of view of energy efficiency and land use throughout the energy chain.

As an energy carrier, hydrogen is in principle suitable for ships sailing short and medium distances, and from a cost point of view preferably in the form of compressed gas to avoid cryogenic cooling (-253°C). The required safety zone on board is smaller than for ammonia: see Maritime shipping.

Sailing using synfuels methanol and ammonia involves limited additional costs, as an extra tank for the 'ignition fuel' and a catalyst are required on board. There is high uncertainty about the costs of other carbon neutral alternatives. Investment costs in hydrogen fuel cell or ICE ships are considerably higher than in diesel ships, and for electric ships also, when the investment in the battery is included. Given the early market stage, no comparison of chain costs per distance travelled is yet possible.

Electric barges could be an interesting option from an efficiency point of view. At the moment, the focus is on container ships and battery swapping systems, whereby an empty battery the size of a sea container is exchanged for a full one in port. The ship owner then does not have to invest in the battery (as it is leased). Technically, batteries on board should be possible for bulk carriers. There is also a chicken-and-egg problem: a network of charging infrastructure or battery swapping points is needed to make electric sailing attractive, but investments in infrastructure are only made if the expected use is high enough.

Maritime shipping

There are various fuel options for covering long distances at sea. In this study, we have investigated FT-biofuels and synthetically produced ammonia, methanol, and Fischer-Tropsch diesel for maritime shipping.

Hydrogen and electricity are not suitable for long distances by sea, as such vessels need to be able to sail for 30-60 days without refuelling or charging. Hydrogen tanks or batteries that can do that would be so large that it would take up to much load capacity. This means electricity is only suitable for short distances by sea and inland shipping.

FT biofuels are cheaper than synfuels per energy unit and on a chain level, although the uncertainties in the costs for both fuel types are large. Should biofuels prove more expensive or not sufficiently available, then synfuels are a good (albeit inefficient) option for the maritime sector. Which synfuel (methanol, ammonia or FT synfuels) is the most favourable is unclear.

A concern with ammonia and FT-fuels is the NO_x emissions during combustion. Catalysts can greatly reduce these emissions, but have the disadvantage that they emit small amounts of N_2O (nitrous oxide), which is a strong greenhouse gas. The

advantage of FT fuels is that they have twice the energy density of methanol and ammonia, which roughly doubles the range of a ship for a given tank capacity. Another advantage of FT fuels is that they can be used in current combustion engines without modification and without making concessions in terms of range.

With ammonia and methanol, as with inland navigation, engine and vessel modifications are necessary (two fuel tanks are required and seals have to be improved because of the volatility). In addition, ammonia must be stored slightly cooled, which imposes requirements on fuel storage. Also, compared to the use of (FT)diesel, the range will decrease if the bunkered volume remains the same. Another option is to build extra fuel tanks on board, but that will be at the expense of cargo capacity.

Aviation

For long-haul flights in the aviation sector, there are probably a limited number of options for carbon neutrality in 2050. Flying long distances (in large aircraft such as the current Boeing 787 with 330 seats) with electricity or hydrogen is not possible due to the weight and space requirements of the batteries and hydrogen tanks respectively in combination with the fuel cell system. In addition, these technologies have a low TRL.

In this study we have therefore only looked in more detail at biokerosene and synthetic paraffin produced from hydrogen and CO_2 for aviation.

Biokerosene and synthetic kerosene have the advantage that the energy density of the fuel is high and that the tanks and (jet) engines of the aircraft do not have to be modified. Of the two options, biokerosene has lower fuel costs and therefore the costs of the energy chain are lower. The fuel costs of biokerosene depend largely on biomass and production costs, both of which are highly uncertain.

The costs of synthetic kerosene are also uncertain, as the technology is still under development. In the long run, it could prove that synthetic kerosene is more economical to use than biokerosene. The availability of sufficient sustainably grown and advanced biomass may be an issue, particularly if other sectors also require this biomass to become carbon neutral. This applies to residues but also to woody energy crops, as the latter require a lot of land area.

Because synthetic and biokerosene are physically interchangeable, both could be used alongside or in combination with each other in aviation by 2050.

6.7 Barriers and uncertainties

In the previous chapters, we looked into the efficiency, costs and land use of options for achieving carbon neutral mobility by 2050. Now we will briefly discuss other potential bottlenecks and uncertainties in the four energy chains.

Electric energy chain:

- The limited availability of raw materials for batteries (and to a lesser extent for solar panels and wind turbines), particularly lithium, cobalt, nickel and some rare earths such as neodymium and praseodymium, as well as the environmental and social impacts of their extraction. Strategies for recycling materials are being developed, but fully circular battery life cycles are still a long way off.
- In the case of electric road systems (ERS), high levels of copper may be released into the environment through the wear of the overhead wires.
- The volume and weight of batteries for heavy-duty vehicles reduces the vehicle's capacity or, if a smaller battery is used to save weight and volume, the vehicle's range.

- In electric transport, the charging time is longer than the refuelling time of the other energy carriers. This applies to all modes of transport, but it is particularly relevant for heavy-duty vehicles.
- The required expansion of the electricity grid in various scenarios for electrified mobility. This applies to low and medium voltage grids (particularly for electric cars, but potentially to chargers for trucks as well). It could also possibly apply to to higher voltage levels. Additionally, it is still unclear what impact ERS will have on the electricity grid.
- The lack of qualified technicians to install the charging infrastructure and expand and upgrade the electricity grid. This lack of technicians may also apply to other energy chains.

Hydrogen energy chain:
- The scarcity of raw materials described for electricity production also applies to electrolysis, because this technique requires a high-capacity connection to the grid (about 1.4 GW_e per GW of electrolysis capacity). Other parts of the hydrogen energy chain also require a lot of power for compression, cooling, conversion to ammonia, etc. On the other hand, hydrogen can be used to buffer temporary electricity surpluses.
- Electrolysers require scarce raw materials, such as platinum and iridium.
- Electrolysis requires large amounts of water. This can be a problem if this process takes place in regions with water scarcity or in periods of drought.
- Methane leakages in the SMR-CCS sub-chain during the transport of natural gas from the gas field to the production site. The greenhouse effect of methane is 23 times greater than that of CO_2.
- Risk of leakage of CO_2 in CCS (in the SMR-CCS sub-chain).
- Contaminations in H_2 can cause the rapid degradation of fuel cells.
- Leakage of H_2 in various parts of the energy chain (H_2 is not a greenhouse gas itself, but it does augment the greenhouse effect of methane and ozone).
- Potentially rapid degradation of fuel cells in general.
- Just as fossil fuels, the combustion of H_2 produces NO_x.

Synfuels energy chain:
- Ammonia and methanol are volatile and toxic substances, requiring additional safety measures during storage, bunkering and on board. If additional measures are taken, the risks will be similar to those of fossil fuels.
- The transport of ammonia by tankers and trains is a socially sensitive issue due to the safety risks. For this reason, this transport is carefully regulated and discouraged. There does not seem to be any societal resistance to the transport of ammonia by ship and its storage in ports, but it is unclear whether this will remain the case if ammonia is transported on a large scale by inland vessels and stored near inland transhipment points.
- Synfuels are most efficiently produced in a continuous process, whereas the availability of renewable electricity fluctuates.
- It is unclear whether there will still be enough CO_2 point sources in 2050, and, if there are, whether they can be used for the purposes of climate neutral mobility.
- The combustion of synfuels leads to emissions of NO_x and particulates.
- The use of synfuels in aircraft causes other non-CO_2 climate effects.

Biofuels energy chain:
- The availability and supply of feedstock for advanced biofuels are uncertain, both for crop residues and for energy crops. Moreover, other sectors than transport will also require biomass for energy.

- Soil degradation (crop residues also include organic material that is important for the quality of the soil).
- Possible harmful environmental effects due to the use of water for the cultivation of energy crops.
- The combustion of biofuels leads to emissions of NO_x and particulates.
- The use of biofuels in aircraft causes other non-CO_2 climate effects.

6.8 Overall conclusions

In this study we analysed 4 carbon neutral energy chains for application in 5 modalities (light and heavy road transport, inland navigation, long-distance shipping and intercontinental aviation). This report summarises existing knowledge and aims to contribute to the public debate and policy development in this field. We looked at the chains in terms of three criteria: energy efficiency, land use and costs. The perspective is well-to-wheel (WTW). This means that we have included the entire chain in our analysis, from production of the energy carriers up to and including application in the vehicle. From this WTW perspective, carbon neutral mobility can be achieved through the use of carbon neutral energy carriers and the corresponding vehicle drivelines. Even if all the analysed energy chains are carbon neutral (which is the starting point), the score on energy efficiency, space usage and costs differs. We draw the following main conclusions:

Electric chain is efficient in terms of energy, space and costs

On a well-to-wheel basis, compared to hydrogen and synfuels, the electric transport chain has relatively high energy efficiency, low costs and low land use. When hydrogen and synthetic fuels are used, 3 to 6 times more energy must be produced than is ultimately used by the vehicle at the wheels (or propeller); with electricity, only about 1.4 times. This also means that 2 to 5 times more wind farms are needed for hydrogen from electrolysis and for synfuels than for electricity in BEV. In the case of biofuels, the land take depends very much on the origin of the biomass, and may therefore vary from smallest (in the case of residues) to highest (energy crops).

Seen from the perspective of the three main criteria, the chains for hydrogen, synfuels for application in mobility are at a disadvantage compared to electricity. They only make sense when their higher costs, energy and space consumption outweigh the disadvantages in the electricity chain, such as the long charging time (if not factored into the costs), the use of scarce materials for batteries and the complexity of matching supply and demand for electricity from carbon neutral sources. Hydrogen and synfuels in particular could be a solution to the latter, for example by storing excess electricity from solar PV in the summer for use in the winter (seasonal storage). Biofuels have the advantage of being 'stand-alone', i.e. not dependent on electricity as a raw material.

Land use of sustainable energy carriers for mobility challenge

In order for all road vehicles in the Netherlands to drive on electricity, a wind farm the size of the province of Utrecht would be required. To make synfuels for the planes and ships that currently refuel in the Netherlands, an area 9 times the size of the province of Utrecht is needed, or a quarter of the Dutch continental shelf (North Sea).

For the production of biofuels, residual flows from agriculture can be used to a certain extent. These do not result in additional land use, but biofuels from energy crops have very high land use . The question is whether this is appropriate in the Netherlands. To replace all bunker fuels with biofuels from energy crops would require an area twice the size of the Netherlands.

Should it not be possible or desirable to produce all energy in the Netherlands, the import of, for example, hydrogen and synfuels (which are then produced from electricity elsewhere) is an option. This should be possible on a global scale: Theoretically, covering four times the surface area of France with solar panels is enough for the current global energy demand.

When importing energy carriers, the space requirements of carbon neutral energy chains are 'exported', as it were. The advantage of importing carbon neutral energy is that it can be produced in sparsely populated or uninhabited areas where space is less scarce and effects such as noise and sight pollution may play a lesser role. In addition, the production of electricity from solar energy is also less space-intensive the closer it is to the equator. A disadvantage is the loss of energy during transport, which means that more energy is used in the entire chain and therefore more space and raw materials are required.

Synfuels and biofuels can be applied with limited adaptation of infrastructure

An advantage of both synfuels and biofuels is that the costs of transport, storage, distribution and refuelling are relatively low. For FT fuels (which are chemically almost identical to their fossil counterparts) all infrastructure can be re-used. For the other biofuels and synfuels it is likely that a large part of the existing infrastructure can be (re)used (with some minor adjustments). The FT fuels also have the advantage that they can be used in standard combustion engines.

Direct air capture needed for large scale production of synfuels

For carbon neutral production of FT-synfuels and methanol, a carbon neutral carbon source is needed in addition to hydrogen. This can be a CO_2 point source from industry, for example, or CO_2 capture from the air (direct air capture, DAC). Since in a climate-neutral scenario in 2050 there will be far fewer point sources than now, DAC will probably be necessary. However, this is much more expensive than capture from point sources, and the technology for this is still in its infancy.

Costs are uncertain: various options could benefit from R&D

Many of the technologies used are still in the development phase and therefore uncertain. For example, methanol based on CO_2 capture from the air could be more cost-effective in 2050 than in 2030, while the cost of electricity will not decrease between 2030 and 2050. On the other hand, the higher efficiency of the electricity chain also means lower sensitivity to energy price fluctuations. This means that it is too early to conclude that a chain does not have a future because of its cost. It is still worth investing in relevant, problem-solving research and development (R&D), because we cannot afford to write off options now, given the major task of carbon neutral mobility.

Potential bottlenecks: technicians and scarce raw materials

Lack of technicians is a potential bottleneck for all chains that involve a lot of technology, especially those for electricity, hydrogen and synfuels. This includes the installation of charging infrastructure, wind farms and electrolysis units, and the reinforcement of the electricity grid. At the same time, electric vehicles need less maintenance than fuel cars, so fewer mechanics are needed in the garage. Scarcity of technicians could have a cost-increasing effect on the transition to sustainable mobility.

The long-term availability of scarce materials is uncertain. This applies, for example, to lithium, cobalt, nickel and some rare earth metals such as neodymium and praseodymium. The environmental and social effects of their extraction also deserve attention.

Careful comparison of the costs and benefits of each chain needed

The energy chain for a given mode of transport is not necessarily unsuitable if it scores 'poorly' for one of the three criteria, because many other aspects also play a role. It is crucial to consider all the costs and benefits, among others because the various energy carriers in a carbon neutral energy system will become increasingly interconnected. For example, vehicles will also contribute to the energy system through bidirectional (V2G) charging, and hydrogen will also play a dual role as a fuel for vehicles and as a storage medium in the energy system. Other criteria also need to be considered in the cost-benefit analysis, such as security of supply (e.g. diversification of energy sources and suppliers), the distribution system, the synergy between the sectors, or the user-friendliness of a given option.

Energy saving remains useful for saving space and resources

With the use of carbon neutral energy carriers and energy-efficient drivelines in vehicles, carbon neutral mobility can be achieved. This does not alter the fact that reducing energy consumption per distance travelled (e.g. through aerodynamics and lighter vehicles) and limiting distances travelled can still be a good idea. This saves space and raw materials.

6.9 Further research directions

There are many topics within the theme of carbon neutral mobility that require further research. We have listed four of them here.

Activity (A) and modal split (S) factors

In the present study the focus is on the Intensity and Fuel factors of the ASIF formula, which are about 'energy intensity' of vehicles (MJ/km) and CO_2 emissions of energy carriers (in g/MJ). We investigated what improvements are possible in both factors, i.e. what efficiency improvements are possible and how (fossil) carbon can be eliminated from the energy chain. Another study could focus on the A and S factors, which are about the need for mobility (km) and modality choice and how it is used (such as occupancy/load factor), or the 'avoid' and 'shift' strategies from the Trias Mobilica. How can the need for mobility be reduced and what are favourable changes in modality choices from the point of view of CO_2 reduction?

Availability of energy sources

The final CO_2 emissions are determined by a combination of all 4 factors. The *availability of* low carbon energy carriers and energy-efficient vehicles and the space they require also play a role. This is therefore not about the relative improvement of factors, but about absolute numbers and quantities. In 2050, will enough vehicles and energy carriers be available to meet mobility needs? And is there enough space for this, in the Netherlands and worldwide? A scenario study can show the numbers and quantities that will cause bottlenecks in the availability of energy carriers, vehicles and space.

Transition paths: policy options on the way to carbon neutrality by 2050

Another study could address the question of which policy options are possible, between now and 2050, to achieve carbon neutrality in mobility by 2050? The European Commission has proposed a policy package to achieve a 55% reduction in greenhouse gas emissions by 2030 compared to 1990. What factors (ASIF) do these policy options from FF55 focus on and what are the targets, and how do we go from there towards carbon neutrality?

In other words: which policy options fit (theoretically) with each of the ASIF factors, to what extent are they already deployed and how can they be deployed further.

Low TRL technologies

In order to fulfil a function in the energy system on a large scale in 2050, a technology must be sufficiently advanced in the short term. This was the reason why we only investigated energy carrier-mobility combinations with a TRL of at least 6 (pilot phase). On the other hand, it may be relevant to search among the technologies with (still) a low TRL for candidate technologies that are viable in the longer term (>2050) and can still play a major role. And the question is then, of course: how are these techniques stimulated in the meantime so that they reach that point?

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Appendix A Costs: assumptions for vehicle costs

The fuel costs were calculated by KiM, based on assumptions provided in this report. TNO made the assumptions for the other parameters to estimate costs per km travelled for each vehicle type. The sources for these are included in this appendix. When a cell is marked yellow, no reliable cost estimates are possible.

Fuel costs (€/MJ)

		Gasoline and diesel (ICE)	Battery electric (BEV)	Fuel cell electric (FCEV)	Hydrogen combustion	Synthetic FT liquids	(e-)Methanol ICE	Ammonia (ICE)	Ammonia (SOFC)	Kerosene (ICE)	bio FT liquids	bioethanol
Light duty vehicles - 2020	Average	0.04	0.04	0.07		0.0649	0.0559				0.0261	0.0487
Heavy duty vehicles - 2020	Tractor-trailer	0.04	0.04	0.07	0.07	0.0649	0.0559				0.0261	
Heavy duty vehicles - 2030	Tractor-trailer	0.04	0.04	0.07	0.07	0.0649	0.0559				0.0261	
Inland shipping - 2020	Inland vessel	0.04	0.04	0.05	0.05	0.06	0.05	0.05			0.0246	
Inland shipping - 2030	Inland vessel	0.04	0.04	0.05	0.05	0.06	0.05	0.05			0.0246	
Sea shipping - 2020	Sea shipping	0.04		0.05	0.05	0.06	0.05	0.05			0.0246	
Sea shipping - 2030	Sea shipping	0.04		0.05	0.05	0.06	0.05	0.05			0.0246	
Aviation	Intercontinental											

Energy consumption (MJ/km)

		Gasoline and diesel (ICE)	Battery electric (BEV)	Fuel cell electric (FCEV)	Hydrogen combustion	Synthetic FT liquids	(e-)Methanol ICE	Ammonia (ICE)	Ammonia (SOFC)	Kerosene (ICE)	bio FT liquids	bioethanol
Light duty vehicles - 2020	Average	2.33	0.73	1.50		2.33	2.33				2.33	2.33
Heavy duty vehicles - 2020	Tractor-trailer	12.61	5.57	8.70	10.70	12.61	12.61				12.61	
Heavy duty vehicles - 2030	Tractor-trailer	12.61	5.57	8.70	10.70	12.61	12.61				12.61	
Inland shipping - 2020	Inland vessel	346.00	154.00	307.00	346.00	346.00	346.00	346.00			346.00	
Inland shipping - 2030	Inland vessel	346.00	154.00	307.00	346.00	346.00	346.00	346.00			346.00	
Sea shipping - 2020	Sea shipping	1,186.00		1,186.00	1,186.00	1,186.00	1,186.00	1,186.00	1,186.00		1,186.00	
Sea shipping - 2030	Sea shipping	1,186.00		1,186.00	1,186.00	1,186.00	1,186.00	1,186.00	1,186.00		1,186.00	
Aviation	Intercontinental									238		

Energy costs (€/km)

		Gasoline and diesel (ICE)	Battery electric (BEV)	Fuel cell electric (FCEV)	Hydrogen combustion	Synthetic FT liquids	(e-)Methanol ICE	Ammonia (ICE)	Ammonia (SOFC)	Kerosene (ICE)	bio FT liquids	bioethanol
Light duty vehicles - 2020	Average	0.09	0.03	0.10		0.15	0.13				0.06	0.11
Heavy duty vehicles - 2020	Tractor-trailer	0.48	0.23	0.59	0.72	0.82	0.70				0.33	
Heavy duty vehicles - 2030	Tractor-trailer	0.48	0.23	0.59	0.72	0.82	0.70				0.33	
Inland shipping - 2020	Inland vessel	12.80	6.30	15.56	17.54	22.04	17.51	17.96			8.51	
Inland shipping - 2030	Inland vessel	12.80	6.30	15.56	17.54	22.04	17.51	17.96			8.51	
Sea shipping - 2020	Sea shipping	43.88		60.13	60.13	75.55	60.01	61.55	-		29.18	
Sea shipping - 2030	Sea shipping	43.88		60.13	60.13	75.55	60.01	61.55	-		29.18	
Aviation	Intercontinental									-		

Investment costs (€)

		Gasoline and diesel (ICE)	Battery electric (BEV)	Fuel cell electric (FCEV)	Hydrogen combustion	Synthetic FT liquids	(e-)Methanol ICE	Ammonia (ICE)	Ammonia (SOFC)	Kerosene (ICE)	bio FT liquids	bioethanol
Light duty vehicles - 2020	Average	35,000	45,000	55,000		35,000	35,000				35,000	35,000
Heavy duty vehicles - 2020	Tractor-trailer	89,000	219,000	254,000	135,000	89,000	89,000				89,000	
Heavy duty vehicles - 2030	Tractor-trailer	91,000	132,000	152,000	118,000	91,000	91,000				91,000	
Inland shipping - 2020	Inland vessel	3,000,000				3,000,000					3,000,000	
Inland shipping - 2030	Inland vessel	3,000,000		6,000,000	4,900,000	3,000,000	3,200,000	3,230,769			3,000,000	
Sea shipping - 2020	Sea shipping	25,000,000				25,000,000					25,000,000	
Sea shipping - 2030	Sea shipping	25,000,000		38,400,000	35,000,000	25,000,000	26,000,000	28,000,000			25,000,000	
Aviation	Intercontinental											

1.076923077

Depreciation period (years)

		Gasoline and diesel (ICE)	Battery electric (BEV)	Fuel cell electric (FCEV)	Hydrogen combustion	Synthetic FT liquids	(e-)Methanol ICE	Ammonia (ICE)	Ammonia (SOFC)	Kerosene (ICE)	bio FT liquids	bioethanol
Light duty vehicles - 2020	Average	19	19	19		19	19				19	19
Heavy duty vehicles - 2020	Tractor-trailer	8	8	8	8	8	8				8	
Heavy duty vehicles - 2030	Tractor-trailer	8	8	8	8	8	8				8	
Inland shipping - 2020	Inland vessel	15				15					15	
Inland shipping - 2030	Inland vessel	15		15	15	15	15	15			15	
Sea shipping - 2020	Sea shipping	28				28					28	
Sea shipping - 2030	Sea shipping	28		28	28	28	28	28			28	
Aviation	Intercontinental											

Kilometre / year

		Gasoline and diesel (ICE)	Battery electric (BEV)	Fuel cell electric (FCEV)	Hydrogen combustion	Synthetic FT liquids	(e-)Methanol ICE	Ammonia (ICE)	Ammonia (SOFC)	Kerosene (ICE)	bio FT liquids	bioethanol
Light duty vehicles - 2020	Average	12,500	12,500	12,500		12,500	12,500				12,500	12,500
Heavy duty vehicles - 2020	Tractor-trailer	86,000	86,000	86,000	86,000	86,000	86,000				86,000	
Heavy duty vehicles - 2030	Tractor-trailer	86,000	86,000	86,000	86,000	86,000	86,000				86,000	
Inland shipping - 2020	Inland vessel	57,000				57,000					57,000	
Inland shipping - 2030	Inland vessel	57,000		57,000	57,000	57,000	57,000	57,000			57,000	
Sea shipping - 2020	Sea shipping	102,000				102,000					102,000	
Sea shipping - 2030	Sea shipping	102,000		102,000	102,000	102,000	102,000	102,000			102,000	
Aviation	Intercontinental											

TCO (€/km)

		Gasoline and diesel (ICE)	Battery electric (BEV)	Fuel cell electric (FCEV)	Hydrogen combustion	Synthetic FT liquids	(e-)Methanol ICE	Ammonia (ICE)	Ammonia (SOFC)	Kerosene (ICE)	bio FT liquids	bioethanol
Light duty vehicles - 2020	Average	0.27	0.26	0.39		0.33	0.31				0.24	0.30
Heavy duty vehicles - 2020	Tractor-trailer	0.62	0.58	1.00	0.94	0.96	0.85				0.47	
Heavy duty vehicles - 2030	Tractor-trailer	0.63	0.44	0.83	0.91	0.96	0.85				0.48	
Inland shipping - 2020	Inland vessel	17.97				27.21					12.68	
Inland shipping - 2030	Inland vessel	17.97		24.91	25.35	27.21	22.96	22.45			12.68	
Sea shipping - 2020	Sea shipping	55.78				87.44					41.07	
Sea shipping - 2030	Sea shipping	55.78		78.40	76.78	87.44	72.38	74.87			41.07	
Aviation	Intercontinental											

Variables		Descriptions	Sources
Discount rate		Based on the discount rate of public projects in the Netherlands	https://open.overheid.nl/repository/ronl-d985cdc5-5da7-4644-be09-4c22bfa885be/1/pdf/rapport-werkgroep-discontovoet-2020.pdf
Energy consumption		TNO note efficiency	
Light duty vehicles	Investment costs / vehicle purchase costs	ICE market prices for 2020 are based on RDW data. Using Ricardo 2016, the costs of the various powertrains are determined, after which the market prices of BEV and FCEV vehicles can be determined. E.g. BEV market price = ICE market price - ICE powertrain + BEV powertrain/battery To arrive at an average market price for light road transport the prices are weighted by fleet shares.	Improving understanding of technology and costs for CO2 reductions from cars and LCVs in the period to 2030 and development of cost curves (europa.eu)
	Depreciation period	The depreciation period for light duty veghicles is based on the average scrapping ages of cars and vans. These ages are weighted by fleet shares to arrive at an average figure	Analysis based on RDW data, publication of study entitled "Import and export analysis of the Dutch fleet in 2021 with focus on environment and climate impact".
	Average annual kilometres	The average annual kilometres are based on CBS. As a result of Covid 19, the average mileages are relatively low. Like the investment costs, these have been weighted by fleet shares to arrive at one average figure.	StatLine - Verkeersprestaties personenauto's; kilometers, brandstofsoort, grondgebied: https://opendata.cbs.nl/#/CBS/nl/dataset/80428ned/table https://opendata.cbs.nl/statline/#/CBS/nl/dataset/80353ned/table?dl=81B3
Heavy duty vehicles	Investment costs	Cost prices have been used for heavy duty vehicles. The figures are based on calculations from the TNO STRIVE project (publication expected). The calculations are based	STRIVE rapport, publicatie 2022
	Depreciation period	No residual value is assumed. This is because the residual value of alternative power trains is not yet known. The depreciation period is 8 years. After 6 years, the average	
	Average annual kilometres	Based on CBS data. Average for vehicles over a period of 8 years.	
Inland and maritime shipping	Investment costs	For inland shipping and sea shipping, costs have been taken from a TNO CHAIN project (2021). The cost estimates were made for the 2030/2040 horizon, but it is expected that there will be little change in costs. Some alternative	TNO 2021 R12635
	Depreciation period	The engine of inland vessels is replaced during its life cycle. In the TCO calculation, we assume the lifetime of the first engine (approx. 15 years). For the hull part, we assume a residual value. For shipping, an average lifespan of 28 years is taken. This	TNO 2020 R12350
	Average annual kilometres	For the average annual kilometres, calculations from the TNO PROMINENT project were used.	https://www.prominent-iwt.eu/
Luchtvaart		No TCO has been drawn up for aviation. Commercial aviation is expected to remain largely dependent on kerosene and kerosene substitutes for decades to come. The aircraft do not need technical modifications for the use of e-kerosene. Therefore, there will only be different	

Appendix B Efficiency

This appendix compares the energy consumption of various propulsion systems. A distinction is made between passenger cars, tractor-trailers, inland navigation, maritime shipping and aviation. See table B.1 for an overview of the combinations of transport modes and and energy carriers considered.

Table B. 9 Overview of combinations of transport modes and propulsion systems

	Diesel/petrol (conventional, bio & synthetic)	Battery Electric (BEV)	Fuel Cell Electric (FCEV)	Hydrogen combustion (H_2 -ICE)	Natural gas (LNG) ICE	Methanol ICE	Ammonia ICE	Ammonia SOFC	Kerosene (conventional, bio & synthetic)
Light duty vehiclestransport	X	X	X						
Heavy duty vehicles	X	X	X	X					
Inland shipping	X	X	X	X	X	X			
Shipping	X		X	X	X	X	X	X	
Aviation									X

The energy consumption of vehicles depends on the demand for mechanical energy for propulsion and the energy efficiency with which the propulsion system provides that mechanical energy. Both are dependent on many factors, which makes it difficult to state a typical efficiency or energy use for a specific vehicle or vessel. Important parameters that have an impact on the energy demand are for example the configuration of the vehicle or vessel, the vehicle weight and the way the vehicle is used (the load profile). The energy demand is also influenced by propulsion characteristics, such as battery-electric propulsion being heavier than a combustion engine propulsion. The resulting load pattern of the drive train (level and dynamic variation of the power demand) then determines the net efficiency of the drive train. Here a distinction must be made between the maximum (peak) efficiency and the average efficiency during normal operation, with which the drive train converts energy from, for example, fuel or a battery into mechanical energy. The peak efficiency of a drive train is generally significantly higher than the average, but only applies to a specific load. The peak efficiency and the typical average conversion efficiency of different drive types are very different.

This appendix gives an overview of the current efficiency and current energy consumption per distance travelled (MJ/km) of different vehicle and energy carrier combinations. In addition, ranges of possible future improvement potential are outlined.

Method

As far as possible, we base the energy consumption of various drive trains on the official emission factors reported in the Dutch Emission Registration (Emissieregistratie, see box below). If no consumption or CO_2 emission factor is known (e.g. because the technology is still new and no measurements are available, or if a vehicle does not emit any CO_2), we use available literature and theoretical values, such as the *Energy Carriers Fact Sheets* (TNO, 2019a) and a number of other sources (see References).

Emission factors and the Emission Inventory (www.emissieregistratie.nl)

The Netherlands Emission Inventory annually records the emissions of pollutants and CO_2 to air, water and soil. The project thus provides the emission data for substantiating environmental policy and forms the basis for many reports, for example those under the Kyoto Protocol. The emission factors for the transport sector are determined by the Task Force Traffic and Transport (collaboration between RIVM, PBL, CBS, RWS-WVL, Deltares and TNO). The factors are largely based on randomised measurements of vehicles, and can be adjusted annually on the basis of new insights.

Reference vehicles

Within a transport mode, many different vehicle configurations are conceivable, each with a different consumption. In order to make a fair comparison between the use of carbon neutral energy carriers, we have defined a reference vehicle and a reference fuel for each modality. In this way, a comparison can be made with the existing status quo. For light and heavy road traffic, the fleet average energy consumption is used as the reference. For inland navigation, shipping and aviation, a typical vehicle within a weight class is taken as an example.

An overview is given in the table below. A further explanation of the selection is given below the table.

Table B.10 Reference vehicles for the different modes

Modalities		Reference vehicle (emission/weight class and example)	Reference fuel	Energy use
Light road transport	Passenger car and light commercial vehicle	Average actual consumption (data 2019)	Diesel & Gasoline	2.3 MJ/km
Heavy road transport	Tractor-trailer combination	Average actual consumption (data 2019)	Diesel	12.6 MJ/km
Inland shipping	Inland vessel	Emission/weight class: Stage V (M8[116]) Example: Large Rhine Ship M8 (110m)	Diesel	345 MJ/km
Shipping	Shipping	Emission/weight class: IMO II or III. Example: General Cargo Ship	Diesel	1186 MJ/km
Aviation	Intercontinental (>800kms)	Emission/weight class: n/a Example: Boeing 787	Kerosene	1 MJ/RPK[117]

[116] M: class is an indication of the weight class of a ship.
[117] Revenue Passenger Kilometre: number of passenger kilometres (paying passengers only).

Overview of different drive trains

Internal combustion engine (ICE)

Diesel engines are used in a wide range of mobility applications, from passenger cars to ships. Most passenger cars run on petrol, most delivery vans on diesel. For all other modes of transport except aviation, the diesel engine is still the most widely used and sold propulsion technology. International aviation uses kerosene as standard.

Combustion engines are relatively easy to adapt to alternative fuels. Natural gas (or methane) and ethanol engines have been available for decades for several modes. Methanol engines are available for shipping. In addition, engines have recently been developed for hydrogen (mostly dual-fuel with diesel combustion) and at research level for ammonia. The advantage of combustion engines is that they are cheap to produce and the technology is rapidly scalable and robust. Especially in heavier applications, the efficiency is quite high. In large engines with non-dynamic use and high average loads, such as in long-distance road transport and shipping, the efficiency of modern diesel engines approaches that of fuel cell systems.

The transmission of the mechanical energy to the wheels is also an aspect of powertrain efficiency. In internal combustion engines, this is usually mechanical, but there are also electric transmissions for both road vehicles and ships (e.g. hybrid vehicle and diesel-electric ship). Such an electric transmission is generally slightly less efficient than a mechanical transmission, but in practice also offers advantages, such as being able to drive auxiliary systems more efficiently and better operating points for the engine. For this study, it was assumed that the electrical energy of a fuel cell drive and the mechanical energy of an engine are equivalent.

Opportunities to increase the efficiency of combustion engines in the future are relatively limited. In addition to improvements to the combustion engine itself, hybridisation or waste-heat recovery may be considered, depending on the application.

Section 'Application of high blends of alternative fuels' gives a comprehensive overview of the fuel quality requirements and already standardised possibilities for blending alternative fuels. These should not be seen as limiting factors for the future. Future expansion is possible, especially for options for which sufficient scale can be expected.

Battery Electric (BEV)

Battery-electric drives are strongly on the rise for road transport, but are also gaining increasing attention in shipping (especially inland shipping). The electric drive is characterised by a very high efficiency and the possibility of using energy generated from very different sources, including a wide range of renewable energy sources. Barriers for heavier transport are mainly the limited energy content of battery systems and the infrastructure and time loss for charging or changing battery systems.

For electric vehicles, the proportion of distances driven on motorways, where the energy demand is greatest "at the wheels", has a major influence on energy consumption. On average, passenger cars drive longer distances in the city than heavy duty vehicles. In the city, vehicles are used more dynamically (more acceleration and braking). For short distances and dynamic use, electric vehicles can derive additional benefit from reclaiming braking energy compared to conventional vehicles.

Hydrogen fuel cell (FCEV)

When determining the efficiency of a hydrogen fuel cell, it is important to take into account the auxiliary systems, also known as the balance of plant, the average load and also the age. In a fuel cell system, efficiency will decrease somewhat due to the ageing of the fuel cell stack. The efficiency of an internal combustion engine hardly decreases due to ageing.

A fuel cell drive is an electric drive because it also contains an electric motor. In most cases, a battery is also present to provide peak power, to optimally load the fuel cell and to recover braking energy. A direct (= non-hybrid) combustion engine drive loses efficiency under dynamic conditions (e.g. in the city), because the engine load is often low and energy is lost in frequent braking. In dynamic deployment, such as for light road transport and regional distribution, the efficiency of the fuel cell drive is significantly higher than that of the combustion engine. See the text box below.

Efficiency differences between FCEV and ICE

The following aspects play a role in the comparison between fuel cell drives and combustion engines:

Drive train:

- A fuel cell drive is generally a hybrid drive because it is electric and usually includes a battery. This allows significant advantages in dynamic use, such as the recovery of braking energy and the ability to load the fuel cell system at a fairly optimum level. An internal combustion engine with direct mechanical drive actually loses efficiency under these dynamic conditions, because the engine is often at low load and energy is lost in the transmission system and during braking.

Efficiency:

- The current generation of diesel engines are very efficient in their optimal operating range, between 40 and 45%. In general, the larger the engine, the smaller the losses. Losses in the propulsion and auxiliary systems must also be taken into account for the entire vehicle efficiency. According to recent studies, the average vehicle efficiency of a diesel truck (including propulsion losses) is approx. 42.5% (+/- 2%) (Ragon & Rodiguez, 2021). A peak engine efficiency of 50% is possible with the application of additional technologies, which focus on the reduction of heat, friction and pump losses (Delgado & Lutsey, 2014).
- With the fuel cell, it is important to consider the efficiency of the whole system, also known as the 'balance of plant'. Pumps that blow hydrogen and air through the fuel cell stack, humidification systems and other auxiliary systems use some of the energy provided by the stack.
- For dynamic deployment, such as for light road transport and regional distribution, the efficiency of the fuel cell drive will be higher than that of the combustion engine. According to research by TU Delft and TNO (Oostdam, 2019) the current efficiency of PEMFC systems is around 50-60%. In the future, this could rise to 70%.
- In a fuel-cell system, the efficiency will decrease somewhat over the long term because of the ageing of the stack. An internal combustion engine does not have this: its efficiency hardly changes over its lifetime. The fuel quality of hydrogen and a robust deployment are important for the proper functioning of the fuel cell. Fuel cells require very pure hydrogen (approx. 99.99%). High deviations from this can lead to rapid degradation of the fuel cells. A strong dynamic usage profile can lead to gradual degradation of fuel cells. More research and long-term

monitoring of hydrogen-electric vehicles is needed to make a more informed judgement on this.

Due to the above-mentioned properties, the efficiency of the fuel cell drive for non-dynamic use and average high load (such as for heavy and long-distance road transport and shipping) is in practice expected to be equal to that of the diesel engine. For dynamic operation and average lower load, such as for light road transport and regional distribution, the efficiency of the fuel cell drive is higher than that of the combustion engine.

Energy consumption (in MJ/km)

Passenger cars

In order to compare light duty vehicles running on different energy carriers, we assume energy consumption measured in the Netherlands. The alternatives to fossil fuel vehicles considered are battery-electric vehicles and hydrogen fuel cell vehicles. The average energy consumption of Dutch passenger vehicles is based on the actual use of new cars in the Dutch fleet (TNO, 2020a).

In the TNO study the consumption data of 259,000 petrol cars, of which 33,000 were (plug-in) hybrids, were analysed. In 2019, the new passenger cars had a real-world fuel consumption of almost 7 litres of petrol per 100 km (CO_2 emissions of 163 gCO_2/km). This corresponds to an energy consumption of approximately 2.3 MJ/km[118].

In the same study, 277,000 diesel passenger cars, including 4,000 (plug-in) hybrids, were analysed. The new diesel passenger cars (including plug-in hybrids) in 2019 had an average practical consumption of about 6 litres of diesel per 100km (converted to 2.1 MJ/km[119]) and an average practical emission of 158 gCO_2 /km (TNO, 2020a).

For diesel delivery vans, the practical consumption in 2019 of newly registered vehicles was 3.1 MJ/km (with average emissions of 226 gCO_2/km) (based on data from 54,000 delivery vans).

The use of biofuels and synthetic fuels does not generally affect engine efficiency (provided the fuels meet the European quality requirements - for more information see section 'Application of high blends of alternative fuels'.

Table B.11 **Light road transport: energy consumption diesel and petrol vehicles (ICEV)**

Vehicle type	Energy use	Number of vehicles[120]	Details	Source
Passenger car (petrol)	2.3 MJ petrol/km	7.133.894	Fuel consumption 2019	TNO (TNO, 2020a)
Passenger car (diesel)	2.1 MJ diesel/km	1.019.183		
Delivery van (diesel)	3.1 MJ diesel /km	899.956		

However, diesel and petrol cars should not be compared on the basis of average fuel consumption because the average diesel car is larger than the average petrol car in terms of size, weight and power. Assuming comparable vehicles in terms of size,

[118] Emission factor of 2370 gCO_2/litre petrol & 32 MJ/litre petrol.
[119] Emission factor of 2650 gCO_2/litre diesel & 36 MJ/litre diesel.
[120] Fleet size 1 January 2021.

weight and performance, diesels are up to 20% more fuel efficient than petrol vehicles.

The energy consumption for the light duty vehicles class is defined here as the average practical consumption of petrol and diesel passenger cars and vans, determined by weighted averaging according to fleet shares. This gives an average consumption per kilometre of light traffic of 2.3 MJ/km.

Battery Electric (BEV)

In the TNO study (TNO, 2020a) user data of 3,100 electric passenger cars were analysed, consisting of 34 different types of vehicles of 18 different makes. Based on these data, it was found that an electric passenger car in the Netherlands uses an average of 20.2 kWh/100 km (0.73 MJ/km) of energy. Depending on the model, the consumption varies between 0.44 MJ/km and 1.0 MJ/km. This is based on paid electricity and therefore includes charging losses. Based on these data, it is not possible to determine the size of the charging losses. On average, electricity consumption is 18% higher than the WLTP value given by manufacturers (TNO, 2020a).

Table B.12 **Passenger cars - energy consumption BEV**

Vehicle type	Electricity consumption [MJ_e /km]	Details	Source
Passenger car	0,73	Consumption data	TNO (TNO, 2020a)

Hydrogen fuel cell (FCEV)

For fuel cell electric vehicles, little is known about the practical consumption, also because of the limited number of FCEVs currently operating in the Netherlands.

In the study for average usage figures of passenger vehicles (TNO, 2020a) no usage data for FCEVs have been included. This is the case in the (as yet unpublished) update with data through June 2021. However, the number of FCEV models is still very limited. Under practical conditions (based on data from 24 unique vehicles) the consumption of these cars is 1.24 kg hydrogen per 100km, which is equivalent to approximately 1.5 MJ/km. This is approximately 30% less than the average energy consumption of fossil fuel passenger cars. Compared with hybrid petrol vehicles such as the Toyota Prius, the practical use is similar. The Toyota Prius uses an average of 5 litres of petrol per 100km (TNO, 2020a)which is also equal to approximately 1.5 MJ/km.

According to test results from the ANWB and laboratory tests on a fuel cell powered passenger car (Lohse-Busch, et al., 2020), the consumption of an FCEV passenger car is around 1.2 to 1.5 MJ/km.

Table B.13 **Light road transport - energy consumption fuel cell electric vehicles (FCEV)**

Vehicle type	Energy use [MJ_{H2}/km]	Details	Source
Passenger car	1,5	Consumption data	TNO (TNO, 2020a)
Passenger car	1,5	Hyundai Nexo	ANWB[121]
Passenger car	1,2	Toyota Mirai	ANWB[122]
Passenger car	1,3[123]	Test	Lohse-Busch et al. (2020)

[121] https://www.anwb.nl/auto/tests-en-specificaties/detail/hyundai/nexo/specificaties/a7ef11d4-b686-4305-b901-7000c5017ff4
[122] https://www.anwb.nl/auto/tests-en-specificaties/detail/toyota/mirai/specificaties/f86d6c3e-7ece-4993-bcf4-eeb3f4cb7c36
[123] 2.044 MJ/mile.

Conclusion light duty vehicles:

Based on the practical consumption of light road transport, it can be concluded that a conventional passenger car or delivery van uses about three times as much energy as a BEV. An FCEV uses about twice as much energy as a BEV.

Heavy road transport

In practice, differences are to be expected for different types of trucks (small, medium, heavy), the loading of these trucks, the use profile (short distance, long distance, distribution). The two most common vehicles used in heavy road transport in the Netherlands are rigid trucks and tractor-trailers, with a distribution in the fleet of about 40%:60%. (CBS, 2021). On motorways this distribution is even 20%:80% (TNO, 2013). Within the group of articulated lorries, a distinction can be made between light and heavy articulated lorries. Light tractor-semi-trailers are the most common (approx. 65%) and have an average total (loaded) mass of 19t (including load) (TNO, 2013). The tractor-trailer was chosen as the reference for energy consumption. The average of the Dutch fleet is used. For the alternative drive trains, various sources of literature were used to determine the energy requirement per distance travelled.

Diesel (conventional, bio and synthetic)

Under practical conditions, the average diesel consumption of a EURO VI tractor-trailer in the Netherlands is 34 litres per 100km (12.6 MJ/km) with an associated average CO_2 emission factor of 914 gCO_2 /km (TNO, 2019a). JRC, based on model calculations, assumes an average energy consumption of 10.4 MJ/km for a 2016 reference vehicle (and 9.4 MJ/km for a tractor-trailer in 2025) (JRC, 2020).

Table B.14 **Heavy duty vehicles - energy consumption diesel vehicles (ICEV)**

Vehicle type	Energy use [MJdiesel/km]	Details	Source
Tractor-trailer	12,6	Consumption data	TNO (TNO, 2019a)
Tractor-trailer	10,4	VECTO simulation 2016	JRC (JRC, 2020)
Tractor-trailer	9,4	VECTO simulation 2025	JRC (JRC, 2020)

This study assumes a practical use of 12.6 MJ/km for the Dutch tractor-trailer fleet.

Battery-electric (BEV)

For battery-electric tractor-trailers, the energy consumption is based on assumptions from the literature, due to a lack of practical data. Table B.7 summarises the results of several studies for different visibility years.

JRC calculates an average energy consumption of 4.7 MJ/km for electric tractor-trailer combinations in 2025 (JRC, 2020). Transport and Environment (T&E) reports an energy use for electric tractor-trailers of 5.5 MJ/km in 2020 (1.52 kWh/km) with a potential improvement towards 4.4 MJ/km in 2030 (1.21 kWh/km) for both regional distribution and long-distance transport (Transport & Environment, 2020a). ElaadNL estimates an average of 5.7 MJ/km for trucks and tractor-trailers (ElaadNL, 2020)[124].

[124] Based on 402 kWh per day, 261 days/year and 65,500 km/year.

Table B. 15 Heavy duty vehicles - energy consumption battery electric vehicles (BEV)

Vehicle type	Energy use [MJ electricity/km]	Details	Source
Tractor-trailer	5.5	VECTO simulation (2016)	JRC (JRC, 2020)
Tractor-trailer	4.7	VECTO simulation (2025)	JRC (JRC, 2020)
Tractor-trailer	5.5	Regional distribution (2020)	T&E (Transport & Environment, 2020a)
Tractor-trailer	4.4	Regional distribution and long distance (2030)	T&E (Transport & Environment, 2020a)
Trucks + tractor-trailers	5.7	Average	ElaadNL (ElaadNL, 2020)

In this study, an energy consumption of 5.6 MJ/km is assumed, as an average of the data until 2020.

Hydrogen fuel cell (FCEV)

Trucks with a fuel cell-electric drive are available to an even lesser extent than battery-electric trucks. Based on calculations with VECTO[125] for 2025, JRC assumes an energy consumption of 6.9 MJ/km for FCEV trucks (JRC, 2020). T&E estimates current energy use at 9.1 MJ/km with potential for improvement to 7.0 MJ/km in 2030 for tractor-trailers for regional distribution (Transport & Environment, 2020a).

Table B. 16 Heavy duty vehicles - energy consumption fuel cell electric vehicles (FCEV)

Vehicle type	Energy use [MJ_{H2} /km]	Details	Source
Tractor-trailer	8.3	VECTO simulation (2016)	(JRC, 2020)
Tractor-trailer	6.9	VECTO simulation (2025)	(JRC, 2020)
Tractor-trailer	9.1	Regional distribution (2020)	(Transport & Environment, 2020a)
Tractor-trailer	7.0	Regional distribution and long distance (2030)	(Transport & Environment, 2020a)

In this study, an energy consumption of 8.7 MJ/km is assumed, as an average of the data until 2020.

Hydrogen combustion (H_2-ICE)

Hydrogen can be used in an internal combustion engine. However, no data are available yet on the fuel consumption in practice. In (TNO, 2019d) research was carried out into four combustion concepts. The efficiency of these was compared with that of the standard diesel engine. The most relevant and quickly implementable variants are H_2 lean-burn combustion (mono-fuel with spark ignition) and H_2 dual-fuel (mix H_2 with diesel). The efficiency of these engine types is very similar to that of the standard diesel engine (see table below). In (TNO, 2021) experimental research was done with a 1-cylinder engine. That study also found an efficiency comparable to that of the diesel engine (see table below). It can be

[125] Model prescribed in European legislation for determining the whole vehicle CO_2 emissions of vehicles covered by the European CO_2 standards for heavy duty vehicles.

concluded that an internal combustion engine on H_2 can have a similar efficiency as a diesel engine.

Table B. 17 List of sources and indicated efficiencies for the application of hydrogen combustion in shipping

Engine type	Efficiency H_2 motor	Diesel reference	Remarks	Source
H_2 lean-burn spark ignition	>46%	46%	Literature review	(TNO, 2019d)
H_2 dual-fuel (diesel pilot)	46%	46%		
H_2 dual-fuel	34,0% - 34,5%	35,4%	Experimental research	(TNO, 2021)

Based on the table, it is concluded that the efficiency for H_2-ICE engines can be considered equal to that of the diesel engine. This amounts to 12.6 MJ/km for the tractor-trailer combination.

Conclusion heavy road transport:

Based on typical drivetrain efficiencies and consumption, the energy requirement in MJ fuel energy of a BEV truck is about 2 times lower than that of a conventional combustion engine truck. For an FCEV truck the energy consumption is about 10-20% lower and for the truck with H_2 -ICE engine the efficiency is the same as for the diesel engine.

Important disclaimer inland shipping and shipping

The efficiencies of the various types of drive trains for inland and seagoing navigation are only known in outline form. Partly for this reason, only one reference vessel has been chosen and the underlying information is collected and explained in section 'Powertrain efficiency heavy duty vehicles and shipping' below.

Available information from different sources is often not comparable and often the exact reference for the standard diesel version is missing. In no case is directly comparable operational data available. It is also important what the sailing profile is in practice regarding normal sailing, manoeuvring and standby or hotel operation in ports. Hybrid or electric propulsion systems may be able to cope with this better. Such a comparison requires a much more extensive analysis, with either an extensive modelling study based on one or more operational profiles, or real-world data.

Inland shipping

A Large Rhine Ship M8 (110m) is taken as the reference vehicle for inland navigation. This assumes an average consumption of 130 litres per hour and an average sailing speed of 13.5 km/hr (PROMINENT D5.7, 2018). This amounts to an energy consumption of 345 MJ/km (energy in diesel fuel). Using an average engine efficiency, the propulsion energy (at the propeller) can be estimated from this, on the basis of which the efficiency of alternative propulsion can then be used to estimate the consumption of ships on alternative energy sources.

The following starting points have been selected for the various drive trains.

- **Internal combustion engines**: For internal combustion engine power trains, it is assumed that they all have the same average efficiency of 40% in inland navigation applications. This is achievable with alternative fuels such as H_2 , LNG, methanol and DME when using dual-fuel or lean-burn combustion concepts. A stoichiometric combustion concept for the alternative fuels generally results in

a loss of efficiency compared to the standard diesel engine. In the table below, energy consumption is based on dual-fuel or lean-burn.

- **H_2 -FC**: The PEM fuel cell has a somewhat higher average efficiency of 45%[126] . This takes into account the 'balance of plant' (auxiliary systems for the fuel cell) and also ageing, which causes the efficiency to decrease slightly during the service life.
- The efficiency of the **battery-electric drive** is about 90%, calculated from the AC electric energy entering the charger. According to a theoretical comparison, the energy consumption is 50-55% lower than for diesel-powered boats. Practice could be even more favourable, especially since the efficiency of the combustion engine is lower in practice. This depends on a number of factors, such as prolonged low-power or stand-by operation of the engines. This can especially be the case when waiting in ports and during a lot of manoeuvring. The value in the table below is seen as an upper limit. Practice may be more favourable.

Table B.10 Comparison of energy consumption of inland navigation vessels on different energy carriers based on a ship of class M8: 110m x 11.4m reference ship with a consumption of 130 litres per hour and an average speed of 13.5 km/hr

	Diesel ICE	**Battery-electric**	**H_2 PEM-FC**	**H_2 -ICE**	**LNG-ICE**	**Methanol/ DME-ICE**
Engine and drive efficiency [%]	40%	90%*	45%	40%	40%	40%
Energy consumption [MJ/hour]	4667	2074	4148	4667	4667	4667
Energy consumption [MJ/km]	345	154	307	346	346	346

*Including charging losses

For the underlying information see the section "Drivetrain efficiency heavy road traffic and shipping"), inland waterway section.

Maritime shipping

Maritime shipping is characterised by an extremely wide range of vessel types and sizes. The sizes vary, for example, from less than 100 metres in length for coastal shipping to more than 400 metres for intercontinental transport. Reference vessels have been defined in various recent studies, on the one hand for worldwide transport and on the other hand for (smaller) typical Dutch vessels. In (Marin, 2020) a detailed description of the vessels and their deployment profiles is given.

- The following reference ships were chosen for the world fleet (Marin, 2020) the following reference ships were chosen for the world fleet: the Handymax bulker, the Post Panamax container and the VLCC tanker (very large crude carrier). Reference consumption figures of 941, 5998 and 3074 kg diesel/hour respectively are given for these ships.
- The most commonly used Dutch vessels are general cargo vessels, tugboats, offshore supply vessels and product carriers. In addition, crew tenders, dredgers and container ships are also used.

As a reference vessel for this study, a 'general cargo' vessel has been assumed, according to (Marin, 2020). This type of ship is common in the Dutch fleet. The reference vessel complies with IMO II and has a deadweight of 9216 tonnes (DWT).

[126] This comparison does not take into account the efficiency loss of the electric motor(s) in the propulsion system, especially since electric motors are often used in diesel propulsion (diesel-electric propulsion). With direct drive, several engines are often running for on-board power and part of the time for bow thrusters. On average, this results in similar losses.

The length of the reference vessel is 118 metres and its width is 18.2 metres. It is based on an installed power of 4290 kW and a diesel consumption of 392 kg/hour. The following deployment profile is assumed: sailing 55% of the time at 13 kts, manoeuvring: 10% at 5 kts, harbour 35% at 0 kts. The relationship between energy consumption per hour and per km follows from this reference profile (Table B.11).

As in the case of inland navigation, the efficiencies of the various energy converters are only known within a broad range. Information is particularly scarce for H_2 and NH_3 in combustion engines and for fuel cell systems in general. Mostly this concerns only laboratory test data and for fuel cells, as far as is clear, only data for small-scale systems. In order to get a good picture, actual field data or detailed simulation data should be available for the different drive trains for various application profiles and vessel sizes. Unfortunately, this is not the case. Therefore, only globally available efficiency data has been used in the table below. See the explanation in section Powertrain efficiency heavy duty vehicles and shipping.

Table B.11 Comparison of total energy consumption (including stand-by in port and manoeuvring) of seagoing vessels on different energy carriers for a general cargo vessel with an average consumption of 392 kg per hour

	Diesel	**H_2 fuel cell**	**H_2 ICE**	**NH_3 PEM-FC**	**NH_3 SOFC**	**Methanol ICE**	**DME ICE**
Motor efficiency	45%	45%	45%	45%	54%	45%	45%
MJ/h	16809	16809	16809	16809	14007	16809	16809
MJ/km	1186	1186	1186	1186	988	1186	1186

Aviation

For aviation, an aircraft for long-haul flights (intercontinental) was selected as the reference, for example the Boeing 787 and the Airbus A350. These aircraft are both relatively new on the market. Depending on the class classification, the Boeing has a capacity of 200 to 250 passengers (787-8), 250 to 300 passengers (787-9) and 300 to 330 passengers (787-10). The Boeing A350-900 typically has room for 300-350 passengers. In addition, a fleet average of two Dutch airlines is described, AirFranceKLM and TUIflyNL. Both airlines fly the Boeing 787 among other aircraft.

Kerosene (conventional, bio and synthetic)

The emissions per passenger (gCO_2 /RPK) are influenced by several factors, such as the type of aircraft, the type of flight (short/long) and the load factor. With a higher load factor (more passengers per aircraft), the average emission per passenger decreases.

The table below shows the average emissions from various sources. The conversion factor used is that combustion of 1 kg of kerosene releases 3.16 kg of CO_2 (ICCT, 2020) and 43.5 MJ (Zijlema, 2020) energy. This means that 1 MJ equals emissions of 72.6 gCO_2 .

The reference year 2019 was used to determine the reference value for the average energy consumption per passenger. The year 2020 is not a representative year due to the corona crises and the low utilisation rate of aircraft. Based on these sources, the conclusion is that the average energy consumption is around 1.1 MJ/RPK. Given the very similar chemical composition of fossil kerosene, biokerosene and synthetic kerosene, the use of alternative fuels has no significant effect on the efficiency.

Table B.12 Literature sources of energy use in aviation

Group	Average emissions [gCO_2 /RPK]	Energy consumption [MJ/RPK]	Source
AirfranceKLM	79	1,1	(AirfranceKLM, 2021)
TUIFlyNL	64	0,9	(TUI Group, 2020)
Global average	90	1,3	(ICCT, 2020)
Boeing 787-9	75	1,1	(ICCT, 2020)
Airbus A350-900	75	1,1	(ICCT, 2020)

In the coming decades, commercial aviation will probably still depend to a large extent on kerosene and kerosene substitutes (bio/synthetic kerosene). For this modality, therefore, alternative forms of propulsion such as battery-electric and hydrogen-electric have not been considered. These forms of propulsion are emerging for small aircraft and short distances, but at the moment there is no comparable data available on energy consumption.

The energy consumption of a commercial passenger aircraft can be expressed as the average energy consumption per paying passenger and is approximately 1 MJ/RPK. In the coming decades, commercial aviation will probably still depend to a large extent on kerosene and kerosene substitutes (bio/synthetic kerosene). For long haul aviation , therefore, alternative forms of propulsion such as battery-electric and hydrogen-electric have not been considered. These forms of propulsion are emerging for smaller aircraft and short-haul flights, but at the moment there is no comparable data available on energy consumption.

Summary table

The table below summarises the energy consumption per distance travelled by various modes, depending on the drive system and energy carrier used. The justification of these values is given above and explained in more detail in the section 'Powertrain efficiencies heavy road traffic and shipping'.

Table B. 13 Energy use of typical reference vehicles with different propulsion and energy carriers (MJ/km or MJ/RPK for aviation)

Market segments		Diesel/petrol (conventional, bio & synthetic)	Battery Electric (BEV)	Fuel Cell Electric (FCEV)	Hydrogen combustion (H_2 -ICE)	Natural gas (LNG) ICE	Methanol ICE	Ammonia ICE	Ammonia SOFC	Kerosene (conventional, bio & synthetic)
Light road transport	Passenger car /	2,3	0,7	1,5						
Heavy road transport	Tractor-trailer combination	12,6	5,6	8,7	10,7					
Inland shipping	Inland vessel	346	154	307	346	346	346			
Shipping	Shipping	1186		1186	1186	1186	1186	1186	988	
Aviation	Intercontinental (>800kms)									1 MJ/RPK

Powertrain efficiency heavy duty vehicles and shipping

Heavy duty vehicles

The average diesel consumption of tractor-trailers was calculated using emission factors for the average Dutch vehicle fleet (Geilenkirchen, et al., 2021). Electric and hydrogen tractor-trailers are still only available to a very limited extent in the Netherlands. The energy consumption of these drives is based on literature, namely the JRC TTW report (JRC, 2020) and T&E (Transport & Environment, 2020a).

Table B.14 Typical powertrain efficiencies for application in heavy duty road vehicles (Transport and Environment, 2020b)

Typical drive train efficiency	**Value**
ICE	
Engine	42%
Total	**42%**
BEV	
Loading	95%
Battery	95%
Conversion (DC/AC)	95%
Electric motor	95%
Total	**81%**
FCEV	
Hydrogen to Electricity (PEM)	54%
Conversion (DC/AC)	95%
Electric motor	95%
Total	**49%**

Inland shipping

A Large Rhine Ship M8 (110m) was taken as the reference vehicle for inland navigation. This is with 32% of all vessels in the fleet and 37% of the vessel movements (Prominent, 2015) the most frequent vessel type on the Rhine corridor. For the diesel reference vessel, an average consumption of 130 litres per hour and an average sailing speed of 13.5 km/h are assumed (PROMINENT D5.7, 2018). This corresponds to an energy consumption of 345 MJ/km (energy content in diesel fuel). Using an average engine efficiency, the propulsion energy (at the propeller) can be estimated from this. By combining this with the efficiencies of alternative propulsion, we have estimated the consumption of ships on alternative energy carriers.

Diesel (conventional, bio and synthetic)

Two important sources for the consumption of a diesel reference vessel are (PROMINENT D5.7, 2018) and (RWS, 2017). In (PROMINENT D5.7, 2018) is based on an average consumption of 130 litres per hour and an average sailing speed of 13.5 km/hr. The RWS inland shipping tool (RWS, 2017) gives an average consumption of 108 litres per hour for a loaded M8 ship at an average speed of 15.7 km/hr.

Table B.15 Inland navigation - energy consumption diesel vessels (ICEV)

Ship type	MJ/hour	MJ/km	Details	Source
M8 large Rhine vessel, diesel	4667	345	A sailing and loaded M8 ship (approx. 130 litres/hour), at 13.5 km/hour	Calculated on the basis of (PROMINENT D5.7, 2018)
M8 large Rhine vessel, diesel	3877	258	A sailing and loaded M8 ship (approximately 108 litres/hour), at 15.7 km/hour	Calculated assuming (RWS, 2017)

The average speed of the second source from Table B. 15 seems too high and does not correspond to other sources. Therefore, the first source is taken as the starting point for the reference consumption per hour and per km: 4667 MJ/hour and 345 MJ/km (4667/13.5) respectively.

Too little measurement data is available to make a comparative analysis of the actual consumption of inland navigation vessels with alternative propulsion (see disclaimer below). Because this information is lacking, the comparison has been made in a simple manner on the basis of average efficiency for the various drive lines under the fairly optimum situation of a sailing, loaded vessel.

Battery Electric (BEV)

Battery-electric sailing for inland navigation is on the rise, both for short-term electric sailing (a few hours, or a few days of hotel operation) and for fully electric sailing. The latter uses 'exchangeable battery containers' of about 2 MWh. In (TNO, 2019b) the electrical energy profiles were investigated on the basis of the drive line and location data of the container ship the Gouwenaar II (M6 motor vessel 90m). There were two trip types, with the following bandwidth in electrical energy consumption (total of 8 return trips):

- Alphen a/d Rijn - Maasvlakte II: 446 - 757 MJ/hour
- Alphen a/d Rijn - Antwerp: 863 - 912 MJ/hour

Trips with a low average consumption per hour correspond with a lot of waiting times and a higher consumption per km and vice versa. The above figures do not include the efficiency of charging and discharging the batteries or the efficiency of the charging installation on shore.

Supplier ZES, Zero Emission Services, recently presented a theoretical comparison between diesel and electric, with an overview of the chain efficiency (ZES, 2021). Based on this, the following conclusions are drawn regarding the comparison of electric versus diesel:

- Calculated based on the battery charge, the electrical energy is 41% of the energy of the diesel fuel, in a diesel-electric drive.
- If the calculation is based on the electricity entering the charger, the efficiency is 43%. If compared to a diesel-direct drive (diesel engine directly drives the propeller), the efficiency is 47%.

Based on this, it is concluded that energy consumption for electric propulsion is approximately 45% of the energy content of the diesel fuel, assuming the current to the charger. This is based on the average of diesel-electric and diesel-direct drive. This theoretical ratio between electric and diesel is converted from the reference diesel consumption to the electric consumption in MJ/hour and MJ/km. This is shown in the table below. The energy consumption of 2074 MJ/hour seems high in relation to the information of the (smaller) Gouwenaar ship. Therefore, this is currently seen

as an upper limit; it is possible that the sailing profile used in practice is more favourable. Further research into practical data is highly desirable for battery-electric sailing.

Table B. 16 Inland navigation - energy consumption battery-electric drive (BEV) based on electrical energy input to the battery charger

Ship type	MJ/ hour	MJ/km	Source
M8 large Rhine vessel, diesel	2074	154	Based on theoretical information diesel-electric ratio (ZES, 2021)

Hydrogen fuel cell (FCEV)

The application of fuel cell electric propulsion in inland navigation in the Netherlands is still limited to small demonstration vessels, such as a tour boat. Suppliers do have standard units under development for medium-sized and large inland navigation vessels. Fuel cell systems are usually built up of units of 40, 100 or 250 kW. Depending on the power requirements of the vessel, several fuel cell units can then be installed as power suppliers for the electric drive. A large Rhine vessel (M8) will require approx. 1000-1100 kW of main power, which then means 4 to 10 units. In general, a battery will also have to be installed for *peak shaving* (to prevent dynamic loading). Fuel cells are sensitive to this (see text box 'Efficiency differences between FCEV and ICE' in section 'Overview of different drives'). As a result, the total power (main engine + auxiliary engines) can be limited to the value mentioned. This has been described, for example, in (TNO, 2019c), although that concerns a medium-sized ship (ca. 90m length), with a total fuel cell power of 600 kW. In the same document the efficiency is specified, see table below. The table also includes two other sources, where (DST, 2020) reports a considerably higher efficiency, but gives no explanation. It probably does not include the 'balance of plant' (auxiliary system around the fuel cells) and nothing about aging is specified either. The efficiencies in (TNO, 2019c) and (TNO, 2020b) are based on direct information from the supplier. Based on this information it can be concluded that a fuel cell drive will probably have a somewhat higher efficiency than a drive with combustion engine. This also depends on the exact configurations of the drive trains. In the case of the fuel cell drive, it is obviously a hybrid drive in which a battery is also used, for peak power, and possibly for very low power, in which the fuel cell is switched off. With diesel-electric drive, a battery can also be added. The specified efficiencies are efficiencies that can be achieved in practice under favourable conditions. Under unfavourable conditions, such as a lot of waiting and manoeuvring, the efficiencies will generally be lower. This applies to both diesel and fuel cell propulsion. A hybrid configuration, such as diesel-electric or fuel cell with battery, will score more favourably under such conditions.

Table B. 18 Overview of sources indicating efficiency of FC drive for inland navigation

Chip type	Efficiency FC system	Diesel engine reference	Remarks	Source
Motor vessel Gouwenaar, 90m	47% new 42% older		10% degradation over lifetime. Specification FC supplier	(TNO, 2019c)
Motor vessel 1125 kW main engine	45%	42%	FC supplier and TNO (no specific measurements)	(TNO, 2020b)
Motor vessel 110m	50-60%	40%	Possibly excluding auxiliary system or balance of plant. Exact source unclear	(DST, 2020)

Based on Table B.17, an average fuel cell efficiency of 45% and an average diesel engine efficiency of 40% are chosen. The first source is the most detailed and specific data from the supplier.

Hydrogen combustion (H_2-ICE)

The efficiency of a good hydrogen powered ICE can be on the same level as the diesel engine, provided the same engine concept and combustion principle is chosen. See the explanation of H_2-ICE for heavy road transport in table B. 9.

As a combustion concept, a lean-burn engine concept with either spark ignition or diesel-pilot ignition (dual-fuel) is mainly considered.

From Table B.9 it is concluded that the efficiency for H_2-ICE engines can be roughly equated to that of the diesel engine. For the Dutch reference vessel an average efficiency of 40% is assumed for inland waterway vessel engines.

Ammonia

NH_3 as a fuel is of particular interest to maritime shipping, both in combination with combustion engines and with fuel cell systems. For inland navigation, NH_3 is not immediately an obvious fuel, as inland navigation is a small market worldwide. Consequently, engines developed for mobile equipment on the one hand and the lightest applications (1-2.5 MW) in the maritime domain on the other are used. Inland navigation is therefore dependent on other sectors. NH_3 engines or FC systems for inland navigation could become available in the future, if these engines or FC systems are developed for stationary energy systems or for marine applications (currently this has a low TRL). NH_3 in an FC system is probably only suitable for large systems, integrating NH_3 reforming and fuel cell. Only then a good efficiency (>40%) is possible. See the shipping section for a more detailed explanation.

Methanol and DME

Methanol can be used in different ways in an internal combustion engine. In (MKC, 2018) extensive research was done into combustion concepts and their influence on engine efficiency. This did not result in precise efficiency figures, as the experimental results found did not generally give a good picture of the efficiency in the total operating range of the engine. However, broad statements were made depending on the type of engine.

Table B.18 **Information on the efficiency of methanol engines according to (MKC, 2018)**

Engine type	Efficiency compared to standard diesel engine	Expected application in inland navigation
Spark ignition stoichiometric	Lower	Smaller engines
Spark ignition lean-burn	More or less equal	
Direct injection - compression ignition	More or less equal	Medium and large engines
Dual-fuel - with diesel pilot	Equal to slightly better	

Table B.19 **Efficiency for use of methanol in internal combustion engines**

Engine type	Methanol engine efficiency	Diesel reference	Remarks	Source
MS 4-stroke dual-fuel	41%	41%		(Brynolf, 2014)

Based on the above information, it is concluded that the efficiency of a methanol engine can be equal to that of the diesel engine. For inland navigation, an efficiency of 40% is assumed for both.

DME, di-methyl-ether, is, unlike methanol, a good 'diesel' fuel with a low auto-ignition temperature. However, it requires a very special fuel injection system and extensive optimisation of combustion to achieve low emissions. This could be done if there is a clear market. For now, this is limited to demonstration projects in the field of trucks and vans in particular.

It is assumed that the same efficiency can be achieved with DME as with standard diesel fuel (Verbeek, 1997). For inland navigation, this is 40% for both.

Shipping
The fuel consumption of typical Dutch ships lies in the range of 140 to approx. 440 kg/hour (Marin, 2020) for the various types of vessels and activities. Exceptions to this are dredging vessels which can have a consumption of approx. 1440 kg/hour.

The possibilities of using alternative fuels and power trains depend on the type of vessel and its use. The following alternative fuels and propulsion systems (energy converters) are being considered for maritime shipping: methanol, LNG, ammonia, hydrogen (carrier). The table below gives an overview of these.

Table B. 20 Options for alternative fuels and power train technology in shipping

	On-board storage	**Drive - short term**	**Long-term - type of drive**
Biodiesel Synthetic diesel	Equal to diesel/MGO	Equal to diesel/MGO[127]	No adjustments - engine efficiency can still be increased slightly
Battery-electric	Battery (container)	Electric motor	Electric motor
Battery-hybrid	Fuel tank + battery	Battery-electric support of combustion engine or fuel cell drive	
Methanol, bio- or synthetic methanol	Larger tank	Dual-fuel or single fuel engine	Fuel cell with reformer (conversion to H_2) Direct methanol/NH_3 fuel cell
LNG, bio- or synthetic LNG	Cryogenic, liquid	Dual-fuel or single fuel engine	
Ammonia	Cooled, -35°C	Dual-fuel engine	
Hydrogen	Compressed or cryogenic	Dual-fuel or single fuel engine	Fuel cell

In (TNO, 2021) an overview is given of the alternative fuels. The focus of this study was on the short term with the application of these fuels in combination with internal combustion engines. (DNV-GL, 2017) and (Sandia, 2017) explore the possibilities of applying different types of fuel cell propulsion.

Diesel (conventional, bio and synthetic)

In internal combustion engines, there can be a significant difference between the optimum efficiency and the efficiency in practice. The differences are mainly determined by the level of average power (average load), and the proportion of standby time (the engine is running, but little or no power is being used). There are various options for avoiding unfavourable load. For example, a hybrid drive with an electric axle motor/generator, possibly in combination with a battery.

[127] Marine Gas Oil

Data on the specific fuel consumption of marine engines are generally publicly available in specification sheets. The specific fuel consumption can then be converted into efficiency via general fuel specifications. In the project (TNO & CE Delft, 2013) different engines were compared, which led to the following efficiency range:

- Short Sea Shipping: 43% - 46%
- Deep-sea shipping: 47% - 50%

The 50% is probably only achievable with the large two-stroke engines. For these engines, it is also possible and sometimes economically feasible to convert exhaust heat into mechanical energy via a Rankine cycle. This would increase the overall efficiency to about 55% (ICCT, 2014).

In general, the use of bio- or synthetic fuel does not have a significant influence on the efficiency. There are examples where the efficiency improves slightly (up to about 5% reduction in consumption on an energy basis, but that is mainly for light engines).

Battery Electric (BEV)

Battery-electric is only suitable for short distances up to several dozen kilometres, for example for ferries to the Wadden Islands from the Dutch mainland. In the future, this could increase further due to improved battery technology. This kind of application is seen in other countries, such as Norway. The batteries are then recharged after each crossing via an automatic connector (pantograph type).

Hydrogen fuel cell (FCEV)

Below is an overview of various sources on the efficiency of a fuel cell electric (FCEV) drive in shipping.

Table B.21 **Fuel cell electric (FCEV) propulsion efficiency in shipping.**

Ship or fuel cell type	Efficiency	Diesel reference	Details	Source
Coastal ship 5500 kW main engine	45%	45%	On the basis of information from suppliers	(TNO, 2019b)
PEM FC	45% (41% - 53)	30%	Chart with quite bad diesel engine	(Sandia, 2017)
MCFC	44.1%	n.b.	Only stack: 52.1% LNG fuel	(DNV-GL, 2017)
Hybrid SOFC	>60%		Felicitas project (Rolls Royce)	(DNV-GL, 2017)
AFC	50%-60%		H_2 fuel	(DNV-GL, 2017)
PEMFC	50%-60%		H_2 fuel	(DNV-GL, 2017)

Using the table in combination with other sources on the efficiency of marine diesel engines, it is concluded that the efficiency for the H_2 fuel cell drive can be roughly equated to that of the diesel engine. For the Dutch reference ship an average efficiency of 45% is assumed.

Hydrogen combustion (H_2-ICE)

The efficiency of a good hydrogen powered engine can be on the same level as the diesel engine, provided the same engine concept and combustion principle is chosen. See the explanation of H_2-ICE for heavy road transport in table B.9.

As combustion concept, a lean-burn engine concept with either spark ignition or diesel-pilot ignition (dual-fuel) is mainly considered. Based on table B.9 it is concluded that the efficiency for H_2 combustion engines can be roughly equated to

that of the diesel engine. For the Dutch reference ship an average efficiency of 45% is assumed.

Ammonia

(De-Vries, 2019) provides a broad overview of the potential of NH_3 as a marine fuel. It examines the options for internal combustion engines, fuel cell systems and steam and gas turbines (figure B.1).

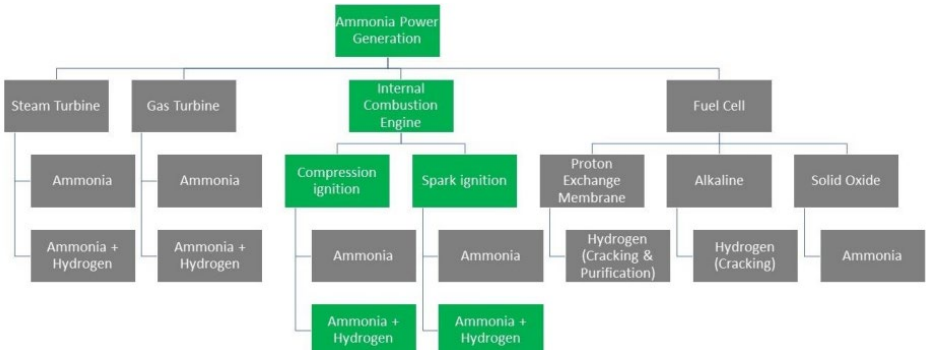


Figure B.11 **NH_3 energy pathways (De-Vries, 2019).**

The use of NH_3 in internal combustion engines or in fuel cell systems is still in its infancy. No actual applications are known yet. De Vries indicates that the development of the NH_3 combustion engine will be more practical and faster than that of a fuel cell system.

NH_3 in combustion engine

Engine manufacturer Wärtsilä and shipowner Grieg announced in December 2020 that they will be the first to produce a tanker powered by a combustion engine in 2024 on NH_3. Engine manufacturer MAN had announced in 2018 that it would be able to produce a NH_3 engine based on the 2-stroke dual-fuel principle with diesel pilot injection in about 2-3 years[128](Laursen, 2018). The diesel pilot then serves to start the combustion of NH_3. It is expected that it will be more difficult to run smaller engines on NH_3. In other studies for small engines, part of the NH_3 (approx. 30%) is converted into H_2, whereby the H_2 is then needed (continuously) to start up the NH_3 combustion.

The table below includes some sources for the efficiency of the NH_3 engine compared to diesel, but this is mainly for large engines. For the efficiency of smaller engines (< 2MW) this still has to be checked. It can be concluded that for large engines, based on the diesel cycle, and possibly only for 2-stroke engines, the efficiency of an engine on NH_3 is comparable to that of the diesel engine.

Table B. 22 **Engine efficiency with NH_3 as marine engine fuel**

Engine type	Efficiency NH_3 motor	Diesel reference	Details	Source
Engine based on NH_3	49.4% - 51.6%	49% - 52%	Range due to aux system or load point	(De-Vries, 2019)
2-stroke engine with diesel pilot	Indication: 50%	50%	Up to 60% with waste heat recovery	(Laursen, 2018)
Coastal vessel 5500 kW main engine	45%	45%		(TNO, 2020b)
Engine - 2-stroke (low speed)	47,3%	-	Biggest engine class	(Elishav, 2020)

[128] Direct injection is a method of fuel injection for diesel and petrol engines. The fuel is injected directly into the cylinder or combustion chamber through an injection nozzle.

Based on the table, it is concluded that the efficiency for NH_3 engines can be considered equal to that of the diesel engine. For the relatively small Dutch reference ship an average efficiency of 45% is assumed.

NH_3 in fuel cell systems

Under the banner of the FCH2 JU (Fuel Cell Hydrogen Joint Untertaking), several maritime projects have been launched based on FC propulsion. The MARANDA and FLAGSHIPS projects focus on PEMFC, while the ShipFC consortium focuses on the direct NH_3 Solide Oxide Fuel Cell (SOFC) concept. In the latter project, a 100 kW SOFC will be scaled up to a 2 MW system, which will then be installed on a ship by the end of 2023.

The table below gives an overview of some studies that give indications of the efficiency of NH_3 fuel cell systems. These are in a range of 44% to 52% with some outliers to 54% and 60%. This is quite comparable to the efficiency of the ship's diesel engine, which, depending on the size, is in the range of 45% to 50%, with an outlier to 60% if the diesel is combined with waste heat recovery based on a Rankine cycle. In (TUD, 2018) research was done into the efficiency of SOFC and gas turbine combined energy systems with natural gas as fuel. The researchers themselves arrive at 56% for the best configuration, although in their literature review, considerably higher efficiencies are also found. It is possible that this combined SOFC and gas turbine system is also a good route for further research for NH_3 .

We conclude that the efficiency of NH_3 fuel cell systems is comparable to that of the diesel engine, with potential for higher efficiency.

Table B. 23 **Efficiency of fuel cell system for shipping with NH_3 as fuel.**

Engine type **Fuel cell type**	**Efficiency NH_3 fuel cell system**	**Diesel reference**	**Details**	**Source**
Deep-sea ship 30,000 kW main engine		47%		(TNO, 2020b)
PEMFC + reformer	50,7	-	H_2 -PEMFC eff. is 63%	(De-Vries, 2019)
AFC + reformer	50% - 52%	-		(De-Vries, 2019)
SOFC	60%	-	Also range 50%-60% indicated	(De-Vries, 2019)
PEMFC + reformer	44,5%	-	PEMFC 55% efficiency adopted	(Elishav, 2020)
SOFC directly NH3	53,8%		SOFC 60% efficiency adopted	(Elishav, 2020)

The above mentioned efficiencies of internal combustion engines and FC systems using NH_3 as fuel do not take into account likely efficiency losses due to the larger space requirements and weight of the large tanks for NH_3 compared to diesel and also those for the FC systems. This loss of efficiency occurs mainly in ships that are laid out on volume, such as passenger ships, general cargo ships and container ships. In this relatively high-level comparison, we have not taken this into account.

Methanol and DME

Methanol, and in particular the sustainable bio- or synthetic methanol, has been circulating for quite some time as a potentially good alternative fuel for maritime

shipping. It has been reported extensively in the Dutch Green Maritime Methanol project. In general, the dual-fuel combustion engine is applied. In this case a small amount of diesel fuel is injected to ignite the methanol. With a dual-fuel engine the efficiency of the engine will be about the same as that of the standard diesel engine, on which the dual-fuel version is based. See also the inland navigation section in this Annex.

DME, di-methyl-ether, is, in contrast to methanol, a good 'diesel' fuel with a low auto-ignition temperature. It does require a very special fuel injection system and extensive optimisation of combustion to realise low emissions. For the time being, its application is limited to demonstration projects in the field of trucks and vans in particular. There are, however, plans to apply it to the maritime sector as well. It is assumed that the same efficiency can be achieved with DME as with standard diesel fuel (Verbeek, 1997).

Application of high blends of alternative fuels

In principle, all vehicles and vessels can drive and operate on blends of conventional fuel with a low proportion of liquid biofuel and synthetic fuel. Special requirements apply to the use of higher blends.

Fuel quality requirements
For each fuel there is a standard that describes the requirements it must fulfil. Technically speaking, bio- and synthetic fuels can be used relatively easily in different qualities and blends (both low-blend and high-blend). Depending on the transport mode, however, this is not always easy in practice.

Road transport, mobile machinery and inland waterways
Current standards for the most common fuels used in road transport, mobile equipment and inland navigation are summarised in the table below.

- The specifications for petrol in the European Union are laid down in the FQD (2009/30/EC) and in the European Standard EN228;
- The specifications for diesel in the European Union are laid down in the FQD (2009/30/EC) and in the European Standard EN590;
- The specifications for kerosene fuels in the European Union are laid down in the FQD (2009/30/EC) and in the European Standard EN15940.

Table B. 24 Fuel standards and biofuel blending limits

Standard	Fuel	Limits for blending
EN228	Petrol and petrol substitutes	Standard EN228 specifies limits for the admixture of bioethanol. These depend on the maximum 3.7% oxygen content (mass percentage). In principle, such EN590 blends can be used in all petrol engines. Newly produced petrol vehicles are generally compatible, but older petrol vehicles in particular may experience problems with seals and fuel injection systems. - E10: According to EN228, 10 vol% ethanol or 22 vol% ethers (ETBE or MTBE) may be added. - E20 and above: if permitted by the car manufacturer.
EN590	Diesel and diesel substitutes	Standard EN590 specifies limits for the admixture of FAME. In principle, such EN590 blends can be used in all diesel engines. - B7: A maximum of 7 vol% FAME may be added to diesel within EN590. - B10 and above: 30% admixture of FAME is possible, but must be permitted by the car/engine manufacturer. - B30: Within EN590 about 30 vol% Fischer-Tropsch fuels and/or HVO can be blended.

Standard	Fuel	Limits for blending
EN15940	Kerosene fuels	Kerosene fuels (such as Fisher-Tropsch synthetic fuels[129] and/or HVO) generally have greater compatibility with almost all new vehicles. The EN15940 stipulates that the use of high blends is permitted provided that the car/engine manufacturer has type approval for them. - 30 vol% FT fuels and/or HVO: HVO can be blended up to approximately 30% with B7 diesel without exceeding the EN590 standard specifications and can therefore be used in all diesel engines and applications. - 100 vol% FT fuels and/or HVO: if approved by the car manufacturer.

Road transport: Higher blends are not automatically applicable in road transport if they do not comply with EN590 (diesel) and EN228 (petrol). In general, only low blends, E7 and B10, are used in the Netherlands. Increasing the blending ratio to, for example, E20 and B30 is technically feasible, but not necessarily applicable to European vehicles due to the sophisticated engine and exhaust after-treatment techniques. For more information on fuel standards and blending limits please refer to the TNO fact sheets on energy carriers for road transport (TNO, 2019a).

- According to research by CEN, vehicles that have been on the market since 2011 can also use E20 as fuel.
- Furthermore, only a few vehicles are approved for high blends of bioethanol (E85). In practice, this is not often used in the Netherlands, partly because E85 is not readily available there. Especially in France and Sweden, bioethanol is widely available and is used more often. For example, Stellantis, the former French PSA, is also releasing the use of 100% HVO for the Euro 5 and Euro 6 diesel engines. Most truck manufacturers also allow 100% HVO in some Euro VI truck types. Other OEMs are testing. These include the performance and service life of seals, fuel injection systems and exhaust after-treatment systems.

Inland navigation: The diesel fuel specifications in inland navigation are almost identical to those of road transport. Biofuels are therefore technically also relatively easy to mix with diesel fuel in various qualities and blends (both low-blend and high-blend). So formally, 7% FAME can be added. On a limited scale, blends of synthetic diesel with 20% FAME have been supplied to the inland navigation sector.

- It is true that B7 has so far only been supplied to a limited extent to inland navigation. It was about 20% of the deliveries in 2019 and 2020, see (Verbeek, 2020). In 2021, this will have virtually dried up (i.e. only B0), partly due to the discussions regarding certain risks of FAME in inland navigation. The risks are described in detail in (Verbeek, 2020). The risks are mainly associated with fuel storage and supply on board the vessel, such as clogging of filters. The inland waterway engines themselves are almost always suitable for B7 and often higher blends.
- Engine suppliers often allow deviating specifications in blends with FAME, GTL and HVO, so that conventional technology can be used. In inland shipping, however, it is logistically difficult to supply different blends side by side. The availability of biofuels for ships therefore depends primarily on the availability of biofuel bunker locations. As far as we know, there is only one bunker location in the Netherlands where an inland vessel was bunkered with fully sustainable biofuel for the first time in 2019.
- For new Stage V marine engines in inland navigation, it is doubtful whether paraffine fuels will be allowed. Engine suppliers will then have to have 100%

[129] Such as power-to-liquid (PTL) and gas-to-liquid (GTL).

HVO type-approved separately. Because of the small market, they are not (yet) inclined to do so.

Shipping
Applicable standards for the most common marine fuels are summarised in the table below. The specifications for marine fuels are laid down in the ISO 8217, the EN 14214 and the ASTM D6751. Depending on the production process, distillate oil and residue oil are distinguished. The fuel category is indicated by a code consisting of three letters:
1. The family letter, "D" for distillate or "R" for residue;
2. The application, "M" stands for "Maritime" (for FAME fuels "M" is replaced with "F");
3. A letter, e.g. "A", "B" ... "Z", which has no meaning on its own, but relates to the specific characteristics in accordance with the product specification.

A good explanation of the fuel types can be found in (Chevron, 2021). Reference is also made to the ISO specifications and the IBIA website.

The shipping industry was late in allowing FAME blends in some fuel types. In the 2017 ISO8217 specification, ISO 8217:2010, the maximum FAME content was set at 0.1% for safety reasons. Later with ISO8217:2017, 7% FAME is allowed for three types of DF fuels: DFA, DFZ, DFB. DM and RM fuels generally have a FAME limit below 0.5%. The same applies to the low and ultra-low sulphur variants (VLSFO and ULSFO). In addition to FAME, Hydrotreatment Vegetable Oil (HVO) is also used on a limited scale for maritime shipping, but this fuel is currently too expensive for this application.

In addition to the official standards, higher FAME blends such as B20 and B30 are often used in the marine sector. Also 'heavier' FAME is used that does not comply with EN14214. This FAME must be heated, also as a blend, for the filters and injection systems of the diesel engines. This is not a problem, because the larger ships often have these facilities to heat residual fuels anyway.

Standard	Fuel	Limits for blending	Limits for the sulphur content
ISO 8217	DF fuels (Marine Gasoil) DFA, DFZ, DFB	Max 7% FAME. FAME specification according to EN14214 standard or ASTM D6751	DFA, DFZ: S < 1.0% DFB: S < 1,5%
	DM fuels (Marine Gasoil) DMA, DMB, DMZ	FAME < 0.5% and no intentional addition	DMB: S < 1.5%
	RM fuels (Heavy Fuel Oil) RMA30, RMB30, RMD80, RME180, RMF180, RMG380, RMH700, RMK700	FAME < 0.5%	RMA, RMB: S < 3.5% RMD: S < 4,0% RME .... RMK: S < 4.5%
	DM fuel (Marine Gasoil) DMX	Completely free from FAME Especially for Cat 1 engines < 5 dm3/cyl	DMX: S < 1,0%
Partly ISO 8217	Very Low Sulfur Oil (VLSFO)	FAME < 0.5%	S < 0.5%
Partly ISO 8217	Ultra Low Sulfur Oil (ULSFO)	FAME < 0.5%	S < 0.1%, according to sulphur directive 2005/33/EC

Appendix C Electricity

Efficiency

Table C. 1 Electricity transport and distribution network losses in different literature sources

Source	What	Value	Notes
Haugen et al. (2021)	Transmission	86% (85-94)	14% loss
Haugen et al. (2021)	AC to DC conversion	93% (87-95)	7% loss
NAW-Leopoldina (2017)	Distribution	95%	5% loss
RVO (2018)	Grid losses	1.5% to 7.5%	About 1.5% to 7.5% of all distributed electricity is lost to grid losses. In cities, the lower end of the range
Den Ouden et al. (2021)	Solar and wind transmission losses	3%	Source RVO 2016
JEC (2019)	Transport losses Distribution losses (MS and LS)	2,6% 7%	For the EU in 2013

Table C.2 Energy efficiency and investment costs of some electricity storage technologies

Storage technology	Efficiency ("round trip")	Investment costs ($ or EUR/MWh)	Source	Notes
System batteries	70-95		Steilen & Jörissen, 2015	Different types
Li-ion battery	75- 97%		Luo et al. (2015)	Meta-study. Widest estimate, most sources 70-80%
Li-ion battery	85-90%	600-2500	Aneke & Wang (2016)	Costs are now lower
Li-ion battery		187	BNEF (2019)	Large scale; potential for cost reduction (see also Mongird et al. (2020)
Li-ion battery		80 (2030)	Rooijers & Jongsma (2020)	In 2020 still 120 €/MWh
Home batteries		200-400	Den Ouden et al. (2020)	
Ni-Cd battery	60-83%		Luo et al. (2015)	
Lead-acid battery	63-90%		Luo et al. (2015)	

Lead-acid battery	70-80%	50-270	Diaz-Gonzales et al. (2012)	Metastudy
Na-S battery	80-90%	300-500	Aneke & Wang (2016)	
CAES	50-89%	2-50	Aneke & Wang (2016)	

Table C.3 Efficiency of conductive charging in various sources

Source	What	Value	
Haugen et al. (2021)	AC - DC conversion Loading	93% (87-95) 87% (84-95)	
Where the Energy Goes: Electric Cars (fueleconomy.gov)	Loading	90%	
NAW-Leopoldina (2017)	Loading	90%	
Apolostolaki-losifudou et al. (2017)	Conversion and charging	83-88%	Largest loss are due to conversion; higher efficiency with higher power
Verbruggen et al. (2018)	Loading efficiency for trucks	90%	
Karlsson & Kushnir (2013)	Loading	85-95%	This includes fast charging. There is potential for higher yields

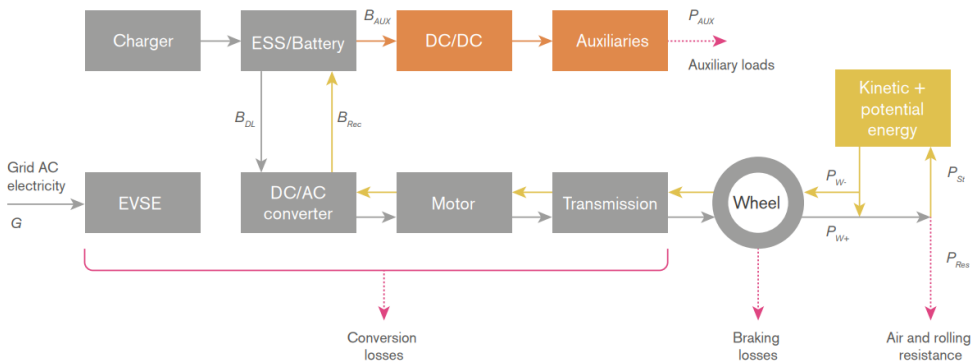


Figure 5.1 The conversion chain in electric vehicles. Energy is transferred from grid electricity (*G*), via the battery (B_{DL} and B_{Aux}), to energy at the wheels (P_{W+}) and auxiliary equipment (P_{Aux}). Part of stored potential and kinetic energy is recovered through the wheels (P_{W-}) to the battery (B_{Rec}).

Figure C.1 Conversion chain in electric vehicles (Karlsson & Kushnir, 2013)

Costs

Table C.4 Illustration of cost projections for PV and wind energy (for the Netherlands unless otherwise mentioned)

What	Costs	Unit	Year	Source	Notes
Onshore wind	47	€/MWh	2025	Dutch Climate agreement (p. 166)	Further cost reduction to EUR 30-40/MWh assumed
Solar PV	58	€/MWh	2025	Dutch Climate agreement (p. 166)	
PV (roofs, solar meadows) LCOE*	39-48	€/MWh	2030	Den Ouden et al. (2021)	
Onshore wind LCOE	30	€/MWh	2030	Den Ouden et al. (2021)	
Production costs of climate-neutral electricity	85 (45-110)	€/MWh	2050	Hoogervorst (2020)	Meta study: most scenarios have 90% or more wind+PV
LCOE 100% renewables for NL	55-60	€/MWh	2050	Bogdanov et al (2019)	Study for 100% RE-elek worldwide

* levelised cost of electricity

Land use

Definition of net land use for off-shore wind: the surface area that can no longer be used for other purposes. Passage for shipping and co-use by passive fishing, for example, can still take place within the boundaries of a wind farm, subject to conditions. A distance of 50 metres to the turbines and 500 metres to the net-to-sea platforms, the so-called safety and maintenance zone, must be observed. Some activities are not permitted, such as diving, kite surfing and trawling (Wind op Zee, n.d.).

The range we see in the results in the literature can be explained by:

- On and off-shore wind:
  - What is and is not included in the geographical boundary
  - Wind supply differs per region
  - Choices in the number of turbines placed per surface area: more turbines can produce more electricity per km^2, but also at a higher cost per MWh (Figure C.2)
- Solar:
  - Where exactly is the geographical boundary of a project?
  - Orientation: east-west gives higher yield in MWh per m^2 than south, where there should be more space between panels
  - For different types of surface (agricultural, infrastructure, on water), there may be different choices of space between panels, and there may be restrictions on the angle of inclination.

Table C.5 Land area required to produce 1 MWh per year through PV and wind according to various sources

Energy source	m^2/MWh	m^2/MWh	Notes	Source
	Current	Future (2030-2050)		
PV		19-25	Utility-scale PV in the EU	Ven et al. (2021) table 1
PV	10	6	Netherlands, average over all surface types.	RVO (2018)
PV	9,4		Yield in GWh/km^2 /yr per typology (averaged over subtypes): Agricultural: 77 Indoor/outdoor water: 102 Infrastructure: 138 In the 'balanced development' scenario, these three types are needed in roughly equal measure (in addition to rooftop solar)	Van Hooff et al. (2021; Appendix C)
PV	10-15		Large-scale solar PV: 90 - 135 km^2 for 9 TWh = 10-15 m^2/MWh	NP-RES (2019)
PV	10 (7-22)		Solar farms 48 - 156 MW/km^2 (assumption: 11% efficiency) (PV on roof 195 MW/km^2)	Kuijers et al. (2020)
Wind	0,7		EU	Fritsche et al. (2017)
Offshore wind		0,3	Assuming 50m around turbine and 500m around platform, 11.5 GW (and 4000 full load hours) takes up 12 km^2	Wind op Zee (n.d.)
Onshore wind	0,3		30 ha direct land take for 1 TWh. This is 85-115 turbines of 3.6 MW, so about 3000 m^2 per turbine.	North Holland Energy Region (2019)
Onshore wind	2,3		US, including infrastructure for access to wind turbine (at 3000 full load hours)	Brown et al. (2012)

Note: liquid biomass (1st/2nd generation) is 200-500 m^2/MWh fuel, compared to oil 0.4 m^2/MWh for oil (Fritsche et al., 2017)

Assumptions for gross space utilisation for offshore wind, i.e. how many MW of installed capacity can be achieved per km^2:

- 7MW/km^2 (KIVI, 2020)
- 6-10 MW/km^2 (Kuijers et al., 2020)
- 4-6 MW/km^2 RVO (2018); larger turbines can bring this down
- Realised Dutch projects are 4-7 MW/km^2 (European MSP Platform, no date)

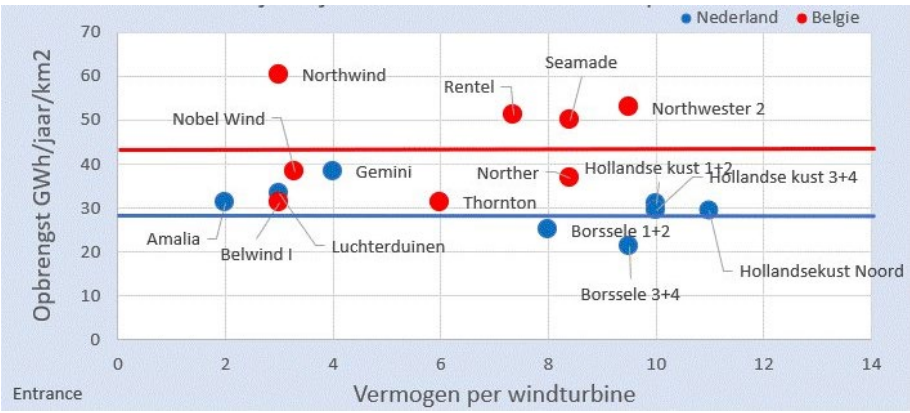


Figure C.2 **Illustration of difference in yield per km² per year between Belgian and Dutch offshore wind farms (Visser, 2022)**

Utility-scale PV:

- 1 MW per ha (CE, but also RVO 2018) (17 GW on 160 km²)
- 0.6 MW/ha (Brown et al., 2012) (6 W/m²)
- 0.5 MW/ha (Arent et al., 2014)

North African countries have a PV yield of about 1900 kWh per kWp of installed capacity per year, compared to 1000-1100 in the Netherlands, i.e. about 81% higher (SolarGIS, 2021).

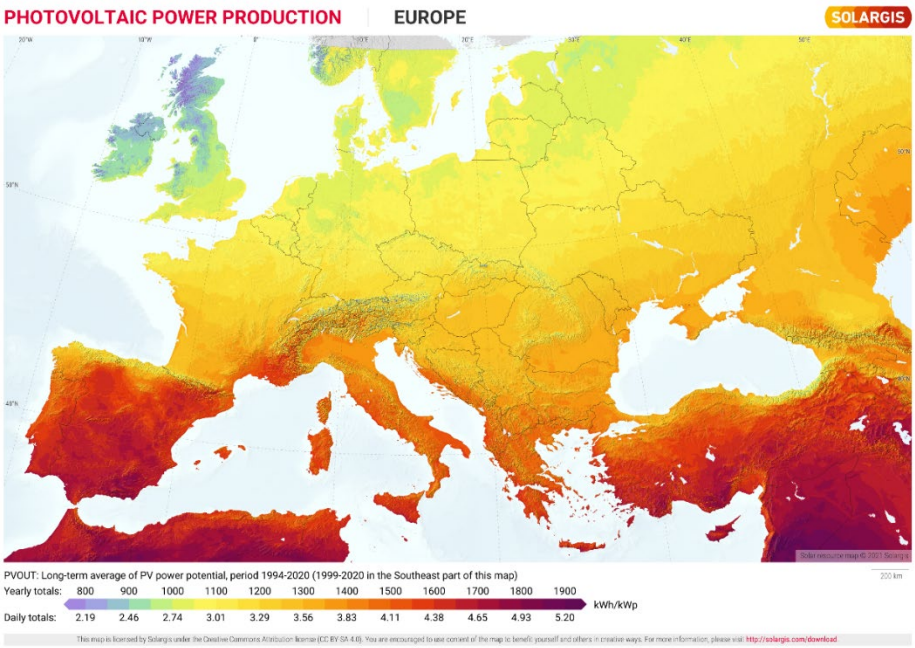


Figure C.3 **PV potential in Europe and North Africa (SolarGIS, 2021)**

Appendix D Hydrogen

Electrolysis

Types of electrolysers[130]

The three main types of electrolysers are PEM, AEL and SOEC.

PEM electrolytic cells use iridium and platinum, while AEL electrolytic cells contain nickel, cobalt and platinum. SOEC electrolytic cells mainly use ceramics and materials that are not very rare.

The main advantages of AEL electrolytic cells over PEM are that the technology has proved its worth, that they are relatively cheap, that the number of electrolysis stacks can easily be increased, and that they contain fewer essential raw materials than PEM. The disadvantages of AEL are its lower current density, lower efficiency and the fact that the electrolytic fluid is corrosive. The typical service life of an AEL electrolytic cell is 10 years.

PEM electrolytic cells use a membrane (a solid polymer electrolyte) between the cathode and anode instead of a liquid. They usually contain iridium, platinum and tantalum. The main advantages of PEM are its high current density and high efficiency, the fast response of the system making it suitable for dynamic operation, and the fact that it is more compact than AEL. Disadvantages of PEM electrolytic cells are the high cost of the components (partly due to the scarcity of essential raw materials), their lower durability and the fact that they contain acid that poses a corrosion hazard. The typical service life of a PEM electrolytic cell is 7 years.

It is very likely that PEM and AEL electrolytic cells will be used simultaneously in the future energy system, due to their typical advantages and disadvantages.

SOEC electrolytic cells, with a TRL of 6, are at a more experimental stage than AEL and PEM. They come in two variants:

- With electrolyte (operating temperature >800°C),
- With anode (operating temperature 600-850°C).

The catalyst layer mainly requires ceramics and few rare materials. Therefore, SOEC has great potential for cost savings in the future. The high temperature required poses a challenge to economic viability. A service life of 25,000 operating hours has currently been achieved. Technological improvements are being made such as stabilising the materials of the components, developing new materials and lowering the operating temperature (to 500-700°C). The current capacity of operational SOEC systems is less than 1 MW. A 2.6 MW SOEC system is being developed in Rotterdam as part of H2020 MULTIPLHY (Koirala, 2020).

Optimum operating time depending on electricity costs

The figure below is taken from IEA (2019a) and shows the costs of hydrogen production based on electricity from the grid, as a function of the operating time of the electrolyser. Electricity prices are variable and are extremely low for a limited number of hours per year and extremely high for a limited number of hours per

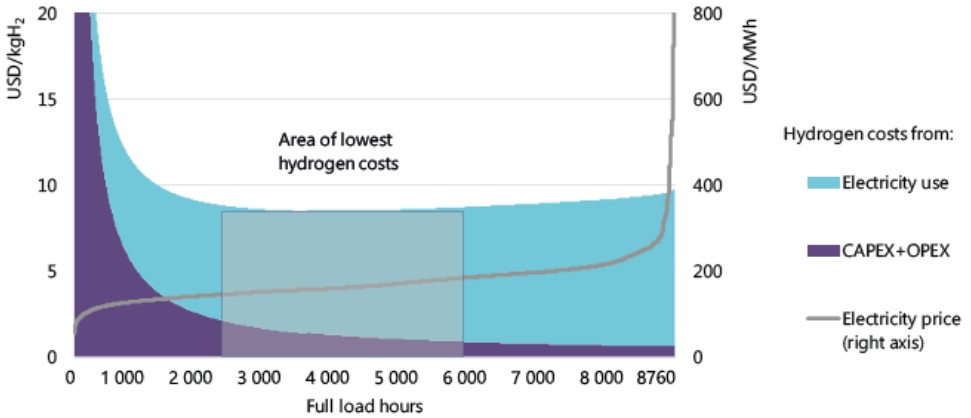
[130] Based on Wieclavska and Gavrilova (2021), Marsidi (2018, 2019) and Koirala (2020).

year; the rest of the time electricity prices are at an average level (represented by the grey line in the figure). The lowest average production costs of hydrogen (under the assumptions used) are achieved if the electrolyser is only in operation when the price of electricity is below about $200/MWh. This is the case for approximately 6,000 hours a year. However, unit costs are higher for an operating time of less than 2000 hours per year, despite the fact that production is only carried out when electricity is cheapest. This is because the fixed capital costs of the electrolyser then start to weigh more heavily on production costs.

The IEA says:

"Electricity at very low cost is generally available only for a very small number of hours per year. With such low electricity costs, the electrolyser achieves only low utilisation rates, which leads to high hydrogen costs (which then mainly reflect the CAPEX costs). By using more expensive electricity to some extent, the number of operating hours increases. Although this increases electricity costs, the higher utilisation rate of the electrolyser reduces the cost of producing a unit of hydrogen to an optimal level at about 3000-6000 equivalent full-load hours. Above that, higher electricity prices during peak hours lead to an increase in the unit production cost of hydrogen. "

Figure 13. Hydrogen costs from electrolysis using grid electricity



Notes: CAPEX = USD 800/kW$_e$; efficiency (LHV) = 64%; discount rate = 8%.

Source: IEA analysis based on Japanese electricity spot prices in 2018, JEPX (2019), *Intraday Market Trading Results 2018*.

Higher utilisation rates help to reduce the impact of CAPEX, but for grid-connected electrolysers this means higher electricity prices; the lowest hydrogen costs are achieved in mid-load operation.

Steam-methane reforming (SMR)

How does the process work?

Steam reformers are traditionally large industrial plants. Production capacity is typically in the order of 1,800-18,000 kg H_2/hour with production costs of 1 to 1.5 €/kg H_2 (Weeda, 2016; IEA, 2019a). Smaller plants are possible, but they are less efficient the smaller they get. The smallest existing plants are still much too large (and too industrial) for, say, a petrol station (Weeda, 2016). Smaller SMR plants are being developed with a production of 200-600 kg H_2 per day (Gigler and Weeda, 2018), but these have a considerably lower efficiency, see text box Small-scale SMR.

The SMR process takes place at temperatures of 800-900°C and pressures in the order of 25-40 bar (Weeda, 2016). A typical SMR plant has an output capacity of 300 MW and produces 9 tonnes of hydrogen per hour (Chen et al., 2020; Janssen, 2018; Gigler and Weeda, 2018).

The reaction consists of two steps in which the first step produces a syngas of carbon monoxide (CO) and hydrogen (H_2). In a subsequent step, the water-gas-shift reaction, the CO is converted with the help of steam into carbon dioxide (CO_2) and H_2. Steam reforming can take place with various hydrocarbons. For steam reforming of *methane*, the sub-reactions and the overall reaction are as follows (Weeda, 2016):

Reforming, syngas production: $CH_4 + H_2O \rightleftharpoons CO + 3\,H_2$

Water-gas-shift (WGS) reaction: $CO + H_2O \rightleftharpoons CO_2 + H_2$

Overall reaction: $CH_4 + 2\,H_2O \rightarrow CO_2 + 4\,H_2$

In the SMR process, CO_2 is generated in 2 ways: 1) in the WGS step and 2) in the production of steam and in the external heating of the reactor, for which natural gas is used. The first stream produces CO_2 at a high concentration, which makes CO_2 capture relatively simple (and often already happens, because the CO_2 can be used, for example, in the conversion of ammonia to urea in the fertiliser industry). Capturing CO_2 from the second stream is more difficult due to its low CO_2 concentration (Gigler and Weeda, 2018).

In industrial applications of SMR, often around 50-60% of the CO_2 is captured. A higher share of capture is possible through process modifications, up to around 90%, but this reduces the energy efficiency by about 7%-points (Gigler and Weeda, 2018). 90% capture means that for every kg of H_2 1 kg of CO_2 is released.

Small-scale SMR at petrol stations: a real option?

Initiatives are being taken by various parties (including the Dutch HYGEAR) to develop small-scale SMR units with capacities of typically 100 and 300 Nm^3 /hour; this corresponds to approximately 200 and 600 kg H_2 per day. This could avoid (expensive) transport of hydrogen to a location where the H_2 is used (Gigler and Weeda, 2018).

The principle of production using small-scale units is the same as for large-scale production. However, the units are not smaller-sized factories, but are completely redesigned processes so that even on a small scale the efficiency is acceptable. Energy efficiencies are in the order of 60-65%. In the period up to 2030, the cost of producing hydrogen with such units could fall to 4-5 €/kg [excluding CCS], with the prospect of further falls to 3-4 €/kg (Gigler and Weeda, 2018).

KiM's estimate is that **combining** these small-scale units **with CCS** is difficult or even unfeasible. Even if it is possible to efficiently capture the CO_2, the question is how the CO_2 should then be transported to an underground storage location.

According to Gigler & Weeda (2018), the current market for the application of small-scale units lies mainly in on-site production at small-scale industrial consumers and not, or less, in production at filling stations. For this, Gigler and Weeda cite 3 reasons:

- From a business point of view, the small-scale production units preferably operate continuously. At filling stations, especially in the start-up phase, a highly variable operation is to be expected.
- The small-scale units produce the hydrogen at a relatively low pressure, so there is a considerable need for compression (to 350-700 bar) at a filling point.

- According to Gigler and Weeda (2018), another point for consideration is the **amount of space required** on the site. At a petrol station, the SMR installation might be difficult to fit in. Because of the space requirements, the most practical and cost-effective option will have to be determined on a case-by-case basis. Local availability of green gas or biogas for sustainable hydrogen production may also play a role.

Space requirements for small-scale SMR unit: Gigler and Weeda (2018) do not quantify the space consumption of the small-scale SMR unit. Due to the lower energy efficiency (60-65%) and a completely redesigned process, we estimate that the small plant occupies 2 times as much space per unit of output power as a large industrial plant. A small SMR plant producing 600 kg H_2 per day would then occupy around 85 m^2 space. This is a rough estimate.

Storage types and characteristics, comparison with battery and fossil fuels

Here we present some general characteristics (physical, chemical) of hydrogen and hydrogen storage in comparison to other energy carriers and storage media.

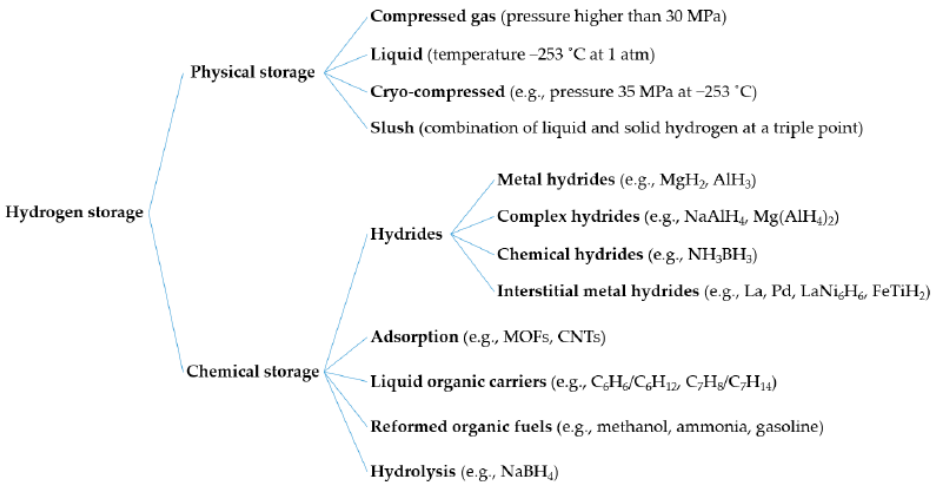


Figure 3. Hydrogen storage options, including physical and chemical storages.

Figure D.1 **Different forms of physical and chemical storage of hydrogen (Aziz, 2021)**

LOHC is listed as: chemical storage - liquid organic carriers. Examples:

- C_6 H_6 = benzene https://nl.wikipedia.org/wiki/Benzeen;C6H12
- C_7 H_8 = toluene https://nl.wikipedia.org/wiki/Tolueen; cited as an example in IEA, 2019b table
- C_7 H_{14} = cycloheptane

Table D.1 Characteristics H_2 storage in different forms and alternatives (Aziz, 2021)

Properties	Compressed Hydrogen	Metal Hydride (MgH_2-10wt%Ni)	Liquid Organic (C_7H_8/C_7H_{14})	Liquid Hydrogen	Liquid Ammonia
Density (kg/m^3)	39 (69 MPa, 25 °C)	1450	769 (1 atm, 20 °C)	70.9 (1 atm, −253 °C)	682 (1 atm, −33.33 °C)
Boiling point (°C)	−253	-	101	−253	−33.33
Gravimetric hydrogen density (wt%)	100	7.10	6.16	100	17.8
Volumetric hydrogen density (kg-H_2/m^3)	42.2		47.1	70.9	120.3
Hydrogen release temp. (°C)	-	250	200–400	−253	350–900
Regeneration temp. (°C)	-	-	100–200	-	400–600
Enthalpy change to release hydrogen (kJ/mol-H_2)	-	118	67.5	0.899	30.6

The density of hydrogen (kg/m^3) depends on the form (gaseous or liquid) in which it is found and at which pressure. Hydrogen at 700 bar has a density (kg/m^3) about 20 times lower than diesel, liquid hydrogen has a density 11 times lower than diesel.

Table D.2 Specific energy, mass density and volume of hydrogen compared to other energy carriers, with and without storage medium (tank/battery)

	Specific energy	**Mass density**	**Energy content per volume, of the energy carrier only**	**Energy content per volume, of energy carrier + storage medium**
	MJ/kg	kg/m^3	Indexed (diesel = 1)	Indexed (diesel = 1)
Hydrogen @1 bar	120	0,09 [a]		
Hydrogen @350 bar	120	31 [b]		
Hydrogen @700 bar	120	42 [c]	6	16
Hydrogen cryogenic (-253°C)	120	71 [a]	4	8
For comparison:				
Ammonia, refrigerated	*18,6*		*3*	*3*
Electricity in battery				*100*
Diesel	*44*	*~830 (820-845)* [d]	*1*	*1*
Petrol		*~750 (715-780)* [d]		
Kerosene		*~800 (775-840)* [d]		

Source volumes: Van Kranenburg et al. (2019) and own calculations. The volume of the propulsion system (fuel cell+electro engine versus diesel engine) has not been considered.

Sources: a: IEA (2019a), b: https://www.dwarsliggers.eu/index.php/2016-04-03-16-33-59/omgeving/421-waterstof, c: https://energies.airliquide.com/resources-planet-hydrogen/how-hydrogen-stored, d: https://www.engineeringtoolbox.com/fuels-densities-specific-volumes-d_166.html

Transport, storage and distribution: cost and efficiency

Costs

For the costs of transport, storage and distribution, we have used the values in the following table. This includes the costs of conversion of gaseous (GH2) to liquid

hydrogen (LH2) and ammonia (NH_3). The costs of hydrogen production with electrolysis have also been included as a reference. The average values correspond to figure 3.6 from section 3.3.4 of the main report.

Table D.3 Costs in €/kg hydrogen of the different chain steps (excluding refuelling) when importing hydrogen from North Africa. Source references are in Table D.4

	GH2			LH2			NH_3		
€/kg	**min**	**average**	**max**	**min**	**average**	**max**	**min**	**average**	**max**
Production (electrolysis)	2.64	4.15	5.80	2.64	4.15	5.80	2.64	4.15	5.80
Conversion				0.75	0.91	0.91	0.36	0.90	0.91
Storage at import and export terminals	0.55	0.80	1.06	1.09	1.09	1.09	0.09	0.09	0.09
Transport (North Africa -EU)	0.11	0.11	0.11	0.18	0.18	0.18	0.06	0.06	0.06
Reconversion							0.64	0.91	1.13
Distribution (100 km)	0.50	0.70	1.20	0.50	0.70	1.20	0.50	0.70	1.20
TOTAL	3.79	5.76	8.17	5.16	7.03	9.19	4.30	6.81	9.20

Table D.4 gives an account of the values and ranges used. The assumptions for production costs are in section 3.2.2.

Table D.4 Assumptions and sources for the costs in the chain steps conversion to distribution from Table D.3. Values in italics are calculated with an exchange rate of 1.1 $/€.

Chain step		Description	€/MWh	€/kg	Source	Notes
Conversion (liquefaction)	LH2		38	1.27	Cihlar et al (2021) based on DOE (2019)	Only the CAPEX. This amount seems much too high (compared to IEA)
			74	2.47	Cihlar et al (2021) based on DOE (2019)	CAPEX + electricity costs. This amount seems far too high
		average		*0.91*	IEA (2019a), fig 32 and fig 27	
		low		0.75	KiM own calculation based on tables in IEA (2019b)	With electricity costs 0.05 €/kWh and discount rate 8%
Conversion to NH_3	NH_3		27	0.90	Cihlar et al (2021) based on IRENA (2019)	Not found in IRENA (2019)
				0.36	IEA (2019a), Fig 32	Why the difference between IEA fig 32 and fig 27?
				0.91	IEA (2019a), Fig 27	Why the difference between IEA fig 32 and fig 27?
Import and export terminals	GH2	low		0.55	Own estimation	Assumption that lower limit of storage GH2 is half cheaper than LH2
		average		0.80	Own estimate based on IEA (2019a)	At this amount, costs of storage+terminals are equal to 0.91 €/kg based on IEA, fig 27
		high		1.06	Own estimation	Difference from average as large as between low and average
	LH2	low/medium/high		*1.09*	IEA (2019a), Fig 32	
	NH_3	low/medium/high		*0.09*	IEA (2019a), Fig 32	
Transport	GH2	tube 1600 km		0.11	Cihlar et al. (2021), Table 3-C "H2 pipe", obv BNEF (2020)	Not clear if this is an existing (refurbished) gas pipeline. Probably so, because it is cheaper than transport LH2
	LH2	Ship N Africa - EU		*0.18*	IEA (2019a), Fig 32	
	NH_3	Ship N Africa - EU		*0.06*	IEA (2019a), Fig 32	
Transport +storage	GH2	tube 1500 km		*0.91*	IEA (2019a), Fig 27	This includes storage
		tube 3000 km		*1.82*	IEA (2019a), Fig 27	This includes storage
	LH2	Saudi Arabia - R'dam, 12000 km	37	1.23	Cihlar et al. (2021)	Costs in the year 2020
		N Africa - EU		1.27	IEA (2019a), Fig 32	Costs in the year 2030
	NH_3	Saudi Arabia - R'dam, 12000 km	11	0.37	Cihlar et al. (2021)	Costs in the year 2020
		N Africa - EU		0.15	IEA (2019a), Fig 32	Costs in the year 2030
Reconversion decentralised	NH_3	high	34	1.,13	Cihlar et al (2021) based on IEA (2019)	How exactly do Cihlar et al. arrive at 34 €/MWh based on IEA?
		average		*0.91*	IEA (2019a), fig 32 and fig 28	Decentralised reconversion NH3
Reconversion centre	NH_3	low		*0.64*	IEA (2019a), Fig 32	Central conversion NH3

Distribution	low (tanker)		0.50	Own estimate based on Reuss et al. (2019) and Cihlar et al. (2021)	Reuss et al. give costs of distribution + filling station of 2-2.7 €/kg, this is reduced by costs of filling station of 1.5 €/kgH_2 obv Cihlar et al. table 2-H
	average (tube)		0.70		
	high (tube)		1.20		
Distribution	tanker 100 km		*0.64*	IEA (2019a), Fig 28	Pipeline cheapest. Is it an existing gas pipeline?
	pipeline 100 km		*0.23*	IEA (2019a), Fig 28	
	100 km, not specified		*0.73*	IEA (2019a), Fig 32	
Distribution + refuelling	petrol station + tanker		2.00	Reuss et al. (2019)	Distribution by tanker is cheapest
	petrol station + tube, min		2.20	Reuss et al. (2019)	Cost at pipeline depending on number of FCEVs
	petrol station + tube, max		2.70	Reuss et al. (2019)	Cost at pipeline depending on number of FCEVs

Value in italics is calculated with an exchange rate of 1.1 $/€.

Efficiency

Efficiency of different ways of storing and transporting hydrogen. In the case of transporting hydrogen by ship or truck, the energy consumption of the ship and truck is not included. It is purely a question of the cost of handling the hydrogen on board ship/truck.

Table D.5: Efficiency (%) or use of thermal or electrical energy (in kWh/kgH_2) for different types of storage and transport and their sub-steps, according to various sources

Storage and transport/distribution	**Haugen et al. (2021)**	**Staffell (2019)**	**IEA (2019), 2030 horizon**	**JRC (2020)**
Compression for transport in pipeline, pressure level not given but 80 bar is sufficient according to Staffell et al.	88% (65-89%)			
Pipeline[131]	98% (80-99%)			
Compression + pipeline transport	86% (88%*98%)			78-80% (in 2016), 82-83% (expected in 2030)
Compression 500 bar (incl. cooling)		93% (89-94%) 2.6 (2-4) kWh_e /kgH_2		
Compression 900 bar (incl. cooling)		90% (87-92%) 3.5 (3-5) kWh_e /kgH_2		
Storage in gas cylinder (what pressure?)	89% (85-93%)			
Liquefaction	70% (65-90%)	72% (69-75%) 13 (11-15) kWh_e /kgH_2	65-75% (11-18 kWhe/kgH_2) (IEA, 2019a) 6.1 kWh_e /kgH_2 (82%) (IEA, 2019b)	54% (in 2016), 60% (expected in 2030)
Cryogenic tank truck	94% (91-98%)			
Truck (gaseous or liquid?)				98%
Ammonia production from electricity (via electrolysis of water)			53%	
Ammonia conversion+transport+reconversion	51% (48-55%)			
- *Ammonia production from H_2*	*70-80%*			
- *Ammonia production from electricity (electrolysis H_2)*			9.8 kWh_e /kgNH_3 (53%)	
- *Ammonia transport*	*90%*			
- *Ammonia cracking*	*76%*		9.7 kWh_{th} /kgH_2 (71%)	
- *Purification*			1.5 kWh_e /kgH_2 (95%)	
LOHC conversion+purification		80% (This takes energy worth 25% of the H_2 energy content)	13.6 kWh_{th} /kgH_2 + 0.4 kWh_e /kgH_2 + 1.1 kWh_e /kgH_2	

[131] It is not entirely clear what Haugen et al. (2019) mean by 'pipeline' in this context, but it probably refers to the efficiency of the intermediate compression stations.

Distance criterion

Which transport mode, combined with which form of the hydrogen, is the cheapest, depends on the distance to be transported and the quantity involved. In addition, it is of course important how intensively a transport route is used. For a one-off transport to a certain location, a pipeline will obviously never be the cheapest solution. A ship or truck is a more flexible means of transport in that case.

The IEA (2019a) uses 1500 km as the tipping point for frequent transport over long distances; see table below. For fine-grained local distribution, the cheapest option depends on the amount of hydrogen to be transported and the distance covered.

Table D.6 **Analysis in IEA (2019a), p.74/75**

Distance, type of transport	**Cheapest option**
Less than 1500 km	Over these distances, transportation of hydrogen **as gas** by pipeline is generally the cheapest option.
Longer than 1500 km	Here, transport by ship in the form of **ammonia** or **LOHC (liquid organic hydrogen carrier)** (ammonia in LPG ship and LOHC in oil tanker, p.77) can be a more cost-effective option, especially if the hydrogen has to be transported overseas, even taking into account the costs of conversion of hydrogen into ammonia or LOHC and back again.
Local distribution[132]	For local distribution, pipelines (**for gas**) are cost-effective when dealing with large quantities of hydrogen over longer distances; in other cases, trucks are likely to be the cheaper option.

How much hydrogen in a tube trailer?

Hydrogen: A tube trailer transporting gaseous hydrogen under pressure contains in practice around 300 kg H_2 at a pressure of 200 bar (IEA, 2014; Verbeek and Cuelenaere, 2019). Highly insulated cryogenic tankers typically carry 400 to 4000 kg of liquefied hydrogen (IEA, 2014). However, more is also possible: IEA (2019) reports tankers capable of transporting 670 kg of gaseous or 4300 kg of liquefied hydrogen.

Tankers for liquid hydrogen are not suitable for transport over long distances (greater than about 4000 km), as the hydrogen heats up and causes a pressure rise in the tank (IEA, 2019a).

Ammonia, LOHC: A tanker truck can transport approximately 5000 kg H_2 in the form of ammonia or 1700 kg H_2 in the form of LOHC. In the case of LOHC, a truck

[132] The IEA gives the example of local distribution: *"If 100 tonnes per day (tpd) are needed at a site 500 km from the point of import, then using trucks would be cheaper than building a pipeline; if 500 tpd are needed, then transport by pipeline is cheaper."* (IEA, 2019a). This situation does not apply to transporting hydrogen to refuelling stations. A filling station converts only between 200 and 1000 kg H_2 per day (IEA, 2019b). So with 100 tonnes of hydrogen per day, hundreds of filling stations can be supplied. It is hard to imagine that it is cheaper to drive 300 trucks a day to a location 500 km away (1000 km for the outward and return trips combined) than to construct a pipeline to that location.

would also be required to return the substance to which the hydrogen is bonded to its original destination after the hydrogen has been extracted (IEA, 2019a).

Costs of transporting liquid hydrogen by ship to refuelling point

Figure D.1 shows the cost of transporting liquid hydrogen by ship as a function of the distance travelled by the ship. The distance travelled by the hydrogen is as follows.

The hydrogen is first stored in the export port. Transport in liquid form requires liquefaction (cooling to -253° C). On landing in the importing country, there is storage in a terminal and then distribution via a pipeline to a receiving plant 50 km away. On the way there, the boil-off of the hydrogen, which is created by pressure build-up in the tanker, is used as fuel for the ship; the ship returns empty and then uses fuel oil. The liquefaction is a relatively large cost item, as is the temporary storage at the export and import terminals. The costs are shown as a function of the distance travelled by the ship. Most of the costs are fixed and therefore do not depend on the distance travelled by the ship. The total costs increase only slightly with the distance travelled.

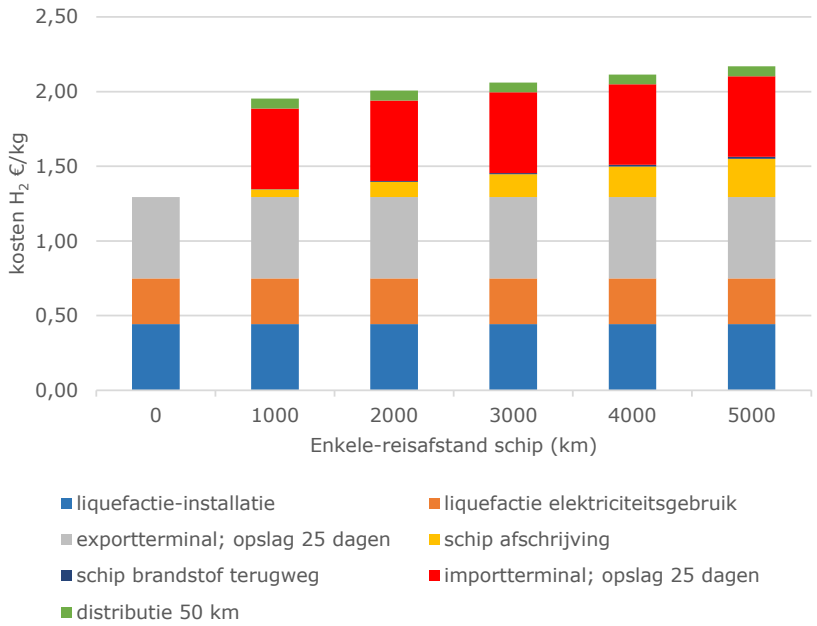


Figure D.1 **Calculation of costs for transport by ship, including liquefaction and storage in export and import terminals, followed by 50 km local distribution by pipeline**

Source: KiM based on IEA (2019b)

Explanation of figure. The calculation of the costs is based on data in IEA (2019b) on costs of technical installations, such as the liquefaction plant and the storage tanks at the terminals, the specific electricity consumption of these installations and the energy consumption of the ship. These data are shown in table D.7. Assumptions for the calculation are: a discount rate of 8% (according to IEA, 2019), electricity costs of 0.05 €/kWh, fuel oil at 0.67 €/L and twice 25 days of storage (25 days at the export terminal and 25 days at the import terminal).

Table D.7 Costs in the hydrogen transport and distribution chain

Type	Capacity/ pressure	Fixed costs	Variable costs	Lifetime
Long distances				
Ship				
Liquefaction	260 ktonnes H_2 /yr	1400 million US $	Annual 4% of fixed costs; Electricity use: 6.1 kWhe/kgH_2	30 years
Export terminal	3.2 kt H_2 per tank	US$ 290 million per tank	Annual 4% of fixed costs; Electricity use: 0.61 kWhe/kgH_2	30 years
Ship	11 ktonnes H_2 per ship	US$ 412 million per vessel	Annual 4% of fixed costs; Fuel consumption: 1487 MJ/km (only if no H_2 on board, otherwise boil-off of the H_2 is used); Boil-off rate 0.2% per day	30 years
Import terminal	3.6 kt H_2 per tank	USD 320 million per tank	Electricity use: 0.2 kWhe/kg H_2 ; Boil-off rate 0.1% per day	30 years
Pipeline				
Pipeline for transmission (long distance)	Design: 340 ktonnes/year; Real utilisation rate 75%; 100 bar	1.21 mln US $ per km	(Electricity for compressors?)	40 years
Short distances				
Pipeline				
Pipeline for distribution to user (short distance)	Design: 38 ktonnes/year; 80 bar	0.5 mln US $ per km		40 years

Source: IEA (2019b)

Costs of using the current Dutch gas grid for hydrogen

If the current Dutch gas network were to be used for the transport and distribution of hydrogen, a number of modifications would be necessary (PwC, 2021). One of the most important (and costly) is the replacement of the current 22 compressors in the main transport network,[133,134] because they are not suitable for hydrogen (PwC,

[133] Source: https://www.gasunie.nl/begrippenlijst/compressorstation.
[134] The natural gas network consists of a combination of a high-pressure gas network (66-80 bar), compressor stations to keep the gas at the desired pressure, measurement and control

2021). In addition, replacement of valves and closures and cleaning of the pipes is also needed (PwC, 2021). Coating the inside is not necessarily necessary, but it helps to transport hydrogen at higher pressures (Wang et al., 2020). Compressors are a relatively expensive part of the network: a compressor station costs 3.4 (2.2-6.7) mln €/MW, both new and retrofit. Per 1000 km, 190 to 330 MW of compressor capacity is needed (Wang et al., 2020). Converted to costs per km per year, the costs are (calculations based on Wang et al., 2020):

- A retrofit pipeline (13 GW, 48 inch) costs on average 0.03 mln €/km per year[135]
- A compressor costs on average 0.05-0.09 m €/km per year.

Hydrogen filling station

Picture D.1 A hydrogen filling station

Source: https://tweakers.net/reviews/6449/5/de-grote-belofte-van-waterstof-het-alternatief-voor-elektrisch-rijden-tankstations.html

Most H_2 filling stations consist of the following parts (Apostolou and Xydis, 2019).

- A **purification unit** to ensure that hydrogen purity meets the standards for fuel cell delivery (purity greater than 99.97%).
- Hydrogen compressor for high pressure storage in the station's H_2 main tanks.
- Hydrogen storage tanks for compressed gas or liquid H_2.
- Hydrogen gas booster, which regulates the pressure to 350 bar or 700 bar during the refuelling procedure.
- **Cooling unit** to reduce the temperature of the hydrogen gas to -40°C so that the hydrogen tank of the vehicle does not become warmer than 85°C during rapid refilling and to ensure safety.

stations where the pressure is reduced from 66 to 40 bar and which form the link with the regional transmission lines (RTL). At the delivery stations (Gas Receiving Stations, GOS), the gas pressure is further reduced to the pressure required by the connected party. This can vary from approximately 20 bar to 3 bar (Gasunie, 2015).

[135] By way of comparison, the cost of a new 13 GW pipeline constructed specifically for H_2 is 0.18 mln €/km per year (calculation based on Wang et al., 2020). To this must be added the compressor costs.

- **Safety equipment** including pressure relief valves, hydrogen sensors and waterless fire extinguishing.
- **Mechanical and electrical equipment** such as valves, pipes, control panels and high-voltage connections.
- **Dispensers to transfer** the hydrogen to the tanks of the hydrogen vehicles.

The storage tanks at the filling station are relatively large, as they are stored at a lower pressure than will ultimately be delivered (IEA, 2019a, p.132). Purification is done with pressure swing absorption (PSA), the electricity consumption of which is 1.5 kWh_e /kgH_2, which is equivalent to 5% of the energy content of the hydrogen (IEA, 2091b). Both hydrogen from electrolysis and that from steam methane reforming can contain impurities (Apostoulou and Xydis, 2019).

Efficiency

Table D.8 shows some efficiencies from the literature.

Table D.8 **Various literature sources on energetic efficiencies in the refuelling process**

Aspect	Efficiency or electricity use	Source
Compression to 350-700 bar	Uses 6-15% of the energy content of H_2. This is equivalent to 2-5 kWh.	IEA (2019a), p.132
Compression 500 bar (incl. cooling)	2.6 (2-4) kWhe/kgH_2. This means an efficiency of 93% (89-94%)	Staffell et al. (2019)
Compression 900 bar (incl. cooling)	3.5 (3-5) kWhe/kgH_2. This means an efficiency of 90% (87-92%)	Staffell et al. (2019
Cooling	0.18 kWh/kg H_2 to cool the hydrogen from 15°C to -20°C and 0.33 kWh/kgH_2 to cool it to -40°C. This amounts to 0.5-1% of the energy content of H_2.	Nistor et al. (2016), p.4
Compression at gas station	On average, 11% of the energy content of the hydrogen is needed. This amounts to 3.7 kWh/kgH_2.	Wipke et al. (2012)
Purification	1,5 kWh_e /kgH_2, which is equivalent to 5% of the energy content of the hydrogen	(IEA, 2091b)

Petrol station costs

Tables D.9 and D.10 give indicative costs of filling stations and the different components.

Table D.9 **Fuel station cost characteristics**

Petrol station	For passenger cars		For trucks	
Turnover (kg/day)	200	1000	500	1300
CAPEX (mln $)	0.9	1.8	1.2	2.1
OPEX as % of CAPEX	5%			
Electricity consumption kWh/kgH_2	GH2 1.6 (5%); LH2 0.6 (2%)			
Service life (years)	10			

Source: IEA (2019b)

Table D.10 Costs of filling station components

HRS Component	Medium HRS	Large HRS
	Cost (thousand €)	Cost (thousand €)
Compressor	324	480
Chiller	162	200
Electrical	40	40
Storage Tanks	171	240
Dispenser	162	280
Piping-Control-Safety	16	16
Labour-Other Expenses	320	350

Source: Apostoulou & Xydis (2019)

For delivery at a pressure of 700 bar, the cost of the compressor can be as much as 60% of the total cost of the filling station (IEA, 2019a, p.132). According to Apostoulou and Xydis (2019, p.10), for a medium filling station (150 kgH_2/day) the compressor constitutes 30% of the cost. The storage tanks, cooler and dispenser each account for about 15% of the cost.

Strong economies of scale can be achieved. According to the IEA, increasing capacity from 50 to 500 kgH_2/day is likely to reduce capital costs per kg of hydrogen refilled by 75%. Costs can also be reduced by shifting to more advanced delivery options (such as very high pressure hydrogen or liquid hydrogen) and by economies of scale in the manufacture of refuelling station products (through mass production of components, such as the compressors) (IEA, 2019a, p.132).

The cost per kg H_2 depends on the utilisation rate of the hydrogen filling stations. For a filling station with a capacity of 50kgH_2 per day and serving 10 customers daily (as is often the case in Europe today), the pumps are in operation less than 10% of the time. In order to recover the costs of building and operating the filling station through fuel sales, a price of approximately \$15-25/kgH_2 (€13-22/kg) is needed for refuelling alone. The price of the hydrogen would also have to be added. A refuelling station with a capacity of less than 50 kg/day may provide a higher utilisation rate, but does not necessarily provide a cost reduction: small stations are capital intensive and cannot benefit from the economies of scale of larger refuelling stations. The cost of refuelling would therefore still be more than \$15/kgH_2 (IEA, 2019a).

Costs of hydrogen purification

Pressure-swing adsorption (PSA) is the existing technique for separating the hydrogen from CO_2 and other pollutants, and can achieve over 99.9% purity, but this does incur production losses. Purification costs at SMR are estimated at \$0.70 per kg (0.6 €/kg) (Staffell et al., 2019). By 2025, this may decrease to \$0.40 \$/kg (Staffell et al., 2019). An alternative to purification with PSA are pressure-driven membrane processes, typically based on palladium. Palladium filters achieve extremely high purity, but they are expensive, only work at 400°C, require a pressure differential of 10-15 bar, cost 3-5% of the yield and can suffer from a short lifespan (Staffell et al, 2019).

How will LOHCs and metal hydrides be refuelled?

The LOHCs cannot be refuelled directly by the vehicle. They must first be converted to H_2 before they can be used in a fuel cell or combustion engine. This costs 25% of the energy content (Staffell et al, 2019). It is possible that in the future this process could take place on board the vehicle, with the advantage that hydrogen compression can be avoided (Staffell et al., 2019). The IEA estimates the cost of

extraction and purification of LOHCs at the point of end use at 2.1 $/kg$H_2$ (IEA, 2019a).

The **metal hydrides**, the hydrogen that is chemically bound in a solid substance, cannot be 'refuelled'. The hydrogen must first be separated, this takes about 30% of the energy content, and the process is too slow to do this on board (Staffell et al., 2019).

Empty weight of ICEV, BEV and FCEV truck

Table D.11 shows the weight of the components of an (empty) truck for 3 powertrain types, based on ATRI (2022). The aim is to see what mass increase a battery-electric and fuel cell-electric system entails. This is for a truck type that does not occur in the Netherlands. Table 1 also shows the total mass (excluding the transported weight) of indexed to the diesel truck.

When correcting for the differences in action radius, the mass of a BEV truck is about 5 times that of a diesel truck, and an FCEV truck is 5 times heavier than a diesel truck. This is without the transported weight.

Table D.11 Mass of components of a truck (type "class 8 sleeper cab") with 3 power train types

	truck type		
	ICEV, 300 gallon diesel	BEV, 1622 kWh	FCEV, 77 kg H_2
Mass of truck and components (kg)			
TOTAL	9008	14407	9679
chassis	4582	4582	4582
body	1506	1506	1506
powertrain	1360		686
transmission	425	181	185
traction motor		281	287
electronic controller		30	31
H_2-tank			2074
lead-acid battery	124	31	31
Li-ion battery		7668	91
liquids	201	129	129
full fuel tank	810		77
Range			
maximum range (average) (km)	3214	1022	1176
MASSAGE per range (kg/km)	2,8	14,1	8,2
MASSAGE Indexed (ICEV=1)	*1,00*	*1,60*	*1,07*
MASSAGE per range indexed (ICEV=1)	*1,00*	*5,03*	*2,94*

Appendix E Synfuels

This appendix discusses various steps of the synfuels chain in more detail.

CO_2 capture from air

Direct CO_2 capture from the air is a relatively new and innovative technology, which is not yet commercially available on a large scale. Capturing CO_2 from the air consists of two steps, a capture step and a regeneration step. The exact form of these steps depends on whether liquid CO_2 solvent or solid CO_2 absorber is used. These are explained in the text box "CO_2 solvent versus solid CO_2 absorber". Not all types of solvents and absorbers are (yet) suitable for synfuel production. This is because synfuel production requires high CO_2 purity, above 99% (Fasihi et al., 2019). This is not always achieved with current solvents and absorbers.

Land use aspects

The CO_2 concentration in the air is around 400 ppm. This means that a lot of air has to be captured to get a substantial amount of CO_2. For example, to get 0.29 tCO_2 per hour, 943 t of air per hour must be treated with a capture efficiency of 50% (Kiani et al., 2020). To put this into perspective, all trucks on Dutch soil emitted 10 $MtCO_2$ in 2018. If all these trucks were to run on synthetic diesel, 10 Mt of CO_2 would be needed annually (without losses) and 33 thousand Mt of air would have to be treated, or 26 thousand km^3 air.[136] This volume is equivalent to the whole of the Netherlands up to an altitude of 690 m.[137]

One of the limitations of CO_2 capture from air is that the CO_2 concentration must not become too low. A low CO_2 concentration reduces the efficiency of the capture process. For example, Socolow et al. (2011) state that in order to capture 1 $MtCO_2$/year, 5 units are required, each 1 km long and 10 m high, which must be spaced 250 metres apart. All in all, this takes about 1.5 km^2 per Mt CO_2. However, as with wind farms, there is a lot of free space that can be used for other purposes. Johnston et al. (2003) estimate that even more space is needed, namely 75,000 km^2 for 3 $GtCO_2$/year, or 25 km^2/Mt CO_2. However, they do state that less surface area is needed if you can go to a higher altitude. Krekel et al. (2018) talk about a much smaller land take, namely 0.04 km^2 per Mt CO_2. A possible explanation for this is that the capacity of this plant is much smaller than for the aforementioned sources, namely 14 $ktCO_2$/year. However, Beuttler et al. (2019), a manufacturer of CO_2 absorbers, also speaks of a relatively low land take of 0.062 $km^2/MtCO_2$, while here the capacity (of 1 Gt) is larger than in Socolow et al. (2011) and Johnston et al. (2003).

In principle, CO_2 capture installations could be located on roofs or in remote areas (Kiani et al., 2020). However, this would mean that the CO_2 would have to be transported. It may be easier to capture the CO_2 where it is needed, near the

[136] One cubic metre of air weighs approximately 1.29 kg.
[137] For this purpose we assume that the Netherlands has a surface area of 37 thousand km^2 . This is excluding the surface of the outer waters and the surface of the overseas part of the Dutch Kingdom.

synfuel production site. This has the additional advantage that the heat released from the synfuel production can be used in the CO_2 regeneration process.

CO_2 solvent versus solid CO_2 absorber

With both technologies, a large quantity of air must be sucked in and passed through the process.

Liquid CO_2 solvent

In the first step, air is sprayed into a vertical vessel with a CO_2 solvent such as NaOH under room temperature and atmospheric pressure. The CO_2 molecules react with NaOH to form Na_2CO_3 and water. In the second step, Na_2CO_3 reacts with $Ca(OH)_2$ to form NaOH and $CaCO_2$. NaOH can again be used as a solvent. $NaCO_2$ is transformed into Na and CO_2 under the influence of heat. This is a very energy-intensive step as a temperature of 900° C is required for this reaction to take place. NaO then reacts with water to form $Na(OH)_2$ and can then be reused in the regeneration step. All in all, this process costs approximately 1535 kWh_e/t CO_2, with the heat also being made with electricity (Fasihi et al., 2019). This technology is the most developed.

The advantage of the technology is that it is a continuous process, allowing a constant flow of CO_2 to be released. A disadvantage is the relatively complex and expensive regeneration process. Furthermore, the process is less suitable for dry areas because water is lost (Keith et al., 2018).

Solid CO_2 absorber

This technology consists of a vessel containing the solid. In this vessel, CO_2 is first absorbed and then regeneration takes place in the same vessel. During the absorption step, air at room temperature and atmospheric pressure is passed through the vessel. This air has to be sucked in from outside. After the CO_2 from the air has reacted with the solid, the regeneration step starts. In this step, the pressure in the vessel is reduced or steam is added. Then the vessel is heated to 80-100° C which causes the CO_2 to release from the absorber. This temperature can probably be achieved by using residual heat from, for example, the production process to make synthetic fuels (Fasihi et al., 2019). Depending on the application, the CO_2 coming out of the process can be further purified, pressurised or used directly (Fasihi et al., 2019).

The advantages of this technology are its relatively low energy demand and low operating costs. The difficulties lie in the fact that a vessel is required that is completely sealed off from the outside air during the regeneration step. Furthermore, there are challenges in finding a solid that absorbs CO_2 well, has low costs and a long economic lifetime in impure air conditions (Keith et al., 2018).

Cost and efficiency

Table E.1 provides an overview of the costs and energy consumption of CO_2 capture from the air. Some processes only use electricity and others also use (residual) heat. For the chain efficiency calculation, we use an electricity consumption of 1.535 MWh/tCO_2 and no heat input based on "the HT solvent-2020" of Fiashi et al. (2019), see table E.1.

Table E.19 Overview of costs and efficiencies of CO_2 capture from air

CO_2 concentration inlet (ppm)	Energy consumption - heat (GJ/tCO_2)	Energy consumption - electricity (MWh/tCO_2)	Investment costs (per ktCO_2/year)	Variable costs (per ktCO_2)	Capacity (ktCO_2/ year)	Costs (€/t CO_2)[a]	Details	Source
400	10.7	1.45	8.4 M$_{2016}$	0.40 M$_{2016}$	2.3	1039	MEA-based	Kiani et al., 2020
400	10.7	1.03	2.6 M$_{2016}$	0.12 M$_{2016}$	2.3	439	Improved solvent	Kiani et al., 2020
400	0	1.535	0.82 M€$_{2019}$	3.7% or CAPEX	1.000	197	HT solvent - 2020	Fiashi et al., 2019
400	0	1.316	0.22 M€$_{2019}$	3.7% or CAPEX	1.000	121	HT solvent - 2050	Fiashi et al., 2019
400	6,3	0.250	0.73 M€$_{2019}$	4% of CAPEX	360	157	LT solid - 2020	Fiashi et al., 2019
400	4,0	0.182	0.20 M€$_{2019}$	4% of CAPEX	360	74	LT solid - 2050	Fiashi et al., 2019
n.a.	8,1	0.494	2.2-2.9 M$	0.09 -0.12 M$	1.000	321-387	HT solvent	Socolow et al., 2011
n.a.	n.a.	n.a.	0.064-0.12 M$	0.03-0.11 M$	n.a.	30-105		Kiani et al., 2020
600 [b]	5.25	0.077	0.61 M $	0.023 M$	1.000	113	Output pressure CO_2 0,1 MPa. Assumed cost-free O_2 - no ASU	Keith et al, 2018
500 [b]		1.01[c]	3.04 M$ full head integration	Material: 0.21 M$	14.15	433	Costs of the sorbent PEI/support are not included	Krekel et al., 2018
						222-268		Brynolf et al. , 2018
						20-950	Based on uncertainty in literature	Dieterich et al. , 2020

a. We calculate these costs by assuming a discount rate of 2.25%, a lifetime of 20 years, an electricity price of 75 €/MWh, a heat price of 10 €/GJ and an exchange rate of 1.12 $/€.

b. These CO_2 concentrations are higher than the current CO_2 concentration in the atmosphere.

c. According to Krekel et al. (2018), this electricity consumption is considerably higher than that of other sources because the energy consumption of the compressor is included. This compressor is needed to compensate for the pressure loss in the system.

Investment costs vary widely, from 0.06 M$/kt$CO_2$ to 8.4 M$/kt$CO_2$. However, the lowest cost estimate is from a manufacturer, who may be optimistic about the cost reduction potential. The highest cost estimate is for a relatively small plant (2.3 ktCO_2 /year) and based on the current CO_2 extraction technology which is less suitable for very low CO_2 concentrations.

For each source we can calculate CO_2 costs (making fixed assumptions on lifetime, discount rate, electricity price and heat price). The CO_2 costs range from 30-1039 €/t. This large range reflects the large uncertainty of the CO_2 costs with direct CO_2 capture. This range is slightly larger than the range documented by Brynolf et al, (2018) in their study, which is between 20-950 €/t based on a literature review. We use this latter range in this study. As best cost estimate of CO_2 based on CO_2 capture from air we use 250 €/t CO_2 based on average (rounded to tens of €/t) from Brynolf et al. (2018).

Theoretical maximum

If we assume normal conditions (20° C, atmospheric pressure) and 400 ppm CO_2 in the air, it takes at least 19 kJ/mol CO_2 or 434 MJ/tCO_2 to capture the CO_2 (Krekel et al., 2018). This is in agreement with the 20-22 kJ/molCO_2 (455-498 MJ/tCO_2) mentioned by other sources (Scolow et al., 2011 and House et al., 2011). This energy consumption does assume complete CO_2 capture, and is therefore somewhat lower if not all CO_2 needs to be captured.

CO_2 capture at large scale industrial point sources

Most industrial sources, such as power stations, chemical industry or steel industry, currently emit CO_2. The concentration of CO_2 in exhaust gases is significantly higher than the CO_2 concentration in the air, so smaller gas volumes are needed. The CO_2 concentration in exhaust gases is 3-4% at a natural gas power plant and 20-27% at steel production (Wang and Song, 2020). This makes CO_2 capture at these point sources more energy and cost efficient than capture from the air (with a CO_2 concentration of 0.04%).

For the synfuel to be CO_2 neutral, the CO_2 must be a residual product that would otherwise end up in the atmosphere. In a fully CO_2 neutral society, CO_2 could come from biomass-fuelled plants.

Current technology

There are different ways to get a relatively pure CO_2 stream from the industry, namely post-combustion, pre-combustion or oxyfuel. In both pre-combustion and post-combustion processes there are different ways to obtain a relatively pure CO_2 stream. The box "Technologies for CO_2 capture at point sources" provides some details on each of the capture methods.

Capacity and spatial considerations

There are several CO_2 capture installations worldwide, mainly for enhanced oil recovery (EOR). For example, there are three large CO_2 capture installations in Canada that capture around 1 Mt/year from a coal-fired power plant. There are also a number of capture installations in the United States, the largest of which captures approximately 1.4 Mt/year (Koytsoumpa, 2018).

Based on the data in table E.2 we can calculate that a 1 Mt/year post-combustion CO_2 capture plant (with a capacity factor of 80%) occupies approximately 13

thousand square metres. A CO_2 compressor alone for 1 Mt/year (with a capacity factor of 80%) takes up approximately 2000 m^2 (based on the data in table E.2).

Technologies for CO_2 capture at point sources

Absorption technologies

Absorption technologies use liquid solvents. The exhaust gases enter the absorber from the bottom and rise up, at the same time the solvent is sprayed from the top. When the two flows come into contact, the solvent absorbs a large proportion of the CO_2 from the exhaust gases. Exactly how much is absorbed depends on the design, but often a 90% capture rate is aimed for (Wang et al., 2017). The solvent is then led to a stripper, where it releases the CO_2 under the influence of steam. The CO_2 then has a high purity (99%).

MEA is a solvent that is currently the most commonly used for post-combustion processes. R&D focuses mainly on reducing energy consumption by process optimisation or by developing other solvents. MEA currently has a TRL of 9 (Kearns et al., 2021).

Adsorption technologies

Another capture technology is based on a solid substance, which absorbs the CO_2. This technique is particularly suitable for flows in which the CO_2 concentration is relatively low. Typical adsorbents are carbon, aluminium, silica and zeolites, but new polymers that can serve as adsorbents are also being developed. As with CO_2 capture from air, this is a cyclical process. In the first step, the solids from the exhaust gases are adsorbed and passed through a vessel. In the second step, regeneration takes place under the influence of a pressure difference or a temperature difference (Dieterich et al., 2020). The processes under the influence of pressure difference have a slightly higher TRL than processes that regenerate under the influence of temperature, namely 9 instead of 6 (Kearns et al., 2021).

Membranes

The idea of membranes is that they allow CO_2 to pass through while other substances do not. The driving force behind membranes is the partial pressure. As this is low in exhaust gases, the pressure is increased on one side of the membrane with a compressor and decreased on the other side with a vacuum pump. Membranes have great potential to separate CO_2 in a cheap and efficient way. However, there are still practical problems with the (capital) costs and the membrane surface area required for a reasonable CO_2 volume. Furthermore, the selectivity of the membranes is currently low, which means that multiple membranes are required in succession. A capture ratio of 90% and a purity of 95% can be achieved with several phases. A number of membrane technologies currently have a TRL of 6 (Kearns et al., 2021).

Table E.20 Space requirements for different CO_2 capture installations (based on Berghout et al., 2015)

	Space requirement(x1,000 m²)	**For the capture of (reference unit):**		**Notes**
Post-combustion	16	56	kg CO_2/s	Including cooling, flue gas cleaning (SCR/FGD), heat exchanger, CO_2 drying and compression.
Pre-combustion	5	10	kg H_2/s	
Oxyfuel				
-Oxygen production	4	25	kg O_2/s	The fuel determines how much oxygen is needed.
-CO_2 drying and compressing	3	65	kg CO_2/s	

1. This land take can be scaled using the following formula: reference land take x (desired unit/unit of reference)^{0,67}

Cost and efficiency of current technology

The costs of CO_2 capture depend very much on the CO_2 concentration, with a higher concentration leading to lower costs, see Figure E.1. If a waste stream has a pressure of 2 bar or 200 kPa and has a CO_2 concentration of 10%$_{vol}$ then the partial pressure is (0.10 x 200 =) 20 kPa. In addition, the volume of the CO_2 flow is also important: the larger it is, the lower the costs will be. An overview of the costs per tonne can be found in table E.3 provides an overview of the costs per tonne of CO_2 captured.

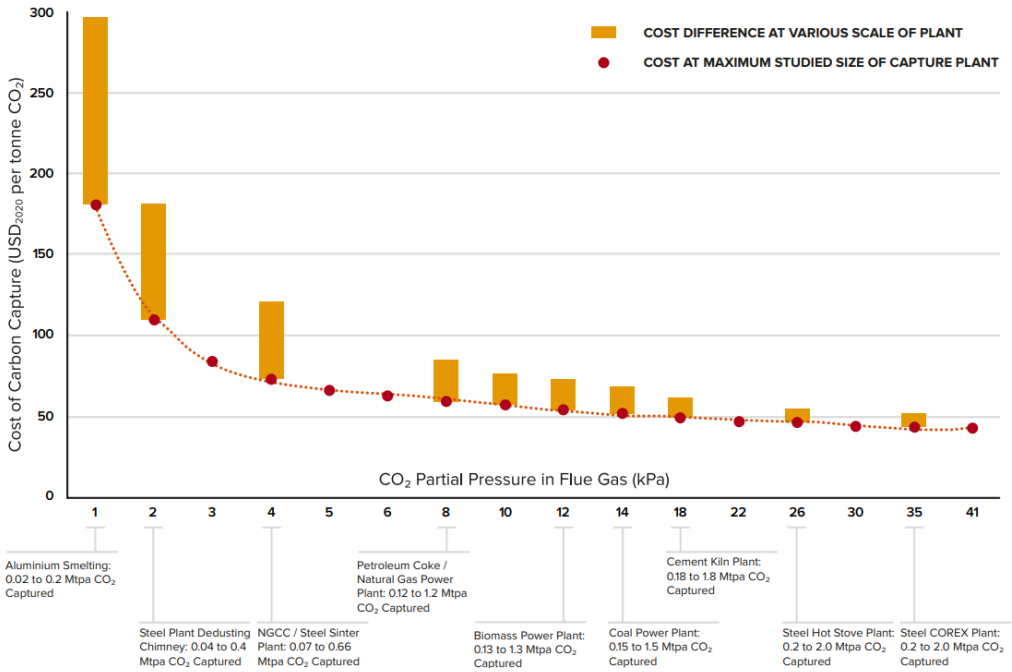


Figure E.12 Costs of CO_2 capture for different CO_2 concentrations and volumes

Source: Kearns et al. (2021)

Table E.21 Overview of CO_2 capture costs from different sources

	CO_2 costs in €/tCO_2		**Source**
Coal gasifier	28-40		Dieterich et al., 2020
Coal-fired power plant	31-49		Dieterich et al., 2020
Gas-fired power plant	47-90		Dieterich et al., 2020
Refinery	18-71		Dieterich et al., 2020
Steel production	70-73		Dieterich et al., 2020
Cement production	58-87		Dieterich et al., 2020
Biogas plant	0-90		Dieterich et al., 2020
CO_{2-} airborne capture by 2020	222-268		Dieterich et al., 2020
	Short/medium-term CO_2 costs in $€_{2015}$ /tCO_2	Long-term CO_2 costs in $€_{2015}$ /tCO_2	
Natural gas power plant	20-60	10-60	Brynolf et al., 2018
Coal-fired power station	30-170	10-100	Brynolf et al., 2018
Refinery / petrochemical industry	60-140	30-90	Brynolf et al., 2018
Cement production	70-150	30-50	Brynolf et al., 2018
Iron and steel production	50-70	30-60	Brynolf et al., 2018
Ammonia production	<20	<20	Brynolf et al., 2018
Bioethanol production, biogas upgrading	<20	<20	Brynolf et al., 2018
CO_{2-} capture from the air	n.a.	20-950	Brynolf et al., 2018

Improvement potential

CO_2 capture based on amine solvents (i.e. post-combustion) is currently the most cost-efficient and developed technology. This technology has also been demonstrated on a commercial scale (Koytsoumpa, 2018). Currently, it takes approximately 2.6 GJ/ton CO_2 of energy to capture CO_2 (Liang et al., 2015). This can be further reduced by optimising heat integration. In addition, the costs could be reduced by further optimising the process components (Koytsoumpa, 2018).

Theoretical minimum

If we assume normal conditions (20° C, atmospheric pressure) and 10-15% CO_2 in the exhaust gases, it will take at least 4.65-5.64 kJ/molCO_2 or 106-128 MJ/tCO_2 to capture the CO_2 (Krekel et al., 2018). In short, there is still considerable room for improvement in the energy use of CO_2 capture.

According to Liang et al. (2015), the current energy use for MEA-based CO_2 capture at a coal-fired power plant is about 2.6 GJ/tCO_2 and could soon be reduced to 2.0 GJ/tCO_2 through new solvents and other mixes.

Production of FT synfuels from CO_2 and H_2

Current technology

Section 5.3.1 of the Biofuels chapter describes the production of FT synfuels from biomass. The process for producing FT synfuels from a pure stream of CO_2 and H_2 is not very different. The main difference is that no gasifier and processes are needed to clean the gas. The supplied hydrogen and CO_2 are most likely already of sufficient quality to be used immediately in the water-gas-shift reactor. The fuel synthesis process does require a CO_2 pressure of around 3 MPa (Keith et al., 2018), which often requires a compressor before synthesis can take place. Since there is no carbon monoxide (CO) present when using hydrogen and CO_2 as feedstock, this does mean that a relatively large amount of H_2 is required to obtain a good ratio of H_2 to CO. About 12 (10-13) kg H_2/GJ_{fuel} and 78 kg CO_2 $/GJ_{fuel}$ are needed (Brynolf et al. 2018). After the WGS reactor, the production process of FT synfuels from biomass or from hydrogen and CO_2 looks identical.

Cost and efficiency of current technology

The cost and efficiency of this step is somewhat different from that of the FT biofuels (Chapter 5), as no gasifier is required. In table E.4 shows an overview of the costs and efficiencies we found in the literature. It is notable that economies of scale can be achieved by making the plant large, as the lowest cost estimates are for the largest plants.

In this study, we adopt the lifetime (25 years), OPEX (4%), average efficiency (73%) from Brynolf et al. (2018). For the lowest CAPEX estimate we assume 0.3 €/MW, for the middle cost estimate 1.3 €/MW and for the highest 3.0 M€/MW.

Table E.22 Cost and efficiency of FT synthesis from H_2 and CO_2

Efficiency	Capital cost (Million/MW)	Scale (MW LHV output)	Service life (years)	O&M (as % of CAPEX)	Notes	Source
73% (63%-83%)	1.3 M€$_{2018}$	5	30	2%	Use of H_2 and CO_2.	Christensen and Petresko (2017), costs based on Brynolf et al.
n.a.	3.0 M€$_{2015}$	2	5 (depreciation period)	3%	Main equipment cost for direct CO_2 FT synthesis.	Smejkal et al. (2014)
69%	0.79 M€$_{2015}$	28	10	4%	Main equipment cost plus additional indirect cost of 30% (excluding engineering construction costs and contingency)	Tremel et al. (2015)
51% (including H_2 production)	0.66 M€$_{2015}$	27,8	20	7%	Main and auxiliary equipment and installation	Becker et al (2012)
68,2% (44.6% including H_2 production)	0.31 M€$_{2015}$	690	30	7%	FT reactor, hydrocracker and RWGS reformer. 31.2% petrol; 43.9% kerosene and 24.9% diesel	König al. (2015)
73% (63%-83%) LHV	1.3 (0.8-2.1) M€$_{2015}$	5	25	4%		Brynolf et al (2018)
	0.7 (0.4-1) M€$_{2015}$	50				
	0.4 (0.3-0.7) M€$_{2015}$	200				
73% (LHV)	0.89 M$$_{2017}$	n.a.	30	4%	Today	IEA (2019b)
73% (LHV)	0.76 M$$_{2017}$	n.a.	30	4%	2030	IEA (2019b)
73% (LHV)	0.57 M$$_{2017}$	n.a.	30	4%	Long term	IEA, (2019b)

FT synfuel storage, transport, distribution and refuelling infrastructure

FT synfuels are very similar to normal petrol, diesel and kerosene. As a result, the existing transport, storage, distribution and refuelling infrastructure can be used.

Current technology

Crude oil usually enters the port by ship. Via one of the oil refineries in the port area, the crude oil is converted into petrol, diesel and kerosene. In addition, ships that transport fuels directly also enter the port. In the port area, there are large tank cylinders where the crude oil and oil products can be temporarily stored. Via pipelines, barges and railways, the products are further distributed in the Netherlands or transported abroad.

There are various storage and transhipment facilities for liquid fuels in the Netherlands. Here, petrol and diesel is temporarily stored and pumped into tankers that supply roadside petrol stations. Pipelines or ships can often be used for inland waterway vessels, aeroplanes and sea-going vessels as they handle larger quantities of fuel compared to filling stations for cars and trucks. Seagoing vessels are usually refuelled at sea (ship-to-ship method), at the quay, at anchor or while loading or unloading. The latter two options are attractive as they save time (and therefore money). The bunker ship pumps the fuel to the other ship via a hose. The capacity of a bunker ship varies from 1,000 to 10,000 m^3 (Lieshout et al., 2020). In the case of inland navigation vessels, refuelling often takes place via a floating pontoon which is tied up on the shore.

Cost and efficiency

The costs of storage, transport, distribution and fuelling of drop-in fuels are very small compared to the production costs. Partly because of sensitivity to competition, not many cost estimates can be found in the literature. Table E.5 shows the costs of distribution, storage and refuelling of FT synfuels if they are used for road transport, inland shipping and sea-going vessels. If the FT synfuels are needed for trucks or cars, they will probably be delivered to filling stations with tankers. The cost depends on the distance over which they are transported.

For inland and seagoing shipping, the FT synfuels will probably be delivered by ship. In principle, economies of scale also apply here: fewer refuelling trips or less ship volume result in higher costs per energy unit.

As a cost estimate we assume a cost range of 0.6 (0.5-0.9) €/GJ for road transport distribution and 0.9 €/GJ for tank infrastructure. For all other modes we have assumed a cost range of 0.3 (0.15-0.5) €/GJ for tank infrastructure (including storage).

Based on the JRC well-to-wheel study (Prussi et al., 2020), we assume that long-distance transport of 5,500 km by ship costs about 0.03 GJ/GJ_{fuel} . Distribution costs about 0.01 GJ/GJ_{fuel} and is based on a mix of rail (20%), pipeline (60%) and ship (20%). Storing FT fuels consumes about 0.0025 GJ/GJ as energy is needed to pump the liquid (Prussi et al., 2020). In addition, refuelling also uses about 0.01 GJ/GJ_{fuel} . This is electricity for pumping the fuel and lighting, among other things (Prussi et al., 2020).

Table E.23 Distribution and refuelling costs of FT synfuels

	Distance	Cost (€/GJ)	Note	Source
Tank wagon	500 km	1.1	Distribution	SmartPort (2020)
	200 km	0.6	Distribution	
	100 km	0.5	Distribution	
	n.a.	0.9	Road transport refuelling infrastructure	
Inland vessel	n.a.	0.5[a]	Bunker barges of 25 tonnes (1,138 GJ per load) and 4 calls per day.	SmartPort (2020)
Seagoing ship	n.a.	0.15[a]	Bunker sea-going vessels of 500 tonnes (22,750 GJ per load) and 3 calls per day.	SmartPort (2020)
Diesel infrastructure (for ships)	n.a.	0.3[b]	Including storage, handling and bunkering	Taljegard et al. (2014)

[a] The costs are based on the costs of cargo ships and assumptions about the number of refuelling operations per day. These costs still need to be validated by the industry.

[b] Investment costs are 0.1 M€/MW_{fuel} and O&M costs are 2% of investment costs. The lifetime is 30 years. With a discount rate of 4% and a capacity factor of 100% this amounts to 0.3 €/GJ.

Methanol production

Approximately 85 Mt of methanol is produced globally each year (McKinlay et al., 2021). This methanol is used in the production of e.g. paint, carpet, building materials and in the pharmaceutical industry. Meanwhile, fuels and energy-related applications account for almost half of the methanol demand (Port of Rotterdam, 2021).

Currently, methanol is mostly produced from gasification of coal or reforming of natural gas. There is also methanol produced from gasification of biomass or waste. For example, there is a plant in Rotterdam that converts 350 thousand tonnes of waste (including plastic) into 270 million litres of bio-methanol annually (Hobson and Márquez, 2018). Production of methanol from CO_2 and H_2 has a TRL of 6-7 (Pérez-Fortes et al., 2016). Since 2008 there has been a pilot plant with an annual production of 100 t of methanol in Osaka, Japan. In addition, since 2012 there has been a demonstration plant in Iceland producing approximately 4,000 tonnes of methanol per year. This uses 5.5 kt CO_2 captured at a geothermal power plant, and hydrogen from a 6 MW electrolyser (IEA, 2019b; Svanberg et al., 2018).

Current technology

The current process for producing methanol is gasification of coal (65%) or reforming of natural gas (35%) (IEA, 2019b). In addition, oil, biomass or waste can be used. Gasification (or natural gas reforming) produces syngas consisting mainly of CO and H_2 (Liu et al 2019). Using a water gas shift reaction ($H_2 + CO_2 \rightarrow H_2O$ and CO), the mixture can be fine-tuned so that the ratio of H_2 and CO is good. After purification the syngas is converted into methanol via the following reaction:

$2\ H_2 + CO \rightarrow CH_3OH$ -91.0 kJ/mol

This reaction is highly exothermic, requiring a boiling water reactor (BWR) to dissipate the heat formed (Marlin et al., 2018). BWRs are expensive, but necessary to ensure that the catalyst and reactor are not damaged. Due to the high dependence on fossil fuels, approximately 2.3 (0.8-3.1) tCO_2 per t of methanol is emitted, with a range of 0.8-3.1 tCO_2 /t of methanol in different regions (IEA, 2019b). Here the use of coal as a feedstock leads to the highest CO_2 intensity.

When methanol is produced with a pure stream of CO_2 and H_2 the production process is simpler than when using syngas from biomass, natural gas or coal. Firstly, the ratio of H_2 and CO_2 can be precisely controlled and no (reversed) water gas shift reaction needs to take place. Secondly, CO_2 and H_2 can react directly to produce methanol, which creates less heat than the reaction between CO and H_2. This allows the use of a tube-cooled reactor, which is less expensive and less complex than a BWR. In addition, the use of H_2 and CO_2 leads to better conversion efficiency.

The production process is as follows. First, H_2 and CO_2 are compressed to 50-100 bar and heated to 200-300°C (Rivarolo et al., 2016). In principle, lower temperatures lead to more methanol, but then the reaction rate is too slow (Nieminen et al., 2019). The streams are then transferred to a reactor vessel with a $CuO/ZnO/AL_2\ O_3$ catalyst. This catalyst is commercially available and is normally used for CO/CO_2 streams and is less efficient when only CO_2 is available (Pérez-Fortes et al., 2016). In the reactor vessel, the following two reaction equations take place.

$CO_2 + 3\ H_2 \rightarrow CH_3OH + H_2\ O$

$CO_2 + H_2 \rightarrow CO + H_2O$

The first reaction produces the desired product, methanol and water. In the second reaction, CO_2 and H_2 react to CO and H_2O. This reaction is undesirable but cannot be prevented. In the reactor, approximately 20% of the CO_2 is converted to MeOH and less than 1% of the CO_2 is converted to CO (Pérez-Fortes et al., 2016). In addition, a number of by-products are formed such as ethanol, esters (e.g. DME) and ketones (e.g. acetone). Distillation is used to separate these substances from the methanol. However, this takes a lot of energy and is expensive (partly because the boiling points of some by-products are around or above those of methanol). The extent to which by-products are formed depends very much on the concentration of CO. An additional advantage of using pure CO_2 and H_2 is that fewer by-products are formed than when using natural gas, biomass or coal, which can make the separation process easier (Marlin et al., 2018).

After the reaction, the product streams are cooled to around 35°C and de-pressurised. Most of the reacted H_2 , CO_2 and CO is recycled, and a small part is used to generate steam to prevent the build-up of inert gases. The liquid stream is taken to a distillation column. Here the methanol is separated from the water formed (Pérez-Fortes et al., 2016) and other liquid by-products, such as ethanol, ethers and esters.

Cost and efficiency of current technology

A literature review of the costs and efficiencies found for methanol synthesis can be found in table E.6. The efficiencies range from 68% to 90%, with the highest efficiency being for synthesis plants built in 2030 or even further into the future. In general, the electricity generated by burning residual streams (consisting mainly of CO and H_2) covers the electricity demand of the process, which consists of driving the compressors and various pumps. One study mentionsa modest electricity demand and another of a modest electricity production. In this study we assume that the methanol synthesis process does not require electricity import or export.

According to Brynolf et al. (2018), the methanol synthesis process today has an efficiency of about 80% (70%-84%) and improves to 84% (80%-89%) in 2030. We use the average data for 2030 in this study. The entire energy loss is accounted for by the hydrogen input.

The costs also vary between the different sources from 0.02 M€/MW to 1.2 M€/MW. The two sources with costs below 0.05 M€/MW seem to be outliers, as the rest are (far) above 0.2 M€/MW. It is not clear what causes these low capital costs. However, it is clear that in the capital costs, heat exchangers and compressors account for the majority of the costs (Pérez-Fortes et al., 2016). For the calculation we assume the capital costs of Brynolf et al., (2018); that is 0.5 M€/MW for the base case, 1.0 M€/MW as high and 0.3 M€/MW as low cost estimate. In this range all other capital costs fall with the exception of the two outliers of Szima and Cormos (2018) and Pérez-Fortes et al., (2016).

In general, large methanol synthesis plants with an output of around 200 MW have lower capital costs than small methanol synthesis plants. This methanol plant produces about 290 kt of methanol or 5.8 PJ of methanol annually with 8000 running hours. It requires approximately 55-67 kt H_2 and 405-624 kt CO_2 annually.

Table E.24 Cost and efficiency of methanol synthesis from hydrogen and CO_2

Efficiency	CO_2 input (t/tMeOH)	H_2 input (t/tMeOH)	Electricity input (kWh/t methanol)	Capital costs (M€/MW)	Scale (MW output)	Lifetime (years)	O&M (% of CAPEX)	Notes	Source
79% (69%-89%)	1.9 (1.7-2.2)	0.22 (0.18-0.23)		1.0 (0.6-1.2)	5	25	4%	Highest efficiency by 2030	Brynolf et al., 2018
				0.5 (0.3-0.6)	50				
				0.3 (0.2-0.4)	200				
78% (25.4 GJ/t)				0.79	n.a.	25	1.5%	Today	IEA, 2019b
84% (23.7 GJ/t)				0.60	n.a.	25	1.5%	2030	
90% (22.2 GJ/t)				0.38	n.a.	25	1.5%	Long term	
53% (including electrolysis)				0.81	205	n.a.	4%		Clausen et al., 2010
68%				0.83	13	20	n.a.		Nieminen et al., 2019
85%	1.41	0.194	$-6.3 * 10^{-5}$	0.03	63	25	2%	SOTA	Szima and Cormos, 2018
87%	1.40	0.19		0,.63	0.6	15	4%	SOTA	Rivarolo et al., 2016
83%	1.46	0.199	0.169	0.02	278	20	n.a.	SOTA	Pérez-Fortes et al., 2016

Methanol transport, storage and refuelling

Methanol has been produced for 100 years, so there is also a lot of experience in the safe storage and transport of methanol (Hobson and Márquez, 2018; Wartsila, 2021). In Europe, approximately 7.5 Mt of methanol was used in 2018 while only 1.5 Mt of methanol was produced (Lieshout et al., 2020). The Netherlands serves as a European hub in the distribution of the imported from e.g. Trinidad, Venezuela, United States and Russia (Lieshout et al., 2020).

Methanol is currently mainly used in the chemical industry, although its use as a fuel in the maritime sector is growing due to the many pilots. Methanol distribution can be considered a reasonably mature market (Lieshout et al., 2020), while fuelling has been done but is not yet standard practice.

Current technology

In principle, because methanol is liquid, it is as easy to transport and store as current liquid transport fuels (IEA, 2019b). Methanol can be transported by trucks, ships and pipelines. The mode is used to transport the fuel also depends on where and on what scale the fuel is used.

A number of ships are already running on methanol. Methanol is an interesting alternative to regular fuel oil or diesel, because methanol complies with strict environmental requirements that apply in areas with strict sulphur emission regulations, so-called SECA areas.[138] Partly because of this, several ships are equipped with dual-fuel engines that run on both diesel and methanol. Concrete examples are the 240m ferry between Gothenburg and Kiel (Wartsila, 2021) and a touring boat on the German Baldeneysee (Hobson and Márquez, 2018). Waterfront Shipping has been operating methanol-powered ships for five years now, which together have sailed more than 100,000 hours (Port of Rotterdam, 2021).

To make the bunker ships suitable for methanol bunkering, the ships must be slightly modified. The cost of this is estimated at €1.5 million per bunker ship (Svanberg et al., 2018).

Cost and efficiency

Table E.7 lists the costs of transporting and refuelling methanol. Trucks are particularly interesting for distributing relatively small volumes. This is currently the case, as only a few ships run on methanol. However, by 2050 it is expected that methanol will be used on a large scale in the maritime sector or that another fuel will have taken over the market. In this study, we do not include the use of methanol for road transport. This means that distribution by trucks is not considered for this study.

The other three sources are used in this study as a cost range, where we assume 0.4 €/GJ for the base case, and 0.2 €/G and 0.6 €/GJ as minimum and maximum respectively.

Based on the JRC well-to-wheel study (Prussi et al., 2020), we assume that long-distance transport by a large ship over 5500 nautical miles (over 10 thousand km) uses about 0.07 GJ/GJ_{fuel}. Storing methanol consumes about 0.01 GJ/GJ as energy is needed to pump the liquid (Prussi et al., 2020). In addition, refuelling also uses approximately 0.01 GJ/GJ_{fuel}. This is electricity for pumping the fuel and lighting,

[138] In Europe, this includes the Baltic Sea and the North Sea.

among other things (Prussi et al., 2020). Although the latter is energy consumption for road transport, we assume it is comparable to methanol bunkering.

Table E.25 Methanol distribution and refuelling costs

	Distance	Cost (€/GJ)	Note	Source
Truck	500 km	2.6	Distribution	SmartPort (2020)
	200 km	1.4	Distribution	
	100 km	1.0	Distribution	
	n.a.	2.0	Road transport refuelling infrastructure	
Inland vessel	n.a.	0.6[a]	Bunker barges of 25 tonnes (1,138 GJ per load) and 4 calls per day.	SmartPort (2020)
Seagoing ship	n.a.	0.2[a]	Bunker sea-going vessels of 500 tonnes (22,750 GJ per load) and 3 calls per day.	SmartPort (2020)
Methanol infrastructure (for ships)	n.a.	0.4[b]	Including storage, handling and bunkering	Taljegard et al., 2014

a. The costs are based on the costs of cargo ships and assumptions about the number of refuelling operations per day. These costs still need to be validated by the industry.
b. Investment costs are 0.2 M€/MW_{fuel} and O&M costs are 2% of investment costs. The lifetime is 30 years. With a discount rate of 2.25% and a capacity factor of 100% this amounts to 0.4 €/GJ.

Methanol in vehicle

Combustion engines can be adapted relatively easily for methanol combustion (Hobson and Márquez, 2018). Methanol can be used in both a petrol engine and a diesel engine (Liu et al 2019). Few modifications are required for the use of methanol in a gasoline engine (Svanberg et al, 2018). This is different for methanol use in a diesel engine. Since methanol has a higher flammability temperature than diesel, methanol must be mixed with an ignition enhancer to burn it in a diesel engine (Lieshout et al., 2020). Another option is to mix methanol with a small proportion of diesel (2-20%) to make it suitable for use in a diesel engine[139] (Lieshout et al. 2020). It is expected that, especially in the shorter term, the option with diesel will become the most popular as the diesel technology is known and thus the high efficiency is maintained (Lieshout et al., 2020).

Without additional safety requirements, the safety risk increases when methanol is used as fuel in the maritime sector instead of diesel or fuel oil. This is due to the low evaporation point of methanol (< 60°C), which can quickly produce flammable and toxic methanol vapours (Lieshout et al., 2020). With a number of safety requirements, the risk level on the ship can be made comparable to ships that run on conventional fuels. These include, for example, an adapted fuel injection system, sealing materials to prevent leaks, and adapted safety training, systems and procedures (Wartsila, 2021). The risk assessments of eight existing methanol-fuelled

[139] A diesel engine works on the principle that the diesel ignites spontaneously due to the combination of high pressure and temperature.

ships show that these ships are at least as safe as ships that run on conventional fuels. This shows that safety is not a barrier to switching to methanol (Svanberg et al., 2018).

Ammonia production

Current technology

Currently, ammonia is mainly produced via the Haber-Bosch process in which N_2 reacts with hydrogen, see reaction equation below:

$N_2 + 3\ H_2 \rightarrow 2\ NH_3$ (exothermic 2,6MJ/kg NH_3)

The nitrogen needed today is produced by distilling air. Pure oxygen is released during nitrogen production and can be sold as a by-product. The boiling point of nitrogen is -196°C, which means that the air must be cooled strongly. This requires electricity.

The required hydrogen is currently produced mainly from fossil fuels such as natural gas. However, hydrogen can also be produced in a green way using green electricity and electrolysis (Ikäheimo et al., 2018) or with biomass (Nayak-Luke et al., 2021). However, both options are currently still more expensive than using natural gas, so the vast majority of ammonia is produced using fossil fuels.

The Haber-Bosch process is an industrial process with a conversion efficiency of over 95%. This high conversion efficiency is not achieved in one go; the hydrogen and nitrogen are passed through the reactor vessel several times.

Costs and energy consumption

There is a strong relationship between plant size and production costs due to relatively large economies of scale (Nayak-Luke et al., 2021). To get an idea of scale; an ammonia plant with a capacity of 700 tonnes per day can approximately meet the daily energy requirements 4 large (Postpanamax) ships (Ash and Scarbrough, 2019). Table E.8 presents a summary of the costs of ammonia production found in the literature. It is difficult to compare costs one-to-one because some include the costs of hydrogen and nitrogen production, while others do not. Hydrogen production is a dominant cost factor and accounts for half to two-thirds of the capital costs based on current technology (Nayak-Luke et al., 2021). Since we looked in detail at the costs of hydrogen production in chapter 3, we focus here only on the synthesis process.

The capital costs and ultimately the production costs also depend on where the required energy comes from. The electricity required can come from the grid, be self-generated or a combination of both (Nayak-Luke et al., 2021). The advantage of self-generation is that the production costs are much lower and less variable. However, the capital cost of the plant will be higher and the plant will have a lower capacity factor. An ammonia synthesis plant producing 300 tonnes of NH_3 per day will continuously require approximately 8 MW of electricity for the various compressors, or 0.64 MWh_e per tonne of NH_3 (Morgan, 2013).

This means that a storage of about 0.7 GWh_e is needed if there is no wind or sun for a day. If hydrogen production is also done at the same location, even 145 MW_e (or 11.6 MWh_e per ton NH_3) and a buffer of 13 GWh would be needed. Another possibility is to stop ammonia production if no sustainable electricity is available. This is not easy, as the ammonia synthesis process works best when there are no disturbances in the composition of the inflow and in the temperature. Fluctuations in either can permanently damage the catalyst, reducing its efficiency. Another option

is to have nitrogen and hydrogen in stock, so that the synthesis process can run continuously. However, this creates challenges for both the nitrogen and the hydrogen production process. In short, the consequence of variable power generation is a concern for ammonia production.

In this study we assume that the electricity comes from the grid and the ammonia production has a high capacity factor of 80%. For the normal cost estimate we use the data from Nayak-Luke et al. (2021) with a capacity of 1 t NH_3/day. For the optimistic cost estimate, we use the lowest CAPEX estimate from Ash and Scarbrough (2019) for an ammonia synthesis plant with ASU. For the pessimistic cost estimate, we use the data from Ikäheimo et al. (2018).

We use the efficiency data from Aziz et al. (2018) as the base case and lower bound. This gives an ammonia synthesis efficiency of 66.69%. In addition, there is a small amount of electricity output by burning the unreacted hydrogen which increases the efficiency by 0.23% point, bringing the total efficiency to 67%. Aziz et al. (2018), in contrast to Morgan (2013), seem to take better account of heat integration and the fact that unreacted hydrogen cannot be recycled indefinitely in the system because impurities (such as argon) then build up in the system. Morgan's efficiency is 79% and we use this as an upper limit.

Theoretical maximum and improvement potential

The Haber-Bosch process uses more energy (28-31 GJ/t) than the theoretical minimum (18-21 GJ/t). Therefore, there is still some room for improvement. This is mainly in the degree of (heat) recycling and the number of catalytic steps. Per step, only a part of the hydrogen reacts with the nitrogen (approximately 15-20%), and thus the hydrogen and nitrogen have to pass through the process several times to get a good conversion to ammonia.

Pressure reduction and another catalyst are also possible options for improvement (Morlanés et al., 2021). However, not much improvement is to be expected since the process has been around for a long time and a lot of ammonia is already produced. Morlanés et al., (2021) estimate that the energy use of ammonia production (including hydrogen and nitrogen production) could decrease from the current 10 MWh/t NH_3 to 8 MWh/t NH_3 in 2050, or from 36 GJ/t NH_3 to 29 GJ/ton NH_3. As a tonne of ammonia has an energy content of 18.6 GJ, almost twice as much primary energy is needed today to produce the ammonia and this is expected to drop to a factor of 1.6 in the future.

Table E.26 Costs and efficiency of ammonia production

	Electricity (MWh/t NH_3)	**Capacity (tNH_3/day)**	**Capital costs (Million/t NH_3 per day)**	**Service life (years)**	**Variable costs**	**Source**
Ammonia synthesis	0.64	1	2.26 M$	n.a.	1.5% (2-5%) or CAPEX	Nayak-Luke et al., 2021 and Morgan, 2013
		20	0.68 M$	n.a.		
H_2 and N_2 production, ammonia synthesis, storage	11.6	1	3.73 M$	n.a.		
		20	0.68 M$	n.a.		
Ammonia synthesis and ASU	0.64 (+ export of heat 0,7 MWh/t NH_3)	n.a.	4.0 M€	20	2% of CAPEX	Ikäheimo et al., 2018
Ammonia synthesis + H2 production - today	10.5	n.a.	0.95 M$2017	25	1.5% or CAPEX	IEA, 2019b
Ammonia synthesis + H2 production - 2030	9.8	n.a.	0.86 M$2017	25		
Ammonia synthesis + H2 production - long term	9.2	n.a.	0.76 M$2017	25		
Green ammonia plant (excluding energy production) - including desalination plant and electrolyser	10.5	700	0.98-1.13 M$	n.a.	2% of CAPEX	Ash and Scarbrough, 2019.
Ammonia synthesis plant	n.a.	700	0.16-0.34 M$	n.a.	2% of CAPEX	
Ammonia synthesis plant + ASU	n.a.	700	0.23-0.39 M$	n.a.	2% of CAPEX	

Capacity and spatial aspects

It is convenient to locate the sustainable ammonia plant where water and green electricity are available (Nayak-Luke et al., 2021) in order to reduce transport distances of hydrogen and electricity.

Most ammonia plants produce between 1,000 and 1,500 tonnes per day. The really big plants produce 3,000 tonnes per day (Morgan, 2013). An example of such a large factory can be found in Sluiskil, the Netherlands, which produces approximately 1.8 Mt of ammonia per year (and is then further processed into fertiliser). This industrial site has a surface area of 135 hectares (Pellikaan, 2019). However, in addition to three ammonia plants, the site also contains four CO_2 plants, two nitric acid plants, three urea plants and two nitrate granulation plants. In short, a footprint of 75 hectares per Mt ammonia is an overestimate of the actual area.

In the total shipping industry in the Netherlands, almost 500 PJ of fuel was sold in 2020 (CBS, 2021). If we assume the same type of engine efficiency for ammonia as for diesel or fuel oil, this amounts to 27 Mt of ammonia per year. In short, approximately 15 ammonia plants of the size of Sluiskil are needed in the Netherlands to produce the ammonia required to power all the ships in the country.

Ammonia transport

In the United States, approximately 38% of all ammonia was transported by tanker, 32% by pipeline, 23% by ship and the rest by train in 2017 (Elishav et al., 2020). The average distance that ammonia travels for each mode of transport in the US is 190, 450, 1750 and 1850 km respectively (Elishav et al., 2020).

Current technology

Existing natural gas pipelines may be used to transport ammonia (instead of natural gas). New ammonia pipelines could also be built. The advantage of pipeline transport is that operational costs are low and safety risks are low (Nayak-Luke et al., 2021). Technically, pipeline transport of pressurised ammonia is relatively easy (Kranenborg et al., 2020). However, pipelines require large investment costs and they offer little flexibility in terms of destination.

As ammonia is mainly a fuel option for inland and seagoing vessels, it is a logical option to also transport the fuel by ships. Currently, loading infrastructure and large storage tanks for ammonia are already present near the ports. With ship transport, there are relatively large economies of scale: the larger the ship, the lower the cost per tonne of ammonia. This makes it interesting to transport the ammonia with large ships, provided there is sufficient demand for ammonia and the port can handle the ships. As with hydrogen storage, ammonia storage creates a boil-off that needs to be managed (McKinlay et al., 2021).

Ammonia transport by tankers is particularly interesting for bridging short distances and transporting small volumes. The safety risks for ammonia transport by road are higher than for LPG or petrol when normal tankers are used (Duijm et al., 2005). If an accident occurs, consequences are visible at more than 600 m distance from the accident. Because the probability of an accident is small and the number of tankers transporting ammonia is limited, the transport still falls within the maximum permitted individual risk level of 10^{-6} (Duijm et al., 2005). However, Duijm et al. recommend to look at measures that reduce the risks of road transport of ammonia or to choose another modality to transport ammonia.

Costs

Table E.9 shows an overview of the costs of transporting ammonia by different modes over different distances. The costs are relatively small and vary from about 0.2-0.4 €/GJ for 200 km by ship, pipeline or train to about 18 €/GJ for 1600 km by truck. The latter, however, is an expensive modality to bridge a long distance. The same distance costs only 0.9-3.6 €/GJ (1-4 $/GJ) by ship, 5.1-7.0 €/GJ by train (5.7-7.8 $\$_{2019}$ /GJ) and 1.7-3.5 €/GJ by pipeline (1.9-3.9 $\$_{2019}$ /GJ).

Table E.27 Summary of ammonia transport costs

	Distance	Costs	Note	Source
Pipeline	1600 km	3.9 $\$_{2019}$ /GJ	Based on price difference between two regions	Elishav et al., 2020
	1600 km	2.8 $\$_{2019}$ /GJ	Commercial rate	Elishav et al., 2020
Pipeline	1600 km	1.9-3.9 $\$_{2019}$ /GJ		Ikäheimo et al., 2018 from Elishav et al.
Pipeline	200 km[1]	0.4-0.5 $/GJ		Nayak-Luke et al., 2021
	1600 km[1]	3.4-4.3 $/GJ		
Train	200 km[1]	0.4 Aus$$_{2018}$ /GJ	Quoted in both The Royal Society and Cardoso et al.	ACIL Allen Consulting, 2018
	1600 km[1]	3.4 Aus$$_{2018}$ /GJ		
Train	1600 km	5.7-7.8 $\$_{2019}$ /GJ	Based on the United States	The public use waybill sample, 2017 from Elishav et al.
Maritime transport	640 km	0.9 $\$_{2019}$ /GJ	Based on the United States, data from 1998	Elishav et al., 2020
Maritime transport	2080 km	2.1 $\$_{2019}$ /GJ	Based on the United States, data from 1998	Elishav et al., 2020
Maritime transport	-	1-4 $\$_{2019}$ /GJ	Cost estimates depending on volume, route and distance.	Elishav et al., 2020
By ship	200 km[1]	0.3 Aus$$_{2018}$ /GJ	(requoted in both The Royal Society and Cardoso et al.)	ACIL Allen Consulting, 2018
	1600 km[1]	2.6 Aus$$_{2018}$ /GJ		
Truck	200 km	1.7 €/GJ	Chilled	SmartPort, 2020
Truck	200 km[1]	3.5 Aus$$_{2018}$ /GJ	(requoted in both The Royal Society and Cardoso et al.)	ACIL Allen Consulting (2018)
	1600 km[1]	28 Aus$$_{2018}$ /GJ		

1. Distances assumed, price is per km.
2. It is assumed that 1 Australian dollar is €0.63, based on exchange rates in early 2022.
3. It is assumed that 1 US dollar is €0.89, based on exchange rates in early 2022.

Ammonia storage

Since large-scale production of ammonia already takes place, a storage infrastructure is also already in place. Especially many seaports can tranship and temporarily store ammonia. The largest ammonia storage units are also located in the ports. The United States currently has around 10,000 different ammonia storage units (The Royal Society, 2020).

Current technology

Ammonia can be stored under light pressure, refrigerated or a combination of both. Under normal conditions, ammonia is gaseous so it takes up much more volume than when it is liquid or under pressure (Nayak-Luke et al., 2021). Pressure storage has the advantage that it does not require extra energy to keep the ammonia in a liquid phase so that operational costs are minimal. The disadvantage, however, is that it requires more steel (due to thicker walls) than refrigerated storage tanks. For this reason, large-scale storage usually takes place in cold conditions (-33° C) under atmospheric pressure. This can be done in a single or double insulated tank. A single tank is cheaper to purchase but has higher maintenance and operational costs. In addition, double-walled tanks have an additional safety advantage, as they are less prone to leakage (Nayak-Luke et al., 2021). In a double-walled tank, approximately 0.03% of the ammonia per day evaporates under the influence of heat from the environment. This ammonia boil-off is captured and recycled (Morgan, 2013).

Cost and efficiency

The cost of ammonia storage is relatively low due to relatively high density and no major losses (Ikäheimo et al., 2018). T Table E.10 shows the costs of ammonia storage. The capital costs are mostly around 1 M$/kt or 0.9 M€/kt. However, there are two outliers upwards of 2 and4 M$/kt or 1.8 and 3.6 M€/kt. The first is based on a small-scale ammonia tank with a capacity of up to 270 tonnes. The other is a large-scale storage tank that is not located at a plant. Nayak-Luke et al. (2021) also show that storage tanks are approximately 50% more expensive if they are not located at a factory but at ports, for example.

We could find almost no sources for the amount of energy it takes to keep the ammonia cool and for the variable costs. The exception is Nayak-Luke et al. The energy consumption and maintenance costs from this source are therefore used in this study.

Table E.28 Cost of ammonia storage.

	Pressure (bar)	Temperature (degrees C)	Storage capacity (tNH_3)	Capital cost (Million/kt)	Variable costs	Note	Source
Double-walled storage	1	-33	9000	0.72 M$2010/kt	n.a.	Including the cost of ammonia recycling	Morgan, 2013
Large-scale storage - near factory	1	-33	4,550	1.06 M$2019/kt	3% maintenance 37.8 kWh/t NH_3 (for cooling)	Costs including cooling system and construction.	Nayak-Luke et al., 2021
			25,000	0.81 M$2019/kt			
			50,000	0.56 M$2019/kt			
Large-scale storage - near port			4,550	1.59 M$2019/kt			
			25,000	1.22 M$2019/kt			
			50,000	0.84 M$2019/kt			
Storage tank for liquid ammonia	n.a.	n.a.	$30 * 10^9$	0.52 M$/kt	n.a.		From Leighty and Holbrook (2012) in Ikäheimo et al., 2018
Cylindrical double-walled storage tanks	1	-33	n.a.	0.65-0.90 M€/kt	n.a.		Ikäheimo et al., 2018
Small-scale storage	10	20	Max. 270	3 M$/kt	n.a.	Based on small-scale tanks used in agriculture	Nayak-Luke et al., 2021
Refrigerated ammonia storage tank	n.a.	n.a.	10	2-4 $M\$_{2019}$ /kt	n.a.	Standalone storage tank	The Royal Society, 2020

Space requirement

The space required for storage is closely related to the storage capacity. A factory needs approximately one month of storage capacity. Export terminals need a storage capacity that is at least 25-50% larger than the capacity of a ship to cope with early and late arrivals (Nayak-Luke et al., 2021). An ammonia ship has a capacity of approximately 15,000 m^3 with which it can transport approximately 11 kt of ammonia at a temperature of -34° C and a pressure of 1 bar. This means a storage capacity of at least 14-17 kt.

An import terminal must have a stock of 7-20 days (Nayak-Luke et al., 2021). A plant with a capacity of 300 t/d, using the rule of thumb of one month of storage capacity, needs a storage of at least 9000 t. With a margin of certainty of 10%, this means a volume of 14,500 m^3 . A double-walled tank of this volume has a diameter of 32 m and a height of 22 m (Morgan, 2013). This equates to an area of about 800 m^2. At the Qatar Fertiliser Company, two storage tanks of 50 Mt of refrigerated ammonia each occupy a piece of land of about 160 m by 90 m (or about 1.5 ha) (The Royal Society, 2020). Despite the storage volume being over 10,000 times larger, the area occupied is only 20 times larger. This demonstrates great economies of scale.

Improvement potential and theoretical maximum

Since a lot of ammonia is already produced and stored, it is not expected that there is much improvement potential in ammonia storage. In addition, there is not much room for improvement in terms of efficiency. Under the influence of heat, only 0.03% of the ammonia evaporates per day (boil-off). This ammonia is captured and recycled (Morgan, 2013). Better insulation could reduce this proportion. However, it is questionable whether this would be cost-effective.

Ammonia refuelling infrastructure

Technology description

Ammonia is only included in this study for shipping. The reason for this is that in the Netherlands ammonia is currently considered unsafe for road transport (Kranenburg et al., 2020). The risk of the toxic gas ammonia escaping in, for example, a tunnel and resulting in fatalities is considered too great for road transport. This risk is less great for ships, where sufficient safety measures can be taken to limit the risks.

Since ammonia is a gas, it has to be stored in the tank at a low temperature of -33 degrees Celsius and at atmospheric pressure. For inland vessels, the ammonia could also be stored at higher pressure (10 bar) and room temperature. However, this takes up almost twice as much space as refrigerated ammonia (Kranenburg et al. , 2020).

Costs

There are few cost estimates for ammonia tank infrastructure in the literature, see tabele E.11. Costs in the literature range from 0.3 to 1 €/GJ. These costs are relatively small compared to the production costs of ammonia which are (including hydrogen production) around 55 €/GJ.

Table E.29 Cost estimation for ammonia distribution and tank infrastructure

Mode	Cost (€/GJ)	Note	
Distribution and refuelling infrastructure for seagoing vessels	0.34 [a]	Including distribution costs. Bunker sea-going vessels of 800 tonnes (14,880 GJ per load) and 3 calls per day.	SmartPort (2020)
Distribution and tank infrastructure for inland vessels	1.01[a]	Including distribution costs. Bunker barges of 40 tonnes (744 GJ per load) and 4 calls per day.	SmartPort (2020)
Ammonia infrastructure (for ships)	0.8[b]	Including storage, handling and bunkering	Taljegard et al., 2014

a. The costs are based on the costs of cargo ships and assumptions on the amount of refuelling per day. These costs still need to be validated by the industry.
b. Investment costs are 0.4 M€/MW_{fuel} and O&M costs are 2% of investment costs. The lifetime is 30 years. With a discount rate of 2.25% and a capacity factor of 100% this amounts to 0.8 €/GJ.

Space requirement

There is a small chance of long-term ammonia leaks at filling stations due to broken fuel hoses. If this happens, there are serious safety risks at 150 m from the filling station, whereas this is 40 m for petrol and LPG (Duijm et al., 2005). However, due to the strong odour, ammonia leaks should be detected quickly (Cardoso et al., 2021). Nevertheless, it is essential to reduce the risk of long-term ammonia leaks.

Appendix F Biofuels additional background

Production routes and land use

In principle, there are several routes to making advanced fuels. The most common are:

- Alcoholic fermentation;
- Anaerobic processing;
- Gasification;
- Pyrolysis;
- Hydroprocessing;
- Hydrothermal liquefaction (HTL)

These routes are explained in more detail below.

Alcoholic fermentation

Alcoholic fermentation is a biochemical conversion route. Although the technology is not yet mature (TRL 8), alcoholic fermentation seems promising for the production of ethanol from "dry" waste streams, such as wood and vegetable, fruit and garden waste. Various demo and pilot plants exist within and outside the EU. In Europe, there are demonstration projects in Sweden, Norway, Finland, Germany and France, among others. These include:

- Clariant (sunliquid plant) in Germany;
- Chempolis Ltd (Chempolis Biorefining Plant) in Finland;
- North European Oil Trade Oy (Ethanolix GOT) in Sweden (capacity: 1-4 kt).

Two more plants are under construction in Romania (50 kt capacity) and Austria (50 kt capacity). At present, alcoholic fermentation cannot yet compete with existing ethanol production technologies. As a result, most of the facilities are shut down or run at low capacity. Among other things, the high energy consumption and the high production costs stand in the way of large-scale production. Therefore, in the coming years, much research will be done to improve the robustness and (cost-) effectiveness of alcoholic fermentation.

Anaerobic processing

Anaerobic processing is a biochemical conversion route and is used in particular for the production of biogas and biomethane from 'wet' waste streams, such as manure and sewage treatment plants (WWTPs). The technology is already commercially deployable (TRL 9).

Gasification

Gasification is a thermochemical conversion route. Suitable raw materials can be converted by gasification into synthetic gas (Syngas) and subsequently into liquid biofuels such as methanol and DME Fischer-Tropsch (FT) liquids. The current technology for biomass feedstock is not well developed (TRL 6-8), not cost-effective and so far only limited in its application. There are only two operational demonstration projects that produce Fischer Tropsch (FT) liquids on a small scale (Uslu et al., 2019). In addition, there are the Guessing gasifier in Austria and the Swedish GoBiGas, but both plants have been closed due to economic reasons.

Although existing operational capacity is small, a large number of new plants are planned in Europe for the production of methanol from waste streams in particular (approximately 50% of total planned capacity). These include the Waste2Chemical (W2C) project in the Netherlands. This is a joint venture between Air Liquide, Nouryon, Enerkem, Port of Rotterdam and Shell to build a methanol plant with a production capacity of 220 ktons (270 million litres). Non-recyclable waste is used as a raw material.

Pyrolysis

Pyrolysis is a thermochemical conversion process that converts biomass into liquid intermediate products known as pyrolysis oil or bio-oil. In pyrolysis, raw materials such as sawdust or roadside grass are heated to around 500 degrees Celsius in the absence of oxygen, resulting in crude bio-oil. With this technique, this process takes a few seconds, whereas it takes nature several million years to convert biomass into petroleum. On the one hand, this oil can be used for energy and heat generation (e.g. as an application in the built environment). On the other hand, pyrolysis oil can also be used to produce biofuel. The technology is well developed (TRL 9). Currently, there are three operational pyrolysis plants in the world, including one in Finland (Green Fuel Nordic OY) and one with a production capacity of 24 ktonnes (per year) in the Netherlands.

Hydroprocessing

Hydroprocessing is a thermo-chemical conversion process*. Hydrotreated vegetable oil* (HVO) and *Hydroprocessed Esters and Fatty Acids* (HEFA) are produced by hydroprocessing oils and fats. When animal fats and (used) cooking oil are used as raw materials, the fuel can be counted 'double' towards the renewable energy target according to the RED guideline. One of the largest commercial parties in Europe for the production of HVO is Neste Oil, with installations in Finland and the Netherlands. UPM Biofuels in Finland also produces HVO with tall oil.

Hydrothermal liquefaction (HTL)

HTL is a thermochemical conversion route. HTL is a promising technology used to convert wet biomass into liquid hydrocarbons under moderate temperature and high pressure. This technology is still under development at laboratory scale (TRL 3-4), but has the potential to revolutionise the production of gasoline and diesel substitutes.

Table F.1 gives efficiencies and costs of the FT process according to various sources. This does not include the cost of the biomass (the feedstock).

Table F.1 Costs and efficiencies of the FT process, based on the current state of the art of technology

Raw material	Capacity (MW)	Efficiency	Fixed costs	Variable costs	Details	Source
Eucalyptus pellets	804	54.9% à HHV	1391 M€$_{2008}$	474 M€$_{2008}$ over 20 years at 4%	65% CO_2 capture; basically polygeneration plant that can produce both power and fuels.	Meerman et al., 2012, 2011
Torrified wood pellets (TOPS)	990	58.4% to HHV	1461 M€$_{2008}$	498 M€$_{2008}$ over 20 years at 4%	60% CO_2 storage without taking into account energy needed to make TOPS	Meerman et al., 2012, 2011
Wood to diesel	n.a.	45.1% (with and without CCS)	n.a.	n.a.	Without CCS an electricity surplus of 0.1238 MJ/MJ_diesel otherwise a deficit of 0.0827 MJ/MJ_diesel.	Prussi et al., 2020
Wood to DME	n.a.	51,1%	n.a.	n.a.		Prussi et al., 2020
	200 MW	73% (63%-83%) to LHV	400 (300-700) (€2015/kWfuel	n.a.	Based on literature review and simple scale factor of 0.7	Brynolf et al,
Syngas (already produced from biogas and H_2)		62% for FT process à LHV				Hänggi et al., 2019
	1000 GW (7 billion of fuels)	53%	2023 (694-4930) $2005/kW	125 (46-654) $/kW	70% coal 30% biomass With CO_2 storage, 0.39 t/MWh and 0.07 emissions.	Aitken et al., 2016
Coal	2000 t/d Sasol seam 4 Coal a 29,74 MJHHV/kg dry coal. Coal has a moisterue content of 4,2%. à 1.87E + 08 GJ/y syngas		3190.6 MM$2005	127.62 MM$/y (O$M) + 785.20 MM$ (feedstock) - 22.6 MM$ (by-product revenue - sulphur)	100% coal	Chiuta et al., 2016

Based on the table we arrive at an average price of the FT process (excluding biomass feedstock) of 15.5 €/GJ biofuel. The minimum and maximum costs of the FT process are 1.2 and 42.7 €/GJ biofuel (based on the lower bound in Brynolf et al.

and the upper bound in Aitken et al., 2016 respectively), again excluding the cost of the feedstock (biomass).

Land use of biofuels

Due to the objectives and limits regarding the feedstocks for various biofuels, we specifically looked at the feedstocks as mentioned in Annex IX Part A of the EC Renewable Energy Directive II (RED II) (see figure 5.1 in chapter 5).

For a selection of these feedstocks, the land use (in m^2 per GJ biomass) was searched in literature. These feedstocks and their category in Annex IV Part A (including justification) are listed in table F.2. To indicate how these feedstocks fit into the potentials mentioned in Saddler (2020), visible in Table 5.2 in Chapter 5, it is also mentioned in which categories of that paper the feedstocks belong.

Table F.2 Feedstocks from literature and their category in Annex IV Part A

Feedstock from literature	Category in Annex IV Part A	Accountability	Category in Saddler (2020)
Short rotation coppice (Trainor et al., 2016)	*Other non-food cellulosic material*	In the Excel sheet with calculations from Trainor et al. (2016), data from *Miscanthus* and *Switchgrass* are used. These two crops are specifically mentioned in the definition of *Non-food cellulosic material* in EC (2018, p.23).	Agriculture (it is an energy crop)
Maize, rice field, wheat and soybean residues (Holmatov et al., 2021)	*Biomass fraction of industrial waste not fit for use in the food/feed chain*	These agricultural residues are not suitable for food or feed (EC, 2018, p.23-24).	Agricultural waste, residues and processing residues from forestry and agro-industry

Land use of energy crops
Land use for a number of feedstocks is shown in tabel F.2 and is based on a number of studies. Trainor et al. (2016) base the data for short rotation coppice on several papers, in which they look at dense vegetation of the studied wood species on one side, and wide vegetation on the other side. For both these extremes, they look at how many gallons of bioethanol one acre of coppice produces per year. The data they use assumes that the coppice is used specifically as biomass. There are no other uses, which means that 100% of the land use can be attributed to biomass production. (This is subject to the requirements of RED II and RED Rev. 3 (EC, 2018; 2021) on land use change and biodiversity conservation.) With an energy density factor (MJ/gallon) they determine the energy yield. It is not reported where this factor comes from, but the value used corresponds to public sources, such as the US Department of Energy (n.d.).

Land use biomass from agricultural residues
Holmatov et al. (2021) base their land use information on FAOSTAT, which provides data on global agricultural area and crop yields (in hg/ha) for all mentioned crops. They then apply residue production ratios from Koopmans & Koppejan (1997). In Koopmans & Koppejan (1997) the *residue-to-product ratio* (RPR) on a mass basis for

a large number of crops was determined on the basis of many earlier studies. In most of these earlier studies, it was explained how much mass of the crop is harvested in relation to the mass that remains in the field. Holmatov et al. (2021) then determined the energy content of each feedstock using heat of combustion (in MJ/kg). For the residue feedstocks, the required land is determined using the FAOSTAT data and the previously mentioned residue production ratio. The energy contained in the residue is then determined by Holmatov et al. (2021) based on its composition: the ratio of lignin, cellulose and hemicellulose, each with its own heat of combustion. It is important to note that residues are a good feedstock, but harvesting them depletes the land. As a result, extra fertiliser has to be used (as opposed to leaving more of the residue at harvest time), which in turn leads to higher CO_2 emissions. This is not considered further.

It is important to note that the data on cellulose in Trainor et al. (2016) already include the efficiency of conversion to fuel. In other words, the reported m^2 /GJ already refers to the final product. In Holmatov et al. (2021) this is not the case: here the combustion value of the crop is used for the calculation. In order to compare the different crops, an energy efficiency (the ratio of the amount of energy contained in the end product to the raw material) was therefore included in the reported value for the residues. The averages of the above-mentioned energy efficiencies were taken for this purpose. For bioethanol the energy efficiency is 43%, for FT biofuels 59%. By including the energy efficiency in the reported values, all values in table F.2 refer to the same parts of the process.

Finally, Trainor et al. (2016) only report the land use required for the production of bioethanol from cellulose, and not for FT biofuels from cellulose. In order to still be able to make a statement about the land use required when energy crops are used for the production of FT biofuels, the aforementioned energy efficiency is back-calculated. The range of Trainor et al. (2016), 35-230, concerns the land needed for a certain amount of bioethanol energy when an energy crop (cellulose) is used. For conversion to ethanol, an energy efficiency of 43% applies. This means that the land required for a certain amount of energy from the energy crop itself is 15-99 m^2 /GJ. By then applying the energy efficiency of FT biofuels, 59%, to this, the land required for a certain amount of energy from FT biofuels is obtained. This amounts to 26-168 m^2/GJ. This range is included in table F.3.

Table F.3 **Type of feedstocks and land use per primary energy unit**

Fuel	Feedstock	Land use (m^2 /GJ per annum)	Source
Bioethanol	Cellulose, rotational crop	35 - 230	Trainor et al (2016)
Bioethanol (EE 43%)	Maize residue	209 - 326	Holmatov et al. (2021)
	Rice field residue	163 - 209	Holmatov et al. (2021)
	Wheat residue	395 - 605	Holmatov et al. (2021)
	Soya bean residue	233 - 395	Holmatov et al. (2021)
Bio-FT liquids (EE 59%)	Cellulose, rotational crop	26 - 168	Trainor et al (2016)
	Maize residue	153 - 237	Holmatov et al. (2021)
	Rice field residue	119 - 153	Holmatov et al. (2021)
	Wheat residue	288 - 441	Holmatov et al. (2021)
	Soya bean residue	169 - 288	Holmatov et al. (2021)

Note that the values of the residues already include energy efficiency (EE), so all values refer to the same parts of the process.

Land use of biofuel production at 0% allocation of residue
It is possible to argue that the residue used as a feedstock for biofuel production is nothing more than a residue from the cultivation of the main crop. In other words, the land is allocated entirely to the cultivation of the main crop, and thus 0% to the residue. This means that 0 m^2/GJ is needed for the production of residues.

The literature, however, contains little information on further land use (i.e. apart from feedstock production) for biofuel production. In order to be able to make some statements about the land use of biofuel production at 0% allocation, the values for synfuels are assumed. The various types of biofuels have a reasonable chemical similarity to synfuels, and some are even produced using the same process (Fischer-Tropsch). In addition, it is possible to use both in the existing infrastructure. For these reasons, it is likely that the land use will be close. The land use for FT synfuel production is 0.025 m^2/GJ. This is more or less the same order of magnitude as the practical example of a methanol plant (see F.6).

How much land is needed for bunker fuels for shipping and aviation?
To illustrate how efficient biofuel is in terms of land use, we work out here what area would be needed to meet the current demand for bunker fuels for air and shipping in the Netherlands if the entire demand were to be met by an energy crop. This has been done for 2019, as 2020 is not considered representative due to the corona pandemic. This has only been worked out for FT biofuels, as this is the only biofuel that can be used in aviation and shipping (bioethanol is not used in ships or aircraft).

For energy demand, the sales of motor fuels are used, based on data from CBS (2021a). This concerns fuel sold in the Netherlands (mainly fuel oil, diesel, petrol and kerosene). The consumption of this fuel does not have to take place in the Netherlands. In 2019, 484 PJ of shipping fuel was sold, and 168 PJ of aviation fuel. To express the land use, the total land area of the Netherlands is used, which is 33,893 km^2 (Indexmundi, n.d.). The required land and which part of the Dutch surface this is, can be seen in table F.4. If all fuel bunkered in the Netherlands by air and shipping in 2019 were FT biofuels, a total land area of 0.5 to 3 times the Netherlands would be required.

Table F.4 **Land requirements to meet the energy demand of shipping and aviation (2019) with FT biofuels from energy crops**

Feedstock	Land use (m^2 /GJ per annum)	Area required for shipping (km^2)	Share of surface area in the Netherlands	Area required for aviation (km^2)	Share of surface area in the Netherlands	Σ
Cellulose, rotational crop	26 (lower limit)	12,600	37%	4,400	13%	50
	168 (upper limit)	81,300	240%	28,200	83%	323

To also give an indication of how much land use there would be if residues were used as a feedstock for energy needs in aviation and shipping, the above was also determined for the manufacture of FT biofuels from residues. For this purpose the so-called 'gross numbers' were used, i.e. the land use where 100% of the land is allocated to the residues. This shows that in the best case 2.5 times the Dutch surface is needed, and in the worst case about 8.5 times. See table F.5.

Table F.5 Land requirements to meet the energy demand of shipping and aviation (2019) with FT biofuels from residues

Feedstock	Land use (m^2 /GJ per annum)	Area required for shipping (km^2)	Share of surface area in the Netherlands	Area required for aviation (km^2)	Share of surface area in the Netherlands	Σ
Maize residue	153 (lower limit)	74,000	218	25,700	76	294
	237 (upper limit)	114,700	338	39,800	117	456
Rice field residue	119 (o)	57,600	170	20,000	59	229
	153 (b)	74,000	218	25,700	76	294
Wheat residue	288 (o)	139,400	411	48,300	143	554
	441 (b)	213,400	630	74,000	218	848
Soybean residue	169 (o)	81,800	241	28,400	84	325
	288 (b)	139,400	411	48,300	143	554

Area required for biofuel processing

In addition to the land needed to grow the feedstocks, land is also needed for the facilities to convert the crops into fuel. However, it appears difficult to determine the required m^2/GJ based on literature. One of the few papers that addresses this question is Hammond & Li (2016), who indicate that the required cultivated land has a negligible area compared to the land needed to grow the crops. However, it is not possible to draw a unified picture of the amount of land required to process each type of feedstock.

To give an idea of the size of these facilities, a number of companies with processing facilities in the Netherlands were asked to supply data on surface areas and energy output (per year). It is important to note, however, that not all companies produce the biofuels or use the feedstock from the previous sections. As can be seen in table F.6, the order of magnitude of the processing facilities is many times lower than that of the feedstocks.

Table F.6 Biofuel processing area required per GJ of fuel produced.

Company	**Biofuel**	**Feedstock**	**Land use (m^2 /GJ per annum)**
Company 1	Methanol (advanced)	Non-recyclable waste (RDF/SRF) and non-recyclable B-wood	0.05
Company 2	Fatty acid methyl ester (FAME)	Used Cooking Oil (UCO)	1.33

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In this corrected version, costs for fuel for fossil-ICE vehicles have been corrected in figure 6.6 and 6.7.

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