E-fuels: a techno-economic assessment of European domestic production and imports towards 2050

Concawe and Aramco have jointly commissioned a study[1] to provide a techno-environmental (Part 1) and economic (Part 2) analysis of different e-fuels pathways produced in different regions of the world (northern, central and southern Europe, as well as the Middle East and North Africa) in 2020, 2030 and 2050, with assessments of sensitivities to multiple key techno-economic parameters.

This article summarises the findings of a new study commissioned to provide a detailed techno-environmental analysis of e-fuels production efficiency, energy consumption and mass balance, as well as the carbon intensity of the produced e-fuels, in different regions and for different time frames. In addition, an economic analysis considers the costs of e-fuel supply for nine e-fuels, in four geographies and over three time frames. Both parts of the study incorporate sensitivity analyses which consider the impact of a range of key technical and economic parameters.

Author

Abinash Ramasary (Concawe)

The e-fuels pathways included in the scope of this study are: e-hydrogen (liquefied and compressed); e-methane (liquefied and compressed); e-methanol; e-polyoxymethylene dimethyl ethers (abbreviated as OME_{3-5}); e-methanol to gasoline; e-methanol to kerosene; e-ammonia; and e-Fischer-Tropsch kerosene/diesel (low temperature reaction). The e-hydrogen is considered as a final fuel but also as a feedstock for producing other e-fuels.

The study also includes:

- an assessment of stand-alone units versus e-plants integrated with oil refineries;
- a comparison of e-fuels production costs versus fossil fuels/biofuels/e-fuels produced from nuclear electricity;
- an assessment of the impact of intermittency and seasonality of renewable energy supply on storage requirements, synthesis plant sizing and production costs;
- an analysis of the context of e-fuels in the future in Europe (potential demand, CAPEX, renewable electricity potential, land requirement, feedstocks requirements); and
- a deep dive into the safety and environmental considerations, societal acceptance, barriers to deployment and regulation.

The e-fuels techno-environmental assessment (Part 1 of the analysis) has been developed by Concawe and Aramco, using the Sphera GaBi platform as a modelling tool, and the e-fuels economical and context assessment (Part 2 of the analysis) has been conducted by the consultants LBST and E4tech, under the supervision of Concawe and Aramco. All the assumptions are fully aligned between both parts of the study.

For the base cases, it is assumed that the e-fuel plant produces 1 million tonnes of e-diesel equivalent (based on conventional diesel EN 590) per year. Hence, the nameplate capacities of hydrogen generation via water electrolysis and downstream processes depend on the characteristics of the regional renewable electricity supply.

Techno-environmental assessment

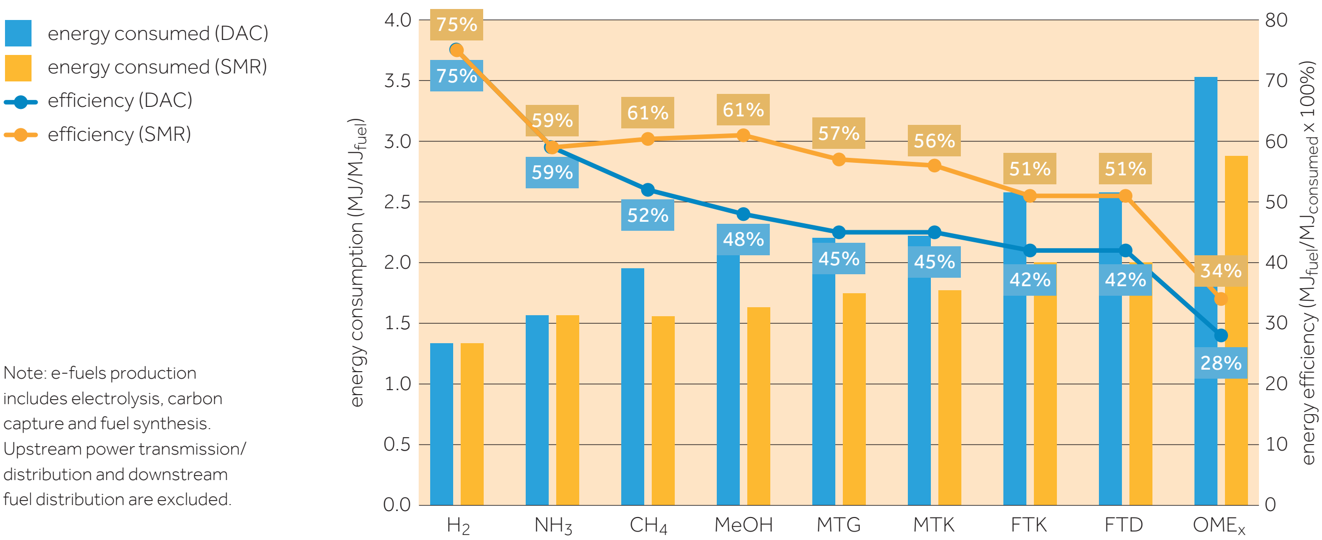
In Part 1 of the analysis, a detailed analysis of the e-fuels production efficiency, energy consumption, mass balance and carbon intensity of the e-fuels produced has been conducted in the different regions and time frames. In addition, sensitivity analyses of relevant technical parameters, such as technology development, electricity power sources (including the grid), carbon sources, carbon capturing location and hydrogen transportation via hydrogen vectors have been included.

For the base cases, a 100% concentrated (point) unavoidable CO_2 source is considered in 2020 and 2030, while only direct air capture (DAC) is considered in 2050. The choice of 100% DAC in 2050 was made for the sake of compliance with announced restrictions concerning the origin of CO_2 for e-fuels[2] and assuming that the unavoidable and sustainable CO_2 sources in 2050 would be limited.

Figure 1 shows that the energy consumption for e-fuels production increases depending on the length and complexity of the synthesised molecules. The simplest molecules, like hydrogen, require less energy consumption for their production than the more complex ones. As an example, for fuels synthesised from air-captured CO_2 (DAC), 1 MJ of Fischer Tropsch (FT) e-diesel requires 2.4 times the energy needed to produce 1 MJ of e-hydrogen, while 1 MJ of the more complex molecule e-$OME_{3\text{-}5}$ needs 3.6 times that amount.

Accordingly, the opposite trend is observed for the e-fuel efficiency, defined as the ratio between the energy contained in the fuel and the energy used to produce the fuel. The simplest molecule, e-hydrogen, has an energy efficiency of 75% driven by the electrolysis efficiency (alkaline electrolyser). The efficiency continues to drop as hydrogen is combined with nitrogen, carbon or oxygen to produce larger fuel molecules. The reduction in efficiency from shorter to longer carbon chains is not proportional: the energy efficiency of the simplest fuel containing a carbon atom, e-methane, is 52% when produced from air-captured CO_2, but it drops to 42% for more complex molecules like FT e-diesel or FT e-kerosene. The lowest efficiency comes from the e-$OME_{3\text{-}5}$ (OME_x), a non-drop-in fuel and an exception compared to the other molecules, estimated at 28%. This is due to the higher complexity of the process for OME_x that requires more energy consumption compared to other e-fuels.

Figure 1: Comparison of energy consumption and energy efficiency for e-fuels production when using CO_2 from DAC and a concentrated CO_2 source (steam methane reforming—SMR) (Timeline: 2050)



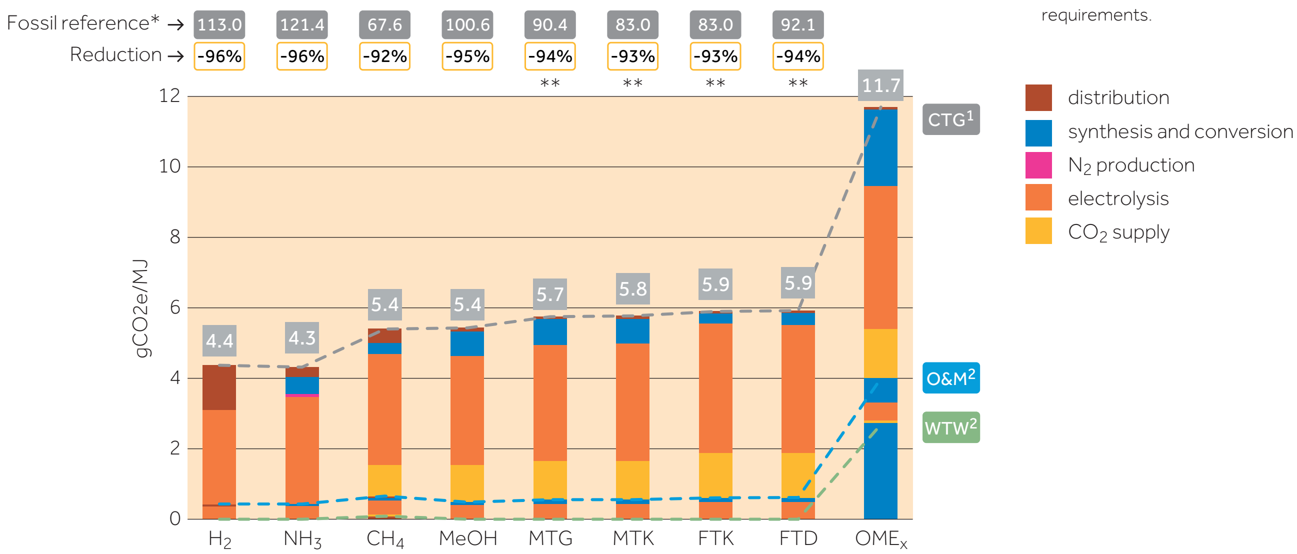
Note: e-fuels production includes electrolysis, carbon capture and fuel synthesis. Upstream power transmission/ distribution and downstream fuel distribution are excluded.

These values correspond to the cases with carbon capture from DAC in the 2050 timeline. If the carbon capture is obtained from a concentrated source, the Fischer-Tropsch diesel and kerosene (FTD and FTK) efficiencies increase up to 51%, and for polyoxymethyl dimethyl ethers (OME_{3-5}) they increase to 34%. The energy efficiencies of the production pathways were improved by assuming heat integration between the fuel synthesis and the carbon capture process, whenever possible. Additional potential efficiency improvements, like heat recovery from low temperature electrolysis, were not considered in the base cases.

In Figure 2 it can be observed that, taking northern Europe as an example, the net greenhouse gas (GHG) emissions of the different e-fuels pathways on a cradle-to-grave (CTG) basis are around 4.3–6 gCO_2eq/MJ (except for the e-OME_{3-5}) and around 0.5 gCO_2eq/MJ if only the emissions from operation and maintenance (O&M) are counted. The well-to-wheels (WTW) emissions are almost zero because of the use of renewable energy for all operations except power for distribution. These values are in the same order of magnitude for all the e-fuels pathways, as e-fuels that are less energy-intensive to produce (such as e-hydrogen) are more energy-intensive to transport than drop-in fuels such as e-gasoline or e-diesel.

Figure 2 also shows that GHG emissions come mainly from electrolysis, with a share of roughly 65–80% of the CTG impact (except for OME_{3-5}, where it accounts for around 40%). The emissions from O&M represent between 9–12% of the total CTG emissions (around 35% for OME_{3-5}). This means that roughly 90% of the total emissions from e-fuels are associated with the infrastructure required, mainly for renewable electricity.

Figure 2: Cradle-to-grave GHG emissions of different e-fuel pathways (Case: North EU, 2050 as an example (details for the other regions and timelines are included in section 1.6 of the full report[1]



Notes on Figure 2:

* JEC WTT Study v5,[3] GaBi Database.

** Additional reduction if RED II fossil fuel comparator (94 gCO_2eq/MJ) is used.

1 CTG includes O&M emissions plus emissions from building the infrastructure to produce the e-fuels, emissions from their feedstocks, and their energy requirements.

2 O&M includes WTW emissions plus emissions from maintaining the infrastructure to produce the e-fuels, emissions from their feedstocks, and their energy requirements.

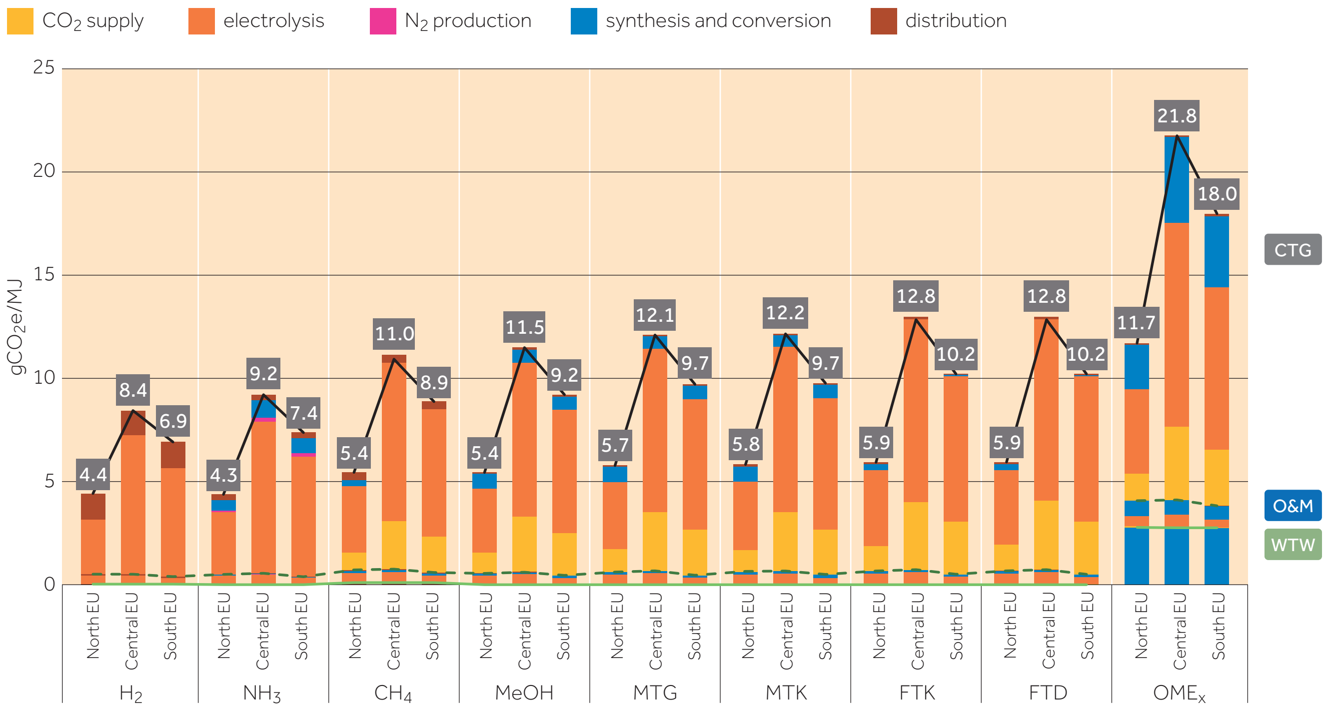
3 WTW includes emissions from production, transport and use of the e-fuels, emissions from their feedstocks, and their energy requirements.

All the e-fuels pathways (except e-OME_{3-5}) achieve a GHG reduction higher than 92% versus the fossil alternative (without emission reductions). All the e-fuels pathways comply with the RED II emissions limit for 'renewable fuels of non-biological origin' (RFNBO) (28.2 gCO_2eq/MJ), which mandates a 70% reduction in GHG versus the fossil reference defined in the RED II (94 gCO_2eq/MJ). This reduction is reached even considering a CTG basis. This might suggest that some more economical schemes might be possible, which are not 100% dependent on green power as the sole energy input but accept some use of fossil energy while staying within the limit. However, any kind of fossil-green mixed versions of e-fuels is out of the scope of this study. It is important to note that the reduction rates assumed in the present study consider CTG emissions from all feedstocks, including renewable electricity. If emissions from the manufacturing of the solar panels or wind turbines are excluded (i.e. not a CTG basis), the GHG reduction would be even higher.

GHG emissions from e-OME_{3-5} production are around 11.7 gCO_2eq/MJ. The emissions are more than twice those of the other e-fuels due to the higher complexity of the process that requires more energy consumption, while still being compliant by far with the RED II criteria for sustainable e-fuels (28.2 gCO_2eq/MJ). OME_{3-5} presents other benefits when blending with diesel components, such as the low soot and NO_x emissions[4] that could be considered for commercial fuel blending.

Figure 3 shows that GHG emissions from O&M are very similar among regions for all the e-fuels pathways in 2050 (around 0.5 gCO_2eq/MJ for northern Europe).

Figure 3: Cradle-to-grave GHG emissions from e-fuels production by European region in 2050

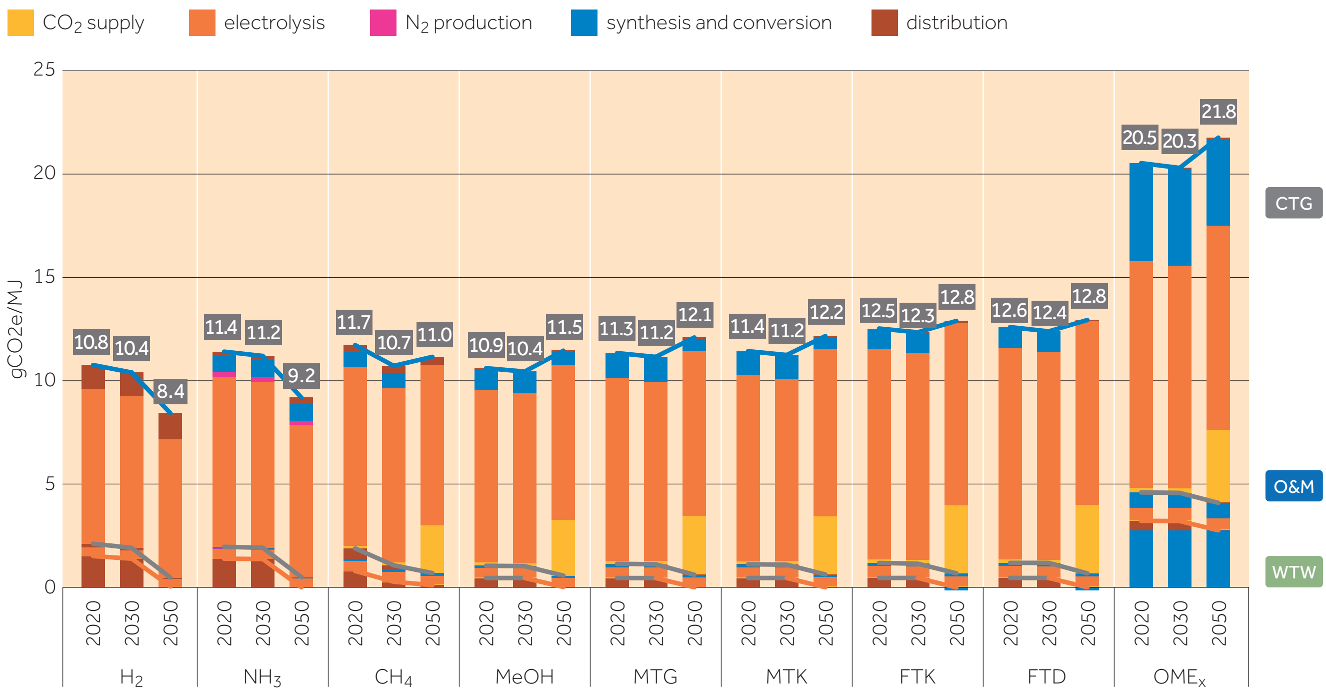


However, the CTG values show lower levels in northern Europe (around 5.5 gCO_2eq/MJ), followed by southern Europe (around 10 gCO_2eq/MJ) and central Europe (around 12.5 gCO_2eq/MJ) in 2050 for all the e-fuels pathways. The highest values observed for central Europe are due to the higher carbon intensity of the available renewable power in the region. This results from the lower full load hours of renewable electricity and the higher contribution of photovoltaic renewable electricity (PV) versus wind renewable electricity. PV presents higher CTG carbon emissions than wind electricity (2.6 to 6 times higher depending on the region).

Long distance transport of fuels is mostly subject to the carbon intensity of the fuel used for ship propulsion, and is not expected to significantly increase the GHG emissions of e-fuels. The carbon intensity of the electricity used for e-fuel production will still be the most dominant factor.

Figure 4 shows that a progressive reduction of CTG GHG emissions is observed over time only for hydrogen and ammonia, while for carbon-based fuels they first drop and then increase. As an example, for FTK the CTG GHG emissions in gCO_2eq/MJ go from 12.5 in 2020 down to 12.3 in 2030 and then up to 12.8 in 2050. This is due to opposite effects overlapping: on one side, an improvement in electrolyser efficiencies and the generalisation of the use of e-fuels for maritime and truck transport favour a decrease over time in emissions from H_2 supply and distribution. On the other hand, the displacement of concentrated sources of CO_2 by the use of DAC requires more energy-intensive operations to capture CO_2 from the atmosphere and results in a net increase in emissions by 2050.

Figure 4: Cradle-to-grave GHG emissions from e-fuels production in central Europe in 2020, 2030 and 2050

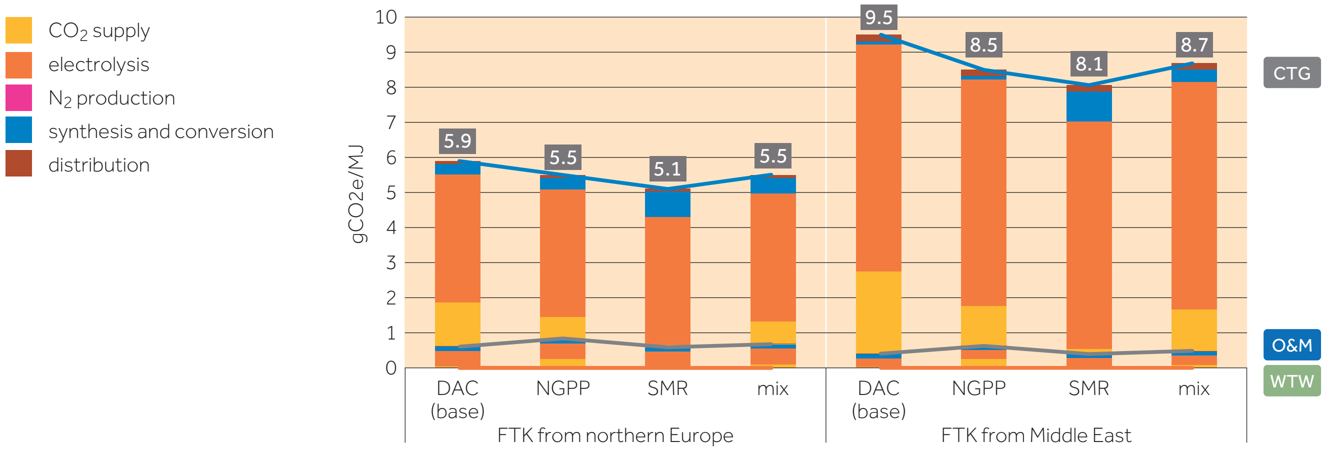


The contribution of O&M remains stable over time (around 0.5 gCO_2eq/MJ for FTK) until 2050. The WTW GHG emissions drop steadily until 2050 for all fuels as the emissions from the additional renewable electricity required for DAC are assumed to be 0 on a WTW basis. Sensitivities to this assumption are included in section 1.7 of the full report.[1]

Figure 5 depicts the impact of switching to different CO_2 sources for e-fuel synthesis. In the FTK pathway, the utilisation of a high CO_2 concentration, like steam methane reforming (SMR) pre-combustion off-gases instead of CO_2 captured from the atmosphere via DAC, reduces the GHG impact by 0.8 to 1.4 gCO_2eq/MJ depending on the geographical location. The use of flue gases from a natural gas power plant (NGPP), which are less concentrated than SMR off-gases but more concentrated than air, also reduces the GHG emissions by 0.4 to 1.0 gCO_2eq/MJ depending on the geographical location.

Other sensitivities are further analysed in the full report,[1] such as the use of different renewable energy sources, the use of CO_2 captured in Europe for e-fuel synthesis in the Middle East and North Africa (MENA), and the impact of using energy carriers instead of liquefaction to transport H_2, in a case where e-fuels are produced in Europe with hydrogen coming from MENA.

Figure 5: Comparison of GHG emissions from Fischer-Tropsch kerosene production from different CO_2 sources and different production locations in 2050



Economic assessment

Part 2 of the study[1] presents a detailed analysis of the costs of e-fuel supply for nine e fuels for four geographies (northern, central and southern EU and MENA) and for three time frames (2020, 2030 and 2050), plus a series of key sensitivities have been taken into account, leading to more than 100 assessments.

Figure 6 shows the costs of e-fuels produced in central Europe, and Figure 7 shows the costs of e-fuels produced in MENA and transported to the EU in 2050, as examples (the other regions and time frames are presented in the full report[1]). The figures show that between 40% and 80% of the cost including electricity storage comes from the renewable electricity cost.

Figure 6: Costs of e-fuels produced in central Europe in 2050

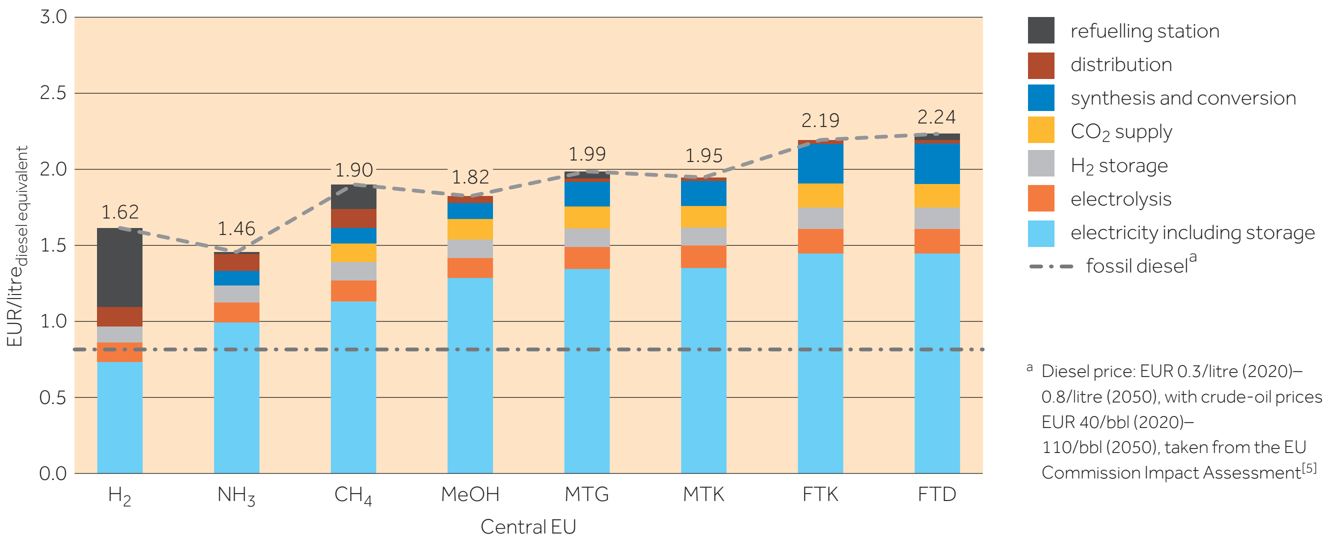
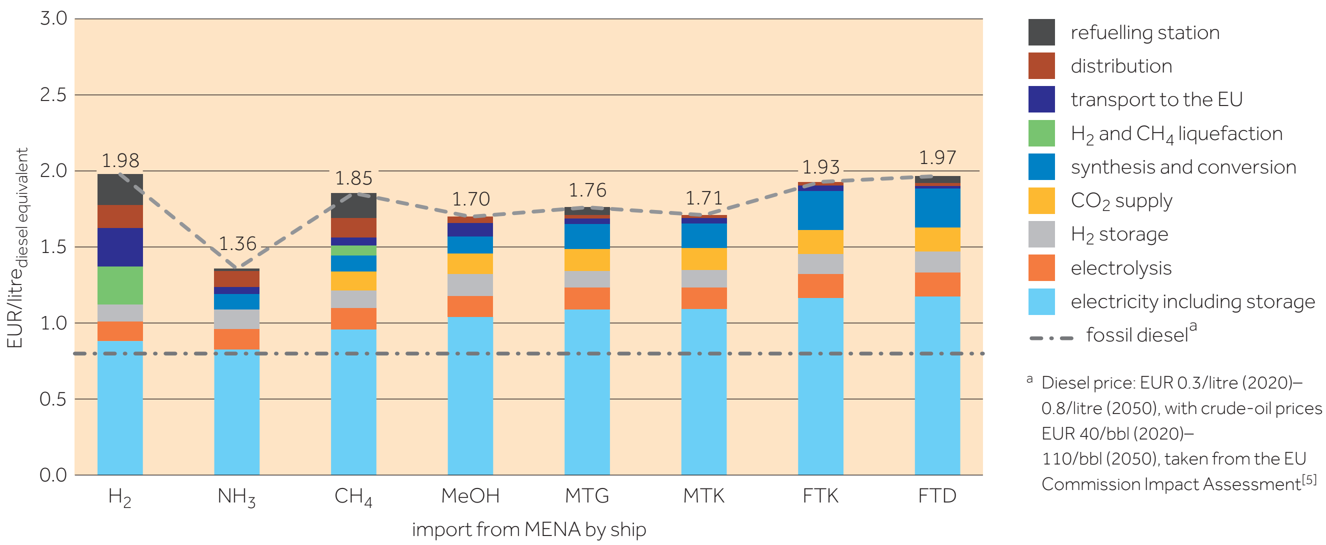


Figure7: Costs of e-fuels produced in MENA and transported to the EU in 2050



The figures show the strong correlation between energy requirements for e-fuel production and associated costs. E-fuels that are less energy-intensive to produce generally lead to lower costs of fuel production, such as e-hydrogen and e-methane. However, subject to transport distance and mode, e-hydrogen and e-methane need to be liquefied, thus increasing the transportation effort.

Based on the assumptions taken, this economic assessment of e-fuels towards 2050 shows that fuel supply costs across all regions range between EUR 1.7 and 4.6 per litre of diesel-equivalent in the short term, and between EUR 1.4 and 2.8 per litre in the long term if the outlier OME_x is excluded. For OME_x the fuel supply costs range between EUR 3.2 and 6.8 per litre of diesel equivalent in the short term, and between EUR 2.7 and 4.3 per litre of diesel equivalent in the long term.

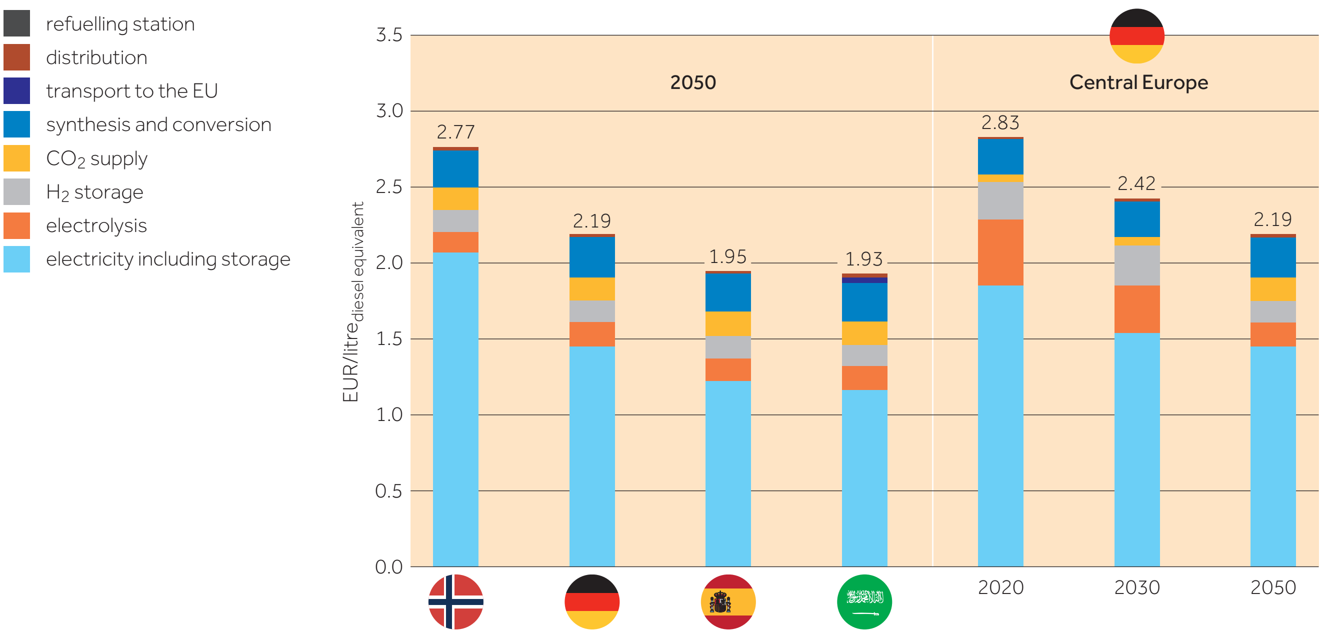
Figure 8 shows that FTK produced in MENA and southern Europe represent the lowest fuel costs, followed by central and northern Europe. This is directly linked to the full load hours and the renewable electricity cost.

Note that in this study for northern Europe, 100% offshore wind has been taken into account assuming that new additional e-fuels plants would rely on this source. If hydropower is used as the primary electricity source, the e-fuel production cost in northern Europe would be lower.

Figure 8 also shows that the cost of e-fuels produced in central Europe is reduced with time (20%) due to decreasing CAPEX for wind and PV plants, electrolysis, and improvement of electrolysis efficiency despite lower availability of concentrated CO_2 sources.

Figure 8: Costs of Fischer-Tropsch e-kerosene

The left part of the chart refers to 2050, and the right refers to central Europe (see the full report for details of the other regions and timelines[1])

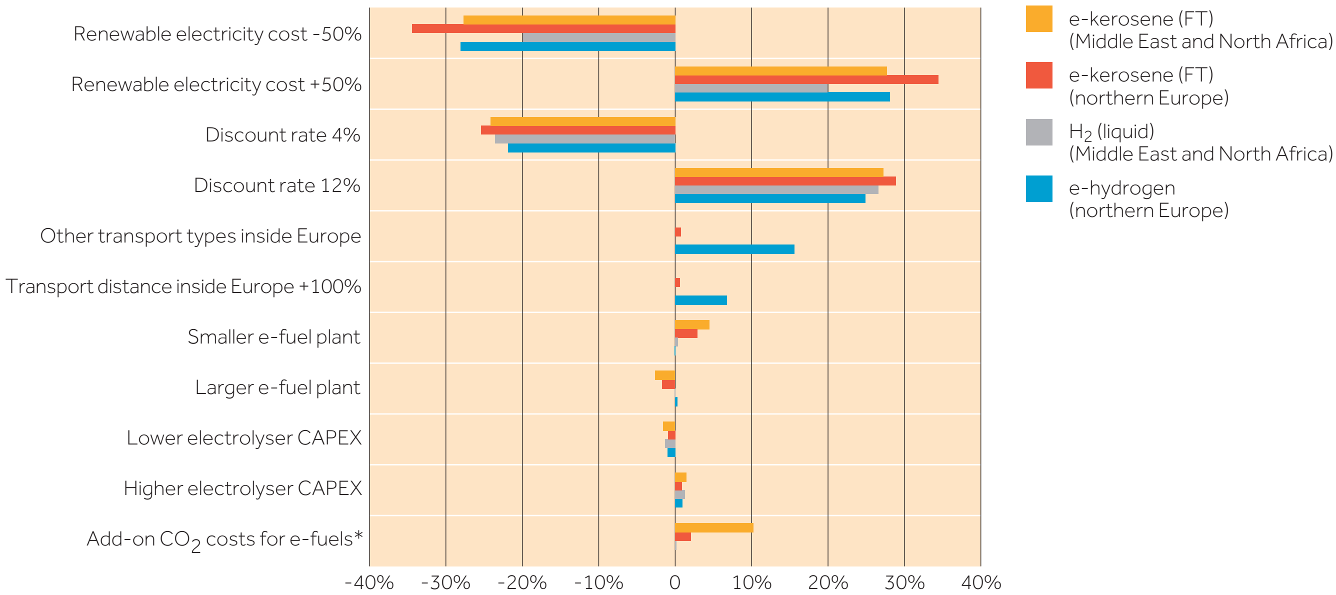


For this part of the assessment, the same H_2 and CO_2 buffer storage capacities have been assumed for all regions. An evaluation of the impact of the regional weather conditions on the size of the buffer capacities, and its cost, is conducted later in the intermittency and seasonality assessment.[1]

Sensitivities to key economic parameters

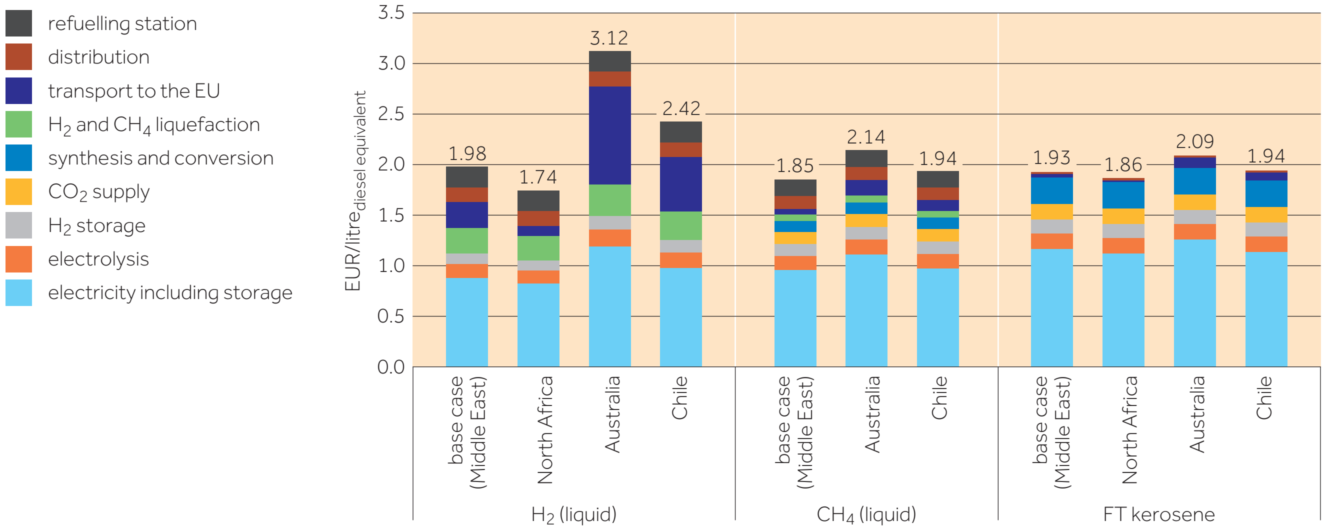
Figure 9 shows the sensitivities studied. Electricity costs and discount rates have a significant impact on overall fuel supply costs. A 50% change in electricity supply costs or discount rate assumptions resulted in a change of about 25% in the supply cost. Other factors investigated, such as transport type and distance inside or outside Europe, or e-fuel plant size, have only marginal impacts (single-digit percentage points). The cost impacts relative to the final production costs are similar for 2020 and 2050 except in the case of CO_2 add-on costs for CO_2 for e-fuels. In 2050 CO_2 from concentrated CO_2 sources with CO_2 add-on costs have been applied as sensitivity compared to CO_2 from direct air capture without CO_2 add-on costs in the base case.

Figure 9: Sensitivity—impact of the variation of selected parameters (2050 base case)



A deep dive into the e-fuels production cost when produced and imported to Europe from most distant regions of the world, such as Australia and Chile, has been conducted and is shown in Figure 10 on page 20. The results show that for liquid e-fuels, even very long transport distances lead to minor changes in e-fuel production costs, of similar ranges as for e-fuels produced domestically in southern Europe. For e-hydrogen, long distance transport over many thousands of kilometres significantly increases the production costs.

Figure 10: The impact of geography—imports of e-fuels into the EU from other regions (2050)



A further relevant sensitivity analysis looked at the use of alternative carriers for H_2 import to feed synthesis processes. The use of ammonia and methylcyclohexane as H_2 carriers to feed synthesis processes leads to higher e-fuels production costs (EUR 3.20 per litre of diesel equivalent for ammonia and EUR 4.52 per litre of diesel equivalent for methylcyclohexane, compared to EUR 3.14 per litre of diesel equivalent in the base case). The use of methanol as an H_2 carrier, however, compares favourably at EUR 2.93 per litre of diesel equivalent.

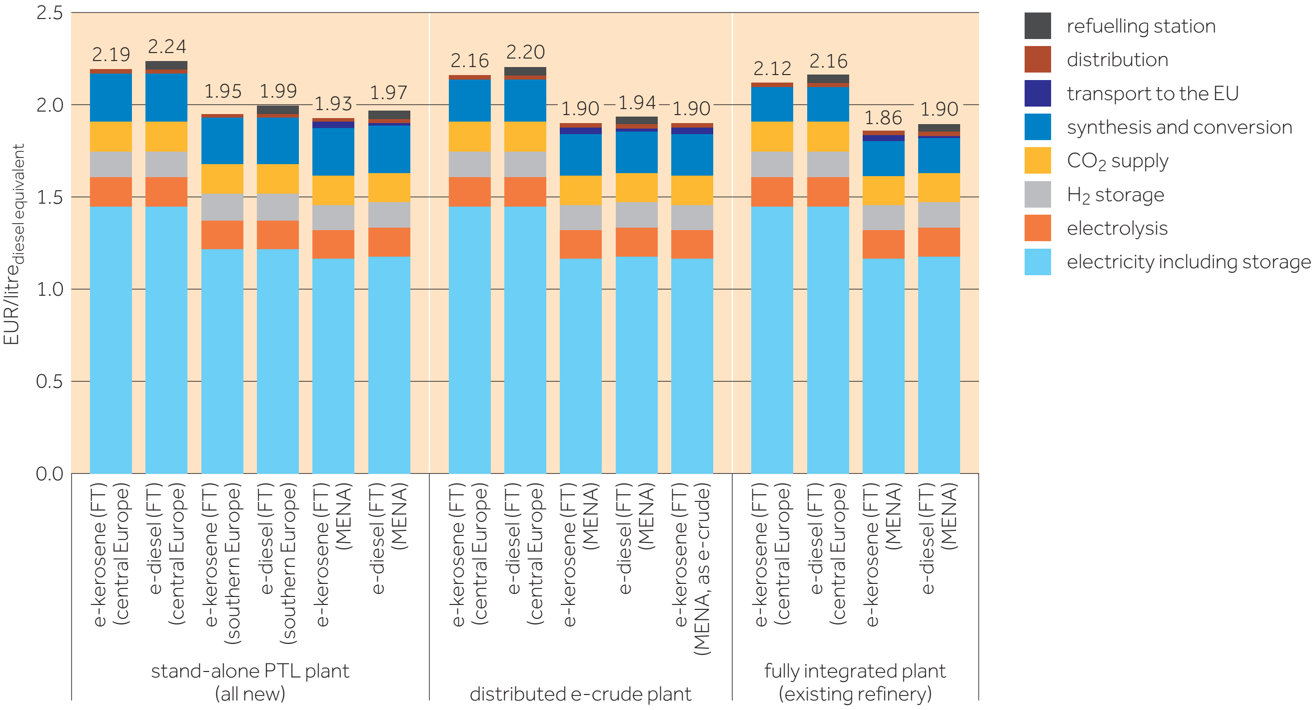
Stand-alone plants versus distributed e-crude plants versus fully integrated plants

The comparison between a stand-alone e-fuel plant (all-new integrated plant for hydrogen production, synthesis to e-crude, and final upgrading), a distributed e-fuel plant (new hydrogen production and synthesis to e-crude units, and e-crude upgraded in existing refineries) and a fully integrated e-fuel plant (the hydrogen production, synthesis to e-crude, and final upgrading is all fully integrated into an existing refinery) was also studied.

Existing refineries can play a facilitating role in the energy transition to e-fuels. They have been bulk consumers of hydrogen for decades and offer valuable knowledge in many aspects of hydrogen infrastructure, storage and end use. Switching natural gas-based hydrogen production at refineries to hydrogen from on-site electrolysis and/or supply via pipeline allows for an accelerated cost reduction path of electrolyser CAPEX and/or deployment of H_2 pipelines. The additional costs for deploying several hundreds of megawatts of electrolyser capacity per average refinery site are amortised over a product output of many gigawatts, resulting in marginal additional final product costs in the order of EUR 0.005 per litre of diesel equivalent.[6] Furthermore, the existing refining assets can, in part, be used to upgrade FT syncrude, allowing an efficient use of existing investments. Since refineries are complex, have diverse configurations, and differ in terms of supply infrastructure and product mix, refinery-specific feasibility studies are recommended to assess the opportunities in the field.

The difference between a stand-alone plant and a fully integrated plant in a refinery is that, in the case of the fully integrated plant, there are no capital costs for hydrocracking, fractionation (upgrading), utilities and logistics. Only OPEX is taken into account for these processes. However, these capital cost elements have a low contribution (~3%) to the total e-fuel production costs. In 2050 the e-fuel production costs range between EUR 1.93 and 2.24 per litre of diesel equivalent for stand-alone e-fuel plants, and between EUR 1.86 and 2.16 per litre of diesel equivalent for e-fuel plants that are fully integrated into an existing refinery.

Figure 11: Comparison of e-fuels production costs in a stand-alone, distributed and fully integrated plant (2050)



In the short to medium term there may be advantages in utilising existing refineries to minimise capital expenditure. There is a potential advantage of co-processing in the early e-fuel development. The lower the CAPEX, the higher the probability that a company will invest, aiming to have a return on investment in a shorter time.

In 2050, the CAPEX for the stand-alone FT plant without H_2 and CO_2 supply amounts to about EUR 1,800–2,000 million including indirect costs. The CAPEX for the distributed FT e-crude plant without H_2 and CO_2 supply amounts to about EUR 1,400–1,500 million. The CAPEX of the FT plant fully integrated into an existing refinery without H_2 and CO_2 supply amounts to about EUR 1,000–1,100 million. (Note that no learning curve has been applied to FT plant as the technology can be considered mature. However, the capacity of the plants changes between 2030 and 2050 due to an increase in the flexibility of the FT plant leading to a higher CAPEX of the FT plants in 2050 than in 2020 and 2030).

Comparison of e-fuel production costs versus fossil fuels, fuels produced from nuclear electricity, and biofuels

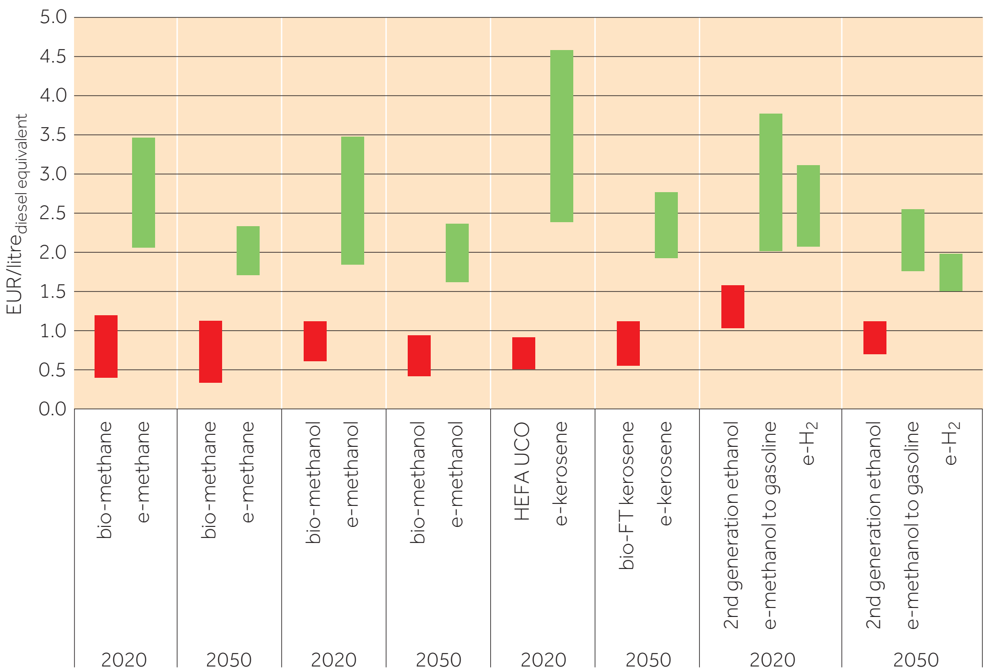
Based on the assumptions made, the costs of e-fuel supply are higher than those for fossil crude oil-based fuels, even in 2050 taking into account the improvement in technology and the decrease in electricity costs. In 2050 the costs of e-fuels supply ranges between EUR 1.5 per litre of diesel equivalent for e-hydrogen and EUR 2.8 per litre of diesel equivalent for FT kerosene. The costs of crude oil-based diesel amount to about EUR 0.8 per litre of diesel equivalent in 2050 (for a crude oil price of EUR 110 per barrel of oil equivalent).[5]

Based on the assumptions made,[7,8,9,10] nuclear electricity would result in higher e-fuels production costs in 2020 versus PV or on-shore wind electricity if new nuclear plants have to be built (except off-shore wind).

Based on biofuel cost data,[11] the production costs and GHG abatement costs for biofuels are lower than those for e-fuels. In 2050, the production costs of biofuels are expected to range between EUR 0.3 per litre of diesel equivalent (lower limit for bio-methane) and EUR 1.1 per litre of diesel equivalent (upper limit for bio-methane, bio-FT kerosene, and second-generation ethanol). The higher cost for e-fuels is attributable primarily to the cost of green hydrogen production as compared with biomass gasification. The FT process step is broadly the same for the e-fuel and biofuel cases while the cost of producing green hydrogen is high owing to high input electricity costs and, to a lesser extent, high CAPEX (electrolysis). By contrast, the CAPEX of gasification plant is high while the input feedstock costs are relatively low.

Fuel costs
Fossil fuel comparator (diesel~kerosine):
2050: 0.80 EUR/litre$_{\text{diesel equivalent}}$
Today: 0.30 EUR/litre$_{\text{diesel equivalent}}$

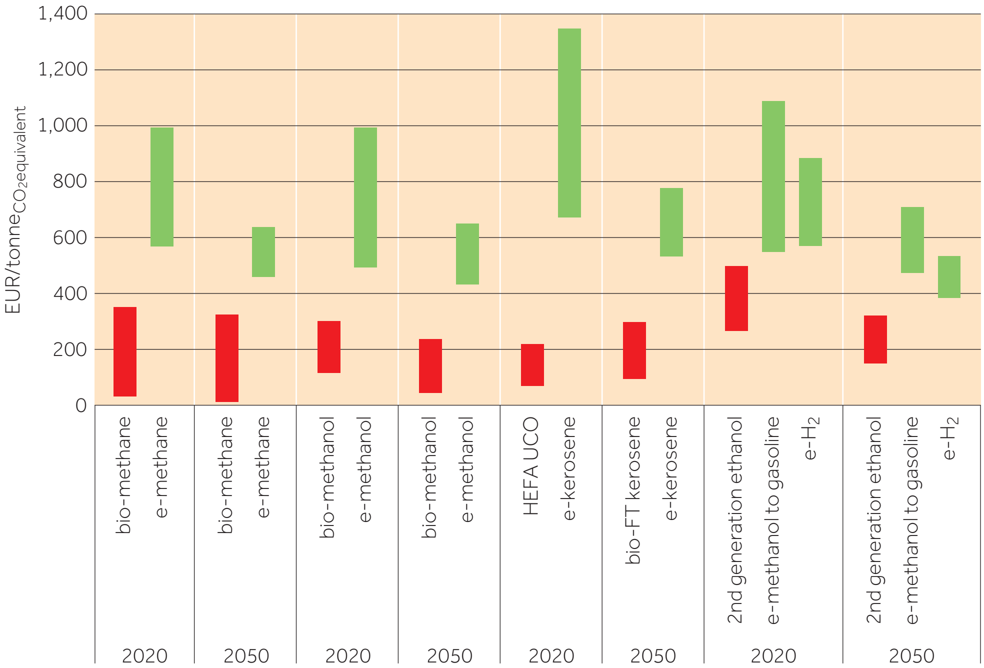
Figure 12: Production costs for e-fuels versus biofuels



Over time electrolyser CAPEX is likely to fall (perhaps more quickly than gasification plant CAPEX), but while the cost of renewable electricity will also fall it is not expected to match the lower costs of biofuel feedstock. However, while this study[1] provides a high-level cost comparison between e-fuels and biofuels based on acknowledged literature sources, it is neither designed to assess their cost differentials nor differentials between costs and prices.

The GHG abatement costs for e-fuels are expected to decrease from about EUR 480–1,350 in 2020 to some EUR 390–780 per tonne of avoided CO_2-equivalent in 2050. The GHG abatement costs for biofuels are expected to decrease from EUR 30–500 per tonne of avoided CO_2 equivalent in 2020 to some EUR 10–320 per tonne of avoided CO_2-equivalent in 2050.

Figure 13: GHG abatement costs for e-fuels versus biofuels



It should be noted that these abatement costs refer only to fuel supply (including embedded carbon), without accounting for use-case efficiencies. For example, fuel cell electric vehicles (FCEVs) have a higher efficiency than internal combustion engine (ICE) vehicles leading to lower abatement costs for hydrogen fuel. The powertrain assessment was not included in the scope in this study.

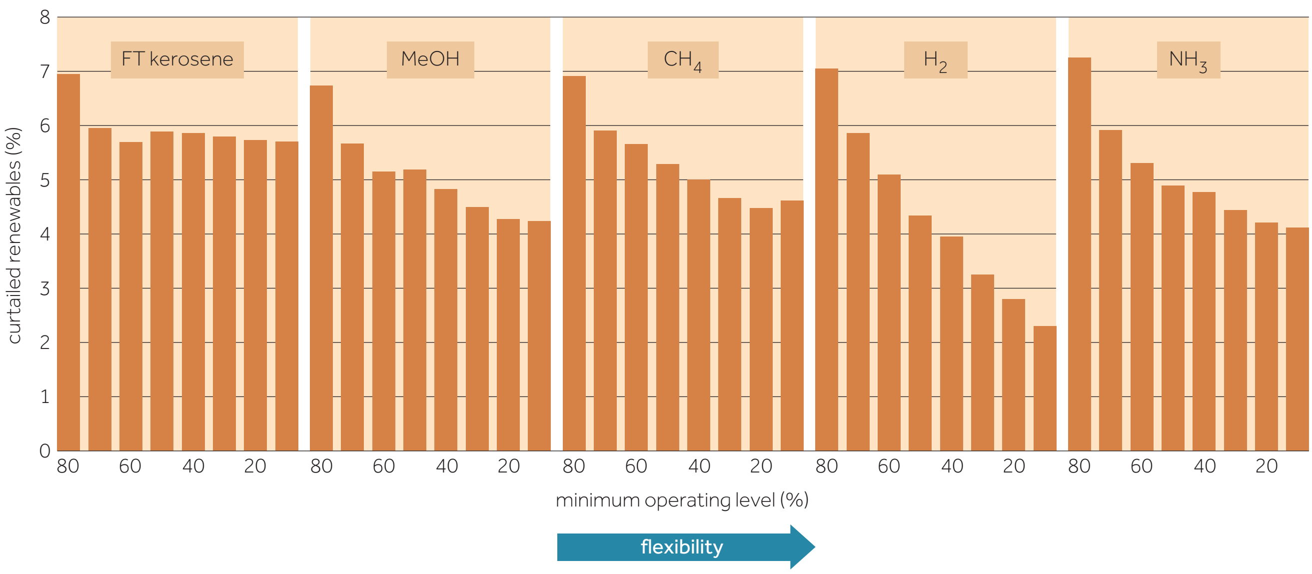
Intermittency and seasonality of renewable energy supply

The intermittency of renewable electricity sources and the operational flexibility of fuel production processes have a direct impact on the costs of e-fuel production. In this study,[1] the degree of variability in renewable power supplies was explored with a focus on wind and solar power. The results of this analysis provided inputs for the broad assumptions used in the rest of the study including the mix of PV and wind, the amount of renewable curtailment, and the size of storage elements. These include electricity storage based on battery systems, hydrogen storage, and CO_2 storage necessary for e-fuels production along with the cost impacts of production flexibility.

PV and wind are intermittent, but complementary to a large extent. Site-specific co-optimisation allows smoothing of the the electricity supply. The PV/wind ratio for least-cost production is driven by the combination of multiple parameters, including CAPEX for the different system facilities (PV and wind power plants, buffer storage of electricity, H_2 and CO_2, electrolysis plants and synthesis processes) and the equivalent full load hours. The CAPEX values for renewable electricity and for various components of the e-fuel plant change over time, leading to different PV/wind ratios also evolving over time.

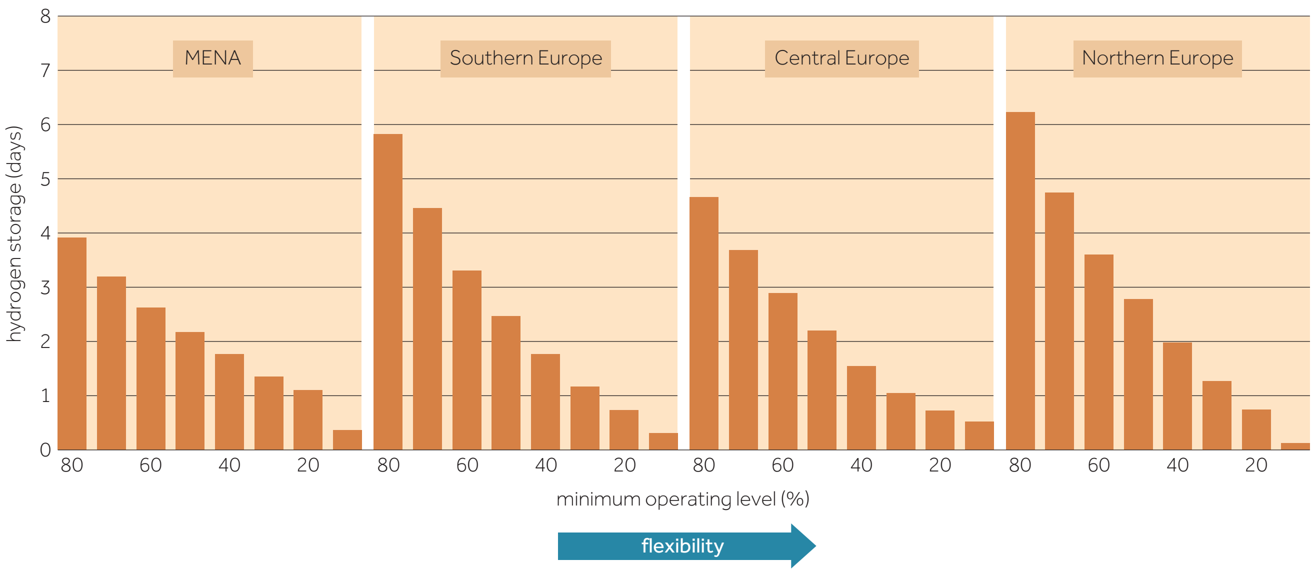
Figure 14 shows, for central Europe, the average amount of curtailed electricity across all operational points and fuels, which is about 5.8%. The level of curtailment decreases when the operational flexibility of the synthesis units increases. The study also shows that in northern Europe the curtailment amounts to only 2.6% on average across the range of fuel and conditions modelled. In MENA, the average electricity curtailment across all fuels and all operational conditions is around 6.6%. In southern Europe the inflexible cases see a much higher degree of curtailment due to the impacts of periods with low wind speed and low solar irradiation in renewable production, leading to overbuilding of assets, with an average of around 6.7% electricity curtailed across all fuels below a minimum part load of 60%.

Figure 14: Electricity curtailment in central Europe in 2050



As shown in Figure 15, the hydrogen storage capacity required depends on the flexibility of the downstream synthesis processes, such as the maximum change rate in hourly production and the minimum part load. This is also valid for the CO_2 storage capacity. The higher the flexibility of the downstream synthesis process, the lower the hydrogen and CO_2 storage requirements. Furthermore, the characteristics of renewable electricity supply over time also influence the H_2 and CO_2 storage requirements. The study shows that a higher PV share is related to higher H_2 and CO_2 storage requirements, except in regions with regular daily irradiation (batteries for day/night balancing). In most regions, increasing flexibility by 30% reduces the storage capacity requirements by more than half.

Figure 15: H_2 storage requirements (Fischer-Tropsch kerosene, 2050)



The study shows that, in general, as operational constraints become more flexible, the capacity of the synthesis plant increases with its load factor correspondingly decreasing. This is because the plants need to be oversized to allow higher production in times of high renewable energy availability, and compensate for lower production in times of lower renewable energy production in order to achieve the targeted annual production volume. The final capacity of the plant is a result of the balance between costs and load factors on all the different components in the system.

The study also demonstrates that a significant cost reduction in fuel production can be achieved with moderate flexibility of synthesis technologies. In the case of central Europe, 70–85% of the cost reduction potential can be achieved by moving the minimum part load from 80% down to 40%.

Context of e-fuels in the future of Europe — potential demand and feasibility

Technical potentials for renewable power production in Europe of more than 22,000 TWh/year as estimated in this study[1] is a factor of seven of today's electricity demand of approximately 3,000 TWh/year, and thus exceeds the foreseeable energy demand for all energy uses in a carbon-neutral future in principle. However, this is subject to social acceptance of the significant infrastructure that would need to be built. The technical potential in other regions of the world such as MENA is even greater but brings with it geopolitical and energy dependency risks.

High and low explorative scenarios for e-fuels developed for this study suggest that the demand for e-fuels in Europe could be in the range of 63 to 115 million tonnes of oil-equivalents (or 733 and 1,337 $TWh_{fuel,LHV}$, respectively). The low case is in line with the IEA World Energy Outlook (WEO) 2022[12] estimates for e-fuels, while the high case assumes that the remaining fossil fuels and biofuels in the IEA WEO scenario are also replaced with e-fuels. This would require the deployment of 278 to 1,531 GW of newly installed renewable generation capacity depending on the geographic distribution, generation mix and demand scenario chosen. Gross land use requirement for this is significant, around 0.1 million km^2, but it represents only around 2% of the total usable European land area (a little over 4 million km^2). The CAPEX required to deliver this amount of e-fuels process plant and associated renewables would lie in the range EUR 1–2.3 trillion or the equivalent of an annual investment of between 0.2 and 0.6% of EU GDP. This level of expenditure is consistent with other estimates (such as McKinsey, 2020[13]) of the investment required to achieve net zero.

The challenges involved in meeting e-fuels demand in both the high and low explorative scenarios are significant. Vast amounts of investment are required, and sizable amounts of resources will need to be mobilised, but it seems to be technically feasible. For example, the low and high explorative scenarios evaluated in this study, derived from IEA (2022).[12] result in a renewable electricity demand of 1,319 TWh (low scenario) to 2,805 TWh, respectively, which compares to a technical renewable electricity production potential of some 22,000 TWh/year in Europe. The main limitation to exploit the significant renewable electricity potentials in Europe may be social acceptance of mass deployment of wind and solar power plants, but not the technical renewable power production potentials.

In addition, suitable sources of CO_2 are needed as feedstock for electricity-derived synthesised hydrocarbon fuels. Use of concentrated CO_2 sources lead to lower overall fuel costs and higher e-fuel production efficiency, making it an interesting option until technologies for DAC are available at scale and while the availability of unavoidable CO_2 sources is foreseen.[14] However, the availability of industrial CO_2 sources, such as from steel production or cement industries, is set to decline in line with ETS[1] requirements, increased recycling efforts, and a general move towards a more circular economy towards 2050. Further industrial CO_2 sources will only be allowed for e-fuels production before 2041.[15] Beyond this date, only DAC and biogenic CO_2 sources will be allowed.

[1] Emissions Trading System — https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/what-eu-ets_en

The demand for water required specifically for the production of electricity-based fuels is negligible compared to water demand for energy crops (a few litres versus several thousand litres of water per litre of energy-equivalent.[16] The use of dry cooling towers and/or closed-loop water cycling is recommended (where needed) to minimise net water demand. Some DAC technologies also provide water that can further reduce the net water demand from e-fuels plants. For regions that are prone to, or already face, water-supply stress, such as the MENA region, the net water demand of an e-fuel plant needs to be supplied by seawater desalination plants (less than 1% of e-fuel total costs). Despite the low specific water footprint, e-fuels production plants at scale are significant point water consumers. Diligent assessment of water supply, demand and reservoir characteristics is highly relevant in the preparation of environmental and social impact assessments accompanying plant approval processes.

A deep dive into the safety and environmental considerations, societal acceptance, barriers to deployment, regulation and new technologies is also included as part of the study.[1]

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