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Renewable electricity requirements to decarbonise transport in Europe with electric vehicles, hydrogen and electrofuels

Investigating supply-side constraints to decarbonising the transport sector in the European Union to 2050

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Authors:

Nick Ash, Alec Davies, Claire Newton

Reviewed by:

Colin McNaught

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Executive summary

This report follows on from Transport & Environment's (T&E) study entitled "*How to decarbonise European transport by 2050"*, which outlines realistic transport decarbonisation pathways to 2050 for the European Union. The purpose of this report is to investigate whether the T&E decarbonisation pathways are achievable within the limits of renewable electricity potential that is available within the European Union as well as other potential supply-side constraints.

This study finds that there is sufficient renewable electricity potential within the European Union to decarbonise road, shipping and aviation by 2050. However, the significant land area required and water demand for production of electrofuels (including hydrogen) could mean that a portion of the renewable electricity and electrofuels will be imported to complement domestic production. The future costs of renewable electricity in other regions and the costs to produce and transport electrofuels to Europe will play a major role in determining the split between imports and exports in the coming decades.

Achieving the goal to decarbonise transport by 2050 will require clear direction from policy makers in the 2020s. The details of today's policies need to be considered carefully because they will have significant ramifications on the renewable energy demand by 2050.

Direct electrification is the most efficient means of decarbonising the transport sector. However, the large power requirements of some transport modes (e.g. large ships and aeroplanes) mean that direct electrification is not feasible with current or future technologies. These modes will need other zero carbon fuels in 2030 and 2050.

The Base Case scenario in this report is based on an approach of "direct electrification where possible" and the efficient use of green electrofuels where it is not. The additional renewable electricity requirement to achieve T&E's forecast levels of decarbonisation by 2030 is 245 TWh/y for the EU28 countries. For comparison, grid operators predict that the demand for electricity in EU28 countries will be about 3,500 TWh/y in 2030.

To achieve full decarbonisation of transport with T&E's Base Case forecast, about 2,800 TWh/y will be required by 2050. This represents a significant scale-up between 2030 and 2050. For comparison, the predicted demand for renewables from the decarbonised electricity grid in 2050 is predicted to be about 3,350 TWh/y.

This study shows that the potential for additional renewable electricity in the EU28 countries comfortably exceeds the projected demand to decarbonise transport and the electricity grid by 2050. Studies show that the total exploitable potential for renewable electricity (solar PV, onshore wind, offshore wind & geothermal) in the EU28 countries is about 27,000 to 28,000 TWh/y.

In addition, even if the decarbonisation of heating and heavy industry in 2050 is achieved using only hydrogen, the renewable electricity required to produce this hydrogen remains within the limits of the available potential within the EU28 countries, when added to the needs to decarbonise the grid and transport.

T&E present two alternative decarbonisation scenarios to compare with the Base Case. Scenario 2 sees more of a contribution from hydrogen, while Scenario 3 considers the implications of using synthetic hydrocarbon fuels to complement direct electrification. The differences in renewable electricity consumption are significant: Scenario 2 requires 23% more electricity than the Base Case in 2030 and 16% more in 2050; while Scenario 3 requires about 71% more than the Base Case in 2030 and 50% more in 2050. Pursuing these alternative scenarios would therefore increase the cost of decarbonisation significantly by 2050, especially if the synthetic hydrocarbon route is chosen.

Analysis of the costs of hydrogen production and transportation show that significant cost penalties are incurred when the hydrogen needs to be processed for bulk transportation (whether in liquid form or converted to ammonia). This means that:

- Production should be located as close as possible to the point of use.
- With current renewable electricity prices, it is generally cheaper to produce hydrogen within Europe or an immediate neighbour and distribute it in gaseous from than it is to ship it in from other regions, primarily due to the additional cost of converting the hydrogen to a suitable form for bulk transportation.

This study identified the following key messages for policy makers concerning specific modes of transport:

- Focus on direct electrification for road transport, wherever possible, as it is the most efficient path to decarbonisation.
- Road transport will decarbonise more rapidly than shipping and aviation to 2030, but by 2050 shipping and aviation will dominate, requiring more electricity than road transport.
- Shipping is projected to be the largest consumer of renewable electricity by 2050 (30% of the total) of all the modes. Therefore, there should be a special policy focus on decarbonisation of the shipping sector.
- Policy decisions about zero-emission heavy-duty trucks in the early 2020s will have significant ramifications for electricity demand by 2030 and 2050.
- Small changes to the fuel mix of light road vehicles has a large impact on electricity requirements.
- The renewable electricity requirements to decarbonise aviation are relatively insensitive to fuel choice because all scenarios rely heavily on e-kerosene.

This study also found that there will be significant improvements to air quality when fossil fuels are replaced by direct electrification and electrofuels, these are in addition to the reduction in greenhouse gas emissions. It also found that although the water consumption requirements for electrolysis are significant, they are low compared with the requirements for biofuels.

Therefore, adopting a policy of "direct electrification where possible" is optimal for decarbonising transport in the European Union because it requires the lowest amount of renewable electricity and has the lowest burden on Europe's water resources of the scenarios considered.

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List of Acronyms

CCC	Committee on Climate Change
CCS	Carbon capture and storage
CO	Carbon monoxide
CO_2	Carbon dioxide
DAC	Direct air capture
EC	European Commission
EEDI	Energy Efficiency Design Index
ENSPRESO	Energy System Potentials for Renewable Energy Sources
EU	European Union
FCEV	Fuel cell electric vehicles
GHG	Greenhouse gas
ICE	Internal combustion engines
JRC	Joint Research Centre
LCOE	Levelised cost of energy
LH_2	Liquid hydrogen
LNG	Liquefied natural gas
N_2O	Nitrous oxide
NO_x	Nitrogen oxides
PtL	Power-to-liquids
SCR	Selective catalytic reduction
SEEMP	Ship Energy Efficiency Management Plan
SHCF	Synthetic hydrocarbon fuel
SMR	Steam methane reformation
SOFC	Solid oxide fuel cell
t	Tonnes
T&E	Transport & Environment
TTW	Tank-to-wheel / wake / wing (for road transport, shipping and aviation respectively)
TYNDP	Ten-Year Network Development Plan
TWh	Terawatt-hours
UK	United Kingdom
WTW	Well-to- wheel / wake / wing (for road transport, shipping and aviation respectively)

1 Introduction

1.1 Background

In 2018 Transport & Environment (T&E) published an important assessment entitled "*How to decarbonise European transport by 2050"* [1], which outlines realistic transport decarbonisation pathways to 2050 for the European Union. The report is referred to in this document as the "Synthesis Report" because it summarised the results from individual reports published for passenger cars and vans[1], land freight and buses[2], aviation[3], and shipping.

Although the Synthesis Report was extensive, its scope did not include an in-depth analysis of the supply-side constraints associated with the production of hydrogen and other electrofuels. It was also published before the European Commission's (EC) Hydrogen Strategy was published in July 2020 [2], which lays out the initial steps for the hydrogen economy in Europe.

To decarbonise transport in Europe, the required volumes of renewable electricity and electrofuels (including hydrogen) must be available. In addition, policy makers and industry participants need to have a clear view of the scale of the opportunity to develop the renewable electricity required to spur the necessary investment. Hence T&E commissioned this study to explore these supply-side constraints and determine realistic levels of renewable electricity and electrofuels production up to 2030 on the path to 2050.

1.2 Purpose and scope

The purpose of this report is to investigate whether the T&E decarbonisation pathways are achievable within the limits of renewable electricity potential that is available within the EU27 countries and the United Kingdom, which was a member of the EU28 countries in 2018 when the Synthesis Report was written. It also explores other potential supply-side constraints to provide the renewable energy required to achieve the 2050 decarbonisation pathways.

This study will use energy demand forecasts provided by T&E for decarbonisation of the following modes of transport:

- Road vehicles – motorbikes, cars, vans, buses, trucks (<16t) and trucks (>16t)
- Shipping
- Aviation.

In addition to direct electrification, the following fuels were considered: hydrogen, e-diesel, ammonia (for shipping) and e-kerosene (for aviation).

The study also includes a study into other electrofuels for shipping in particular, specifically e-methanol and e-liquefied natural gas (e-LNG), which is presented in Appendix C.

1.3 Transport decarbonisation options

The main finding in the Synthesis Report is that direct electrification of vehicles (i.e. electric vehicles), aeroplanes and vessels is the most energy efficient approach to decarbonising the transport sector. However, there are technical barriers that prevent direct electrification of some modes of transport. Therefore, the Synthesis Report presented alternative approaches that could be considered, which involved the use of electrofuels.

[1] See URL: https://www.transportenvironment.org/publications/roadmap-decarbonising-european-cars
[2] See URL: https://www.transportenvironment.org/publications/roadmap-climate-friendly-land-freight-and-buses-europe
[3] See URL: https://www.transportenvironment.org/publications/roadmap-decarbonising-european-aviation

Electrofuels are synthetic fuels that require the production of hydrogen using electrolysers, purified water and electricity. The hydrogen may be used as an electrofuel directly or it may be combined with other molecules in a chemical process to produce other electrofuels, such as e-diesel, e-kerosene (where the "e" in the names denote that the hydrogen in the fuel was produced by electrolysis) and ammonia. Although these are the three non-hydrogen electrofuels considered in this study, it is possible to produce a variety of other synthetic fuels by altering the fuel synthesis process. Other examples include e-methanol and e-LNG, which are discussed in Appendix C as shipping fuels.

By convention, "green" is added as a prefix to electrofuels (e.g. "green hydrogen") to indicate that the electricity used for electrolysis is provided exclusively by renewable sources. For simplicity, this report omits the "green" prefix because all of the electrofuels referenced are assumed to be from renewable sources.

The concept of "additionality" is important in the discussion about green electrofuels. This refers to the necessity for the renewable electricity to be supplied over and above the requirements to decarbonise the electricity grid. In other words, the renewable electricity required to produce electrofuels should not be diverted from supplying the demand of traditional uses through the grid (e.g. lighting, cooling, etc.), such that the displaced electricity would require an increase in contributions from fossil fuel power plants.

This report refers to e-diesel and e-kerosene collectively as synthetic hydrocarbon fuels (SHCFs), which are also known as "power-to-liquids" (PtL). As indicated by the name, SHCFs contain carbon and produce carbon dioxide (CO_2) when they are combusted in an engine. Therefore, to be carbon-neutral over their lifecycle, the carbon dioxide used to produce SHCFs needs to be extracted from the existing stock in the atmosphere in a process known as direct air capture (DAC), powered by renewable electricity. This report assumes that all SHCFs are produced in this way and the renewable electricity requirements for DAC and synthesis are included in the calculations. It is also assumed that the DAC plant is located near the synthesis plant so that the heat requirements for DAC are provided by the synthesis process.

For road transport, the electrofuels analysed as possible alternatives to direct electrification are:

- Fuel cell vehicles using green hydrogen as a fuel.
- Internal combustion engines using SHCFs.

Due to the high energy density (units of energy within each kilogram of fuel) required for aviation, the Synthesis Report assumed that e-kerosene (a SHCF) would be primarily used with limited contributions from advanced biofuels.

The shipping sector includes a variety of vessels from small ferries and fishing vessels to ultra-large container vessels. The optimal decarbonisation option for each vessel depends on the size, application and typical voyage length. This study assumed that the shipping fleet could be decarbonised through a combination of electrification, hydrogen, ammonia and SHCF.

The Synthesis Report used road transport as an example to show how the well-to-wheel (WTW) energy efficiencies for passenger cars differ between the three approaches to decarbonisation:

- WTW efficiency for direct electrification: 77%
- WTW efficiency for hydrogen fuel cell vehicle: 30%
- WTW efficiency for SHCF (e-diesel): 13%

It is clear from this list why the Synthesis Report concludes that electrification is the best approach, where the transport application allows.

1.4 Updating calculations provided in the Synthesis Report

In the period since the publication of the Synthesis Report, T&E has revised its forecasts for the various modes based on the latest available information and has refined its calculations for the WTW efficiencies. Table 1-1 provides the revised demand data in 2050 if each mode were to solely be provided with one type of fuel.

Table 1-1. Electricity requirement (TWh) if decarbonisation were achieved solely through each approach for 2050.

Mode	EV & Battery	Hydrogen	SHCF
Motorbikes	36	70	159
Cars	500	968	2,195
Vans	153	297	674
Buses	126	242	392
Trucks (<16t)	119	228	370
Trucks (>16t)	387	741	1,201
Shipping	N/A	922	1,041
Aviation	N/A	N/A	745
Total (excl. aviation)	**1,322**	**3,468**	**6,032**

For reference EU28 electricity consumption in 2018 was about 2,800 TWh [3].

The revised energy efficiencies for the three approaches in 2050 are:

- WTW efficiency for direct electrification: 81% (smaller vehicles), 80% (larger vehicles)
- WTW efficiency for hydrogen fuel cell vehicle: 42%
- WTW efficiency for SHCF (e-diesel): 18% (smaller vehicles), 26% (larger vehicles[4])

These were revised as the efficiencies of electrolysis and fuel synthesis processes are updated in accordance with the system boundary assumptions of this study, based on the latest available sources [4] [5] [6]. In addition, predicted efficiency improvements for fuel cell systems (i.e. hydrogen to electricity conversion onboard) in 2050 is taken into account [7].

It is worth noting that the forecasts provided by T&E in the Synthesis Report were based on the forward outlook at the time of compilation and therefore do not consider the impact to transport energy demand that has been caused by the COVID-19 pandemic in 2020. The impact of the pandemic on transport demand is not yet known and is still subject to significant uncertainty; therefore, this report assumes a relatively rapid return to transport activity levels prior to the pandemic and that no other unexpected European demand influencing disturbances occur between 2030 and 2050. However, one of the possible positive results from the pandemic is that the demand for transport could be permanently reduced due to revised commuting habits (e.g. more working from home), which in turn will reduce the amount of renewable electricity required to decarbonise the sector. This will only become apparent in the months and years to come.

[4] The thermal efficiency of larger vehicle engines is assumed to be 42% in 2030 and 2050 for this study.

1.5 Methodology and scenario assumptions

This study relies on the forecast energy requirements developed for the various modes of transport in the Synthesis Report to estimate the additional renewable electricity consumption required to achieve the intermediate decarbonisation target in 2030 and full decarbonisation by 2050. Three scenarios were defined to reflect the uncertainties associated with the different approaches available to achieve decarbonisation. The themes for the scenarios are:

- **Scenario 1 and Base Case – High electrification**: Direct electrification wherever practicable and optimal electrofuels selected for other modes.
- **Scenario 2 – Higher hydrogen**: Hydrogen displaces electrification in some applications.
- **Scenario 3 – Higher SHCF**: SHCFs displace electrification in some applications.

The scenarios also include assumptions for the proportion of decarbonisation that is achieved from switching from fossil fuels to the alternatives. The fuel switching assumptions are summarised below:

- Road transport: as per the Synthesis Report, some decarbonisation is achieved through energy efficiency measures (e.g. modal shift to less carbon intensive modes, demand reduction policies, tank-to-wheel (TTW) energy efficiency improvements, etc.). The remaining decarbonisation is achieved by switching from fossil fuels to electrification, hydrogen and/or SHCF.
- Shipping: 20% decarbonisation is assumed to be achieved through energy efficiency measures (e.g. slower steaming, wind assistance, etc.) in 2030 and 2050, while the balance is achieved by switching from fossil fuels to electrification, hydrogen and/or SHCF.
- Aviation: some decarbonisation is achieved by adopting advanced biofuels, which the balance is achieved by switching from fossil fuels to SHCF (e-kerosene).

A summary of the high-level assumptions for the three scenarios is provided in Table 1-2.

Table 1-2. Summary of assumptions for the three scenarios.

Modes	Base Case – High electrification	Scenario 2 – Higher hydrogen	Scenario 3 – Higher SHCF
Motorbikes	100% direct electrification	100% direct electrification	100% direct electrification
Cars	100% direct electrification	10% hydrogen + 90% direct electrification	10% SHCF + 10% hydrogen + 80% direct electrification
Vans	100% direct electrification	10% hydrogen + 90% direct electrification	10% SHCF + 10% hydrogen + 80% direct electrification
Buses	100% direct electrification	50% hydrogen + 50% direct electrification	50% SHCF + 25% hydrogen +25% direct electrification
Trucks (<16t)	100% direct electrification	10% hydrogen + 90% direct electrification	10% SHCF + 10% hydrogen + 80% direct electrification
Trucks (>16t)	100% direct electrification	50% hydrogen + 50% direct electrification	50% SHCF + 50% hydrogen
Shipping	19% direct electrification + 28% hydrogen + 53% ammonia	5% direct electrification + 75% hydrogen + 20% ammonia	100% SHCF
Aviation 2030	47% SHCF + 53% advanced biofuels	63% SHCF + 37% advanced biofuels	100% SHCF
Aviation 2050	84% SHCF + 11% advanced biofuels + 5% direct electrification	90% SHCF + 5% advanced biofuels + 5% hydrogen	100% SHCF

The assumptions above apply to the portion of the fleet that are assumed to be decarbonised. I.e. the proportions shown in Table 1-2 are only applied to a portion of the fleet in 2030 (details are provided in section 2), with the remainder still operating on fossil fuels. In 2050 however, full decarbonisation is assumed, so the proportions above are applied to the full fleet. More details about the decarbonisation assumptions for each mode are presented in section 2.

The WTW energy requirements were calculated for each mode by dividing the motive energy[5] requirements (forecast for 2030 and 2050) by the WTW energy efficiency values for each decarbonisation approach in the proportions shown in Table 1-2. Then the WTW energy requirements for all modes were aggregated to determine the total renewable electricity requirement for that scenario.

The total electricity requirements for each scenario in 2030 and 2050 were then compared against the exploitable renewable energy potential within the EU28 bloc (after subtracting the forecast demand for renewable electricity from the grid). If the forecast electricity requirements to decarbonise the transport system were less than the available renewable potential (accounting for additionality), it would indicate that the bloc is capable of producing the renewable electricity from within its borders. On the other hand, if the requirements were larger than the available renewable potential, then it would suggest that renewable electricity or electrofuels would need to be imported from other countries to make up the shortfall.

[5] "Motive energy" refers to the total final propulsion energy requirements for the fleet.

2 Demand forecasts

2.1 Road vehicles

Road vehicles account for 72% of EU transport-based greenhouse gas emissions in 2017 and therefore is the most important mode to decarbonise [8]. The T&E forecast assumes various improvements in vehicle efficiency including hybridisation for energy recovery, aerodynamics, lightweight materials and internal combustion engine thermal efficiency.

In the Base Case scenario, all road vehicles that are not using fossil fuels are assumed to be electric vehicles. By 2030 electric vehicles are predicted to represent around 7% of the total tank-to-wheel (TTW) energy requirements for road transport, rising to 100% by 2050.

In Scenario 2 (Higher hydrogen) electric road vehicles also dominate, but with share for hydrogen-powered fuel cell electric vehicles (FCEV) compared with the Base Case scenario. In 2030 and 2050, this is predominantly for buses and trucks with loads larger than 16t (where 50% of zero-emission of truck and bus sales are hydrogen-fuelled), with a smaller uptake in cars, vans and trucks with loads less than 16t (10% of motive energy). It is assumed that there is no hydrogen uptake in motorbikes.

In Scenario 3 (Higher SHCF), electrofuels take a larger role in the road fuel mix with uptake of SHCF being favoured with a supplementary uptake of hydrogen. However, as with Scenario 2, direct charging of electric vehicles is still the largest demand in road transport, followed by SHCF and hydrogen vehicles respectively. For trucks greater than 16t, 50% of motive energy is provided by SHCF with the remaining half supplied by hydrogen. For trucks carrying less than 16t, vans and cars 10% of their energy requirements come from SHCF, 10% come from hydrogen and the remaining 80% come from electrification. 50% of buses are powered by SHCF, 25% by hydrogen and 25% through electrification. Lastly, it is assumed all motorcycles are electrified.

Across all three scenarios uptake of zero emission road vehicles is expected to begin slowly from 2020 to 2030 in the T&E pathways, contributing 7 to 9% of total motive energy requirements[6] across the three scenarios in 2030. The balance of motive energy requirements is fulfilled by fossil fuels. The adoption rate for zero-carbon vehicles expected to increase dramatically thereafter, particularly as national fossil fuel car bans come into effect soon after 2030. By 2050, 100% of road vehicles are assumed to have zero emissions.

2.2 Shipping

Maritime transport accounts for the third highest EU transport-based greenhouse gas emissions at 13% [8]. International maritime transport will also release greenhouse gas emissions while in international waters and when in third countries.

In all scenarios, it is assumed that 80% of the forecast carbon reduction is achieved through fuel switching. The remaining 20% is achieved through improvements in energy efficiency. Capping operational speeds and providing idle ships with direct electrification at ports are expected to contribute to this, as well as a range of short and mid-term measures, such as the Energy Efficiency Design Index (EEDI) and the Ship Energy Efficiency Management Plan (SEEMP) or wind propulsion.

Due to their relatively low energy density, batteries are only used for short distance and light applications with frequent access to ports (e.g. domestic ferries, fishing vessels, etc.). In the Base Case scenario, batteries represent 19% of the zero emission shipping fuels and ammonia dominates with a share of 53%, with liquid hydrogen making up the remaining 28%.

Ammonia is used for larger vessels such as container ships, bulk carriers and tankers that require longer journeys. This is due to ammonia's relatively high energy density compared with batteries thereby reducing payload losses. Mid to short range vessels will favour hydrogen for the same reason. The percentage allocation between the different types of zero emission fuels for shipping are assumed to be the same in

[6] This is for the total stock on the road, including legacy vehicles as well as new vehicles.

2030 and 2050, noting that ammonia is entirely used for internal combustion engines (ICE) in 2030, but is split equally between ICE and solid oxide fuel cells (SOFC) in 2050.

In Scenario 2 (Higher hydrogen), hydrogen dominates the fuel mix at 75%. The balance is contributed by ammonia (20%) and battery-electric vessels (5%). As with the Base Case scenario, the percentage allocation between the different types of zero emission fuels for shipping is assumed to be the same in 2030 and 2050, noting that ammonia is entirely used ICEs in 2030, but is split equally between ICE and SOFCs in 2050.

In Scenario 3 (Higher SHCF), 100% e-diesel is used for all vessels. Table 2-1 provides a summary of the fuel mixes assumed for the three scenarios.

Table 2-1. Proportions of zero-emission fuel mixes assumed for the three shipping scenarios.

	Base Case		Scenario 2		Scenario 3	
Fuel	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
Battery	19%	19%	5%	5%	-	-
Hydrogen	28%	28%	75%	75%	-	-
E-diesel	-	-	-	-	100%	100%
Ammonia (ICE)	53%	26.5%	20%	10%	-	-
Ammonia (SOFC)	-	26.5%	-	10%	-	-

The uptake of zero emission fuels is forecast to be slow in the 2020's and increase steadily between 2030 and 2050 along an S-shaped curve to the point where fossil fuels are eliminated from the fuel mix.

2.3 Aviation

Aviation accounts for the second highest EU transport-based greenhouse gas emissions at 14% [8].

Technical and operational efficiencies have been considered in the projection of future energy requirements to 2030 and 2050. Developments in engine efficiency, winglets and improved lightweight materials are expected to make contributions.

In the Base Case scenario for 2030, the assumption is that 47% of the carbon-neutral fuels required for aviation (in TWh) will be provided by e-kerosene, accounting for 1.5% of the total fuel mix. The remaining 53% met by advanced biofuels, accounting for 1.7% of the total fuel mix. In 2050, 5% is met through electrification, 11% is contributed from advanced biofuels and the remaining 84% is made up by e-kerosene. The energy associated with advanced biofuels is not captured in the total zero emission electricity demand for aviation[7].

In Scenario 2 (Higher hydrogen) for 2030 e-kerosene is the largest contributor towards zero-emission fuels (63%), accounting for 2% of the total fuel mix. There is a substantial role for advanced biofuels (37%), accounting for 1.3% of the fuel mix. In 2050, hydrogen represents 5% of the fuels with e-kerosene reducing to 90% and a 5% contribution from advanced biofuels.

It is assumed that in Scenario 3 (Higher SHCF) e-kerosene provides 100% of the carbon-neutral fuel requirements for aviation in 2030 (3.2% of fuel mix) and 2050. A summary is provided in Table 2-2.

[7] The feedstock potential for biofuels is also not investigated in this report.

Table 2-2. Proportions of zero-emission fuel mixture assumed for the aviation sector.

	Base case		Scenario 2		Scenario 3	
Fuel	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
Advanced biofuels	53%	11%	37%	5%	-	-
e-kerosene	47%	84%	63%	90%	100%	100%
Electrification	-	5%	-	-	-	-
Hydrogen	-	-	-	5%	-	-

As for shipping, the T&E decarbonisation pathways for aviation assume an S-shaped adoption curve, with 3.2% of zero-carbon fuels in 2030, with accelerated adoption thereafter to achieve full decarbonisation in 2050.

3 Aggregate electricity demand for the three scenarios

3.1 Base Case Scenario

The aggregate of the renewable electricity requirements for each mode of transport were calculated for the Base Case scenario. The results in Table 3-1 show that in 2030, the total electricity demand for zero emission transport is predicted to be 245 TWh per year. The largest contributor is direct electrification (driven by electric vehicle uptake in road transport), followed by e-kerosene (SHCF) from the aviation sector, ammonia and hydrogen for shipping.

Table 3-1. Summary of EU28 electricity demand for alternative fuel transport in the Base Case scenario for 2030.

Mode	Base case electricity requirement (TWh per year) in 2030				
	Direct electrification	Hydrogen	SHCF	Ammonia	Total
Motorbikes	10	0	0	0	10
Cars	100	0	0	0	100
Vans	21	0	0	0	21
Buses	23	0	0	0	23
Trucks (<16t)	10	0	0	0	10
Trucks (>16t)	31	0	0	0	31
Shipping	3	10	0	19	32
Aviation	0	0	18	0	18
Total	**198**	**10**	**34**	**19**	**245**

The predicted demand for these modes in 2030 for the EU27 countries is 209 TWh, which is about 14% lower than the value for the EU28.

Table 3-2 shows that by 2050 direct electrification is predicted to have the highest electricity requirement, followed by e-kerosene for aviation, ammonia for shipping and hydrogen for shipping. The total electricity demand across all transport modes in 2050 is 2,783 TWh.

Table 3-2. Summary of EU28 electricity demand for alternative fuel transport in the Base Case scenario for 2050.

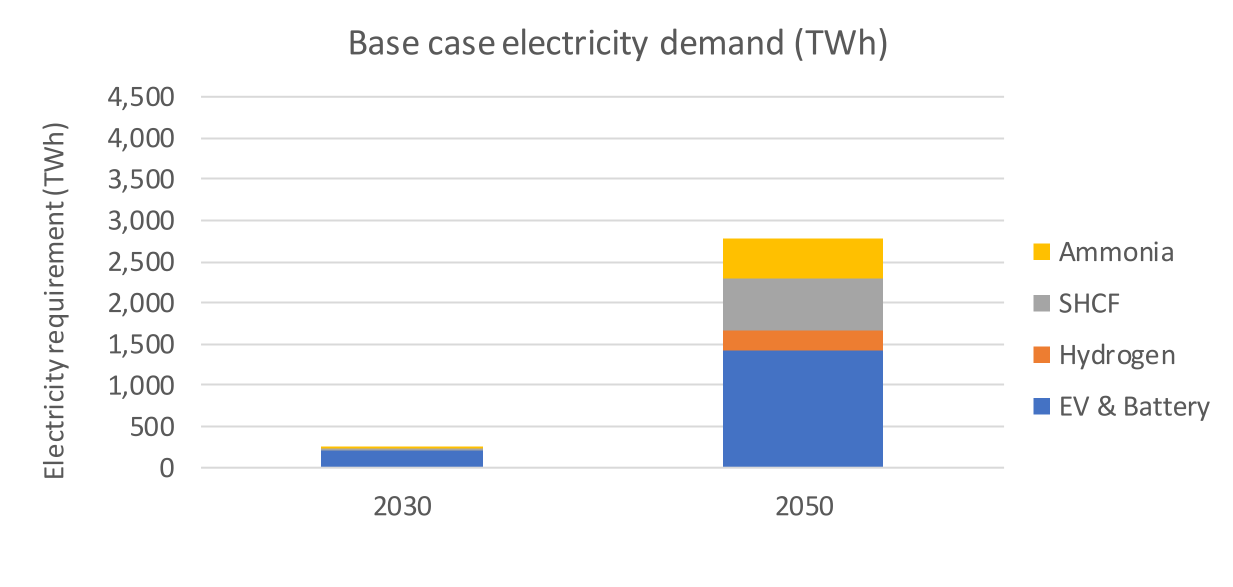
Mode	Base case electricity requirement (TWh) in 2050				
	Direct electrification	Hydrogen	SHCF	Ammonia	Total
Motorbikes	36	0	0	0	36
Cars	500	0	0	0	500
Vans	153	0	0	0	153
Buses	126	0	0	0	126
Trucks (<16t)	119	0	0	0	119
Trucks (>16t)	387	0	0	0	387
Shipping	76	254	0	494	823
Aviation	12	0	626	0	638
Total	**1,410**	**254**	**626**	**494**	**2,783**

The predicted demand for these modes in 2050 for the EU27 countries is 2,414 TWh, which is about 13% lower than the value for the EU28.

Reviewing the results by mode in 2030, road transport is predicted to have the highest demand for renewable electricity, followed by aviation and shipping respectively. In 2050, road transport is predicted to have the highest requirement and the requirement for shipping has surpassed aviation.

In 2030, Figure 3-1 shows that direct electrification is predicted to require the largest share of the renewable electricity, with 81%. Its dominance is reduced in 2050, when it is expected to have a 51% share.

Figure 3-1. Total electricity demand in EU28 by energy type for the Base Case scenario.



Illustrative example – Base case scenario

It is useful to relate the values in the tables and charts above to real-world projects to give a sense of scale. Appendix A of this report shows a hypothetical offshore wind farm off the coast of Antwerp sized at 2 GW, which has dimensions of 25 km x 15 km. According to Wind Europe [9], new offshore wind farms off the coast of Europe have a typical capacity factor[8] range of 35 to 55%[9]. Based on a median value of 45%, a typical offshore wind farm of 2 GW capacity would generate about 7.9 TWh per year.

Providing the 245 TWh required for the base case scenario by 2030 (see Table 3-1) would require about 31 wind farms like this, a total capacity of 62 GW. Whereas, 352 wind farms would be required to provide the 2,783 TWh by 2050 (see Table 3-2). As of 2019, there was a cumulative capacity of about 22 GW installed in European waters [9]. This represents a significant increase in capacity, especially bearing in mind that offshore wind farms are also required to decarbonise the electricity sector. However, with a required average build rate of 3.1 plants per year to 2030, the scale-up is achievable. The increase from 2030 to 2050 – the equivalent of 321 x 2 GW wind farms over 20 years – will require a more concerted effort.

However, as explained in section 4.4, the renewable electricity will be sourced from multiple renewable technologies (not only offshore wind farms) and plants will be distributed around Europe. In addition, section 6 shows that some of the renewable electricity and/or electrofuels could be imported from other regions as well.

[8] Capacity factor is defined as the amount of electricity exported from the wind farm (in MWh) divided by the amount of electricity that would have been exported if it had operated at 100% output for the full year.

[9] The average capacity factors achieved by operating wind farms in 2019 were 41% in the UK and Denmark [73, 75] and 37% in Belgium and Germany [74, 76]. These include older and smaller turbines, which have lower performance than currently available models.

3.2 Scenario 2 (Higher Hydrogen)

In Scenario 2, hydrogen plays a larger role than the Base Case scenario. The aggregate renewable electricity requirements for each mode of transport in 2030 are shown in Table 3-3. The total electricity demand for zero emission transport is predicted to be 302 TWh. The largest demand is for direct electrification (52%), followed by hydrogen (38%).

Table 3-3. Summary of EU28 electricity demand for alternative fuel transport in Scenario 2 for 2030.

Mode	Scenario 2 electricity requirement (TWh) in 2030				
	Direct electrification	**Hydrogen**	**SHCF**	**Ammonia**	**Total**
Motorbikes	10	0	0	0	10
Cars	90	22	0	0	111
Vans	19	5	0	0	24
Buses	11	25	0	0	36
Trucks (<16t)	9	2	0	0	11
Trucks (>16t)	15	34	0	0	49
Shipping	1	28	0	7	36
Aviation	0	0	24	0	24
Total	**156**	**115**	**24**	**7**	**302**

The predicted demand for the EU27 countries in 2030 is 258 TWh, which is about 15% lower than the value for the EU28.

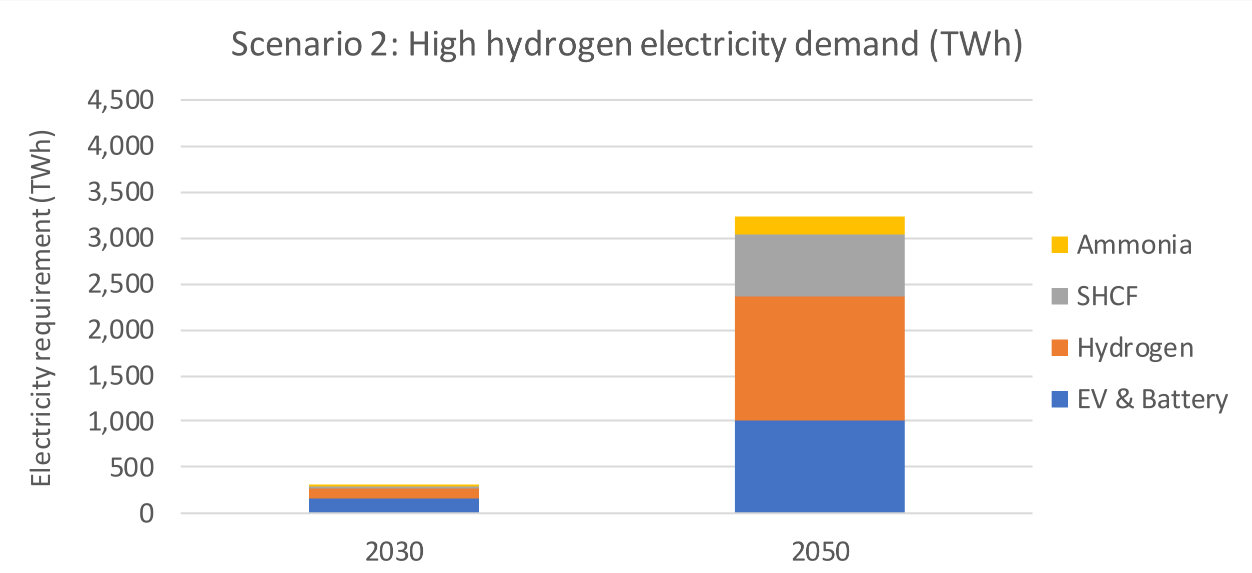
By 2050, the aggregate demand is expected to increase to 3,223 TWh in Scenario 2, as shown in Table 3-4. The predicted demand for the EU27 countries is 2,797 TWh, which is about 13% lower than the value for the EU28.

Table 3-4. Summary of EU28 electricity demand for alternative fuel transport in Scenario 2 for 2050.

Mode	Scenario 2 electricity requirement (TWh) in 2050				
	Direct electrification	**Hydrogen**	**SHCF**	**Ammonia (ICE)**	**Total**
Motorbikes	36	0	0	0	36
Cars	450	97	0	0	547
Vans	138	30	0	0	168
Buses	63	121	0	0	184
Trucks (<16t)	107	23	0	0	130
Trucks (>16t)	194	371	0	0	564
Shipping	20	691	0	184	895
Aviation	0	28	670	0	698
Total	**1,008**	**1,360**	**670**	**184**	**3,223**

Hydrogen's share is predicted to increase to 42% in 2050 with direct electrification responsible for 31%. The relative contributions of the various energy types in 2030 and 2050 are shown in Figure 3-2.

Figure 3-2. Total electricity demand in EU28 by energy type for Scenario 2.



Illustrative example – Scenario 2
Providing the 302 TWh required for Scenario 2 by 2030 (see Table 3-3) would require about 38 of the 2 GW offshore wind farms shown in Appendix A. An average build rate of 3.8 plants per year would be required to 2030, compared to 3.1 for the Base Case. These figures are only illustrative to provide a sense of scale. As explained in section 4.4, the renewable electricity will be sourced from multiple renewable technologies (not only offshore wind farms) and plants will be distributed around Europe. In addition, section 6 shows that some of the renewable electricity and/or electrofuels could be imported from other regions as well.

3.3 Scenario 3 (Higher SHCF)

The assumptions for Scenario 3 are similar to Scenario 2, with the main difference being an increased contribution from SHCFs rather than hydrogen.

The aggregate renewable electricity requirements for each mode of transport in 2030 are shown in Table 3-5. The total electricity demand for zero emission transport is predicted to be 418 TWh. The largest demand is for SHCF (53%), followed by direct electrification (29%).

Table 3-5. Summary of EU28 electricity demand for alternative fuel transport in Scenario 3 for 2030.

Mode	Scenario 3 electricity requirement (TWh) in 2030				
	Direct electrification	Hydrogen	SHCF	Ammonia	Total
Motorbikes	10	0	0	0	10
Cars	80	22	46	0	147
Vans	17	5	10	0	32
Buses	6	12	37	0	55
Trucks (<16t)	8	2	3	0	13
Trucks (>16t)	0	34	50	0	84
Shipping	0	0	39	0	39
Aviation	0	0	38	0	38
Total	**121**	**75**	**223**	**0**	**418**

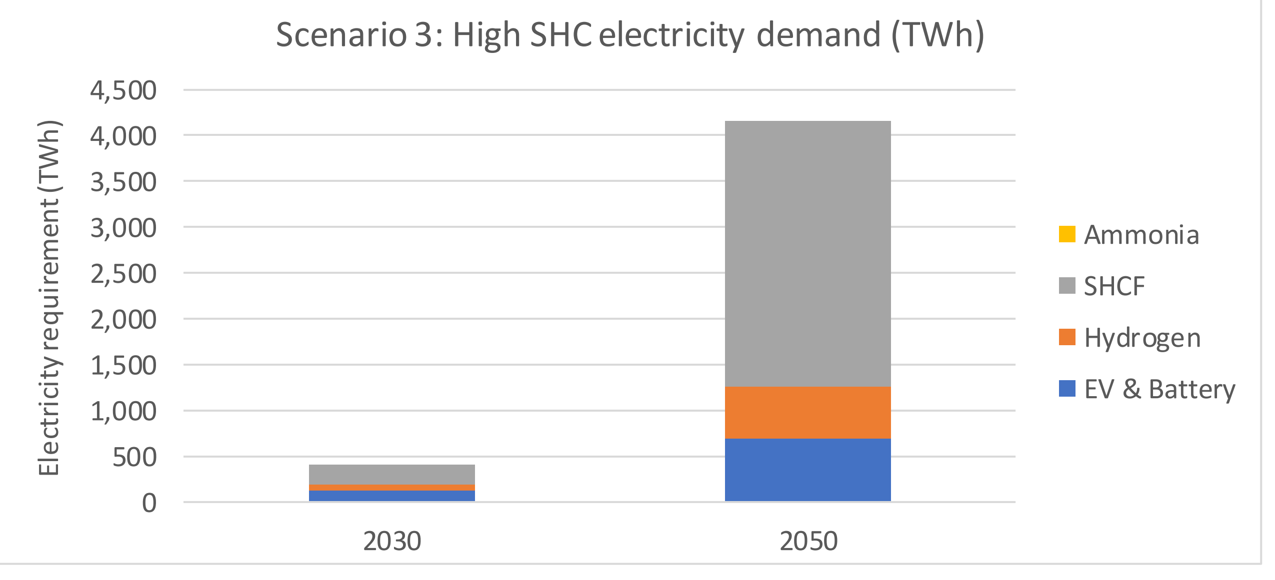
The predicted demand for the EU27 countries in 2030 is 356 TWh, which is about 15% lower than the value for the EU28. By 2050, the aggregate demand is expected to increase to 4,172 TWh in Scenario 3, as shown in Table 3-6. The predicted demand for the EU27 countries is 3,598 TWh, which is about 14% lower than the value for the EU28.

Table 3-6. Summary of EU28 electricity demand for alternative fuel transport in Scenario 3 for 2050.

Mode	Scenario 3 electricity requirement (TWh) in 2050				
	Direct electrification	Hydrogen	SHCF	Ammonia	Total
Motorbikes	36	0	0	0	36
Cars	400	97	220	0	716
Vans	123	30	67	0	220
Buses	32	60	196	0	288
Trucks (<16t)	95	23	37	0	155
Trucks (>16t)	0	371	601	0	971
Shipping	0	0	1,041	0	1,041
Aviation	0	0	745	0	745
Total	**686**	**581**	**2,906**	**0**	**4,172**

The relative contributions of the various energy types in 2030 and 2050 for Scenario 3 are shown in Figure 3-3.

Figure 3-3. Total electricity demand in EU28 by energy type for Scenario 3.



Illustrative example – Scenario 3
Providing the 418 TWh required for Scenario 3 by 2030 (see Table 3-5) would require about 53 of the 2 GW offshore wind farms shown in Appendix A, at an average build rate of 5.3 plants per year. This is significantly more than the Base Case (3.1 plants per year) and 3.8 plants per year for Scenario 2. These figures are only illustrative to provide a sense of the scale required. As explained in section 4.4, the renewable electricity will be sourced from multiple renewable technologies (not only offshore wind farms) and plants will be distributed around Europe. In addition, section 6 shows that some of the renewable electricity and/or electrofuels could be imported from other regions as well.

3.4 Aggregate renewable electricity requirements to decarbonise transport

This section summarises the results from across the three scenarios in 2030 and 2050. The aggregate electricity requirements for the EU28 and EU27 in 2030 are shown in Table 3-7.

Table 3-7. Comparison of aggregate renewable electricity demand across for the three scenarios in 2030.

	Electricity demand by fuel type (TWh)		
	Base case	Scenario 2	Scenario 3
Battery	198	156	121
Hydrogen	10	115	75
SHFC	18	24	223
Ammonia	19	7	0
Total (EU28)	**245**	**302**	**418**
Total (EU27) for comparison	209	258	356

In 2030, the renewable electricity requirements for Scenario 2 are about 23% more than the Base Case scenario; while the requirements for Scenario 3 are about 71% more than the Base Case.

Illustrative example
Relating these values back to a “typical” 2 GW offshore wind farm like the one in Appendix A, Scenario 2 would require an additional 7.2 of these wind farms compared with the Base Case (a 57 TWh difference) and Scenario 3 would require about 21.9 more than the Base Case (a 173 TWh difference).

Similarly, the results for 2050 shown in Table 3-8 indicate that the renewable electricity requirements for the Base Case scenario are significantly lower than the other two scenarios. In Scenario 2, the renewable electricity requirement is 18% higher than the Base Case; whereas for Scenario 3, it is 49% higher for the EU28 countries.

Table 3-8. Comparison of aggregate renewable electricity demand across for the three scenarios in 2050.

	Electricity demand by fuel type (TWh)		
	Base case	Scenario 2	Scenario 3
Battery	1,410	1,008	686
Hydrogen	254	1,360	581
SHFC	626	670	2,906
Ammonia (ICE and SOFC)	494	184	0
Total (EU28)	**2,783**	**3,223**	**4,172**
Total (EU27) for comparison	2,414	2,797	3,598

Illustrative example
The scale of the differences between the scenarios in 2050 becomes apparent when it is pictured in terms of typical 2 GW wind farms. The Base Case would require about 352 of these wind farms, while Scenario 2 would require 408 and Scenario 3 would need 528. This reinforces the significant differences between these scenarios by 2050.

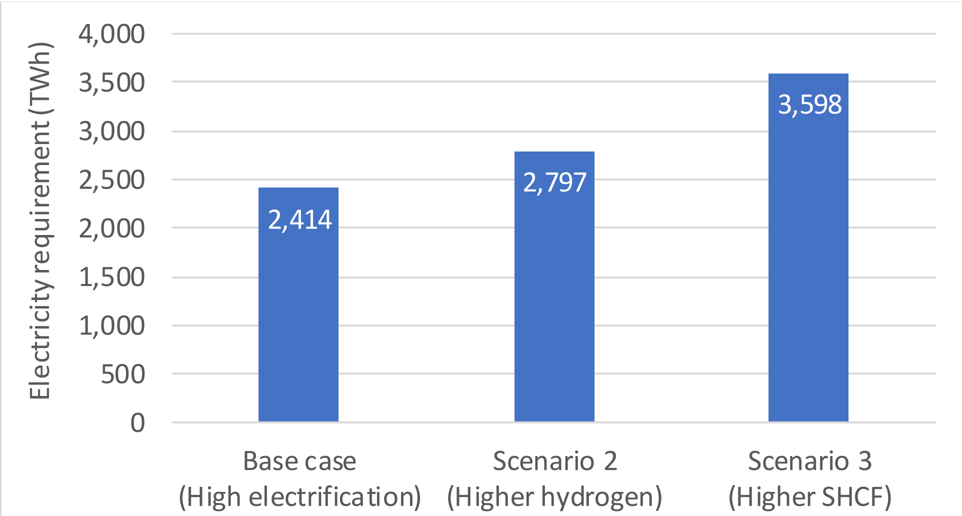
3.5 Key messages for policymakers

This section draws out the key implications and messages from the analysis presented in sections 3.1 to 3.4, with an emphasis on the results for the EU27 countries.

Focus on direct electrification where the application allows

The aggregate electricity requirements for Scenario 2 (Higher Hydrogen) is expected to be 16% higher than the base case (High electrification) for the EU27 countries in 2050; while Scenario 3 (Higher SHCF) is expected to be 49% higher (see Figure 3-4). This underscores the main finding in the T&E Synthesis Report that direct electrification is the preferable approach to decarbonising the transport sector in Europe, where the modal technology allows.

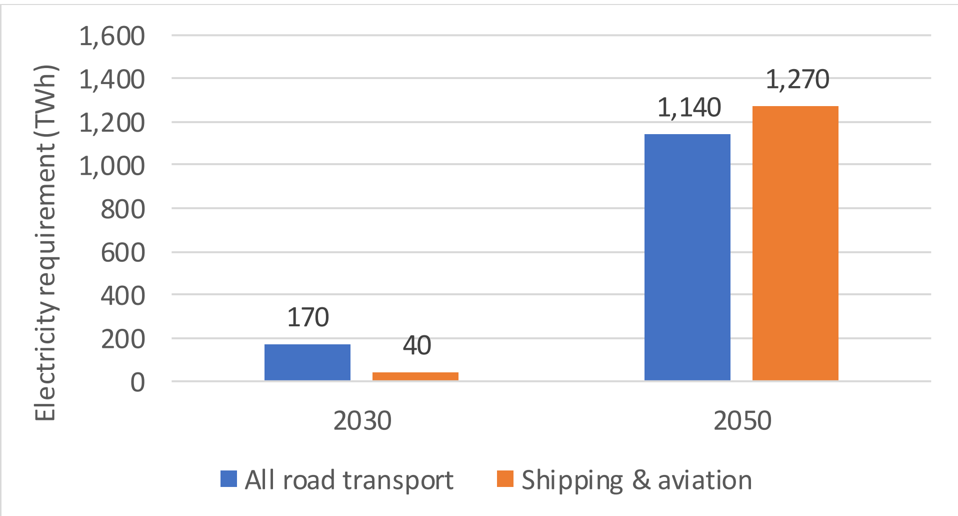
Figure 3-4. Expected electricity requirement for the three scenarios in the EU27 countries in 2050.



Road transport drives demand in the near-term but shipping and aviation dominate in 2050

The results in Figure 3-5 show that the Base Case forecasts for 2030 expect adoption of zero-carbon road transport to accelerate quicker than shipping and aviation, with 81% of the electricity demand for transport in the EU27 countries. However, shipping and aviation are predicted to dominate in 2050, requiring 53% of the total renewable electricity to decarbonise transport.

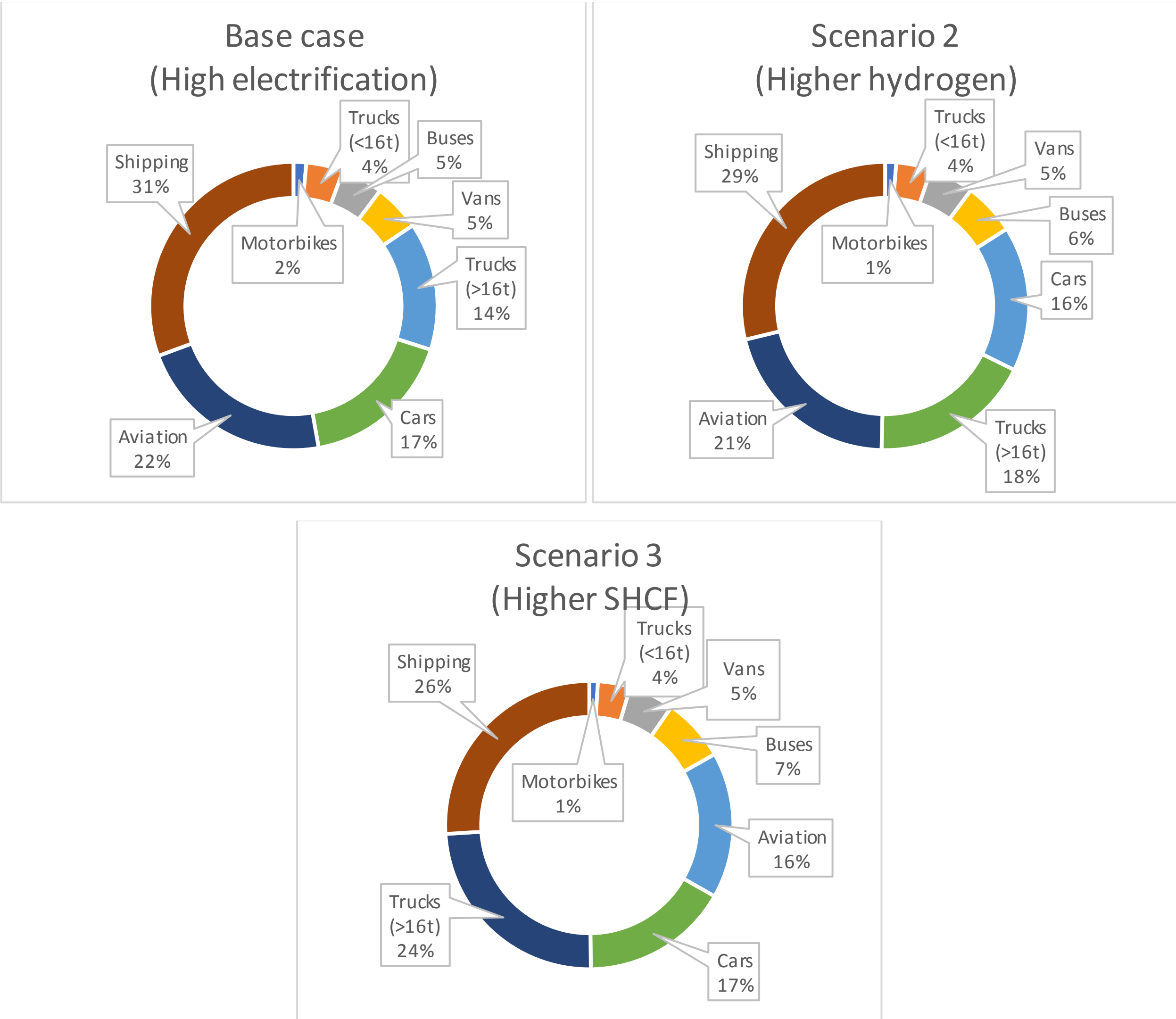
Figure 3-5. Comparison of electricity requirements for road transport with shipping plus aviation in EU27.



Shipping will have the biggest share by 2050

Due to the large power requirements for propulsion of ships, direct electrification is only practicable for about 19% of the fleet (see assumptions in section 2.2). Therefore, electrofuels are required to decarbonise the balance of the fleet, which has a large impact on the electricity demand due to the lower WTW efficiency compared with direct electrification. The shares of the various modes are shown in Figure 3-6. See Appendix C for a detailed analysis of the alternative fuel options for shipping.

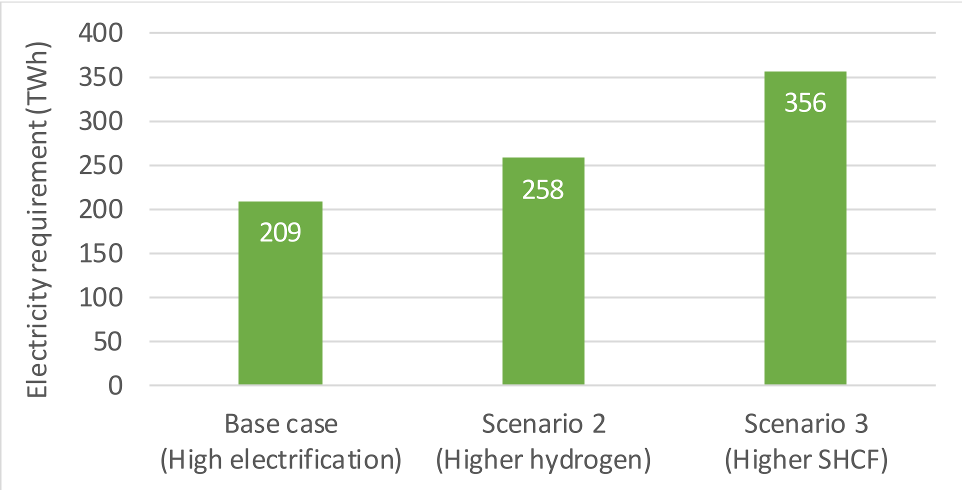
Figure 3-6. Shares of electricity requirements for decarbonisation for the EU27 in 2050.



Direct electrification requires a more modest ramp-up to 2030 than the other scenarios

The results for 2030 show that the differences between the electricity requirements are expected to be more pronounced in the near-term. Compared with the Base Case scenario, the Higher Hydrogen scenario is expected to require 23% more electricity, while the requirement for the Higher SHCF is expected to be 70% more for the EU27 in 2030 (see Figure 3-7).

Figure 3-7. Expected electricity requirement for the three scenarios in the EU27 countries in 2030.



Small changes to the fuel mix of light road vehicles has a large impact on electricity requirements

The forecasts in Figure 3-7 for all modes in the EU27 countries are also reflected when the scope is focussed on the lighter modes of road transport that are more suited to direct electrification (motorbikes, cars, vans, buses and trucks less than 16 tonnes). The fuel mix assumptions for the portion of fuel use in 2030 that is zero-carbon are listed in Table 3-9 (copied from Table 1-2 for ease of reference). The assumptions apply to the portion of the fleet that are assumed to be decarbonised. I.e. the proportions shown in Table 3-9 are only applied to a portion of the fleet in 2030 (details are provided in section 2), with the remainder still operating on fossil fuels. In 2050 however, full decarbonisation is assumed, so the proportions are applied to the full fleet.

Table 3-9. Fuel mix assumptions of lighter road transport modes (for the portion of fuel use in 2030 that is zero-carbon).

Modes	Base Case – High electrification	Scenario 2 – Higher hydrogen	Scenario 3 – Higher SHCF
Motorbikes	100% direct electrification	100% direct electrification	100% direct electrification
Cars	100% direct electrification	10% hydrogen + 90% direct electrification	10% SHCF + 10% hydrogen + 80% direct electrification
Vans	100% direct electrification	10% hydrogen + 90% direct electrification	10% SHCF + 10% hydrogen + 80% direct electrification
Buses	100% direct electrification	50% hydrogen + 50% direct electrification	50% SHCF + 25% hydrogen +25% direct electrification
Trucks (<16t)	100% direct electrification	10% hydrogen + 90% direct electrification	10% SHCF + 10% hydrogen + 80% direct electrification

Table 3-10 shows the forecast renewable electricity requirements for the three scenarios for these modes.

Table 3-10. Electricity requirement in 2030 for bikes, cars, vans, buses and trucks (<16t) in EU27.

	Base Case	Scenario 2	Scenario 3
Renewable electricity requirement in 2030	140 TWh	164 TWh	219 TWh
Percent relative to Base Case requirement	100%	118%	157%

Although the majority of these are electric vehicles with relatively modest contributions from hydrogen or SHCFs, there is a marked difference in the renewable electricity requirements: Scenario 2 requires 18% more electricity than the Base Case and Scenario 3 requires 57% more. To provide a sense of scale, the difference of 79 TWh between Scenario 3 and the Base Case is equivalent to 10 of the typical 2 GW offshore wind farms shown in Appendix A.

Policy decisions about heavy-duty trucks in the next few years will have big impacts by 2050

Focussing on the requirements for heavy-duty trucks (larger than 16 tonnes), the data shows that the policy pathways selected in the 2020's will have large implications by 2050. In Scenario 2 (Higher hydrogen), it is assumed that half of heavy-duty trucks use hydrogen and the other half are electric; while in Scenario 3 (Higher SHCF) the fleet is split evenly between hydrogen and SHCF. Compared to the base case (where all heavy-duty trucks are electric), Scenario 2 requires 59% more electricity in 2030 and 46% more in 2050. There is a greater difference between the base case and Scenario 3, which requires 171% more in 2030 and 151% more in 2050. (The consumption values are shown in Figure 3-5.) This potential impact is important for the discussions about the European CO_2 standards regulation for new trucks

To give this difference a sense of scale, the difference of 45 TWh between Scenario 3 and the Base Case in 2030 is equivalent to about 5.7 offshore wind farms of 2 GW capacity. This illustrates the impact that imminent policy decisions about decarbonising trucks could have in 10 years' time.

Changes in assumptions for aviation have a small impact

The electricity requirements to decarbonise aviation are predicted to be 535 TWh in 2050 for the EU27 countries under the Base Case assumptions. This is only 9% more in Scenario 2 (Higher hydrogen) and 10% more in Scenario 3 (Higher SHCF). This is mainly because e-kerosene (a SHCF) is expected to play a major role in all three scenarios.

4 Supply-side constraints for renewable electricity

The key focus of this study is to outline the amount of renewable energy capacity that would be required to meet the demand for zero-emissions transport presented in sections 2 and 3, and to understand how much of this could be produced within the EU28 countries. This is the renewable generation required to decarbonise transport in addition to the ambitions for decarbonising the electricity sector.

4.1 Total electricity demand from renewable generation

The forecast total electricity generation to meet demand for the EU28 and the EU27 is shown in Table 4-1 below.[10] Based on the "Distributed Energy" scenario within the Ten-Year Network Development Plan (TYNDP) 2020 [10] for the electricity and gas networks, which is closely aligned with the "1.5TECH" scenario in the EU 2050 Long-Term Strategy for decarbonisation [11]. The electricity generation forecast in the TYNDP included an estimate for transport, which was deducted so that the T&E Synthesis Report forecasts could be used instead.

The portion of the UK generation of the EU28 total is assumed to be 10%. This proportion has been selected based on a review of:

- The UK's National Grid 2019 Future Energy Scenarios [12] based on the "Consumer Evolution" scenario, which similar to the 1.5TECH scenario.
- The EU Reference Scenario 2016 for energy, transport and GHG emissions trends to 2050 [13].

The resulting forecast electricity demands from the electricity sector for 2030 and 2050 are summarised in Table 4-1.

Table 4-1. Forecast energy demand (TWh) from the power sector excluding transport but including transmission and distribution losses.

	2030	2050
EU28	3,477	3,885
EU27	3,129	3,497

Of this total electricity generated, the share of renewable energy generation is assumed to be 64% in 2030 and 86% in 2050, with solar and wind sources contributing 44% in 2030 and 66% in 2050[11]. In 2050, the remaining 14% is assumed to be provided by nuclear plants, while in 2030, the contribution from nuclear is predicted to be 16%[11]. Nuclear currently contributes approximately 26% electricity supply in the EU28 countries [3]. The predicted electricity sector demands met by renewable generation in 2030 and 2050 are shown in Table 4-2.

Table 4-2. Forecast renewable generation (TWh) from the power sector met by renewable sources.

	2030	2050
EU28	2,225	3,341
EU27	2,003	3,007

Renewable energy from non-wind and solar sources is primarily provided by hydro and biomass sources at about 20% of the total electricity demand, as per the TYNDP.

[10] This includes transmission and distribution network losses (6%).
[11] The 2030 estimates are based on the forecast in the TYNDP Distributed Energy scenario [10] and the 2050 estimates are based on the Transforming Energy Scenario in IRENA's Global Renewables Outlook 2020 [77].

4.2 Renewable potential in the EU28 countries

Data for the theoretical potential for electricity supply from various renewable sources is presented in a European Commission (EC) report published in 2020 with the title *"Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure"* [14]. In this section, the data from the EC report has been compared with the Energy System Potentials for Renewable Energy Sources (ENSPRESO) dataset [15], which is an open dataset published by the Joint Research Centre (JRC) in 2019, covering the period up to 2050. ENSPRESO is published on EU Science Hub [16], the European Commission's science and knowledge service, where it is recommended for use with energy models as it "analyses of the competition and complementarity of energy technologies". ENSPRESO is provides resource data for solar (photovoltaic and concentrating), wind (onshore and offshore) and biomass; but the biomass potential data is not used in this report. The resource potential listed in the EC report is from a range of sources dating from 1992 to 2018; therefore, it is useful to cross-reference the values quoted in the EC report against a more current estimate based on current technology trends, as provided in ENSPRESO.

4.2.1 Solar

Solar and wind are likely to provide the most significant contribution to renewable generation in Europe, given the uptake of both technologies (and reduction in costs) in the last decade, and the potential for further developments.

The EC report [14] gives a range for solar photovoltaic (PV) of 1,800 to 5,000 TWh/y, but selects a reference value of about 2,000 TWh/y. The range for solar thermal is given as 1,800 to 2,100 TWh/y, also with a reference value of 2,000 TWh/y. On the other hand, ENSPRESO [15] includes a low estimate of 10,700 TWh for solar PV and solar thermal combined. However, the ENSPRESO estimate assumes the inclusion of 100% artificial area (e.g. rooftops and other building features) and 3% non-artificial area (e.g. active and disused farmland). This is considered unrealistic because only a portion of buildings within Europe have characteristics that are suitable for solar PV and the use of active farmland should be avoided.

However, the EC report estimate of 4,000 TWh for solar PV and solar thermal combined is considered too conservative because it does not include disused and marginal farmland. Therefore, this study has selected a combined potential of 5,000 TWh for solar technologies.

4.2.2 Wind

The data for wind potential is based on the ENSPRESO modelling for onshore and offshore wind. The wind potential assessment uses high-resolution geo-spatial wind speed data and considers setback distances for onshore wind. Setback is the minimum distance required from a wind turbine to locations including residential properties, roads and environmentally or historically sensitive areas. The ENSPRESO study considers three scenarios for onshore wind potential:

- A reference scenario (base case): current setback distances (which vary by EU member state) stay the same.
- A high wind scenario: setback distances in all countries converge to the lowest setback currently observed which is 120m for small turbines and 400m for large turbines.
- A low wind scenario: setback distances in all countries converge to the highest setback currently observed which is 1,200m for small turbines and 2,000m for large turbines.

Certain land areas (e.g. forests and urban areas) are assumed to be unavailable for onshore wind. Within each scenario, wind potential is estimated for varying capacity factors. For this report, wind potential with a capacity factor of less than 20% has been ignored, as this may not be economically feasible.

For offshore wind, three scenarios have been considered, with differing approaches to offshore exclusion zones (e.g. protected areas, sea depth and shore distance).

The totals for the ENSPRESO data are provided in Table 4-3 for onshore and offshore wind.

Table 4-3. Estimated wind potential in Europe for ENSPRESO reference scenario.

	EU28	EU27
Onshore wind potential (TWh)	8,400	7,700
Offshore wind potential – fixed foundation (TWh)	1,300	900
Offshore wind potential – floating up to 100m depth (TWh)	4,100	2,200

These values are similar to the those given in the EC report [14], which gives an approximate range of 5,000 to 11,800 TWh for onshore wind (reference value: approx. 8,200 TWh) and an approximate range of 200 to 1,200 TWh for fixed foundation offshore wind (reference value: approx. 700 TWh).

The potential for floating offshore wind given in the EC report is about 12,800 TWh. This estimate compares well with values of 12,700 TWh and 13,000 TWh in other reports [17, 18]. Floating offshore wind farms have been demonstrated at commercial scale [19, 20], so it is realistic to assume that they will be used extensively by 2050. Therefore, the selected wind potential is summarised in Table 4-4.

Table 4-4. Selected wind potential for use in this report.

	EU28	EU27
Onshore wind potential (TWh)	8,400	7,700
Offshore wind potential – fixed foundation (TWh)	1,300	900
Offshore wind potential – floating up to 100m depth (TWh)	12,800	6,900

4.2.3 Geothermal

Geothermal power generation is a relatively small contributor to renewable generation in Europe. As of 2018, the installed capacity of geothermal power generation in Europe was 2,960 MW [21] with an annual production of 18 TWh. The theoretical potential for electricity generation from geothermal is very sensitive to assumptions about technology improvements and the market price of electricity [22], especially for estimates decades into the future. Least cost modelling by Dalla Longa et. al. [23] provides high and low estimates for electricity production from geothermal sources in Europe in 2030 and 2050. These are given in Table 4-5.

Table 4-5. Geothermal potential in Europe (TWh/year).

	Low estimate	High estimate
Geothermal economic potential in 2030 (TWh)	40	75
Geothermal economic potential in 2050 (TWh)	100	210

The high estimates are used in the analysis in the next section. These values are similar to those given in the EC report.

4.2.4 Total Renewable Energy Potential

The total renewable energy potential in the EU28 countries from solar, wind (onshore and offshore) and geothermal generation is summarised in Table 4-6. Note that biomass potential has been excluded from this analysis due to the environmental concerns, such as Indirect Land Use Change (ILUC), associated with using biomass as an energy source. However, biomass is included in the TYNDP forecasts to supply consumers through the electricity grid, so the projected contribution from biomass is included in the next section. It is assumed that none of the electricity generated from biomass is used in the production of electrofuels.

Table 4-6. Total renewable potential in Europe from solar, wind and geothermal in 2050.

	EU28	EU27
Solar potential (TWh)	5,000	4,730
Onshore wind potential (TWh)	8,400	7,700
Offshore wind potential (TWh)	14,100	7,800
Geothermal economic potential in 2050 (TWh)	210	200
Total	**27,710**	**20,430**

The next section compares how the exploitable potential compares with the projected demand from the electricity sector and to decarbonise transport.

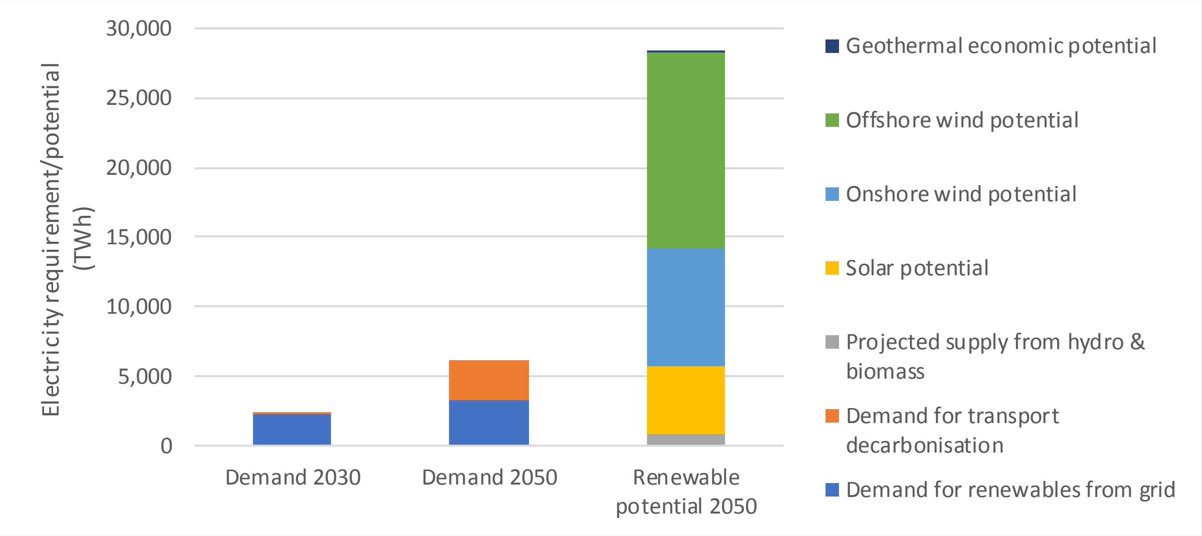
4.3 Comparison of renewable electricity potential with forecast demand

The total electricity requirements to decarbonise transport on the T&E pathways in 2030 and 2050 are calculated in section 3 and the projected demand for renewable sources from the electricity grid are shown in section 4.1. This section compares the potential demand for renewables from these two sectors against the renewable potential described in section 4.2.

4.3.1 Base case scenario

The forecast demand for renewable electricity from the grid[12] and transport for the Base Case scenario in 2030 and 2050 are shown in Figure 4-1.

Figure 4-1. Forecast demand for renewable electricity and exploitable potential for the Base Case.



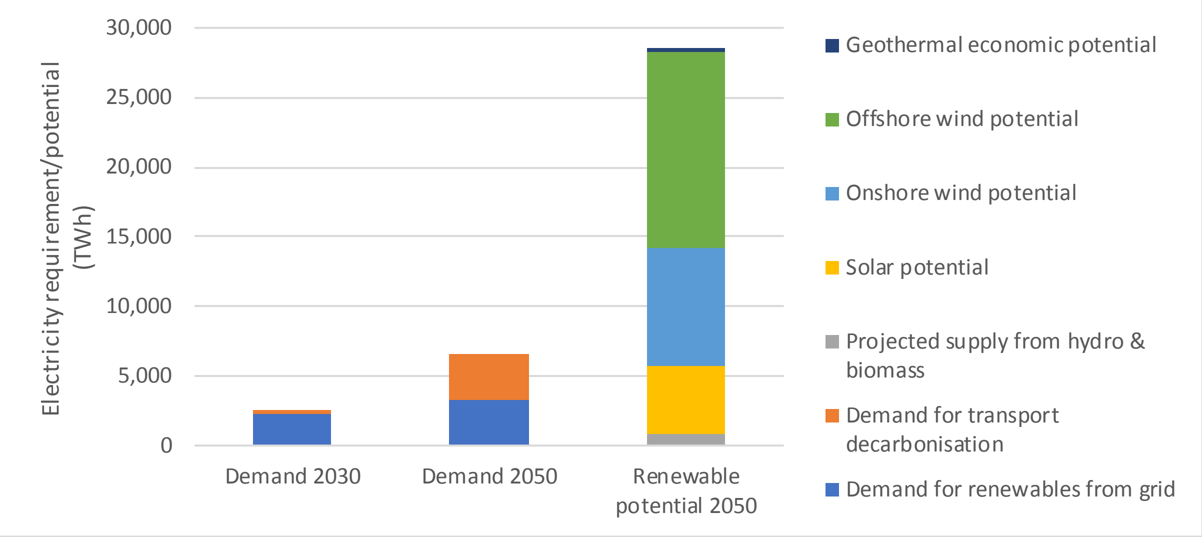
The renewable potential comfortably exceeds the projected demand from the grid and transport in 2030 and 2050. In 2050, the exploitable potential is about 4.5 times the projected demand.

[12] Note that the contribution from biomass is taken from the forecasts for the electricity grid. None of this electricity is assumed to be used for production of electrofuels.

4.3.2 Scenario 2 (Higher hydrogen)

The forecast demand for renewable electricity from the grid[12] and transport for Scenario 2 in 2030 and 2050 are shown in Figure 4-2.

Figure 4-2. Forecast demand for renewable electricity and exploitable potential for Scenario 2.

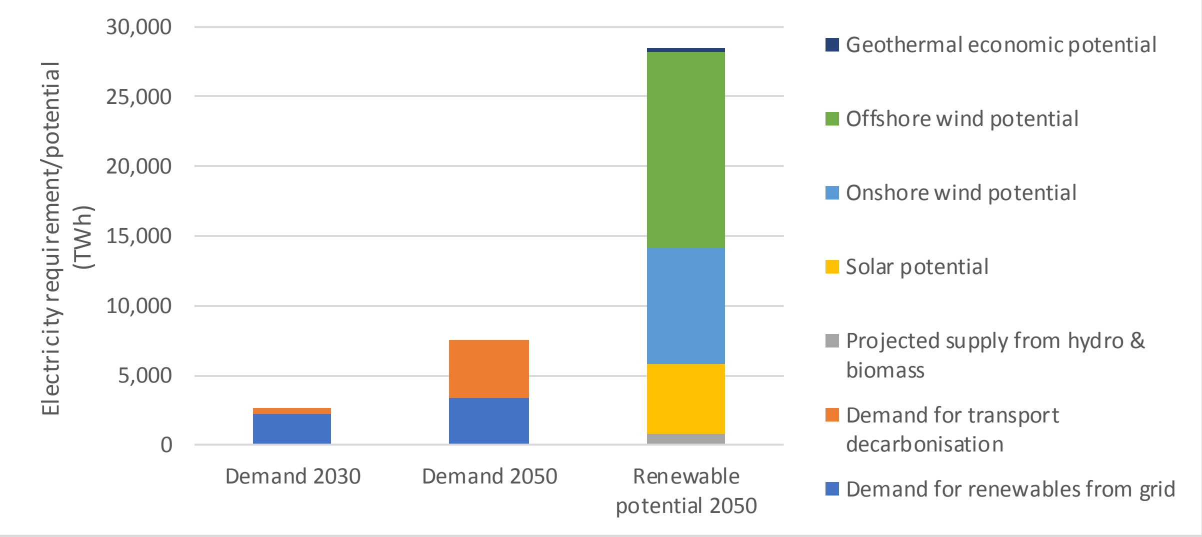


The renewable potential comfortably exceeds the projected demand from the grid and transport in 2030 and 2050. In 2050, the exploitable potential is about 4.1 times the projected demand.

4.3.3 Scenario 3 (Higher SHCF)

The forecast demand for renewable electricity from the grid[12] and transport for Scenario 3 in 2030 and 2050 are shown in Figure 4-3.

Figure 4-3. Forecast demand for renewable electricity and exploitable potential for Scenario 3.



The renewable potential comfortably exceeds the projected demand from the grid and transport in 2030 and 2050. In 2050, the exploitable potential is about 3.7 times the projected demand.

4.3.4 Preliminary observations

Although the charts above show that the renewable potential comfortably exceeds the projected requirements in 2050 for all three scenarios, there are other supply-side constraints to consider. These include availability of water resources, competing demands for hydrogen from other sectors and availability of lower-cost alternatives from other regions. These aspects are discussed in sections 5 and 6 of this report.

4.4 Land use requirements

This section has been included show the calculated electricity demands for the scenarios in a tangible way. In comparison to fossil fuel generation, solar and wind plants require significantly more space per unit of electricity produced. For this exercise, land/marine area requirements were selected for solar PV, onshore wind and offshore wind, reflecting direct and indirect land use requirements of real-world projects (see Table 4-7). Direct land use is the land covered by the physical equipment and supporting infrastructure; whereas indirect land use accounts for all other areas up to project boundaries required for the project. These values vary for each project, but average values are available in the literature. The land/marine area values for this project were selected for a typical utility-scale project in Europe.

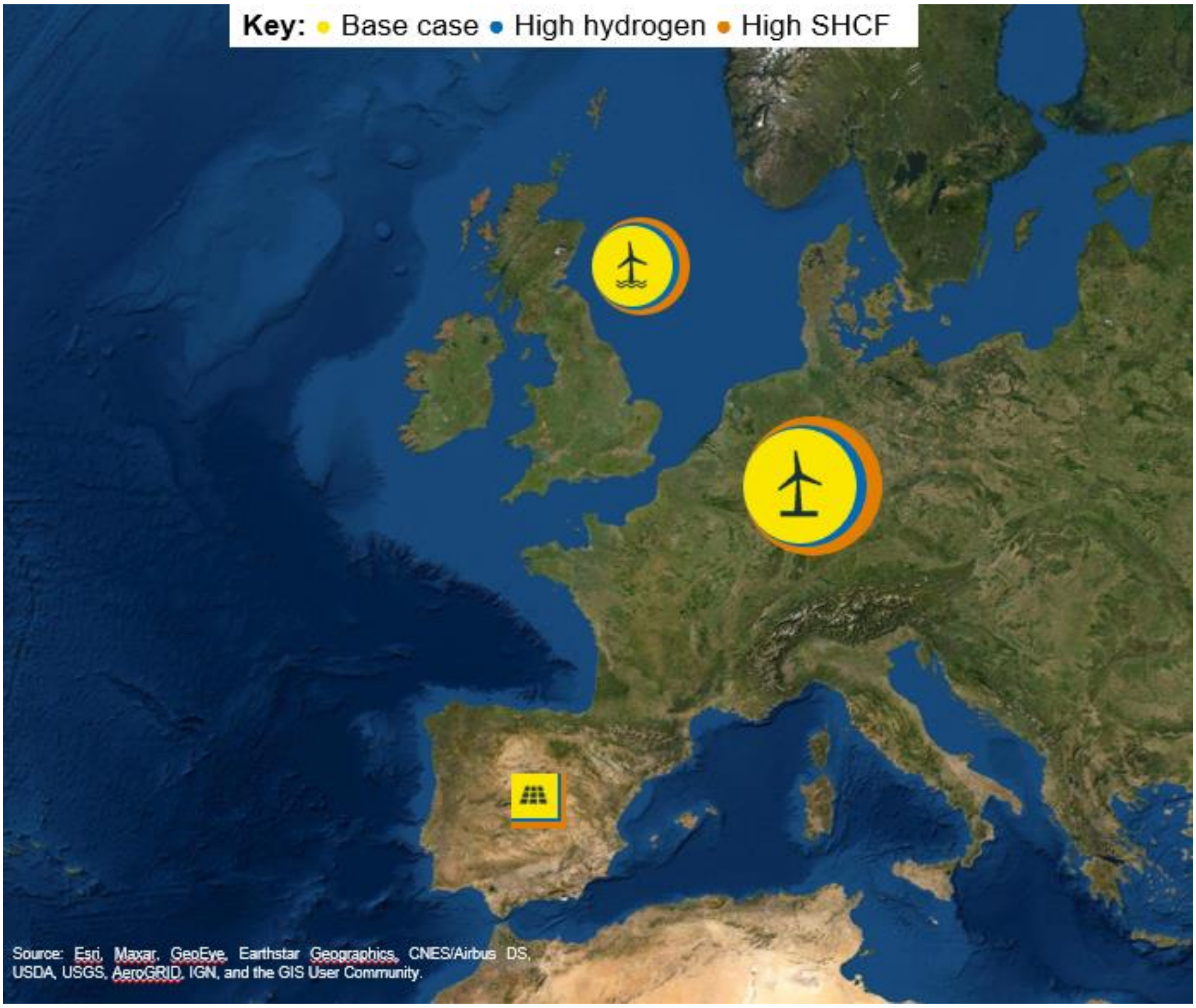
The land/marine area requirements are shown on a map in Figure 4-4 to bring the numbers to life. Typical generation performance values were assumed for particular countries, as listed in Table 4-7 below. Solar PV was assumed to be in Spain, onshore wind was assumed to be in Germany and the offshore wind was located to the northwest of the UK.

Table 4-7. Assumptions for calculating land use requirements.

	Solar	Onshore wind	Offshore wind
Country	Spain	Germany	UK
Capacity factor	21% [24]	33% [9]	45% [9]
Land/marine area use factor (MW/km^2)	31 [7]	3.75 [25]	5.4 [26]

The areas shown in Figure 4-4 indicate the area required for each of the three technologies to provide one third of the electricity requirements of the three scenarios to decarbonise road, shipping and aviation in Europe in 2050. The largest area in each case shows the area required to produce the electricity for Scenario 3 (Higher SHCF), the smallest area is for the Base Case scenario, while the area between these is for Scenario 2 (Higher hydrogen).

Figure 4-4. Visualisation of the land area requirements to decarbonise transport in Europe in 2050 assuming that a third of electricity is provided by solar PV, onshore wind and offshore wind respectively (Smallest area is for scenario 1, with scenarios 2 and 3 being progressively larger).



The image is for illustrative purposes only and does not consider any pre-existing land uses or terrain constraints and is based on a representative average capacity factor for those locations. In reality, the plants and their renewable power supply would be a mix of technologies that are geographically distributed across the EU, ideally as close as possible to areas of high fuel demand.

The calculations underlying this data are presented in Table 4-8.

Table 4-8. Land/marine area requirements for each technology to supply one third of electricity demand in 2050.

	Demand in 2050 (TWh)	Solar land use requirement (km^2)	Onshore wind land use requirement (km^2)	Offshore wind marine area requirement (km^2)
Base case scenario	2,783	16,664	86,891	43,579
Scenario 2 – High hydrogen	3,223	19,298	100,628	50,469
Scenario 3 – High synthetic hydrocarbons	4,172	24,981	130,258	65,330

Solar proves to be the most efficient of the three technologies from a land-use perspective despite its lower capacity factor. This is attributed to the high density of solar panels that can be placed within a project boundary. It is possible to design solar farms such that the land can also be used for other purposes, such as agriculture, but this tends to increase the cost.

In comparison to solar PV, onshore wind appears to need more land area to provide an equivalent electricity supply (more than 5 times that of solar). However, wind turbines need to be spaced apart to avoid interfering with the air flow patterns of neighbouring turbines, which can cause greater turbine wear and reduce energy yields. Energy yields are also affected by surrounding terrain obstacles and roughness that hinders and slows wind passing over land. The generous spacing between turbines means that wind farms can be easily co-located with agricultural activities and other productive uses.

The marine area required for offshore wind farms is about 2.6 times the land area required for solar PV. Marine area is not directly comparable to land area as it does not have the same productivity potential unless it has been designated as a shipping channel. Offshore wind farms typically have higher yields than onshore wind farms due to higher wind speeds and the absence of obstacles and topology variations. Like their onshore counterparts, they need to be spaced apart from each other to minimise air flow interference. Other key constraints for spacing are water depth and seabed conditions; although innovations such as jacket and floating foundations are available to overcome these.

5 Other supply-side considerations

5.1 Water resource constraints

Electrolysis requires significant volumes of purified water, which is in high demand for many other uses in Europe. Levels of water stress vary spatially in Europe but tend to be greatest in the west and south. In addition, evidence suggests that droughts in Europe are becoming more extreme as global temperatures increase due to climate change. For example, the severe droughts in central Europe in 2018 and 2019 have been linked to the fact that the summer periods in these two years were two of the three hottest on record [27]. With the likelihood of droughts within Europe increasing in the coming years, availability of water is an important consideration.

Water availability and depletion risk will be a key consideration in feasibility and environmental studies for electrofuel plants. Therefore, in countries susceptible to drought, electrofuel plants should be located near the coast to use seawater, in which case water will be pre-treated with a desalination plant. Moreover, purification of water requires energy, mainly electricity, for pumping and purification.

To produce hydrogen by electrolysis, about 9 litres of purified water is required per kilogram of hydrogen produced [28]. However, the amount of water into the purification process depends on the source and quality of the raw water. For example, about 22 litres of seawater are required to produce 9 litres of purified water [29]. Therefore, about 0.17 litres of seawater (to produce 0.07 litres of purified water) would be required per 1 MJ of energy stored in the hydrogen. For comparison, the total lifecycle water requirements to produce 1 MJ of first generation biofuel are between 33 and 476 litres [30, 31]. This shows that the water resource requirements for electrofuels are relatively low compared with a first-generation biofuel alternative. However, it should be noted that it is a direct comparison of water consumption between electrofuels and biofuels can be misleading because electrofuels require the water to be treated, while in general, biofuels do not.

About 196 billion litres of purified water per year would be required to produce the electrofuels (including hydrogen) for the EU27 Base Case scenario in 2050. To put this in context, it is estimated that hydropower, fossil fuel and nuclear power plants in Europe consumed about 68,000 billion litres of un-purified water in 2015 [32]. However, it should be noted that most of the water used for electricity generation is untreated river or seawater, so it is not directly comparable with the requirements for electrolysis, which requires water of a high purity.

The potential sources of the water required for electrolysis can be divided into four groups, each with their own advantages and disadvantages:

1. Freshwater – water extracted from a land-based source, either a river, lake or reservoir.
2. Groundwater – freshwater extracted from below the ground.
3. Seawater – water extracted from the sea.
4. Wastewater – water that has been discharged as a waste product from an industrial or domestic process.

The advantages and disadvantages of each source are listed in Table 5-1.

Table 5-1. Advantages and disadvantages of water sources for electrolysis

Source	Advantages	Disadvantages
Freshwater	• The water that is abstracted is likely to have a low level of hazardous solutes (dependent upon a careful choice of source location).	• The source is less reliable than saltwater or wastewater and is susceptible to seasonal fluctuation. • Not feasible in areas with very low levels of rainfall.
Groundwater	• The water that is abstracted is likely to have a low level of hazardous solutes (dependent on a careful choice of source location). • The source is more reliable than surface freshwater, being less susceptible to seasonal fluctuation.	• The source can be susceptible to seasonal fluctuation and extended dry periods. • Extracting groundwater in significant volumes can be energy intensive. • Groundwater reserves vary spatially and this may not be a feasible source in many areas. • In many areas of Europe, groundwater is an important source of drinking water that may increase in demand and would be prioritised in times of drought.
Seawater	• The supply can be assumed to be constant, with no seasonal fluctuation. • Environmental impacts from terrestrial water shortages will not affect supply.	• Desalination is required to demineralise the water, which increases the electricity requirements marginally (less than 0.1% of the electricity requirements for electrolysis). • Brine is created as a waste product which would need to be treated and reintroduced to the environment responsibly.
Wastewater	• The supply is relatively constant. • A waste product is being used that would otherwise require disposal. • Abstraction permits are not required. • There are little to no geographical restrictions to wastewater use.	• The source product will require extensive processing to provide required water purity.

5.2 Potential of curtailed power for hydrogen production

The penetration of renewable energy generation has grown significantly in Europe over the past decade and is set to increase further in the decades to 2050. This brings climate benefits, but also poses challenges for electricity system operation to balance supply and demand.

The intermittent nature of solar and wind power generation means that system operators are sometimes forced to request that renewable power producers forcibly reduce their output, which is known in the industry as "curtailment".

There are a number of drivers for curtailing generation, including:

- Localised oversupply, e.g. due to sudden and unexpected variations in renewable power output, or reductions in demand.
- Network constraints, e.g. the electricity generated in a certain location cannot be exported to other parts of the grid.

Levels of curtailment are significant in some countries in Europe, and in particular in those where the share of intermittent power in the energy mix has rapidly grown over the last decade or so. For example, it is estimated that the aggregate volume of renewable electricity curtailment was over 5.5 TWh [33] in Germany in 2017, over 2.4 TWh [33] in Lithuania in 2017, and over 1.3 TWh in the UK in 2015 [34]. In Ireland, 6% of the total available wind energy was curtailed in 2018 [34]. The majority of curtailment requests are for wind generation, reflecting the lower predictability of wind compared with solar.

There is a cost of curtailing generation – either to system operators (and hence electricity customers) or to generators. In general, large renewable electricity plants are compensated financially for responding to requests from the system operator to curtail their output. But smaller and/or distribution connected generators are less likely to receive financial compensation. They would, however, integrate the risk of lost revenue due to curtailment in their business case leading to their Power Purchase Agreement price. In both cases, end-user retail rates are ultimately impacted negatively. The volume and financial impact of renewable electricity curtailments are expected to increase with rising levels of renewable penetration across Europe, although this is expected to be somewhat offset by reinforcements of the regional transmission network (such that oversupply in one country can be transmitted to another country with a supply deficit or existing storage facilities).

In principle, renewable electricity that would otherwise be curtailed could be used to produce hydrogen. Many research papers and studies have aimed to demonstrate this on a theoretical/conceptual level. The Joint Research Centre at the EC, for example, has established that the total energy curtailed in Germany in 2015 (4.12 TWh) could theoretically be converted to enough hydrogen to power 230,000 (low case) to 606,000 (high case) cars for a year [34]. However, there are a number of factors to consider, which are summarised below.

- **Renewable energy curtailment can be difficult to predict.** Improvements to forecasting techniques are likely to help maximise wind energy output (and reduce curtailment volumes), but forecasting challenges add a significant risk factor to any power-to-electrofuel project relying onto curtailed renewable energy as its sole energy source.
- **Electrofuel production is only one of several options to reduce and/or make use of curtailed power.** National and regional grid reinforcements would help to further reduce curtailment rates and the economics (i.e. costs/benefits) of such projects, in many instances, may constitute the least-cost solution to maximise the economic value of curtailed power. In addition, power otherwise curtailed could also be stored (centrally or locally) and falling battery storage costs paired with developments in flexibility services markets will make this option more attractive in the years to come.
- **Curtailed energy is not necessarily "free electricity".** As highlighted previously, the largest generators subject to renewable electricity curtailments often receive compensation payments from system operators. Electrofuels producers would theoretically need to purchase curtailed power.
- **Not all of the renewable electricity curtailments could be used.** As a significant portion of the total renewable electricity curtailment is related to network constraints, such network constraints could also make it impractical to transmit curtailed energy to an electrofuel production facility (where it is remote from the renewable electricity plant). I.e. The electrofuel plant would need to be located reasonably close to the renewable generator. The same is true for generation curtailed to meet statutory system operating requirements.
- **The low availability of curtailed power is insufficient to make a competitive business case.** This is because the levelised cost of hydrogen can become disproportionally weighted on capital expenditure. A study by Ajanovic and Haas [35] found that it is necessary to have plants operating at more than 4,500 full load hours per year to provide a suitable return on capital investment. An exponential incline in levelised cost of hydrogen occurs as full load hours are reduced with the most noticeable rate of change beginning after 2,000 full load hours. This effect is even more drastic on smaller scale plants that don't benefit from economies of scale.
- **There may be merits in designing hybrid power to electrofuel solutions using curtailed power amongst other sources.** Consideration should be given to electrofuel production projects which would not solely rely on curtailed power for supply. Hybrid models could consider a combination of curtailed power, local renewable supply, and other power supply arrangements.

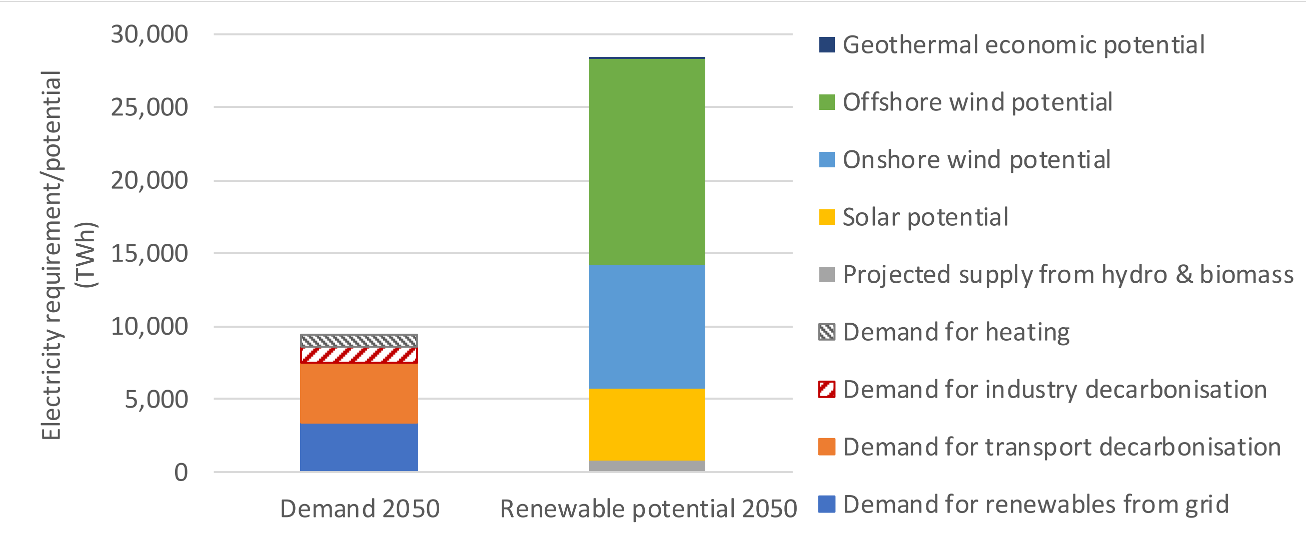
In conclusion, making use of renewable electricity that would otherwise have been curtailed is likely to have only a small role in producing the hydrogen and electrofuels needed to decarbonise Europe's transport sector to 2050. It will be useful to prevent curtailment in specific locations with relatively limited connectivity to the larger grid, but it is unlikely to play a meaningful role at a continental-level.

5.3 Competing demands for hydrogen

Recent studies have concluded that hydrogen could play a major role in decarbonising sectors other than transport, including heavy industry and heating. The Hydrogen Roadmap for the EU published by the Fuel Cells and Hydrogen Joint Undertaking [36] states that "hydrogen is the best (or only) choice for at-scale decarbonisation of selected segments" including "the decarbonisation of the gas grid" and the decarbonisation of industrial activities involving high-grade heat – in which case hydrogen could be used as feedstock. The production of green hydrogen to decarbonise those segments would require additional renewable electricity.

With multiple sectors potentially looking to hydrogen as key to their decarbonisation, this study sought to estimate the renewable electricity requirements to produce green hydrogen for the competing sectors. To estimate the worst-case demand, the Ambitious Scenario in the Hydrogen Roadmap was used as a basis to estimate the total renewable energy requirements to produce the volume of green hydrogen required to decarbonise heating for buildings and heavy industry. Figure 5-1 shows the total renewable electricity requirements with the additional demand from heating and industry added to the EU28 Base Case transport requirements from section 4.3.1.

Figure 5-1. Forecast demand for renewable electricity and exploitable potential for the EU28 Base Case, including demand for decarbonisation of industry and heating.



The projected electricity requirements to decarbonise heating in 2050 is about 25% of the requirements to decarbonise transport under the base case scenario; whereas the requirements to decarbonise industry are about 40%.

The total demand for renewables by 2050 shown in Figure 5-1 is about 30% of the total renewable energy potential. Therefore, the availability of renewable electricity is unlikely to be a significant constraint to decarbonising transport in the EU, even if there is significant competition from other sectors for green hydrogen. It is more likely however, that cost will be a key factor in determining the proportion of hydrogen that is produced domestically within the bloc and how much is imported. This is discussed in the next section.

6 Cost considerations

Sections 4 and 5 have shown that the EU has the resource potential to domestically produce its own electricity and electrofuels (including hydrogen) to meet the projected transport demand in 2050 in all three scenarios. However, there can be economic opportunities in importing hydrogen from countries that are rich in renewable resources. As electricity is the highest cost component in production of electrofuels, it could be cheaper to produce electrofuels in other countries with lower-cost and abundant renewable electricity and import the electrofuels to Europe.

This section investigates the costs of domestic production within the EU in comparison with importing green hydrogen produced in selected renewable-rich countries. A levelised cost of energy (LCOE) methodology was used, drawing on data from a report for the European Commission entitled “Hydrogen Generation in Europe: Overview of costs and key benefits” [37] as well as Ricardo’s hydrogen production cost database. Input assumptions are shown in Appendix B.

The countries that have been selected as good prospects for import and have been included in this analysis are Norway with its abundant hydropower and high offshore wind potential as well as Morocco and Saudi Arabia with their high solar potentials.

6.1 Pipeline transmission

Morocco and Norway have added interest as their close proximity to the EU opens up the opportunity to use directly connected pipelines. Pipelines are a safe and efficient method of transporting gases, including hydrogen, continuously over long distances and in large quantities. Transmission by pipeline also avoids the need to liquefy the hydrogen for bulk transportation, which requires significant energy and cost. However, they require significant planning and have long development timescales.

Pipelines are included here as a theoretical exercise to indicate the impact on costs compared with other options. It is likely that a preferable approach in reality will be to install cables to import the energy as electricity and produce the hydrogen in the EU.

6.2 Shipping and conversion costs

Importing hydrogen from Saudi Arabia and other renewable-rich countries further afield will rely on shipping for bulk transportation. Long distance hydrogen shipping aims to maximise the payload delivered by converting the state of hydrogen into the form of ammonia or into a liquid form through cryogenic cooling to -260^{0}C. In the analysis below, liquid hydrogen is denoted as LH_2.

Liquefaction and conversion to ammonia and ammonia’s reconversion back into hydrogen have associated costs that will impact the final LCOE. The values for conversion and ammonia reconversion have been sourced from the Hydrogen Generation in Europe report [37]. Note that the LCOE quoted for ammonia assumes that it is converted back to hydrogen at the destination. It therefore does not represent the LCOE for ammonia as a fuel in its own right for shipping.

A separate study is presented in Appendix C to discuss the costs of SHCFs for shipping.

6.3 Plant costs

The LCOE model used for this investigation uses capital expenditure, capitalised interest, operational expenditure, refurbishment costs and electricity cost data points as inputs. Cost of capital has been removed so as to remain comparable with the Hydrogen Generation in Europe report. The cost of hydrogen production is primarily driven by the cost of electricity, consequently the financial and operating assumptions surrounding the renewable electricity plant will have the largest impact to the LCOE. These have been assumed as shown in Table 6-1.

Table 6-1. LCOE input assumptions.

	Germany	Spain	Norway	Morocco	Saudi Arabia
Renewable technology	Onshore wind	Solar PV	Offshore wind	Concentrated solar	Solar photovoltaic
Electricity price (€/MWh)	39	28	45	41	28
Annual full load hours*	2,847	1,796	3,942	3,000	2,100
Source	[38]	[39]	[38]	[40]	[37]

* Based on renewable electricity technology; to calculate the capacity factor, divide by the number of hours in a year, 8,760.

In a full-scale commercialised plant operating with a continuous output, a blend of generation and storage technologies would be required to maximise the load hours of the plant and avoid risks incurred by renewable generation variability.

6.4 Analysis

Ten supply pathways have been considered for providing hydrogen to Europe. Four consider domestic production in Germany and Spain. Two pathways consider production followed by pipeline transmission to a point of use 20km away within Europe. The other two pathways present the cost associated with converting hydrogen into a carrier fuel at the point of production and reconverting the fuel at the point of use.

The remaining six pathways consider import from Norway, Morocco and Saudi Arabia. Norway and Morocco's pipeline pathways imports hydrogen across distances of 1,280 km and 2,600 km respectively, to the port of Rotterdam. Again, these distances are assumptions to the model to provide a like-for-like comparison with the other pathways. In reality, a cost benefit analysis would be conducted to determine whether it is preferable to import the energy over a cable as electricity. If imported by pipeline, the length of the pipeline would be minimised as far as possible.

The Morocco and Saudi Arabian shipping pathways assume conversion to carrier fuels and shipping across distances of 3,115km and 12,036km respectively, to the port of Rotterdam.

Storage costs are not shown in the results but are calculated to be approximately 2 €/MWh in addition for all scenarios. The totalled LCOE of hydrogen[13] for each supply pathway are shown in Table 6-2 for domestic production and Table 6-3 for imported hydrogen. The input assumptions for these calculations are provided in Appendix B.

Table 6-2. Levelised cost of hydrogen – domestic production and transport.

Domestic production	Germany, 20km pipeline	Germany, NH_3 transport	Spain, 20km pipeline	Spain, LH_2 transport
(€/MWh H_2)	89	150	87	161

Table 6-3. Levelised cost of hydrogen – imported to Rotterdam.

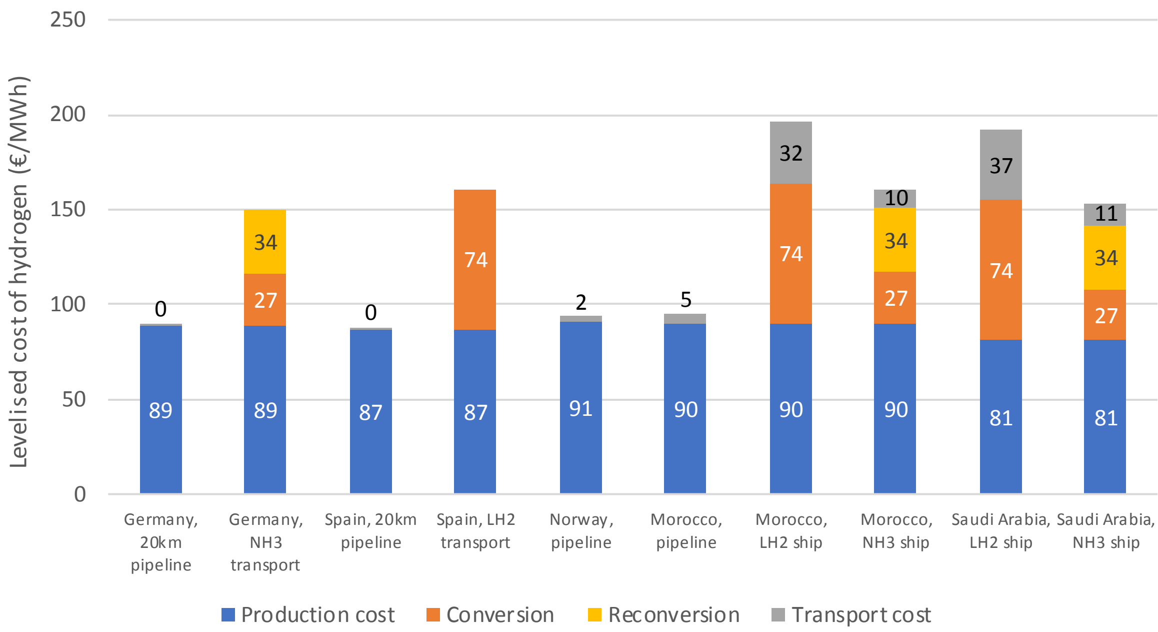
Imported fuels	Norway, pipeline	Morocco, pipeline	Morocco, LH_2 ship	Morocco, NH_3 ship	Saudi Arabia, LH_2 ship	Saudi Arabia, NH_3 ship
(€/MWh H_2)	93	95	196	161	192	153

[13] Expressed in Euros per MWh of energy stored in the fuel on a lower heating value basis to be consistent with the data in [37].

The four pathways involving supply by pipeline are the lowest cost because they avoid the significant energy costs of conversion to a higher density medium for transport. The lowest cost solution is to produce hydrogen domestically in Spain due to the low cost of electricity input from solar farms. The second cheapest is domestic production in Germany due to the relatively low cost of electricity input from onshore wind farms. The third most cost-effective route is to import from Norway (using offshore wind) via pipeline. Importing hydrogen from Morocco is the fourth-cheapest option.

The effect of conversion and reconversion of carrier fuels can be seen clearly on Figure 6-1., in many cases costing nearly as much as the production of hydrogen itself.

Figure 6-1. Levelised cost of domestic hydrogen production vs imported hydrogen.



6.5 Key sensitivities

Importing fuel means there is less transparency and regulation of the way that the fuel is produced. There are potential opportunities for suppliers to create hydrogen through cheaper, carbon intensive methods and still claim that the product is “green”. Therefore, an effective certification programme is required to validate that suppliers are providing authentic zero-carbon hydrogen. A testing procedure could be developed to check hydrogen for any impurities that might suggest that the fuel has come from a carbon-based process such as SMR.

The long-term reliability of the consistency of supply from foreign countries is also a consideration, due to the risk of political instability. A possible mitigation of this risk is to establish a strong domestic supply chain within Europe and import from a diverse range of countries when there are potential cost advantages in doing so.

6.6 Conclusion on costs

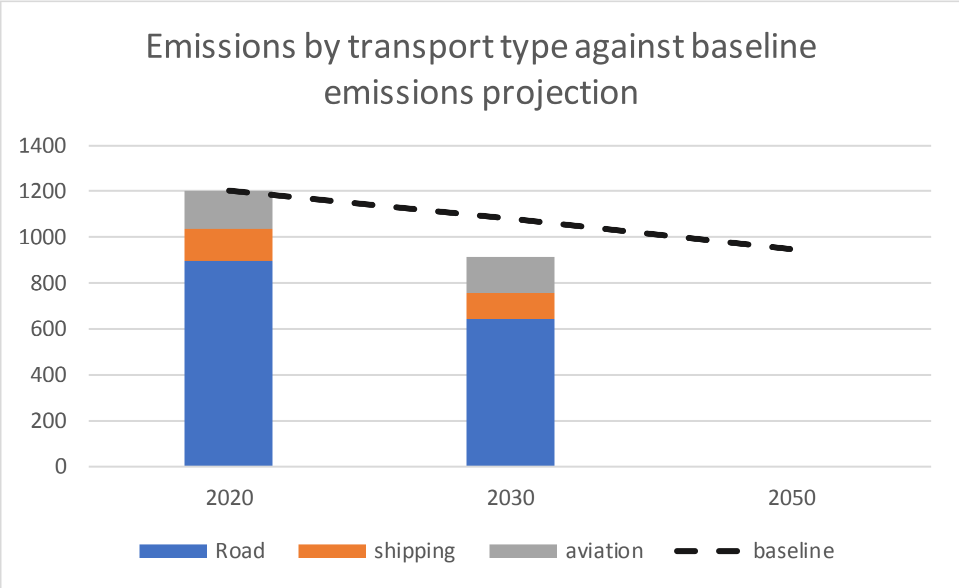
Considering the sheer volume of electrofuels that are required to decarbonise transport in Europe to 2050, both domestically produced and imported electrofuels will probably be required. Market forces will determine the proportion that is imported and in the short term there are still some uncertainties about the costs associated with the conversion of bulk hydrogen carriers into hydrogen when they are offloaded in the EU. It is clear that Europe needs encourage the development of a mature and diverse domestic hydrogen market as soon as possible. Developing such a market quickly would also make the EU a world leader in this technology. The ambition to achieve these aims this is clear in the EC’s Hydrogen Strategy [2] as well as the country-level strategies that have been announced in recent months.

7 Discussion about environmental aspects

7.1 Potential greenhouse gas savings

This section estimates the potential greenhouse gas savings associated with pursuing the T&E decarbonisation pathways against a counter-factual scenario where full decarbonisation is not pursued. As stated previously, it should be noted that the impacts of the Covid-19 pandemic have not been included in these forecasts. The results are summarised in Figure 7-1. The reductions in 2030 are based data provided by T&E. A breakdown of emissions and references can be found in Appendix D.

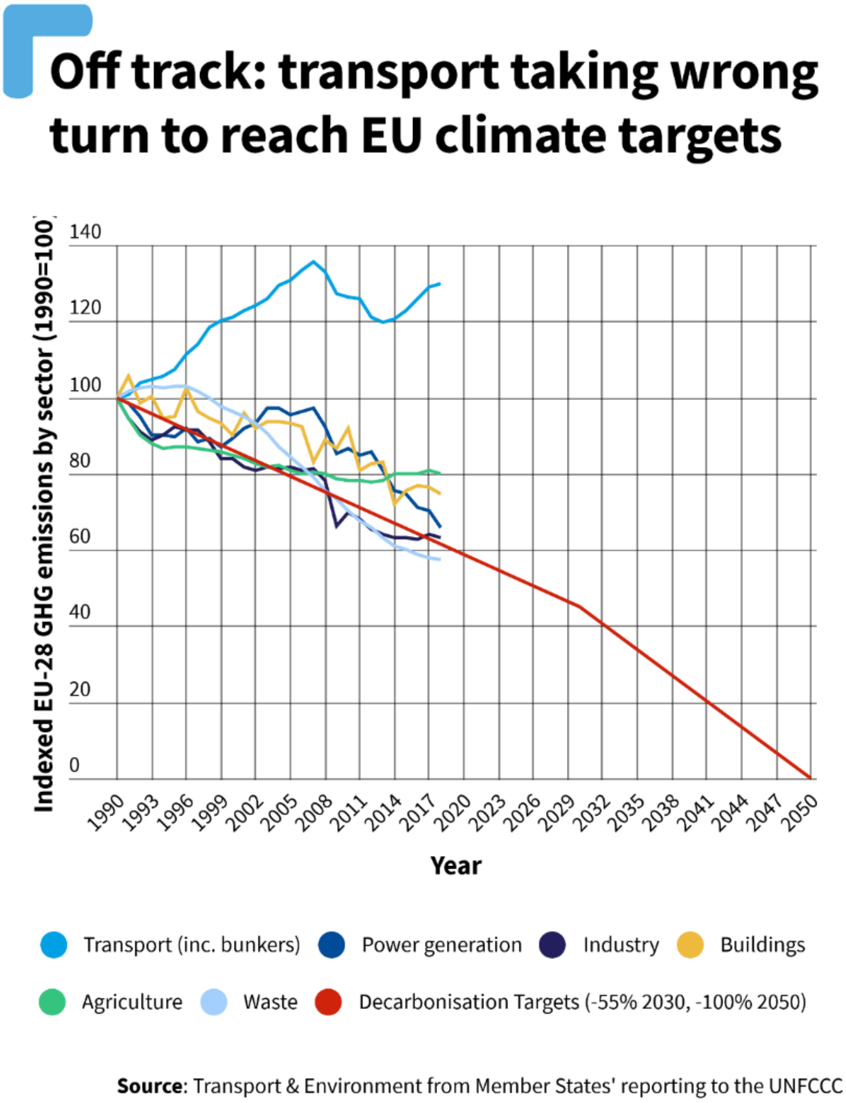
Figure 7-1. Emissions by transport sector against a baseline projection.



Based on T&E long term strategy data [41], the transport sector currently emits about 1,200 Mt CO_2e on an annual basis. Emissions are projected to decrease to 950 Mt CO_2e by 2050 when applying the factor of decrease predicted by the baseline scenario of the EC's Cleaner Planet for All report [11] and the addition of projections for growth in the shipping industry assumed by T&E. Road vehicles dominate the emissions with shipping and aviation about equal. Without any interventions, shipping emissions are forecast to grow by 69% to 2050; unlike road and aviation, which are projected to decrease under enacted and proposed European policy.

The total emissions of transport are projected to be about 910 Mt CO_2e in 2030 according to the T&E forecasts, which is 16% lower than the baseline as shown in Figure 7-1. This would be a significant shift from the business-as-usual trend, which has been increasing since 2014, as shown in Figure 7-2.

Figure 7-2. Chart by T&E showing EU27 and the UK indexed greenhouse gas emissions (Source: [41], used with permission).



7.2 Air quality impacts at the point of use

As well as their primary objective to reduce carbon emissions, alternative fuels can produce less harmful pollutants than conventional fossil fuels at the point of use. Some of the pollutants produced from fossil fuels are present because they are the result of contaminants mixed in with the fossil fuel. Synthetic fuels avoid these contaminants and have a higher purity.

Pollutants like Nitrogen Oxides (NOx), Sulphur Oxides (SOx), heavy toxic metals, particulate matter[14], hydrocarbons, polycyclic aromatic hydrocarbons have a negative effect on local air quality and are harmful to human health. The pollution content varies depending on the fuel type, the quality of the combustion process and the propulsion technology. The technologies considered within this report are summarised in this section.

[14] Particulate matter includes emissions of ash, which are metal oxides produced from combustion of lubricant and engine wear. The level of ash emissions from synthetic fuels as well as the effect of ash nanoparticles on human health require further research and are not specifically covered in this report.

7.2.1 Hydrogen fuel cell

Hydrogen fuel cells are the cleanest technology after direct electrification and produce no harmful pollutants. They use the chemical energy of hydrogen combined with oxygen as an oxidizing agent to cause an electrochemical reaction within the fuel cell to generate electricity. During the chemical reaction, oxygen from the air combines with the hydrogen to form water vapour and heat.

7.2.2 Synthetic diesel combustion

The crude oil produced from power to liquid technology is sometimes known as blue crude. Blue crude can be refined into e-diesel that can be used as a drop-in fuel for existing diesel engines. This avoids the need to redesign vehicles for new fuels and can be used with existing internal combustion engines.

In contrast to fossil-derived fuels, synthetic fuels do not contain impurities such as heavy metals and sulphur, but the exhaust does contain particulate matter, NOx, carbon monoxide (CO) and CO_2. The amounts of particulate matter are likely to be lower than fossil fuels (due to the absence of impurities[15]) and studies have shown that NOx emissions from synthetic diesel are similar or lower than fossil-derived diesel [42, 43]. However, deNOx exhaust aftertreatment technology can be used to reduce NOx levels. In general, CO and CO_2 would be similar to fossil fuels.

7.2.3 Hydrogen combustion in an engine (for shipping)

Hydrogen combustion avoids fuel contaminants and thereby eliminates pollutants caused by sulphur dioxide, carbon monoxide, heavy metals and hydrocarbons, causing particulate matter to decrease substantially.

Hydrogen internal combustion engines mix with atmospheric air that predominantly consists of nitrogen (78%) and oxygen (21%). At efficient air-to-fuel ratios, the high temperature of combustion creates a reaction between oxygen and nitrogen, causing them to combine to create NOx emissions that are released at quantities equivalent to fossil fuel combustion [44]. There are some abatement technologies such as selective catalytic reduction (SCR), which uses urea to reduce NOx to nitrogen and water vapour via a catalyst. SCR has been shown to be 90% effective at removing NOx.

As a solution, SCR technologies have limitations in that they require ongoing operation and maintenance to operate effectively. Without any accountability or recourse for emissions exceedances, ship owners may be tempted to neglect operation and maintenance to save on costs. Therefore, a compliance or monitoring programme may need to be established to ensure that they operate as required.

7.2.4 Ammonia combustion in an engine (for shipping)

Much like hydrogen combustion, ammonia combustion eliminates pollutants caused by impurities and releases NOx emissions. SCR technology, which uses urea as its feedstock, can be implemented to capture NOx at the exhaust. Nitrous oxide (N_2O) emissions can be generated by SCR systems, so the calibration of SCR systems to minimise N_2O will be important to emissions of this greenhouse gas [45]. There is a risk of unburned ammonia fuel being released to atmosphere with exhaust gases (“ammonia slip”), but this can be minimised through engine calibration and the use of ammonia slip catalysts in SCR systems.

Particulate matter is still present in emissions albeit in lower concentrations than emissions of conventional fuels, some particles of fuel would also contribute to particulate matter by remaining unburned. However, this can be minimised to a safe level through future developments in correct engine calibration and controlled combustion conditions.

7.2.5 Ammonia solid oxide fuel cell (for shipping)

Solid oxide fuel cells (SOFC) are a novel technology where the electrolyte material is made from solid oxide or ceramic material. SOFCs benefit from high combined heat and power efficiency, low cost and fuel flexibility allowing for ammonia to be used as an input fuel. The high operating temperature of typically 750^{0}C which can result in long start-up times. The SOFC causes oxygen to react with the ammonia,

[15] The impurities that lead to higher particulate matter from diesel engines are sulphur-containing heterocyclic and polycyclic aromatic molecules. These are both precursors of sulphate and particulate emissions and are generally are not present in synthetic fuels.

releasing NOx and water as by-products of electricity generation. As with hydrogen combustion, NOx can be captured at the exhaust by SCR technology.

7.2.6 Synthetic kerosene combustion (for aviation)

Synthetic e-kerosene is produced from synthetic crude in much the same way as e-diesel but is refined to be suitable as a jet fuel. The development of new aircraft based on novel fuels require significant research and development, investments, and accompanying regulation to ensure safe, economic aircraft. Commercialisation and certification of aircraft can take more than 10 years [46]. Drop-in fuels like e-kerosene are the most immediate solution that would only require development of the supply infrastructure.

As with e-diesel, fuel impurities are removed, but the exhaust from e-kerosene combustion still contains CO_2, CO, NOx and particulate matter. Emissions of the first three pollutants would be at a similar level to fossil-derived kerosene, but the concentration of particulate matter is likely to be lower.

Aviation has difficulty reducing these emissions due to technical solutions adding weight to the aircraft and requiring technical complexity that could have an impact on passenger safety. In addition, an issue unique to aviation is that the fine particulate matter results in contrails, creating cirrus clouds that contribute to short-term global warming [47]. The effects of NOx emissions from aeroplanes are complex [48]. On the one hand, they increase ozone formation, which has negative effects on respiratory health (at ground level) and is a greenhouse gas but NOx also shields the earth's surface from harmful UV radiation at high altitudes. While on the other hand, NOx tends to reduce methane levels, which is itself a significant greenhouse gas.

7.3 Environmental risks with blue hydrogen

Blue hydrogen is hydrogen that has been derived from fossil-fuel hydrocarbons, with carbon capture and storage (CCS) deployed to capture and permanently store the resulting CO_2 that is generated in this process. Carbon capture is not 100% effective with current technology, so there are still CO_2 emissions from the process. Therefore, blue hydrogen from fossil fuels is considered as a low-carbon fuel rather than a zero-carbon solution. If biomethane is used as an input instead of natural gas, there is potential to produce blue hydrogen with negative emissions.

The most widespread technological pathway for generating blue hydrogen is by steam methane reformation (SMR) coupled with CCS. More recently, the auto-thermal reformation (ATR) process has gained interest due to potentially higher CO_2 capture rates and could replace SMR as the preferred solution in future. Blue hydrogen could also be produced from the gasification of coal with CCS, though hydrogen from coal gasification is less widespread than SMR, and the carbon intensity of coal is much greater than that of natural gas. Hence, the assessment of blue hydrogen's environmental risks described below has focussed on the steam reformation of natural gas.

7.3.1 Blue hydrogen's lifecycle environmental impact

Environmental assessments of blue hydrogen must consider its full supply chain and not just the production stage. There are leakages upstream of the hydrogen production process during the extraction and transportation of the natural gas feedstock. Beyond the hydrogen production process, the captured CO_2 must be transported and stored, which will also be subject to fugitive emissions. However, the end-use of the hydrogen itself, either through combustion or its use in fuel cells, results in zero direct greenhouse gas emissions.

It is important to note that the lifecycle emissions of blue hydrogen will vary considerably depending on the upstream natural gas processing emissions, transportation requirements of the natural gas feedstock, the reformation technology and the capture rate of the CCS technology. The lifecycle greenhouse gas emissions (in terms of CO_2 equivalent) of blue hydrogen produced from reformation of natural gas with CCS are given in Table 7-1, reported by two sources.

Table 7-1. Lifecycle emissions of blue hydrogen.

Source	Estimated lifecycle emissions (gCO_2e/kWh hydrogen)
H21 Leeds City Gate Project Report [49]	86
Hydrogen in a low-carbon economy [50]	30 to 99

For comparison, the lifecycle emissions of natural gas combustion (including upstream and downstream emissions), is in the region of 210 gCO_2e/kWh. The lifecycle emissions of blue hydrogen are lower than unabated natural gas, but they are still significant. A breakdown of these emissions and further environmental considerations is given in the following sections.

7.3.2 Upstream of blue hydrogen production

The extraction, processing and delivery of natural gas leads to greenhouse gas emissions. Upstream emissions arise due to venting, flaring, leakages, energy requirements in processing and energy requirements for transportation.

There is a wide range in the estimates of upstream greenhouse gas emissions for natural gas in the available literature, depending on the method and location of extraction (production) as well as the other aspects listed above. The UK Committee on Climate Change (CCC) estimates the upstream emissions from UK based onshore shale natural gas production to be in the region of 15 to 70 gCO_2e/kWh of natural gas. An extensive literature review by Balcombe et. al. [51] identified ranges of 10 to 118 gCO_2e/kWh for gaseous natural gas and 25 to 209 gCO_2e/kWh for liquefied natural gas (which is typically transported by sea). It is worth noting that these wide emissions ranges are due to differences in input assumptions for the calculations.

On an energy basis, the conversion of fossil-fuel feedstocks to hydrogen is subject to losses (SMR currently achieves around 65% conversion efficiency, whilst ATR may achieve up to 85%). This increases the amount of fossil-fuel feedstock required per unit of hydrogen produced and must be considered when assessing upstream emissions. Applying a 65% conversion efficiency on the range identified by the CCC, yields an increased range of 23 to 108 gCO_2e/kWh of hydrogen from upstream emissions (assuming that the natural gas is not liquefied for transportation).

7.3.3 Blue hydrogen production

The reformation of natural gas to yield hydrogen results in the generation of CO_2. Without carbon capture, the carbon intensity of hydrogen from this process is about 285 gCO_2/kWh [50]. The capture rates achieved by current operational SMR plants with CCS are in the region of 60% [50], which would suggest a reduction in carbon intensity to around 114 gCO2/kWh of hydrogen. However, a literature research by the Department for Business Energy and Industrial Strategy (BEIS) [52] found two sources which suggested that carbon intensities of 37 and 45 gCO_2e/kWh could be achieved based on higher capture rates of 84 to 87%.

It is thought that these capture rates can be improved, with SMR achieving up to 90% and up to 95% with ATR. Modelling by CE Delft demonstrated that carbon intensities of 28 gCO_2e/kWh and 19 gCO_2e/kWh could be achieved by SMR with 90% capture and ATR with 95% capture respectively [53].

It should be noted that steam reformation generates emissions other than CO_2, particularly: methane, N_2O, volatile organic compounds, CO, NOx, SOx and particulates. Work by Salkuyeh et al. [54] has also indicated that the integration of CCS into SMR plants could increase the non-CO_2 emissions, due to the increased energy requirements of the CCS plant.

7.3.4 CO_2 transport and storage

Further emissions will arise from any leakages and the energy requirements associated with the transportation of CO_2 and its storage operations. Mass storage of CO_2 will likely be achieved by the use of underground geological formations such as depleted oil and gas reservoirs. An obvious risk is the direct leakage of CO_2 from these sites, though research has indicated that this concern is unfounded. The Intergovernmental Panel on Climate Change [55] state that they consider 99% or more of injected CO_2 will be retained for 1,000 years. Research by Alcalde et al. [56] demonstrated that over 98% of the injected CO_2 would be retained in the subsurface over 10,000 years.

The energy requirements of transportation will largely be dependent on the distance required and mode of transportation (e.g. pipeline or ship). Emissions will arise in the storage phase, either due to leakages or any energy requirements of the injection of CO_2 at the storage site. The emissions arising from the transportation and storage phases are not widely discussed in literature and are thought to be relatively small in comparison to upstream and hydrogen production emissions.

7.3.5 Conclusion about the role of blue hydrogen

Blue hydrogen from fossil fuels is not a zero-carbon solution due to upstream greenhouse gas emissions in the production and transportation of natural gas, the inefficiencies of carbon capture and the potential for leakage of captured CO_2. Therefore, blue hydrogen is not a realistic long-term solution to full decarbonisation of transport in Europe.

8 Conclusions

Direct electrification is the most efficient means of decarbonising the transport sector. However, the large power requirements of some transport modes (e.g. large ships and aeroplanes) mean that direct electrification is not feasible with current or future technologies. These modes will need other zero carbon fuels in 2030 and 2050.

The Base Case scenario in this report is based on an approach of “direct electrification where possible” and the efficient use of green electrofuels where it is not. The additional renewable electricity requirement to achieve T&E’s forecast levels of decarbonisation by 2030 is 245 TWh/y for the EU28 countries. For comparison, grid operators predict that the demand for electricity in EU28 countries will be about 3,500 TWh/y in 2030.

To achieve full decarbonisation of transport with T&E’s Base Case forecast, about 2,800 TWh/y will be required by 2050. This represents a significant scale-up between 2030 and 2050. For comparison, the predicted demand for renewables from the decarbonised electricity grid in 2050 is predicted to be about 3,350 TWh/y.

This study shows that the potential for additional renewable electricity in the EU28 countries comfortably exceeds the projected demand to decarbonise transport and the electricity grid by 2050. Studies show that the total exploitable potential for renewable electricity (solar PV, onshore wind, offshore wind & geothermal) in the EU28 countries is about 27,000 to 28,000 TWh/y.

Even if the decarbonisation of heating and heavy industry is achieved using hydrogen, the renewable electricity required to produce this hydrogen remains within the limits of the available potential within the EU28 countries, when added to the needs to decarbonise the grid and transport.

T&E present two alternative decarbonisation scenarios to compare with the Base Case. Scenario 2 sees more of a contribution from hydrogen, while Scenario 3 considers the implications of using synthetic hydrocarbon fuels to complement direct electrification. The differences in renewable electricity consumption are significant: Scenario 2 requires 23% more electricity than the Base Case in 2030 and 16% more in 2050; while Scenario 3 requires about 71% more than the Base Case in 2030 and 50% more in 2050. Pursuing these alternative scenarios would therefore increase the cost of decarbonisation significantly by 2050, especially if the synthetic hydrocarbon route is chosen.

Analysis of the costs of hydrogen production and transportation show that significant cost penalties are incurred when the hydrogen needs to be processed for bulk transportation (whether in liquid form or converted to ammonia). This means that:

- Production should be located as close as possible to the point of use.
- With current renewable electricity prices, it is generally cheaper to produce hydrogen within Europe or an immediate neighbour and distribute it in gaseous from than it is to ship it in from other regions, primarily due to the additional cost of converting the hydrogen to a suitable form for bulk transportation.

This study identified the following key messages for policy makers concerning specific modes of transport:

- Focus on direct electrification for road transport, wherever possible, as it is the most efficient path to decarbonisation.
- Road transport will decarbonise more rapidly than shipping and aviation to 2030, but by 2050 shipping and aviation will dominate, requiring more electricity than road transport.
- Shipping is projected to be the largest consumer of renewable electricity by 2050 (30% of the total) of all the modes. Therefore, there should be a special policy focus on decarbonisation of the shipping sector.
- Policy decisions about zero-emission heavy-duty trucks in the early 2020s will have significant ramifications for electricity demand by 2030 and 2050.
- Small changes to the fuel mix of light road vehicles has a large impact on electricity requirements.
- The renewable electricity requirements to decarbonise aviation are relatively insensitive to fuel choice because all scenarios rely heavily on e-kerosene.

This study also found that there will be significant improvements to air quality when fossil fuels are replaced by direct electrification and electrofuels, these are in addition to the reduction in greenhouse gas emissions. It also found that although the water consumption requirements for electrolysis are significant, they are low compared with the requirements for biofuels. A policy of “direct electrification where possible” would significantly reduce the burden on Europe’s water resources.

In conclusion, this study finds that there is sufficient renewable electricity potential within the European Union to decarbonise road, shipping and aviation by 2050. However, the significant land area required and water demand for production of electrofuels (including hydrogen) could mean that a portion of the renewable electricity and electrofuels will be imported to complement domestic production. The future costs of renewable electricity in other regions and the costs to produce and transport electrofuels to Europe will play a major role in determining the split between imports and exports in the coming decades.

Achieving the goal to decarbonise transport by 2050 will require clear direction from policy makers in the 2020s. The details of today’s policies need to be considered carefully because they will have significant ramifications on the renewable energy demand by 2050.

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Appendix A: Case study of offshore wind for Port of Antwerp to produce electrofuels

Antwerp, the second largest city in Belgium, is home to half a million people and is located 50km north of Brussels. Its port, the Port of Antwerp, is a main economic driver in the country and is the second most important European port in terms of throughput, right behind the Port of Rotterdam, Netherlands, which is located just 50km north of Antwerp. In addition to their strategic locations, the two ports are well connected by rail, road, pipeline and inland waterway to the rest of the continent. In 2019, 469.4 million tonnes of goods were moved through the Port of Rotterdam, making it the 4th busiest cargo port in the world. In contrast, the Port of Antwerp held the 17th place in the world ranking with 238.2 million tonnes.

Figure A - 1 Satellite image showing a hypothetical offshore wind farm to supply renewable electricity to the Port of Antwerp

About a third of the vessel fleet passing through the Port of Antwerp in 2019 was comprised of container carriers, which were responsible for transporting about 140 million tonnes of containerised goods (or about 60% of the overall throughput) that year [57]. On average, about 13 such ships dock in the port every day, carrying an average cargo of 30,200 tonnes. It would take 5 hydrogen plants, each consuming 225MW of renewable energy and producing 100 tonnes of green hydrogen per day, to refuel one container carrier of this size every day with enough fuel for a 34-day journey. Similarly, it would require 4 ammonia plants, each consuming 280MW of renewable energy and producing 700 tonnes of green ammonia per day, to refuel one such vessel every day with enough fuel for a 32-day journey.

Considering the great offshore wind potential on the Belgian and Dutch coasts, the green hydrogen and ammonia plants could be mainly powered by offshore windfarms. Figure A - 1 shows the area that a 2GW windfarm would occupy (about 25km by 15 km) to power one container carrier per day as per the example above. Such a windfarm could provide as much as 85% of the total annual energy required to operate the plants at full capacity (assuming a plant availability of 91%). The remaining 15% could be imported from the grid. About 6% of the energy generated by the wind farm over the year would be surplus energy, which could be either stored using batteries and used when wind is not blowing or exported to the grid and be used to offset the cost of importing from the grid. Further data is available in the table below.

With the two ports being so close to each other, efforts and resources could be combined to develop major green hydrogen and ammonia hubs in the area, and trigger investment in renewable energy.

Table A - 1. High level plant operation assumptions.

Description	Units	Value
Fuel production (tpd)	Tonnes per day	H_2: 500 NH_3: 2,800
Fuel plant availability factor		91%
Fuel plant maximum electricity demand	GW	1.12
Offshore wind capacity	GW	2
Number of turbines		286
Capacity of individual turbines	MW	7
Land area of wind farm	km	25 x 15
Fuel plant annual electricity demand	GWh	8,930
Est. annual electricity generated – wind farm	GWh	8,060
Est. electricity imported from grid	GWh	1,360
Est. electricity exported to grid	GWh	470

Appendix B: Input assumptions for levelised cost calculations

		Unit	2020
Supply	Power price	€/MWh	As per Table 6-1. LCOE input assumptions
	Capital cost	€/kW_{el}	980
Electrolyser	Operating cost	% of capital cost	3%
	Efficiency	$kWh_{H2\ (LHV)}/kWh_{el}$	66%
	Stack replacement	% of Capex every 7 years	15%

Appendix C: Alternative scenarios focussed on shipping

Introduction

This appendix has been included to investigate the sensitivity of the results to changes in assumptions for the synthetic fuels used for shipping. It presents the results of the following three sub-scenarios:

1. The contribution of shipping in scenario 3, based on 100% consumption of synthetic e-diesel. This scenario has been presented in the main body of the report and is denoted in this appendix as scenario 3.1.
2. The contribution of shipping in scenario 3 if synthetic diesel was replaced by e-methanol . This scenario is denoted as scenario 3.2.
3. The contribution of shipping in scenario 3 if synthetic diesel was replaced by e-LNG. This scenario is hereby denoted as scenario 3.3.

The following sections review the efficiencies and the associated electricity consumption for each of the production methods to analyse the resultant total electricity demand for each scenario. In addition, the costs are compared with those presented in section 6 of the main report.

Comparison of conversion efficiencies of e-diesel, e-methanol and e-LNG

For the purposes of this report, it is assumed that the production plant components are vertically integrated and co-located. This allows for higher efficiencies and is likely to represent production at large scale. The three main components that are feedstocks required for conversion to SHCFs are electricity, water and carbon dioxide (CO_2). Water is converted to hydrogen using an alkaline electrolyser powered by renewable electricity generated from a combination of sources and supported by energy storage to optimise the production process. In order to be carbon-neutral over the fuel's lifecycle, it is assumed that CO_2 is captured from the atmosphere using low temperature direct air capture (DAC) technology. Hydrogen and CO_2 are fed into the SHCF production plants to produce the desired fuel. The three fuel production processes are:

- Fischer-Tropsch (FT) for production of e-diesel.
- Methanol synthesis (MS) for production of e-methanol.
- Sabatier process for production of e-LNG

Low temperature DAC is a method of carbon capture that captures CO_2 from atmospheric air using porous filters. The CO_2 is regenerated using a combination of pressure swing absorption and temperature swing absorption in the temperature range of approximately 100 ^{0}C. An advantage of this method is that the low temperature requirements allow for integration of waste heat from the SHCF synthesis process as opposed to fossil fuels or hydrogen. For the purposes of the analysis in this appendix, it is assumed that DAC is not able to recover waste heat. This assumption has been made to allow for easier comparison with other sources.

Although MS and FT plants have different processes, the literature shows that they are very similar in their costs and operational efficiencies. The efficiency differences between the two production pathways are estimated to be within 1% of each other and so the difference is considered negligible [4, 58, 59, 60]. The conversion efficiency for the synthesis of MS and FT plants ranges from 73% to 80% in the literature [ibid.]; with a value of 79% used for this analysis, taken from the European Commission's 2013 Joint Research Centre (JEC) report [60]. When the electricity requirements for DAC and the fuel synthesis plants are incorporated, the overall efficiency is 72%.

The process of methanation of CO_2 and hydrogen into natural gas (CH_4) through the Sabatier process has a conversion efficiency of 78% [59, 61] which is similar to the FT and MS processes. When the electricity requirements for DAC and the fuel synthesis plants are incorporated, the overall efficiency is 73%.

The synthesis plants feature waste heat recovery to power systems by using low temperature generators that are powered by the Organic Rankine Cycle [61]. A summary of the resultant conversion efficiencies is provided in Table C - 1.

Table C - 1. Conversion efficiencies for the three SHCF synthesis processes

	Fischer-Tropsch	Methanol synthesis	Sabatier
Synthesis conversion efficiency (thermal)	79%	79%	78%
Conversion efficiency including plant electricity consumption	72%	72%	73%

Considering that the differences in conversion efficiencies given in the above literature range from about 2 to 5 percentage points around the average, it can be concluded from Table C - 1 that the conversion efficiencies are approximately equal for FT (e-diesel), MS (methanol) and Sabatier (e-LNG) based on current technologies.

Levelised cost of fuel

Levelised costs of fuel (LCOF) have been calculated to understand the levelised cost for e-methanol and e-LNG and to compare them against ammonia and hydrogen for use as a marine fuel. The cost of green hydrogen is very sensitive to the cost of renewable electricity due to the large quantities of electricity required for electrolysis. Therefore, increasing the efficiency of electrolysis and lowering the cost of electricity will have the biggest impact on levelised cost reduction.

IRENA's global renewables outlook 2020 provides cost reduction forecasts for renewable generation sources between 2020 and 2030 [62]. IRENA's forecasts are based on the weighted average costs globally, covering a wide range in 2020. Since the electricity cost estimates used in the LCOE analysis in section 6 of the main report are among the lowest in Europe, it would be optimistic to apply IRENA's cost reduction forecasts, which are based on the global weighted average. Therefore, a less optimistic approach was adopted, where the IRENA cost reduction forecasts between 2020 and 2030 were halved, resulting in the electricity costs below. In the absence of cost reduction estimates between 2030 and 2050, a reduction of 10% was assumed. This approach assumes that the technologies and supply chains have matured at a global scale by 2030 and improvements thereafter are achieved through incremental technology improvements. The resulting forecasts for renewable electricity costs are provided in Table C - 2.

Table C - 2. Forecast renewable electricity cost inputs for LCOF calculations.

Price (€/MWh)	2020	2030	2050
Concentrated solar power	81	53	47
Solar PV	28	20	18
Onshore wind	39	34	31
Offshore wind	45	32	29

The prices for concentrated solar and solar PV are based on 2019/20 estimates for Spain [63, 39]. The price for onshore wind price is based on recent values for Germany [64], while offshore wind is based on recent values for the UK [38] (see section 6.3 of the report for more details).

Cost assumptions for electrolysis over each time period were assessed from a selection of sources [36, 65, 66, 67, 68]. The electrolyser cost values for 2030 and 2050 were taken from an Agora report entitled *"The future cost of electricity-based synthetic fuels"* [4] as they represent a reasonable median among the other sources. Electrolyser costs in 2020 are based on Ricardo's database and experience. The cost assumptions for the FT, MS and Sabatier synthesis plants are also taken from the Agora report [ibid.]. The costs of ammonia synthesis are taken from the Hydrogen Generation in Europe report [37]. Ammonia, FT/MS and methanation plants are commercially available and mature technologies having been developed for the fossil fuel industry.

Fasihi et al. [5] provides an estimate for CO_2 from low temperature DAC without free heat of €222 per tonne of CO_2 in 2020[16], reducing to €54 per tonne of CO_2 by 2050.

Electricity prices were selected as €39 per MWh for 2020 so as to provide a comparative analysis with the cost of hydrogen production reports for onshore Germany in section 6.4 of the report. Investment cost assumptions were researched and are shown in Table C - 3.

Table C - 3. Levelised cost of energy input assumptions.

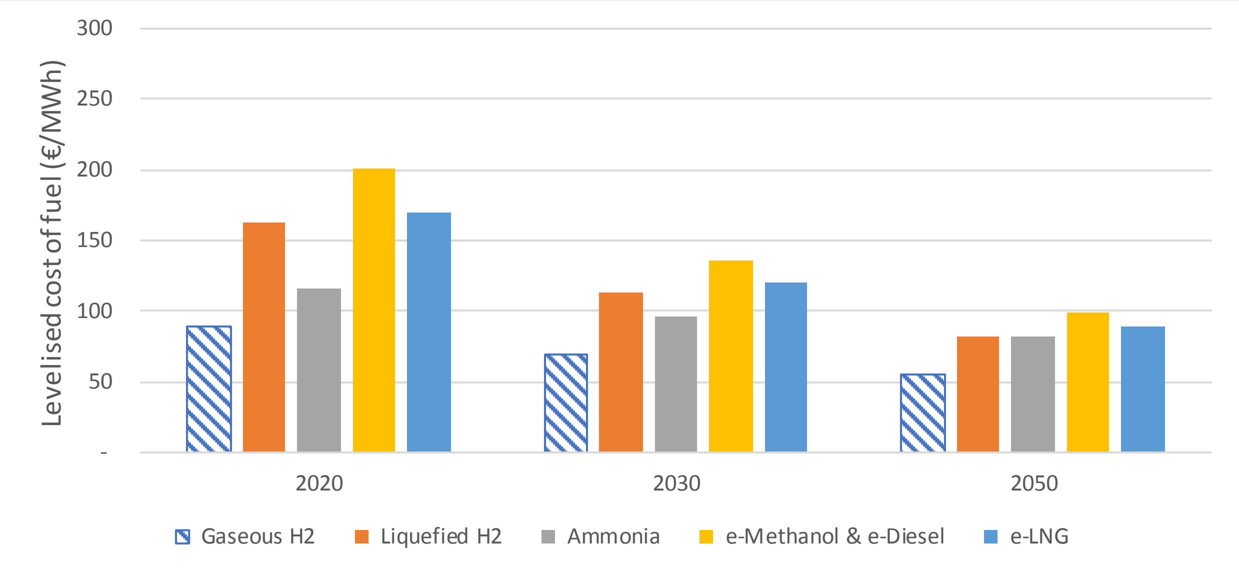
		Unit	2020	2030	2050
Supply	CO_2 supply	€/tonne	222	105	54
	Power price	€/MWh	39	34	31
Electrolyser	Capital cost	€/kW$_{el}$	980	625	450
	Operating cost	% of capital cost	3%	3%	3%
	Efficiency	kWh$_{H2\ (LHV)}$/kWh$_{el}$	66%	67%	72%
	Stack replacement	% of Capex every 7 years	15%	15%	15%
E-diesel and e-methanol production plant	Capital cost	€/kW$_{PtL}$	850	650	500
	Operating cost	% of capital cost	3%	3%	3%
	Power consumption	% of kW$_{PtL}$	11%	11%	11%
E-LNG production plant	Capital cost	€/kW$_{PtL}$	800	654	500
	Operating cost	% of capital cost	3%	3%	3%
	Power consumption	% of kW$_{PtL}$	7%	7%	7%
Liquification	Cost of conversion	€/MWh	74	44	26
Ammonia conversion	Cost of conversion	€/MWh	27	27	27

The ammonia conversion assumptions are derived from the Hydrogen Generation in Europe report [37], as per section 6. Ammonia is assumed to be constant over time due to the Haber-Bosch conversion technology already being mature. The Hydrogen Generation Europe Report [37] is used for liquefaction costs in 2020, which is sourced an U.S. Department of Energy report from 2019 [69]. There are however some sources from between 1986 to 1996 [70] that indicate lower costs. Therefore, there is some uncertainty about the costs of liquefaction as up to now, it has been largely limited to niche applications such as the space industry. Table C - 3 assumes lower liquefaction costs in 2030 (44 €/MWh from [71]) and 2050 (26 €/MWh from [72]), based on cost improvements as the technology is scaled up for widespread use.

[16] Converted with an exchange rate of 0.85 USD/EUR

The results of the levelised cost analysis are provided in Figure C - 1, where values for hydrogen (without liquefaction) are also shown for comparison.

Figure C - 1. Levelised cost results for hydrogen and the other SHCFs for shipping.



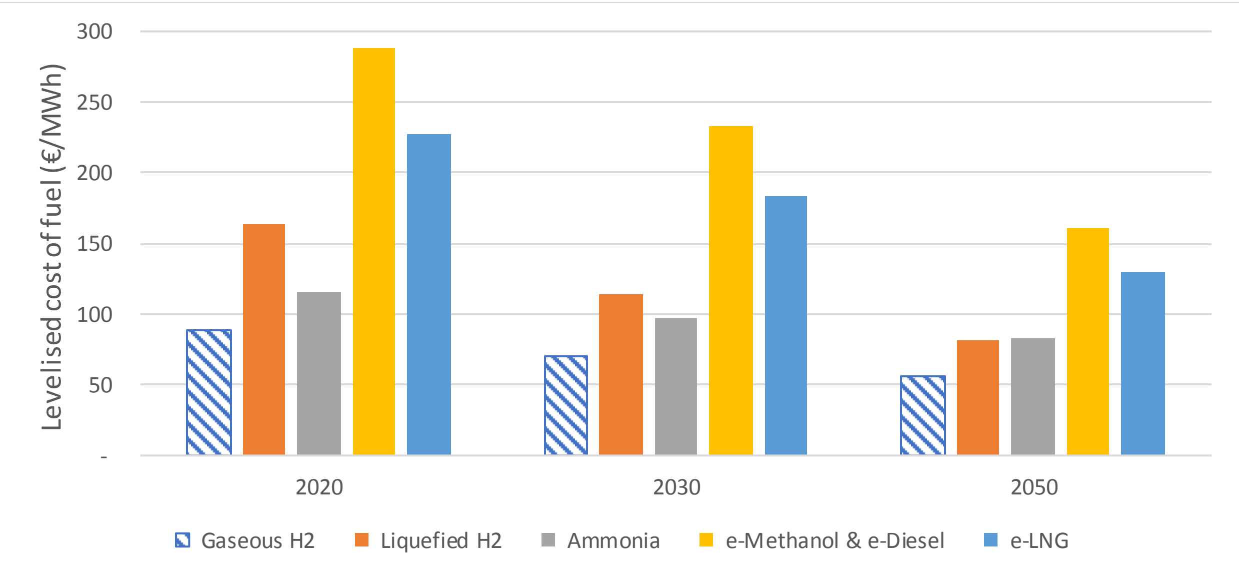
The results show that ammonia is consistently the lowest cost solution based on the cost projections. With the DAC costs shown in Table C - 3, e-methanol, e-diesel and e-LNG are significantly more costly than ammonia in 2020, but the cost difference reduces in 2030 and the costs are relatively similar by 2050. This is mainly due to the fact that zero cost reductions are forecast for ammonia synthesis to 2050.

A further set of calculations were run to investigate the sensitivity of the results to higher costs of DAC. The costs in Table C - 4 were used as alternatives to those listed in Table C - 3 above, with the results presented in Figure C - 2.

Table C - 4. Alternative costs of CO_2 from DAC for the sensitivity case

	Unit	2020	2030	2050
CO_2 supply	€/tCO_2	510	425	255

Figure C - 2. Levelised cost results with higher DAC costs



The results in Figure C - 2 show that the higher costs of DAC have a significant impact on the costs of the SHCFs, increasing by about 55% in 2020. Since DAC technology is still a relatively nascent technology, there is a measure of uncertainty about the current and future costs. These costs have a material impact on the cost of the fuel. Selecting ammonia as the preferred zero-carbon fuel for shipping would mitigate this risk because production of ammonia does not rely on DAC. Rather, it incorporates air separation technology to provide the nitrogen feedstock, which is a commercially mature and proven technology.

Conclusions

The analysis in this appendix for shipping indicates that the predicted electricity consumption values for e-methanol, e-diesel and e-LNG are approximately equal. Based on the analysis in the main body of the report, the renewable electricity requirements for these shipping fuels in Scenario 3 (Higher SHCF) is expected to be approximately 39 TWh per annum in 2030, increasing to 1,040 TWh per annum by 2050.

The LCOF analysis in this appendix shows that ammonia is predicted to be the lowest cost solution as a zero-carbon shipping fuel in 2020, 2030 and 2050. The costs of SHCFs is predicted to reduce in the coming decades, but they are sensitive to variations in the cost of carbon dioxide from DAC. Adoption of ammonia as the preferred fuel for shipping mitigates this risk because it does not require carbon dioxide as an input to the production process.

Appendix D: Emissions data breakdown

Baseline Data	2020	2030	2050	Source
Road and aviation ($Mt\ CO_2e$)	1,064	928	667	2020 - Data provided by T&E 2030 & 2050 – Projected emissions decrease in line with data extracted from the EC's Cleaner Planet for All [11]. Description of scenario: *For the purpose of this assessment, a baseline scenario (referred to below as "the Baseline") was developed to reflect the current EU decarbonisation trajectory based largely on agreed EU policies, or policies that have been proposed by the Commission but are still under discussion in the European Parliament and Council.*
Shipping ($Mt\ CO_2e$)	139	158	231	Data provided by T&E

Decarbonisation Route Data	2020	2030	2050	Source
Road ($Mt\ CO_2e$)	896	643	0	Data supplied by T&E
Shipping ($Mt\ CO_2e$)	139	120	0	Data supplied by T&E
Aviation ($Mt\ CO_2e$)	169	149	0	Data supplied by T&E

T: +44 (0) 1235 753000
E: enquiry@ricardo.com
W: ee.ricardo.com