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E-Fuels: A techno-economic assessment of European domestic production and imports towards 2050

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EXECUTIVE SUMMARY

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

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 a final fuel but also 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 analysis of the context of e-fuels in the future in Europe (potential demand, CAPEX, renewable electricity potential, land requirement, feedstocks requirements)
- A deep dive into the safety and environmental considerations, societal acceptance, barriers to deployment and regulation

The e-fuels techno-environmental assessment (Part 1) has been developed by Concawe and Aramco, using the Sphera GaBi platform as modelling tool, and the e-fuels economical and context assessment (Part 2) 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, a nameplate capacity of 1,370 MW of final e-fuel (based on its LHV, equivalent to 1 million t of e-diesel equivalent[1] per year or about 114 t/h) has been assumed.

Executive Summary part 1: Techno-environmental assessment

In Part 1, a detailed analysis of the e-fuels production efficiency, energy consumption, mass balance and carbon intensity of the produced e-fuels has been conducted in the different regions and timeframes. In addition, sensitivity analyses to 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 (section 1.7.).

The detailed mass and energy balances per type of e-fuel and source of CO_2 is included in Section 7.

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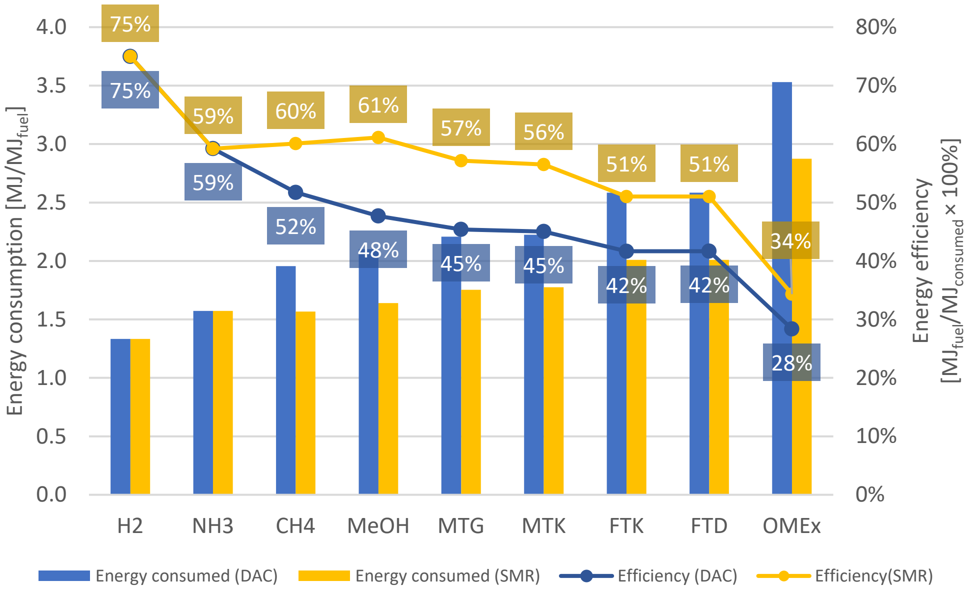
[1] Based on conventional diesel EN 590

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 [EC 2022], and assuming that the unavoidable and sustainable CO_2 sources in 2050 would be limited. The summary of the assumptions made are included in section 1.5. Sensitivities to a mix of concentrated CO_2 source and DAC are included in section 1.7.

Figure I 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, 1 MJ of FT e-diesel requires 2.1 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 2.7 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 does not increase proportionally: The simplest fuel containing a carbon atom, e-methane, has an efficiency of 52% and it drops only to 42% for more complex molecules like FT e-diesel or FT e-kerosene. The lowest efficiency corresponds to the e-$OME_{3\text{-}5}$, a non drop-in fuel and exception compared to the other molecules, estimated at 28%.

Figure I: Comparison of energy consumption and energy efficiency for e-fuels production when using CO_2 from Direct Air Capture (DAC) and a Concentrated CO_2 source (SMR) (Timeline: 2050)



Note: E-fuels production includes electrolysis, carbon capture and fuel synthesis. Does not include upstream power transmission/distribution nor downstream fuel distribution.

The values obtained correspond to the base cases of this study, with carbon capture from DAC in the 2050 timeline. If the carbon capture is 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 II we can observe that, taking North Europe as an example, the net GHG emissions of the different e-fuels pathways in a Cradle-to-grave (CTG) basis are around 5 gCO_2eq/MJ (except from the e-OME_{3-5}) and around 0.5 gCO_2eq/MJ if we only count emissions from Operation & Maintenance (O&M). 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.

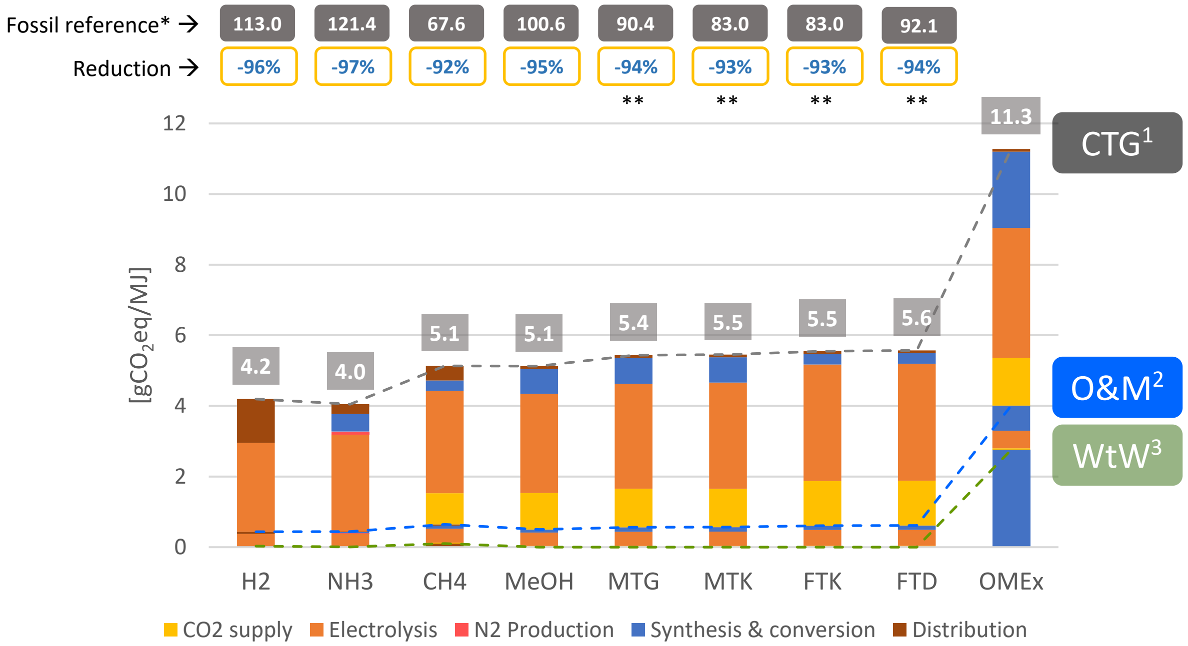
In Figure II we can also observe that GHG emissions are coming mainly from the Electrolysis, with a share of roughly 65-75% of the CTG impact (except for OMEx, where it accounts for around 40%). The emissions from Operation & Maintenance (O&M) represent around 10-15% of the total CTG emissions (35% for OMEx). This means that 85-90% of the total emissions from e-fuels are associated to the infrastructure required, mainly for renewable electricity.

All the e-fuels pathways (except e-OME_{3-5}) **achieve a GHG reduction higher than 92% versus the fossil alternative.** All the e-fuels pathways comply with the RED II limit for ReFuNoBio (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 still within the limit. This could be an opportunity, but 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 manufacturing solar panels or wind turbines are excluded (i.e. not CTG basis), the GHG reduction would be even higher.

Drop-in fuels, such as Methanol-to-Gasoline (MTG), Methanol-to-Kerosene (MTK), Fischer-Tropsch Kerosene (FTK) and Fischer-Tropsch Diesel (FTD), show higher CTG emissions (around 5.5 gCO_2eq/MJ) than non-drop in fuels, such as methanol (MeOH), at 5.1gCO_2 eq/MJ. This is because the energy efficiency is the main driver of the drop-in e-fuel GHG emissions, even if their transport, storage and dispensing infrastructures are already available. The opposite can be observed when comparing the costs of drop-in and non drop-in e-fuel costs (see Part 2: Economic assessment), because the cost of new infrastructure is relatively more impactful over the total cost than their environmental impact over the lifetime GHG emissions.

e-OME_{3-5} GHG emissions are around 11.3 gCO_2eq/MJ. The emissions are more than twice the rest of e-fuels due to the higher complexity of the process that requires more energy consumption, while still being compliant by far to 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 [Lumpp et al. 2011] that could be considered for commercial fuel blending.

Figure II: Cradle-to-grave (CTG) GHG emissions of different e-fuel pathways (Case: North EU, 2050 as an example. Rest of regions and timelines are included in section 1.6.)

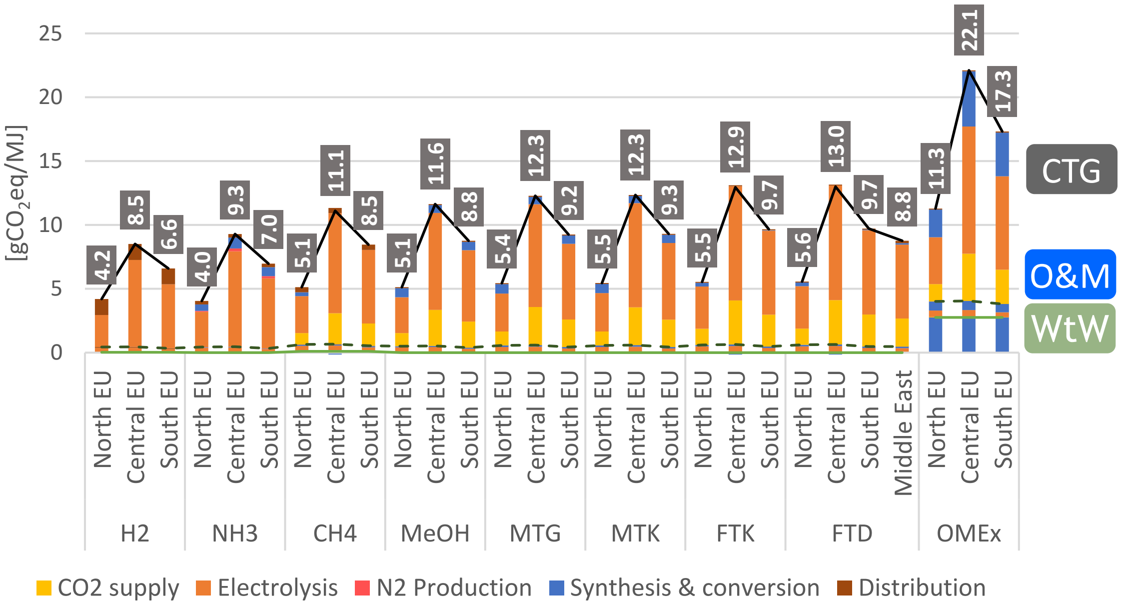


Notes:
* JEC WtT Study v5, GaBi Database / **Additional reduction if RED II fossil fuel comparator (94 gCO_2eq/MJ) is used
[1] Cradle-to-Grave (CTG) includes Operation & Maintenance emissions plus emissions from building the infrastructure to produce the e-fuels, their feedstocks and their energy requirements
[2] Operation & Maintenance (O&M) includes Well-to-Wheels emissions plus emissions from maintaining the infrastructure to produce the e-fuels, their feedstocks and their energy requirements
[3] Well-to-Wheels (WTW) includes emissions from production, transport and use of the e-fuels, their feedstocks and their energy requirements

In Figure III we show that the GHG emissions from Operation & Maintenance are very similar among regions for all the e-fuels pathways in 2050 (around 0.5 gCO_2eq/MJ for Northern Europe). However, the CTG values show lower levels in North Europe (around 5 gCO_2eq/MJ), followed by South (around 9 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).

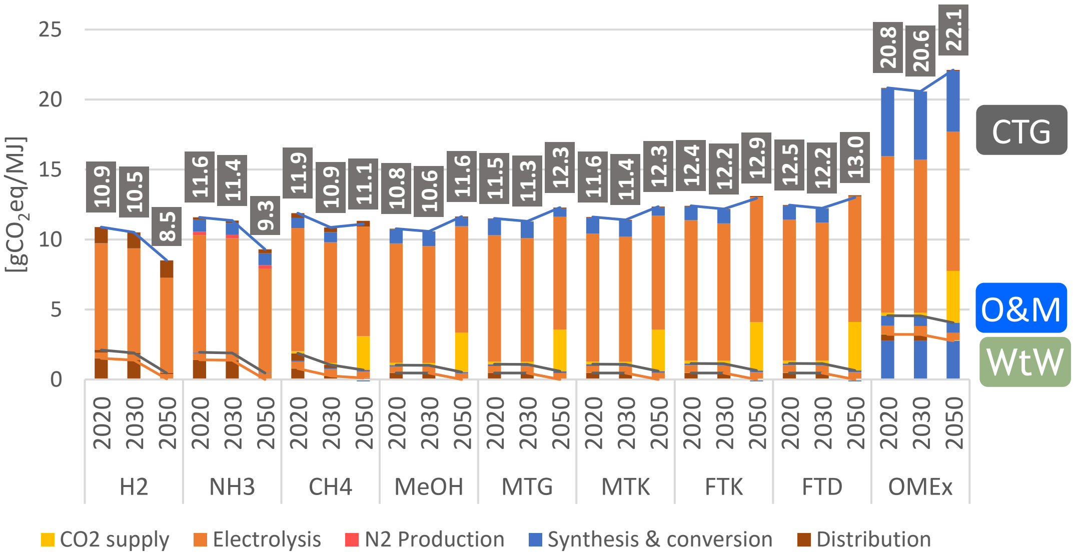
Long distance transport of fuels is mostly subject to the carbon intensity of the fuel used for ship propulsion and is not expected to increase significantly the GHG emissions of e-fuels. The carbon intensity of the electricity used for e-fuel production will still be the most dominant factor.

Figure III: Cradle-to-Grave (CTG) GHG Emissions from e-fuels production by region in Europe in 2050



In Figure IV we see 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 FT Kerosene the CTG GHG emissions in gCO_2eq/MJ for the FT Kerosene go from 12.4 in 2020 down to 12.2 in 2030 and then up to 12.9 in 2050. This is due to opposite effects overlapping: On one side, an improvement in electrolyser efficiencies and the generalization of the use of e-fuels for maritime and truck transport, which favour a decrease over time of H_2 supply and distribution emissions. On the other hand, the displacement of concentrated sources of CO_2 by the use of DAC, which requires more energy-intensive operations to capture CO_2 from the atmosphere and results in a net increase of emissions by 2050. The contribution of Operation & Maintenance remains stable over time (around 0.2 gCO_2eq/MJ for FT kero) until 2050. The WTW GHG emissions drop steadily until 2050 for all fuels as the emissions from the additional renewable electricity required for DAC is assumed to be 0 on a WTW basis. Sensitivities to this assumption are included in section 1.7.

Figure IV: Cradle-to-Grave (CTG) GHG Emissions from e-fuels production in Central Europe in 2020, 2030 and 2050



Figures V and VI show some sensitivity cases of e-fuels GHG emissions with respect to changes in technology. Figure V corresponds to the impact of an "Advanced Technology" scenario, with one main differences compared to the 2050 base case: The use of co-electrolysis (a combination of High Temperature SOEC electrolysis with Reverse Water Gas Shift technology). The results show a slight increase of the carbon intensity observed for the Advanced Technology scenario, mainly explained by the assumptions taken for the base cases of this study: The energy efficiency of the pathways was already enhanced by assuming that a large part of the heat generated from fuel synthesis was transferred to the carbon capture process. Despite having a better electric efficiency, the co-electrolysis configuration does not show benefits in this case because there is not any excess thermal energy available in the base case, and any additional thermal duty requirement will inevitably increase the carbon burden of the process.

Figure V: Comparison of GHG emissions between the base case and the Advanced Technology scenario in 2050

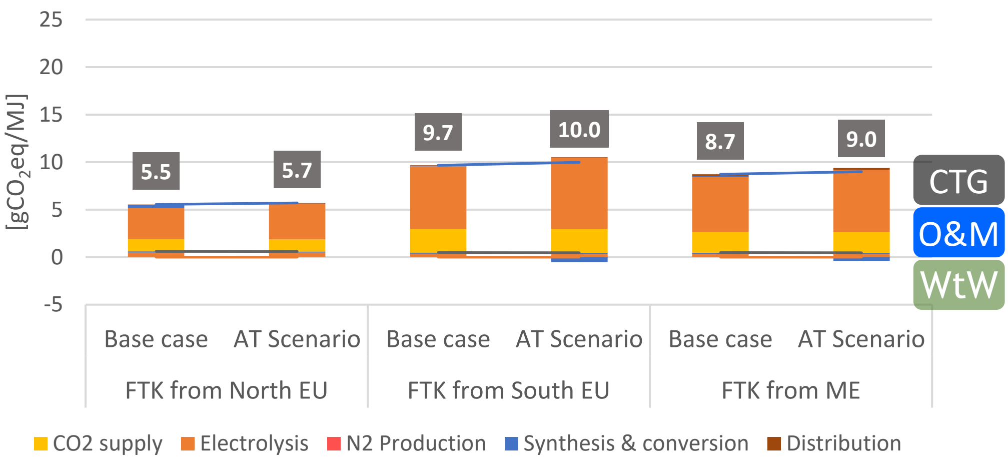
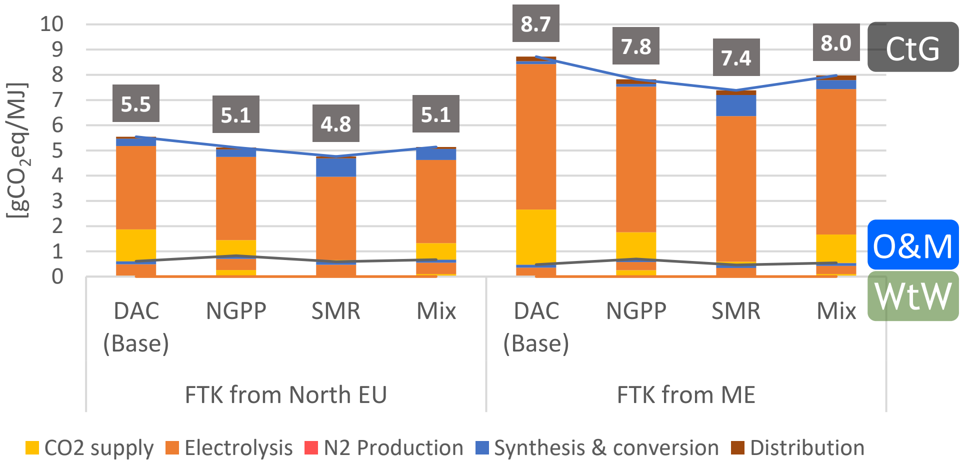


Figure VI: Comparison of GHG Emissions from Fischer-Tropsch kerosene production from different CO_2 sources and different production locations



Note: NGPP refers to Natural Gas Power Plant

Figure VI on the other hand depicts the impact of switching to different CO_2 sources for e-fuel synthesis. In the Fischer-Tropsch kerosene 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 direct air capture (DAC), reduces the GHG impact by 0.7 to 1.3 gCO_2eq/MJ depending on the geographical location. The use of flue gases from a natural gas power plant (NGPP), less concentrated than SMR off-gases but more concentrated than air, also reduces the GHG emissions by 0.4 to 0.9 gCO_2eq/MJ.

Other sensitivities are further analysed in the body of the report, such as the use of different renewable energy sources, the use of CO_2 captured in Europe for e-fuel synthesis in MENA, and the impact of using energy carriers to transport H_2 instead of liquefaction, in a case where e-fuels are produced in Europe with hydrogen coming from MENA (see Section 1.7.).

Executive Summary part 2: Economic assessment

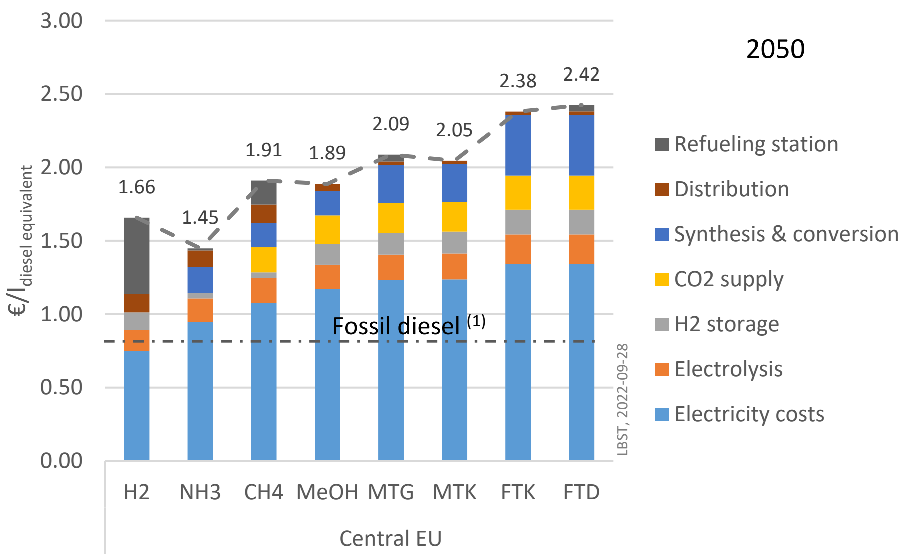
In Part 2, a detailed analysis of the costs for e-fuel supply for 9 e-fuels for 4 geographies (North, Central, South of EU and MENA) and 3 timeframes (2020, 2030 and 2050) plus a series of key sensitivities have been taken into account, leading to more than 100 pathways assessed.

Figure VII shows the costs of e-fuels produced in Central Europe and Figure VIII the ones produced in MENA and transported to EU in 2050, as an example (for the other regions and timeframes, see Section 2). The figures show that the majority of the cost (between 50% and 65%) is coming from the renewable electricity cost. Note that for all the regions the same H_2 and CO_2 buffer storage capacities have been assumed and could be potentially short depending on the region. This will be addressed in detail in an upcoming report, an extension of this one, where a cost minimisation modelling will be done using time series of renewable power supply.

They also show that there is a 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 to the transportation efforts.

Based on the assumptions taken, this economic assessment of e-fuels towards 2050 shows that fuel supply costs range between 1.6 and 4.1 € per litre of diesel-equivalent in the short and between 1.2 and 2.5 € per litre in the long term if the outlier OME_x is excluded. For OME_x the fuel supply costs range between 2.8 and 5.4 € per l of diesel equivalent in the short term and between 2.5 and 3.8 € per l of diesel equivalent in the long term.

Figure VII: Costs of e-fuels produced in Central Europe in 2050



(1) Diesel price: 0.3 €/l (2020) - 0.8 €/l (2050), with crude-oil prices 40 €/bbl (2020) - 110 €/bbl (2050) taken from the EU Commission Impact Assessment [EU COM 2020]

Figure VIII: Costs of e-fuels produced in MENA and transported to South Europe in 2050

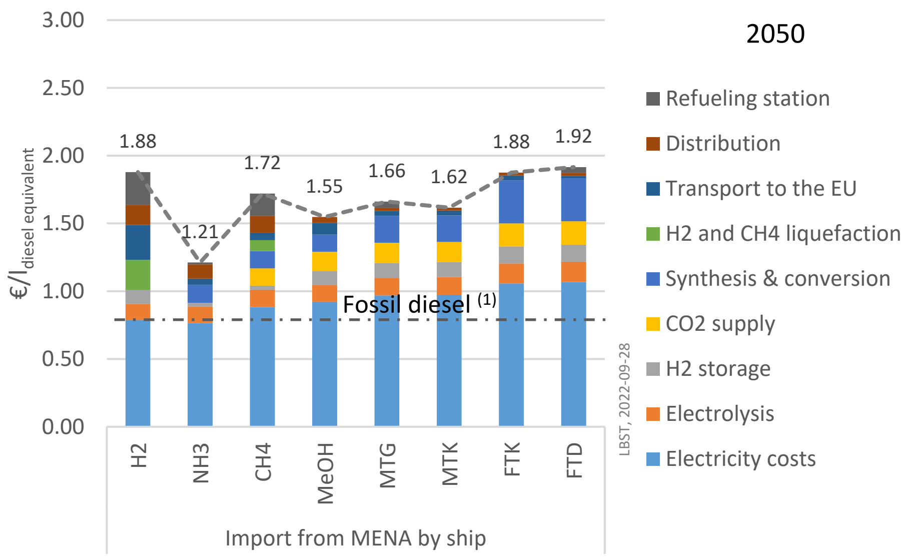
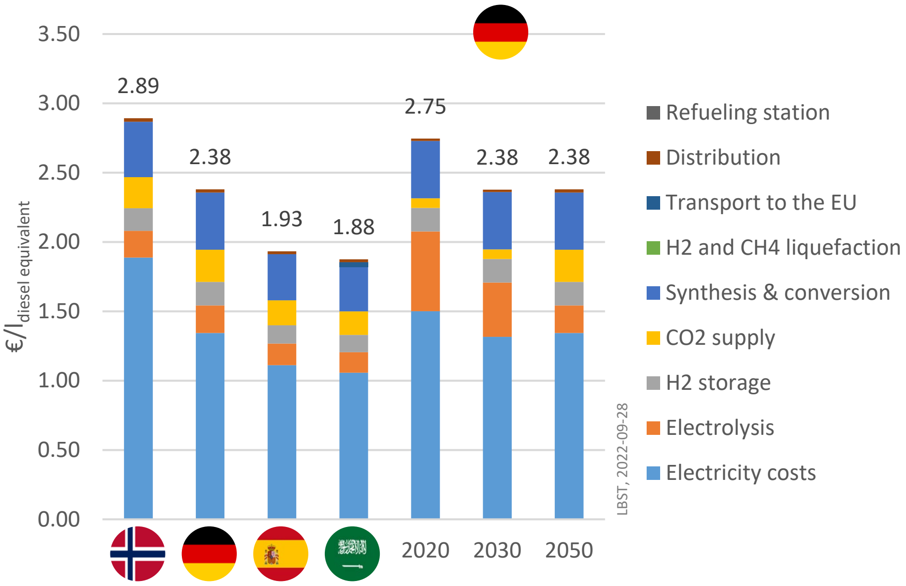


Figure IX shows that Fischer-Tropsch e-kerosene (FTK) produced in MENA and South Europe represent the lowest fuel costs, followed by Central and North Europe. This is directly linked to the renewable electricity cost and the full load hours.

Note that for North Europe, 100% offshore wind has been taken into account assuming that new additional e-fuels plants would rely on this source. In case of using hydropower as primary electricity source, the e-fuel production cost in North Europe would be lower.

Figure IX also show that e-fuels costs produced in Central Europe are reduced with time (22%) due to decreasing CAPEX for wind & PV plants, electrolysis, and improvement of electrolysis efficiency despite lower availability of concentrated CO_2 sources.

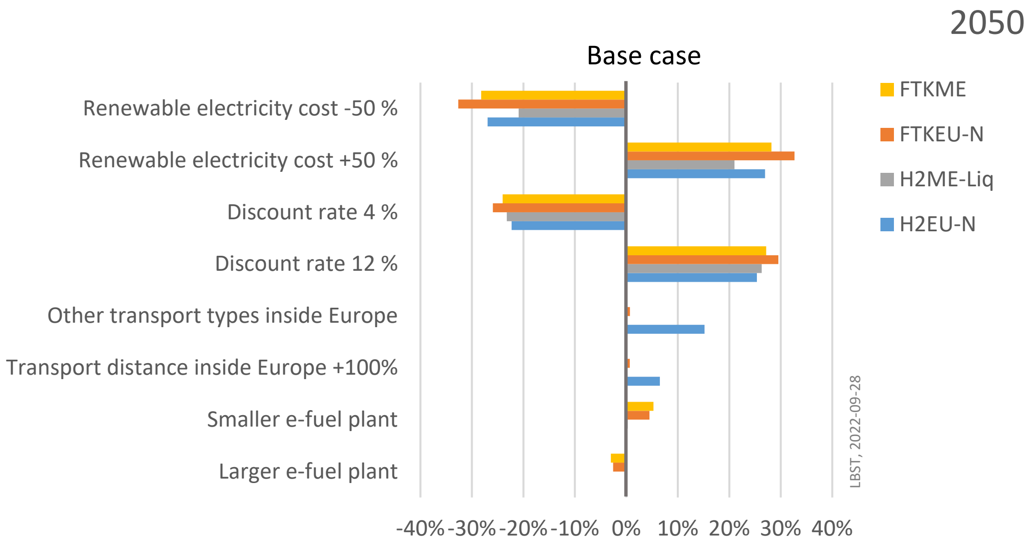
Figure IX: Costs of Fischer-Tropsch e-kerosene, first part of the chart refers to 2050 and the second to EU Central (as an example, see the rest of the timeframes and regions in Section 2)



Sensitivities to key economic parameters

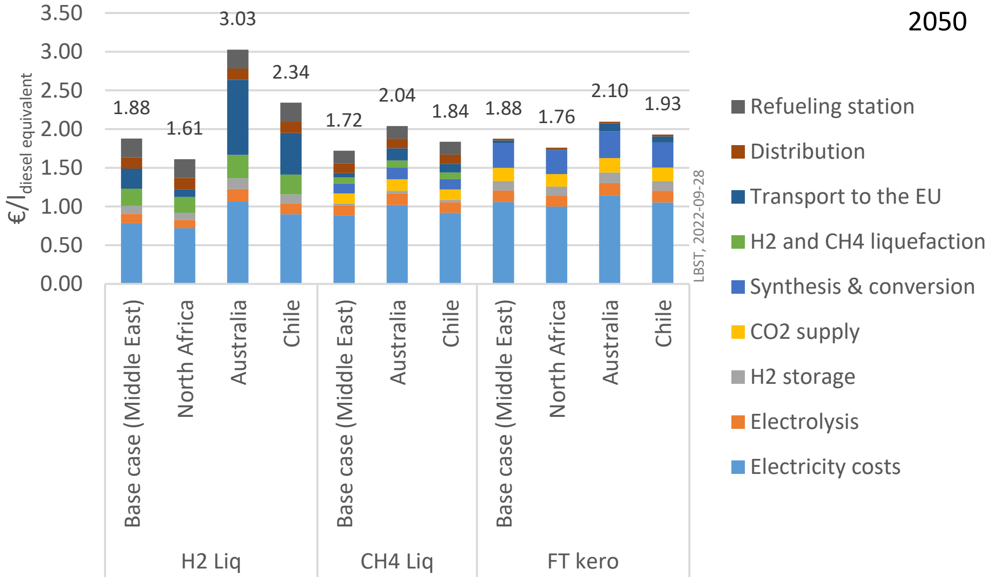
Figure X shows the sensitivities conducted. Electricity costs and discount rate have a significant impact on overall fuel supply costs. 50% change of electricity supply costs or discount rate assumptions resulted in about 25% supply cost. Other factors investigated, such as transport type and distance 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 very similar for 2020 and 2050.

Figure X: Sensitivity: impact of variation of selected parameters



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

Figure XI: Impact of geography. Imports of e-fuels to EU from further regions



Another sensitivity analysis is the variation of the curtailment due to PV/wind overlap. Increase of the PV/wind overlap from 5% to 10% leads to an increase of the fuel costs by only about 5% for all regions where electricity from PV/wind hybrid power plants are used for e-fuel production.

Another relevant sensitivity analysis is the use of alternative carriers for H_2 import to feed synthesis processes. The use of ammonia, methylcyclohexane and methanol as H_2 carrier to feed synthesis processes leads to higher e-fuels production costs (3.32 € per l of diesel equivalent for ammonia, 4.65 per l of diesel equivalent for methylcyclehexane, and 2.88 per l of diesel equivalent for methanol as H_2 carrier compared to 3.02 € per l of diesel equivalent in the base case).

Until now, industry scale e-fuel plants lack commercial experience. Currently, there are only e-fuels plants at demo scale, although some pre-commercial scale plants are already announced, to go into operation in the coming years. Result confidence increases through engineering & business case studies, and deployment.

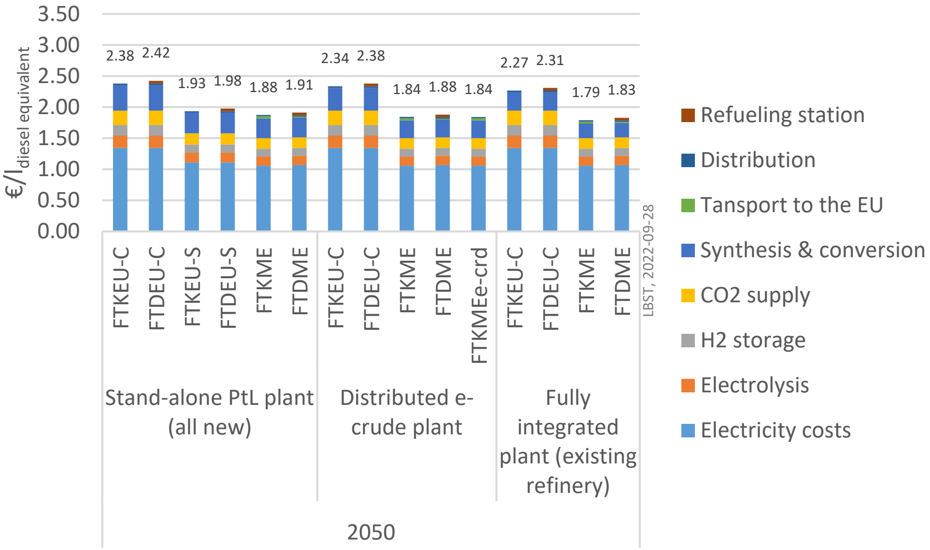
Stand-alone plants vs. distributed e-crude plants vs. fully integrated plants

The analysis of a **stand-alone e-fuel plant** (all-new integrated plants for hydrogen production, synthesis to e-crude, and final upgrading) versus a **distributed e-fuel plants** (new hydrogen production and synthesis to e-crude units, and e-crude upgraded in existing refineries) versus a **full integrated e-fuel plant** (the hydrogen production, synthesis to e-crude, and final upgrading is all fully integrated into an existing refinery) have been conducted.

Existing **refineries** can play a facilitating role in the energy transition to e-fuels. These 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. Given recent geo-political developments, it is also an option to respond to natural gas supply constraints in the wake of Russian invasion into the Ukraine. 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 0.005 €/$l_{Diesel\text{-}eq}$ [LBST 02/2016]. Furthermore, the existing refining assets can, in part, be used to upgrade Fischer-Tropsch syncrude, allowing an efficient use of existing investments. Since refineries are complex, have diverse configurations, and differ in terms of supply infrastructure and products mix, refinery-specific feasibility studies are recommended to assess opportunities in the field.

The difference between stand-alone and fully integrated plant into a refinery is that there are no capital costs for hydrocracking, fractionation (upgrading), utilities, and logistics in case of the fully integrated plant. Only OPEX is taken into account for these processes. However, these capital cost elements in the total e-fuel production costs have a low contribution (~5%). In 2050 the e-fuel production costs range between 2.0 and 2.6 € per l of diesel equivalent for stand-alone e-fuel plants and between 1.9 and 2.4 € per l of diesel equivalent for e-fuel plants fully integrated into an existing refinery. In 2050 DAC has been applied as well as for stand-alone, distributed e-crude plants, and fully integrated e-fuels plants into a refinery.

Figure XII: E-fuels production costs comparison in a stand-alone, distributed and fully integrated plant



In the short to medium term there may be advantages in utilizing existing refineries to minimize capital expenditure. There is a potential advantage of co-processing in the early e-fuel development. The lower the CAPEX, the higher the probability for a company to invest, aiming to have a return of invest in a shorter time. In the long-term it is more likely that integrated e-fuel plants would be developed to maximize system efficiencies.

The CAPEX for the stand-alone FT plant without H_2 and CO_2 supply amounts to about 1500 million € including indirect cost. The CAPEX for the distributed FT e-crude plant without H_2 and CO_2 supply amounts to about 1100 million €. The CAPEX of the FT plant fully integrated into an existing refinery without H_2 and CO_2 supply amounts to about 800 million €[2].

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

Based on the assumptions taken, 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 1.4 € per l of diesel equivalent for e-methanol and 2.6 € per l of diesel equivalent for FT kerosene. The costs of crude oil-based diesel amounts to about 0.3 € per l of diesel equivalent today (for a crude oil price of 40 euro/boe) and about 0.8 € per l of diesel equivalent in 2050 (for a crude oil price of 110 euro/boe)[3]. However, to fulfil the Paris agreement and its goal to limit the global warming well below 2°C, preferably to 1.5°C, compared to pre-industrial levels, fossil fuels have to be almost completely phased out in the long-term.

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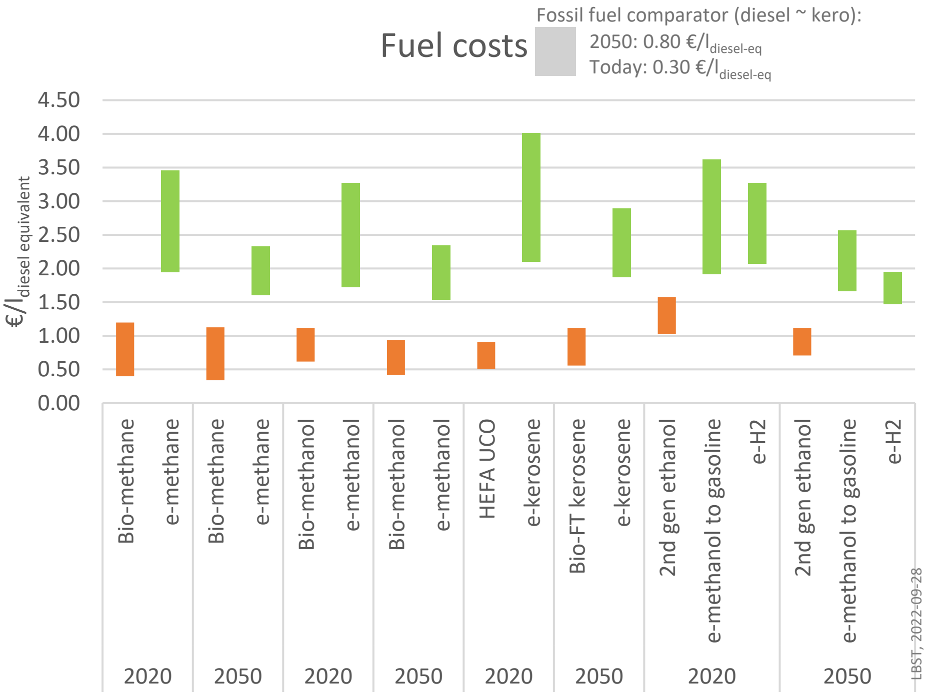
[2] No learning curve has been applied to Fischer-Tropsch plant as the technology can be considered mature.
[3] According to crude oil price estimations in the EU Commission Impact Assessment SWD (2020) 177 final [EU 2020]

Based on the assumptions taken[4], **nuclear** electricity would result in higher e-fuels production costs in 2020 versus PV or wind on-shore electricity (except wind off-shore), if new nuclear plants have to be built. In case of electricity produced from nuclear long-term operation by lifetime extension costs can be as low as 25 to 34 € per MWh_e depending on CAPEX and full load period assumptions in [IEA 2020b]. In 2050, based on the assumptions taken based on real data from the European Pressurized Reactor (EPR), e-fuels produced from nuclear electicity results in higher costs than from Norwegian offshore wind, and therefore higher costs than produced in the rest of the regions analysed in this study.

Based on the assumptions taken, the **production costs** and **GHG abatement costs** for biofuels are lower than those for e-fuels. In 2050 the costs of **biofuels** range between 0.3 € per l of diesel equivalent (lower limit for bio-methane) and 1.1 € per l of diesel equivalent (upper limit for bio-methane, Bio-FT kerosene, and 2nd generation ethanol). The higher cost of abatement for e-fuels is attributable primarily to the cost of green hydrogen production as compared with biomass gasification. Taking FT liquid production, for example, 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. 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.

Figure XIII: E-fuels versus biofuels production costs



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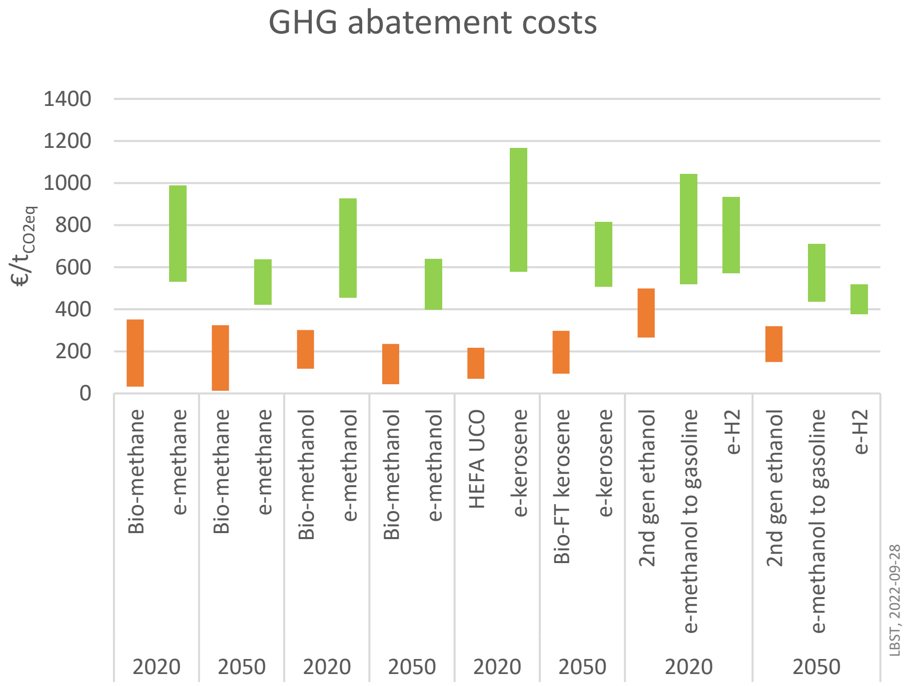
[4] [Areva 2014], [WNA 2018], [WNN 2018], [CourDeComptes 2012]

The GHG abatement costs for e-fuels are expected to decrease from about 460-1170 in 2020 to some 380-820 €/t of avoided CO_2-equivalent in 2050. The GHG abatement costs for biofuels are expected to decrease from 40-510 €/t of avoided CO_2 equivalent in 2020 to some 20-330 €/t of avoided CO_2 equivalent in 2050.

Figure XIV: E-fuels versus biofuels GHG abatement costs



It should be noted that the abatement costs refer to fuel supply (including embedded carbon), without accounting for use-case efficiencies. For example, fuel cell electric vehicles (FCEV) have a higher efficiency than internal combustion engine (ICE) vehicles leading to lower abatement costs for hydrogen fuel. The powertrain assessment has not been included as part of the scope.

Context of e-fuels in the future of Europe. Potential demand and feasibility

Technical **potentials for renewable power production** in Europe (>22,000 TWh/yr, as estimated in Section 4.1.) is a factor of seven of today's (~3000 TWh/yr) electricity demand 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 must be built. The technical potential in other regions of the world such as MENA is even greater, but bring with it geopolitical and energy dependency risks.

High and low **scenarios** for e-fuels developed for this project suggest that demand for e-fuels in Europe could be in the range between 66 and 129 million tons of oil-equivalents. This is based directly on the IEA World Energy Outlook estimates for e-fuels in the low case and then with a shift of IEA WEO fossil and biofuels estimates to e-fuels in the high case. This would require the deployment of anywhere between 362 and 1,723 GW of new renewable generation capacity depending on the geographic distribution, generation mix and demand scenario chosen. The CAPEX required to deliver this amount of e-fuels process plant and associated renewables would lie in the range €1 – 5 trillion or the equivalent of an annual investment of between 0.2 and 1% of EU GDP. This level of expenditure is consistent with other estimates (e.g. McKinsey [McKinsey 2020]) of the investment required to achieve net zero and must be set against the operating cost benefits of switching to renewables (high CAPEX but low OPEX cost profile) not to mention the benefits in terms of energy security. It is also comparatively low considering that the cost of a new generation of telecommunication infrastructure is estimated between €0.3 - 0.5 trillion in the case of European coverage with 5G mobile network. While gross land use requirements are significant, being around 0.1 million km², this represents a very modest proportion of some 2% of the total usable European land area (a little over 4 million km²).

The challenge involved in meeting e-fuels demand in both the high and low scenarios is significant. Vast amounts of investment are required and sizable amounts of resources must be mobilised, but it seems to be technically feasible.

Having into account the 22,000 TWh/a of technical renewable power production potentials estimated from a literature review in chapter 4.2.1.1:

- If **today's transport fuel demand** of EU 28+ was **completely provided with e-fuels** (worst and **unrealistic case**, just to put figures in perspective), this would result in a renewable electricity demand of ~12,000 TWh_e/a, thereof ~1,600 TWh_e/a for aviation. This means that transport only would require more than half the renewable power generation potential. This seem to be insurmountable, taking into account that other sectors may also need renewable electricity to replace their today's fossil consumption.
- Assuming a **more balanced scenario using 100% renewable energy in all transport** for BEV charging, e-hydrogen, e-methane, and e-liquids in EU27+UK by 2050, according to [FVV 2021, p69ff] this would result in 2,570-10,880 TWh_e/a of renewable electricity demand.

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.The use of concentrated **CO_2 sources** lead to lower overall fuel costs and higher e-fuel production efficiency, making it an interesting option until 2030 when technologies for direct air capture are not yet available at-scale and availability of unavoidable CO_2 sources is foreseen [Concawe 2019, p 46f]. However, the potential from industrial CO_2 sources, such as from steel production or cement, is set to decrease with novel production pathways, increased recycling efforts, and a general move towards a more circular economy towards 2050. In the long-term (2050), direct air capture will take a higher contribution due to the scarcity of unavoidable CO_2 sources and the technology development, despite the lower e-fuel efficiency.

Specific **water** demand for electricity-based fuels is negligible compared to water demand for energy crops (few litres versus several thousand litres of water per litre energy-equivalent [UBA 2022]). The use of dry cooling towers and/or closed-loop water cycling is recommended (where needed) to minimise net water demand. Some direct air capture technologies also provide water that can further reduce the net water demand from PtX plants. For regions that are prone to, or already face, water-supply stress, such as MENA region, the net water demand of the e-fuel plant has to be supplied by seawater desalination plants (less than 1% of e-fuel total costs). Despite the low specific water footprint, PtX production plants at-scale are significant point water consumers. Diligent assessment of water supply, demand, and reservoir characteristics are a relevant part in the preparation of environmental and social impact assessments (ESIA) 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 (see Chapter 4).

1. TECHNO-ENVIRONMENTAL ASSESSMENT

1.1. BACKGROUND

Climate change and environmental degradation are an existential threat to Europe and the world. To overcome these challenges, the European Green Deal[1] will transform the European Union into a modern, resource-efficient and competitive economy, ensuring zero net emissions of greenhouse gases by 2050.

Concawe, in partnership with Aramco, aims to assess the technology developments across different transport sectors and the EU refining system with the potential to contribute to these EU long-term decarbonisation goals, where the potential role of e-fuels was identified as one of several promising technologies.

A series of reports in this area was published in 2019 by Concawe:

- [Concawe 2019 Refinery 2050] Exploring the potential replacement of crude oil in EU refineries by Low Carbon Feedstocks, such as lipids, biomass and e-fuels

  https://www.concawe.eu/publication/refinery-2050-conceptual-assessment-exploring-opportunities-and-challenges-for-the-eu-refining-industry-to-transition-towards-a-low-co2-intensive-economy/

- [Concawe 2019 Role of e-fuels in the European transport system – Literature review] https://www.concawe.eu/wp-content/uploads/Rpt_19-14.pdf

However, Concawe and Aramco identified some missing points that motivated taking a further step to better understand the e-fuel technologies and the economic impact of their domestic production compared to the option of importing them from other regions in the world.

Concawe and Aramco have jointly commissioned this study. It proposes a techno-environmental (Part 1) and economic (Part 2) analysis of different e-fuels pathways produced in different regions of the world (North, Centre and South of Europe, Middle East and North Africa (MENA)) with assessments of sensitivities to multiple key techno-economic parameters. The study includes also an assessment of stand-alone units versus e-plants integrated with oil refineries.

The study also includes (Part 2) a comparison of e-fuels production costs versus fossil fuels and biofuels, and an analysis of the context of e-fuels in the future in Europe (potential demand, feasibility, opportunities and challenges).

The E-fuels techno-environmental assessment (Part 1) has been developed by Concawe and Aramco, using the Sphera GaBi platform as modelling tool, and E-fuels economical assessment (Part 2) has been conducted by the consultants LBST and E4tech, under the supervision of Concawe and Aramco.

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[1] https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en

1.2. SCOPE OF PART 1: TECHNICAL ASSESSMENT

The main objective of Part 1 is to estimate for the timeframes **2020**, **2030** and **2050**, the following technical parameters:

- **Energy efficiency** based on the **energy consumption** of each e-fuels production pathway, in the form of electricity and heat requirements.
- **Mass balances** of the different e-fuels pathways, to determine the amount of hydrogen, carbon dioxide, water, oxygen and other feedstock streams needed for their production.
- **Carbon intensities** expressed in grams of CO_2 equivalent per unit of energy for each e-fuel of the scope.

The e-fuels pathways considered in the scope are:

- **e-hydrogen**, in both liquefied and compressed form, used as a final product for fuel cell hydrogen **electric** vehicles, and also as feedstock for producing other e-fuels, abbreviated as **H_2**;
- **e-methane**, in both liquefied **and** compressed form, produced by methanation of syngas, abbreviated as **CH_4**;
- **e-methanol**, produced by single-step reaction of hydrogen and carbon dioxide, used as a final product for **internal** combustion engine vehicles and also as feedstock for producing other e-fuels, abbreviated as **MeOH**;
- **e-polyoxymethylene dimethyl ethers**, produced from **methanol** and oxygen via formaldehyde, abbreviated as **$OME_{3\text{-}5}$** or **OME_x**;
- **e-gasoline and e-kerosene** produced from the methanol-to-gasoline and methanol-to-middle distillates reactions, abbreviated as **MTG** and **MTK** respectively;
- **e-ammonia** produced from the Haber-Bosch reaction of e-**hydrogen** and nitrogen, abbreviated as **NH_3**;
- **e-kerosene and e-diesel** produced from syngas via low-**temperature** Fischer-Tropsch reaction, abbreviated as **FTK** and **FTD** respectively.

The parameters of the e-fuels cited above were analysed in the context of different regions in the world, including:

- Domestic production in Europe in three regions:
  - **North Europe** (taking Norway as the reference)
  - **Central Europe**, inland (taking Germany as the reference)
  - **South Europe** (taking Spain as the reference)
- Production in **Middle East** (Saudi Arabia) / **North Africa** (Morocco), and then imported to the EU, considering two different possibilities:
  - e-Hydrogen import to Europe as final product (hydrogen transported in liquefied form)
  - e-Fuel import to Europe as final products (as drop-in fuels)

Besides the base cases, key sensitivity analyses have been also included to the following relevant parameters:

- **Technology development**: An accelerated scenario is included, taking into account learning curves, improvement in technology (e.g. e-fuels efficiency increase, utilization as fuel for trucks & ships), new technologies penetration (e.g. co-electrolysis).
- **Electricity power sources**: A 100% use of each individual electricity source is considered:
  - 100% Wind: Offshore and onshore (anchored offshore windmills, no floating ones)
  - 100% Solar: Photovoltaic (PV) / Concentrated solar power (CSP)
  - 100% Geothermal
  - 100% Hydro
- **Carbon sources** (CO/CO_2) (taking into account the extraction/purification process, storage and transportation)
  - From a diluted source, taking as proxy a low temperature Direct Air Capture
  - From combustion off-gases, taking as proxy a natural gas power plant
  - From a concentrated source, taking as proxy Steam Methane Reforming (SMR) off-gas or Autothermal reforming (ATR)
- **Carbon capturing location:** Assuming a CO_2 stream captured in EU and shipped from Europe to MENA to produce the e-fuels
- **Hydrogen transported as chemicals** (as hydrogen vectors in order to facilitate transport), such as:
  - e-Methanol (via methanol cracking)
  - Methylcyclohexane (via toluene)
  - e-Ammonia (via ammonia cracking)

The battery limits of the study include:

- Facilities needed to produce the fuels and their feedstocks (hydrogen, CO_2, electricity, thermal energy, etc).
- Sea transmission cables from the offshore wind **to** the coast in the case of North Europe and high-voltage transmission cables from the in the cases of South Europe and MENA.
- The distribution network from the production facilities to the e-fuel service station. Storage of hydrogen has been taken into account to produce e-fuels on a continuous basis, limited to the maximum available full load hours for each specific region (see section 1.5.2).
- Fuel use in the form of combustion emission factors per unit of energy.

The fuel combustion in the engine taking into account specific efficiencies for different powertrain options is not included in the scope.

1.3. METHODOLOGY

1.3.1. General methodology

The present study follows the standard of ISO 14040 [ISO1 2006] and 14044 [ISO2 2006] to evaluate the life-cycle impacts of fuels, electricity, batteries and vehicles.

Foreground data, including material and energy inventory balances of fuel and electricity production, plant construction and end-of-life treatments for streams and materials were based on various sources from public literature and available industry data.

Background data, in particular life-cycle inventory (LCI) data for energy and material supply were taken from the 2021 version of Sphera's GaBi LCI databases [Sphera 2021]. The same methodology was applied and the same data requirements were defined for both the foreground and background data, ensuring their mutual consistency.

The LCA modelling platform used was the GaBi software system for life-cycle engineering [Sphera 2021].

1.3.2. System boundaries and scope

The life cycle of a fuel includes the following stages:

- Production of the raw materials: Electricity, hydrogen, carbon dioxide/monoxide, water, oxygen, etc.
- Fuel synthesis: Methanation reaction, Fischer-Tropsch reaction, Haber-Bosch reaction, etc.
- Fuel distribution: Transportation by ship, truck, pipelines required to transfer the fuels from the production sites to the service stations, including storage systems.
- Fuel utilisation: Expressed only as a combustion emission factor per unit of energy, excluding the efficiency of the vehicle engine.
- Manufacturing, use and end-of-life of the facilities and equipment needed to produce and transport the e-fuels and their feedstock streams: Reactors, compressors, pipelines, storage, etc.

The CO_2 emissions of the fuels are all expressed on a "Cradle-to-Grave" basis. This incorporates:

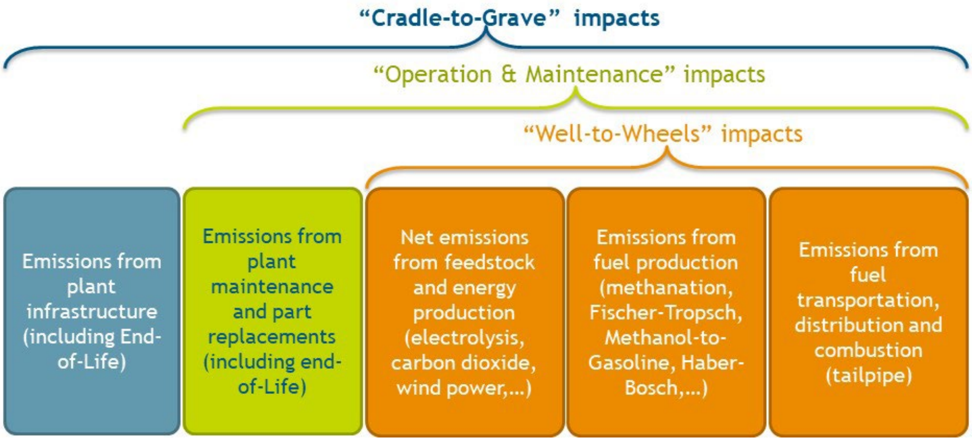
- Net emissions from the fuel production and use: Burdens and credits from energy consumed and produced during synthesis process (fuel burning, steam generation, CO_2 generation from synthesis reactions), transport (fuel burned and power consumed during distribution and storage) and utilisation (combustion);
- Net emissions from the fuel feedstock production: Burdens from energy consumed by the electrolysers, carbon capture and purification, and power plants, including credits from CO_2 captured;
- Net emissions from building the infrastructure and manufacturing the equipment needed to produce the fuels: Burdens from energy and materials consumed to manufacture solar panels and wind turbines, and net credits from material recycling and energy recovery from incineration. Carbon Capture

infrastructure and dismantling is not included but a recent study does not show it to be significant compared to the contribution of the use phase [Terlouw 2021].

- Net emissions from infrastructure maintenance and part replacements: Machine lubrication, turbine blades substitution, etc.

The CO_2 emissions results are also expressed on other scopes for reference purposes, as shown in Figure 1. Scopes such as “Well-to-Wheels” emissions (includes only for net emissions from fuel and feedstock production), and “Operation & Maintenance” (equivalent to the “Well-to-Wheels” impact plus the net emissions from maintenance and replacements).

Figure 1: Scopes of the e-fuels life cycle assessment for the present study



1.4. PRODUCTION PATHWAYS

The different e-fuels pathways considered in this study are described in this section. Annex 7.1 shows the detailed mass and energy requirements for each of the e-fuels pathways.

1.4.1. e-Hydrogen

E-hydrogen (also called green hydrogen when produced from electricity of renewable origin) is a fuel used in fuel cell electric vehicles, but it is also a feedstock for producing the rest of e-fuels. It can be produced by water electrolysis, represented by the following overall reaction:

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2 \quad \Delta H_{R^\circ} = +286 \text{ kJ/mol}$$

There are different hydrogen electrolysis technologies, which can be carried out using low-temperature processes (at 50 to 80°C) or high-temperature processes (700 to 1000°C).

Commercially available, low-temperature processes include alkaline electrolysis (AEC) and proton exchange membrane electrolysis (PEM). In comparison, currently high-temperature electrolysis (SOEC) is less developed.

a) Alkaline Electrolysis Cells (AEC)

This is the state-of-the art industrial process for electrolytic hydrogen production. A 20-40% solution of KOH is used and the electrodes coated with Ni as catalyst. Alkaline electrolysis can be applied at normal pressure or under a pressure of up to 30 bars.

b) Polymer Electrolyte Membrane (PEM) Electrolysis

Over the last 20 years, PEM (Polymer Electrolyte Membrane) electrolysis has been developed. In contrast to the alkaline version, it uses pure water and no treatment or recycling of the KOH solution is necessary. PEM stacks are very compact and can be designed for pressures up to 100 bars.

The main drawbacks of this technology are the investment costs which are dominated by the high costs for materials like platinum and iridium. The system cost of PEM electrolysers is currently about twice that of alkaline systems.

c) Co-electrolysis via high-temperature Solid-Oxide Electrolysis Cells (SOEC)

Higher temperature electrolysis at around 700-1000°C can reduce the electricity requirements as the energy needs can be covered in part by heat input. The electrolyzer uses steam and CO_2 as feeds to produce renewable syngas in only one process step. The integration of waste heat and CO_2 sources reduces electricity demand.

High-temperature electrolysis (SOEC – ion conducting solid oxide electrolysis) are already offered by companies such as Sunfire who offer modular designs, such as the Sunfire-Synlink SOEC technology [Sunfire 2018].

In this study, the low-temperature alkaline electrolysis cells (AEC) technology has been selected as a default technology to compare the different pathways in 2020, 2030 and 2050. In the 2050 Accelerated technology sensitivity scenario, the high-temperature solid-oxide electrolysis (SOEC) technology was selected. The efficiencies of the AEC technologies in 2020, 2030 and 2050 are based on average values from IEA [IEA 2019a]. These efficiencies take into account the electrical and heat efficiencies. The efficiency of SOEC has been taken from the technology provider Sunfire.

Table 1: Electrolysis technology and efficiency chosen for this specific study

	2020	2030	2050	2050 Accelerated technology
Electrolysis technology	100% Alkaline	100% Alkaline	100% Alkaline	100% SOEC Co-electrolysis
Electrolysis efficiency	66.5%	68%	75%	82% (Sunfire)

1.4.2. e-Methane

Synthetic methane can be obtained through the process called methanation, also known as the Sabatier reaction, which combines CO_2 and hydrogen at a temperature of up to 400°C, a pressure of 30 bar and the presence of a nickel or ruthenium catalyst, to produce methane and water. The reaction is exothermic and expressed as:

$$CO_2 + 4H_2 \rightarrow CH_4 + H_2O \qquad \Delta H_R^\circ = -165 \text{ kJ/mol}$$

Table 2 shows the yields and energy consumptions of the methane synthesis modelled for this study. The data is based on assumptions by [Reiter 2015] and [Saint Jean 2015], where the amount of CO_2 required exceeds slightly the stoichiometric ratio of the reaction to favour the sense of the reaction towards the production of methane.

Table 2: Mass and energy balance of the methane synthesis process

CO_2 consumption	3.00	kg/kg fuel
H_2 consumption	0.50	kg/kg fuel
CO_2 emissions	0.25	kg/kg fuel
Methane production	1.00	kg/kg fuel
Water production	2.25	kg/kg fuel
Power consumption	1.15	MJ/kg fuel
Heat production	10.8	MJ/kg fuel

1.4.3. e-Methanol

Methanol in the present study is analysed as a standalone fuel but also as the main feedstock for the Methanol-to-Gasoline and the Methanol-to-Middle Distillates pathway.

Synthetic methanol from electricity can be either supplied via two-step synthesis using a synthesis gas (2-step route) or a one-step process that uses CO_2 directly as feedstock (direct route). The direct methanol synthesis requires a mixture of carbon dioxide and hydrogen in a molar ratio of 1:2.8 [Toyir 2009]. Main reactions are shown below, with a high selectivity for methanol as product.

$$CO + 2H_2 \leftrightarrow CH_3OH \qquad \Delta H_R^\circ = -90.6\ \text{kJ/mol}$$

$$CO_2 + 3H_2 \leftrightarrow CH_3OH + H_2O \qquad \Delta H_R^\circ = -49.4\ \text{kJ/mol}$$

Large-scale example of a synthetic methanol plant using the direct methanol synthesis is the George Olah plant in Iceland, run by Carbon Recycling International (CRI) with a capacity of 4,000 t/a [Stefansson 2015].

Table 3 shows the yields and energy consumptions of the methanol synthesis modelled for this study. The mass balances are based on [Stefansson 2015] and the energy balance is based on [JEC 2020].

Table 3: Mass and energy balance of the methanol synthesis process

H_2 consumption	0.193	kg/kg fuel
CO_2 consumption	1.40	kg/kg fuel
Methanol production	1.00	kg
Water production	0.59	kg/kg fuel
Power consumption	1.07	MJ/kg fuel
Heat production	1.72	MJ/kg fuel

1.4.4. e-Polyoxymethylene dimethyl ethers (OME_{3-5})

Poly(oxymethylene) dimethyl ethers, abbreviated as PODE or, more commonly, OME_x, are oxygenates of the general structure $CH_3\text{-}O\text{-}(CH_2O)_x\text{-}CH_3$, where x is typically 3 to 5 for fuel applications. OME_{3-5} are synthetic fuels that blended with diesel fuel in a ratio of 1:4 have experimentally shown strong potential in reducing vehicle pollution, in particular soot formation and indirectly also nitrogen oxides (NOx) [Härtl 2015]. This has also been studied in dual fuel applications [García 2019].

OME_{3-5} are synthesized from methanol. Their production is complex and can go through alternative routes, but all require the intermediate production of formaldehyde via the following reactions [Schmitz 2016]:

$CH_3OH + ½O_2 \rightarrow CH_2O + H_2O$

$CH_3OH \rightarrow CH_2O + H_2$

Part of the formaldehyde is oxidized into water and carbon dioxide in a competing reaction/

$CH_2O + O_2 \rightarrow CO_2 + H_2O$

At first, methanol then reacts with formaldehyde to produce the simplest oxymethylene, methylal:

$2CH_3OH + 2CH_2O \rightleftarrows CH_3O\text{-}CH_2O\text{-}CH_3 + H_2O$

Finally, the subsequent reaction of methylal with formaldehyde extends the size of the diether, until reaching a certain number of carbons depending on the operating conditions. These reactions are represented by:

$CH_3O\text{-}CH_2O\text{-}CH_3 + (x\text{-}1)CH_2O \rightleftarrows CH_3O\text{-}(CH_2O)_x\text{-}CH_3 + H_2O$

where x typically has a size of 3 to 5, hence the name OME_{3-5}.

Table 4 shows the yields and energy consumptions of the OME_{3-5} process. The mass and energy balances are taken from [Schmitz 2016].

Table 4: Mass and energy balance of the OME3-5 synthesis process

Methanol consumption	1.265	kg/kg fuel
O_2 consumption	0.531	kg/kg fuel
CO_2 production	0.141	kg/kg fuel
OME_{3-5} production	1.000	kg
Water production	0.654	kg/kg fuel
Heat consumption	12.8	MJ/kg fuel

1.4.5. e-Methanol-to-Gasoline

Once the e-methanol is available (see section 1.4.3), the production of gasoline requires two additional steps: (a) methanol to olefins (MTO), and (b) light olefin oligomerisation. These reactions are represented as:

$n/2\ [2CH_3OH \rightleftarrows CH_3OCH_3 + H_2O] \rightarrow (\text{-}nH_2O) \rightarrow C_nH_{2n} \rightarrow n[CH_2]$

The methanol-to-gasoline (MTG) technology was first developed by Mobil in the 1980's, using a multistage process to dehydrate & convert methanol at 300-400°C and 15-20 bar. The overall reaction is exothermic.

The dehydration reaction has high selectivity to water with minimal production of other oxygenates or carbon oxides. The water yield is thus 56-57 wt% on methanol. The hydrocarbon synthesis is a combination of oligomerisation (eg to branched aliphatics) and cyclisation to aromatics. The hydrocarbon product typically comprises 78-80% gasoline, 18-20% LPG, 1-2% fuel gas. The MTG gasoline is typically 50% paraffins, 20% olefins and 30% aromatics. The raw gasoline contains some heavy, highly substituted benzene derivatives (e.g. tetramethylbenzene, durene) so it requires hydrotreatment before use as road fuel. The LPG contains ~10% olefins. Upgrading (hydrotreating) of MTG gasoline is included in both the LCA and economic analysis.

Table 5 shows the *allocated* yields and energy consumptions required to produce 1 kg of e-gasoline with the Methanol-to-Gasoline process. It is an allocated balance, corresponding to the part of feedstock and energy associated to the gasoline only, so no co-products are shown. The total mass and energy balances are taken from [Gudde 2021].

Table 5: Mass and energy balance of the methanol-to-gasoline process

Methanol consumption	2.29	kg/kg fuel
Hydrogen consumption	0.001	kg/kg fuel
Gasoline production	1.00	kg
Water production	1.29	kg/kg fuel
Power consumption	0.710	MJ/kg fuel
Heat production	1.298	MJ/kg fuel

1.4.6. e-Methanol-to-Kerosene

The conversion of methanol-to-kerosene, more generally referred to as methanol-to-middle distillates (MTGD), follows the same chemical pathway of the methanol-to-gasoline described in section 1.4.5.

MTO for C2= and C3= is commercially proven using MeOH from coal and gas; in principle, the same technology would apply to MeOH from other sources.

Light olefin oligomerisation also has been commercialised. PetroSA has operated its unique "COD" unit at the Mossel Bay facility to convert C3-C6 olefins from high-temperature (Fe-catalysed) Fischer-Tropsch conversion into gasoline+diesel. The plant - designed by Lurgi and commissioned in 1993 - also uses a zeolite-based oligomerisation catalyst.

Several commercial refining technologies exist for oligomerisation of C3= and C4= into C9+ olefins suitable for fuels, speciality alcohols, detergents and plastics. Examples include Catalytic Condensation (UOP), Selectopol/Polyfuel/Polynaphtha (Axens), NexOctane (Neste/KBR), Dimersol (Axens). Commercial C2= oligomerisation technologies also exist, particularly for production of alpha-olefins for chemicals specialties.

Integrated MTGD technology is not commercially proven although licenses have been offered by Exxon-Mobil (MOGD) and Lurgi (MtSynfuels) primarily as an alternative to FT-synthesis. Patents show solid-acid aluminosilicate catalysts for both dehydration and oligomerisation.

As with MTG and MTO, the MTGD technology shows almost complete methanol dehydration to water and hydrocarbons. The hydrocarbon product contains ~90% liquids (gasoline & diesel) with 5-8% C3+C4 paraffins and 1-2% fuel gas. The liquid product is about 20-30% naphtha, the rest being diesel.

Table 6 shows the *allocated* yields and energy consumptions required to produce 1 kg of e-kerosene with the methanol-to-kerosene process. It is an allocated balance, corresponding to the part of feedstock and energy associated to the kerosene only, so no co-products are shown. The total mass and energy balances are taken from [Gudde 2021].

Table 6: Mass and energy balance of the methanol-to-kero/diesel process

Methanol consumption	2.32	kg/kg fuel
Hydrogen consumption	0.01	kg/kg fuel
Kerosene production	1.00	kg
Water production	1.31	kg/kg fuel
Power consumption	0.718	MJ/kg fuel
Heat production	1.314	MJ/kg fuel

1.4.7. e-Ammonia

The main commercial method for producing ammonia is the Haber-Bosch process:

$N_2+3H_2 \longrightarrow 2NH_3$ (ΔH^{o}_{298}=-92 kJ/mol)

Today, most of the ammonia is produced from natural gas reforming and coal gasification. There is currently a combined production capacity of 110 million tonnes of methanol/a (90 plants).

Ammonia synthesis is an exothermic reaction that requires the use of a catalyst, high pressure (100-1,000 atm), and elevated temperatures (400-550°C).

Table 7 shows the yields and energy consumptions of the e-ammonia process. The mass and energy balances are taken from [Liu 2020].

Table 7: Mass and energy balance the ammonia synthesis process

N_2 consumption	0.822	kg/kg NH_3
H_2 consumption	0.178	kg/kg NH_3
Ammonia production	1.000	kg
Power consumption	2.16	MJ/kg NH_3
Heat production	2.18	MJ/kg NH_3

1.4.8. e-Distillates: Fischer-Tropsch synthesis and CO_2 reduction via Reverse Water-Gas Shift

Fischer-Tropsch (FT) fuels, such as synthetic diesel, gasoline or kerosene from fossil-derived syngas are proven technologies at commercial scale. Some examples are gasification of coal, like Sasol's Coal-to-Liquid facility in Secunda (South Africa) with a capacity of 160,000 barrels per day and steam reforming of natural gas, like Shell's Pearl Gas-to-Liquid plant in Qatar with a capacity of 140,000 barrels per day.

So far, realised PtX projects using FT synthesis to produce hydrocarbons, like the Sunfire pilot plant in Dresden (Germany), are still in a demonstration/research scale with low capacities. Nordic Electrofuel together with Sunfire and Climeworks announced their intention to build a 20 MW plant (related to electricity input) by 2022 [Sunfire 2019].

The simplified FT reaction can be described as the following equation:

$nCO + (2n+1)H_2 \rightarrow H(CH_2)_nH + nH_2O \quad \Delta H^o_{298} = -152$ kJ/mol [König 2016]

Beside alkanes, some alkenes, alcohols and carboxylic acids are formed. For all products, the molar ratio of the syngas is approximately 2 mol H_2 to 1 mol CO. The product slate is predominantly influenced by the temperature and the catalyst of the FT reaction, on average resulting in lighter hydrocarbons for high temperatures FT (320-350°C) and heavier hydrocarbons for low temperatures FT (190-250°C).

To maximize the yield of transport fuels (gasoline, diesel, kerosene), a low temperature FT can be chosen combined with a hydrocracking step to convert the produced wax into LPG, gasoline, diesel and kerosene, resulting in a product slate of 37% gasoline, 28% diesel, 32% kerosene and 3% LPG. The hydrocracking step is considered in both the LCA and economic analysis. The products from the hydrocracking reaction could be further upgraded via isomerization to improve the cold properties, and this stage could be done in the hydrocracking reaction adjusting the catalyst.

The Fischer-Tropsch reaction requires a mix of hydrogen and carbon monoxide, which means that the captured CO_2 must be reduced to CO prior to the reaction. This can be achieved through an equilibrium reaction called Reverse Water Gas Shift (RWGS), an endothermic reaction where CO_2 is reformed with H_2 to produce CO and water. This reaction requires heat and runs at high temperatures ranged between 800 and 1,000°C, and pressures of up to 30 bar to favour the equilibrium to CO, instead of CO_2 and CH_4. Some electricity is required to run the plant (compression). The RWGS plant is a net electricity and heat consumer.

$CO_2 + H_2 \rightleftarrows CO + H_2O$ ($\Delta H^o_{298} = +42$ kJ/mol)

The model used considers a complete conversion of CO_2, assuming a set of purification, recycling of unreacted CO_2, heating, and compression steps. The reactor technology is mature because of its use in the inverse process, the Water Gas Shift (WGS), largely used in the Steam Reforming reaction for hydrogen production from natural gas. The RWGS process, however, is not often used and thus has a TRL estimated at 7 as it will undergo some development before reaching TRL 9 [Detz 2019]. The energy efficiency of the process is estimated at 83%. Future plants are expected to be more efficient thanks to the development of improved methods like sorption enhanced H_2O removal, currently at TRL 3. This expected technological progress is reflected in the base energy consumption for 2050.

Table 8 shows the *allocated* yields and energy consumptions required to produce 1 kg of e-diesel with the Fischer-Tropsch process. It is an allocated balance, corresponding to the part of feedstock and energy associated to the diesel only, so no co-products are shown. The total mass and energy balances for the Reverse Water-Gas Shift reaction are taken from [Detz 2019] and those for the Fischer-Tropsch reaction from [König 2016] and [de Klerk 2011].

Table 8: Mass and energy balance of the FT e-diesel synthesis process (including reverse water-gas shift)

Hydrogen consumption	0.493	kg/kg fuel
of which RWGS	0.169	kg/kg fuel
of which FT+Hydrocracking	0.324	kg/kg fuel
CO_2 consumption	3.715	kg/kg fuel
CO equivalent	2.364	kg/kg fuel
Gas burned	0.237	kg/kg fuel
FT Diesel	1	kg
Water production	2.971	kg/kg fuel
Power consumption	1.90	MJ/kg fuel
Heat production (net)	9.22	MJ/kg fuel

1.4.9. Carbon capture

Three different scenarios of carbon capture are considered in the present study:

- CO_2 captured from a point source of high CO_2 concentration. The proxy unit for this case is an amine-based high pressure/low temperature capture unit of a Steam Reforming (SMR) pre-combustion off-gas stream with around 45% CO_2 by volume, as described in [Skrebergene 2015].
- CO_2 is captured from a point source of average CO_2 concentration, around 8.5% by volume. The proxy unit for this case is an amine-based capture plant as described in [IPCC 2005].
- CO_2 captured from the air via low temperature direct air capture (DAC) technology. The energy consumptions are taken from Climeworks [Beuttler et al. 2019].

Table 9 provides a summary of all power and heat consumptions assumed for the three proxy technologies of carbon capture, as well as the reference average CO_2 concentrations of each source taken from [IPCC 2005].

A common assumption for all three sources is that the CO_2 is considered as unavoidable waste and carries no carbon burden or cost at its source. Therefore, the only contribution to the carbon intensity of the CO_2 feedstock to the e-fuels synthesis processes is given by the capture and purification stage. Same consideration for the cost of CO_2, whose value is derived from the CAPEX and OPEX of the carbon capture process only with no reference to a carbon price.

To ensure high purity of the CO_2 produced for the downstream synthesis reactions, an additional CO_2 liquefaction stage was incorporated to the carbon capture process. The main purpose of this operation is to eliminate traces of water and other contaminants. Energy consumption for carbon dioxide liquefaction is estimated at 0.104 kWh/kgCO_2 [Element Energy 2018].

Table 9: Energy consumptions and CO_2 concentrations for different carbon capture options

Source Stream of CO_2	Concentrated	Average	Diluted
Proxy technology	Steam Reforming (SMR) pre-combustion gas	Natural Gas Power Plant (NGPP) flue gas capture	Direct Air Capture (DAC)
Power Consumption [MJ/kgCO_2]	0.14 (1)	0.27 (2)	1.44 (3)
Heat consumption [MJ/kgCO_2]	0.90 (1)	3.00 (2)	5.76 (3)
CO_2 concentration [by volume]	45%	8.5%	0.04%

Sources: (1) [Skrebergene 2015]
(2) [IPCC 2005]
(3) [Beuttler et al. 2019]

1.4.10. Blending conditions

Most of the liquid e-fuels[2] are generally considered as 'drop-in fuels', meaning they are assumed compatible with the existing car fleet. This should be analysed in detail depending on the e-fuel. In Figure 2, the qualities of liquid e-fuels are compared with standard fuels.

a) Gasoline fuel standards

Figure 2 is showing the gasoline existing gasoline fuel standards (EN 228) versus the e-methanol-to-gasoline product properties.

Whilst methanol is a potential gasoline substitute, its Lower Heating Value (LHV) is significantly lower than the one of gasoline and even ethanol, and it produces corrosivity and issues with the material use in the car fuel feeding system. The use of pure e-methanol or higher blend rates requires adapted vehicles; hence e-methanol does not have drop-in capabilities. The product of the Methanol-to-Gasoline (MTG) process is a much better substitute for gasoline in spark-ignition engines and represents a gasoline blending component that can be upgraded to full EN 228 compliance by hydrogenation of polyaromatics. The hydrogenation process of MTG-based gasoline was taken into account in the present study.

b) Diesel fuel standards

Figure 3 shows the two existing diesel fuel standards, EN 15940 and EN 590:

- D EN 15940 is the fuel standard for paraffinic diesel. This specification was designed for HVO and GtL, and it is valid for e-diesel. It is similar to conventional diesel (EN590), except from the differences in density (class B 780-810 kg/m^3 versus EN 590 820-845 kg/m^3). Some aspects to consider in the use of e-diesel are:
    - Improvement of the lubricity by additives

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[2] Liquid fuels = liquid state under standard temperature (0°C) and pressure (1 MPa) conditions.

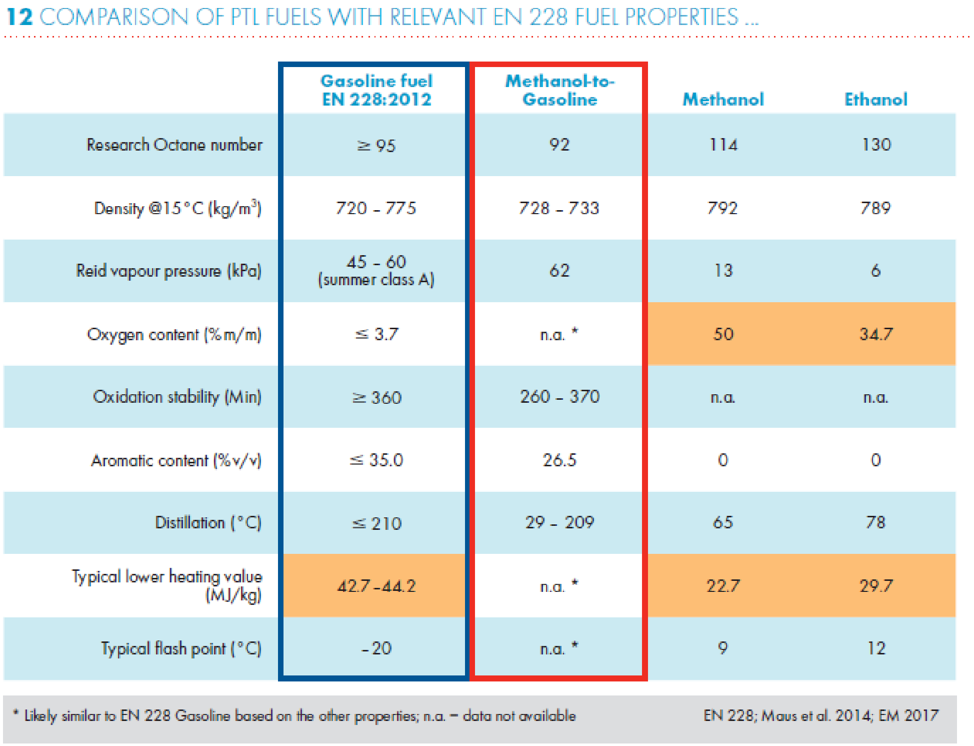
   - Cold properties adjustment through production process (isomerization and distillation)
   - Minor adjustments in the engine (fuel injection control and SCR post-treatment)
   - The impact on LCA of these adjustments in lubricity or cold properties are out of the scope of this project. EN 590 is the fuel standard for conventional diesel. It is possible for e-diesel to match the specification EN590 by blending with other higher-density components (e.g.: FAME, pyrolysis oil). Fischer-Tropsch e-fuels are paraffinic fuels, which require hydrocracking and isomerization to improve the cold properties and fit in the diesel standard EN 590. Paraffinic fuels have substantially higher cetane numbers (>/= 70) and are (nearly) free from aromatics.

e-OME$_{3\text{-}5}$ requires blending with diesel components to meet the diesel fuel standards, with the potential of achieving ultra-low NOx and soot emissions levels.

c) Jet fuel standards

e-Jet (e-kerosene) must comply with the ASTM D7566 standard, which gathers the technical specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons, and includes the technical specification of synthetic paraffinic kerosene from the Fischer-Tropsch process (SPK-FT) (Table 10). Currently, e-jet can be blended up to 50% by volume with conventional blending components or Jet A or Jet A-1 fuel certified to Specification ASTM D1655 (Standard Specification for Aviation Turbine Fuels). Final product, meaning aviation turbine fuel manufactured, certified, and released to all the requirements of ASTM D7566 (Table 11), should meet the requirements of Specification ASTM D1655 (Standard Specification for Aviation Turbine Fuels) and shall be regarded as Specification D1655 turbine fuel. Therefore, the final product does not present any differences with conventional aviation turbine fuel and hence, once the fuel is released according to ASTM D7566, the specific requirements of such specification will be no longer available and any recertification shall be done in accordance to ASTM D1655.

Figure 2: Liquid e-fuel properties (compared to gasoline fuels standards). Source: [Shell 2018]



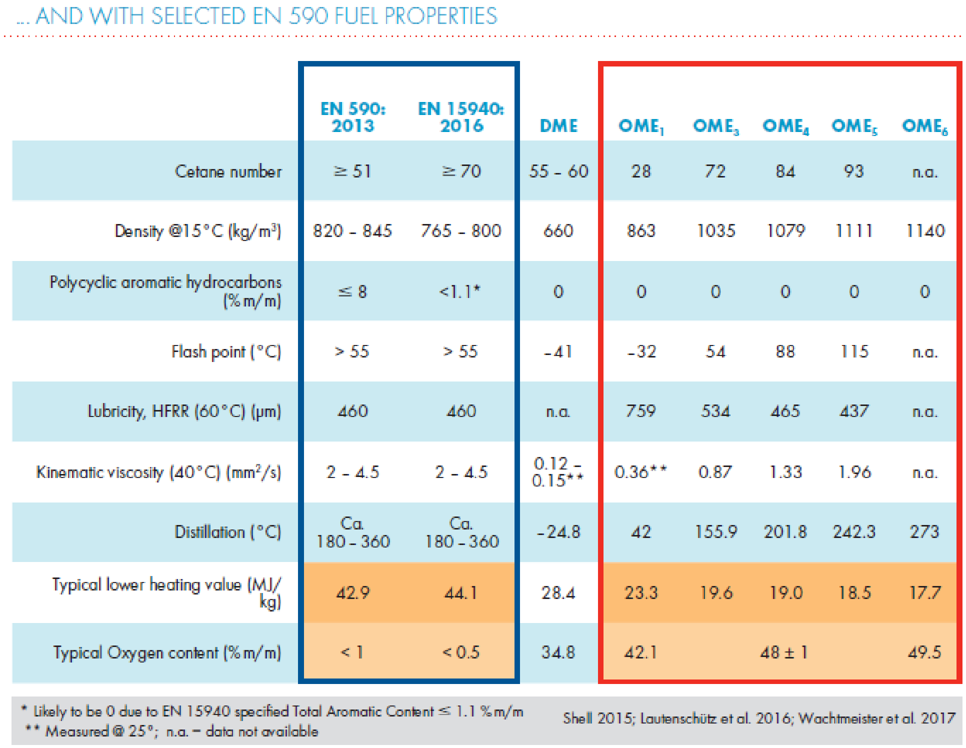
12 COMPARISON OF PTL FUELS WITH RELEVANT EN 228 FUEL PROPERTIES ...

	Gasoline fuel EN 228:2012	Methanol-to-Gasoline	Methanol	Ethanol
Research Octane number	≥ 95	92	114	130
Density @15°C (kg/m³)	720 – 775	728 – 733	792	789
Reid vapour pressure (kPa)	45 – 60 (summer class A)	62	13	6
Oxygen content (%m/m)	≤ 3.7	n.a. *	50	34.7
Oxidation stability (Min)	≥ 360	260 – 370	n.a.	n.a.
Aromatic content (%v/v)	≤ 35.0	26.5	0	0
Distillation (°C)	≤ 210	29 – 209	65	78
Typical lower heating value (MJ/kg)	42.7 – 44.2	n.a. *	22.7	29.7
Typical flash point (°C)	– 20	n.a. *	9	12

* Likely similar to EN 228 Gasoline based on the other properties; n.a. = data not available

EN 228; Maus et al. 2014; EM 2017

Figure 3: Liquid e-fuel properties (compared to diesel fuel standards). Source: [Shell 2018]



... AND WITH SELECTED EN 590 FUEL PROPERTIES

	EN 590: 2013	EN 15940: 2016	DME	OME_1	OME_3	OME_4	OME_5	OME_6
Cetane number	≥ 51	≥ 70	55 – 60	28	72	84	93	n.a.
Density @15°C (kg/m³)	820 – 845	765 – 800	660	863	1035	1079	1111	1140
Polycyclic aromatic hydrocarbons (%m/m)	≤ 8	<1.1*	0	0	0	0	0	0
Flash point (°C)	> 55	> 55	– 41	– 32	54	88	115	n.a.
Lubricity, HFRR (60°C) (µm)	460	460	n.a.	759	534	465	437	n.a.
Kinematic viscosity (40°C) (mm²/s)	2 – 4.5	2 – 4.5	0.12 – 0.15**	0.36**	0.87	1.33	1.96	n.a.
Distillation (°C)	Ca. 180 – 360	Ca. 180 – 360	– 24.8	42	155.9	201.8	242.3	273
Typical lower heating value (MJ/kg)	42.9	44.1	28.4	23.3	19.6	19.0	18.5	17.7
Typical Oxygen content (%m/m)	< 1	< 0.5	34.8	42.1	48 ± 1			49.5

* Likely to be 0 due to EN 15940 specified Total Aromatic Content ≤ 1.1 %m/m
** Measured @ 25°; n.a. = data not available

Shell 2015; Lautenschütz et al. 2016; Wachtmeister et al. 2017

The table in Figure 2 shows that in the methanol-to-gasoline process, octane and Reid Vapour Pressure need to be improved to meet specification, with impact in terms of cost of upgrading (CAPEX, OPEX) and LCA emissions. This is out of the scope of this project and it will be analysed in a third project (to be published).

Table 10: Liquid e-kerosene (paraffinic kerosene from Fischer-Tropsch, SPK-FT specification)

Characteristic	**Unit**	**Limits**		**Norm**
		Min	**Max**	
Total acidity	mg KOH/g	-	0.015	ASTM D3242
Volatility				
Distillation	°C			ASTM D86
10% vol	°C	-	205	
50% vol	°C	Inform		
90% vol	°C	Inform		
T90-T10	°C	22	-	
Final point	°C	-	300	
Residue	%v/v	-	1.5	
Loss	%v/v	-	1.5	
Simulated distillation	°C			ASTM D2887
10% vol	°C	Inform		
20% vol	°C	Inform		
50% vol	°C	Inform		
80% vol	°C	Inform		
90% vol	°C	Inform		
Final point	°C			
Inflamation point	°C	38.0	-	ASTM D56
Density 15°C	kg/m^3	730	770	ASTM D4052
Freezing point Jet A	°C	-	-40.0	ASTM D5972
Thermal stability JFTOT (2,5 h a T control)				ASTM D3241
Temperature	°C	325	-	
Differential pressure drop	mm Hg	-	25	
Classification				
(1) Annex A1 VTR, color code VTR		Lower to 3, no marks or anormals colour deposits		
(2) Annex A2 ITR o Annex A3 ETR, nm average in area of 2,5 mm^2			85	
Cycloparafins	%m/m		15	ASTM D2425
Aromatics	%m/m		0,5	ASTM D2425
Parafins	%m/m	Inform		ASTM D2425
Carbon and Hydrogen	%m/m	99,5		ASTM D5291
Nitrogen	mg/kg		2	ASTM D4629
Water	mg/kg		75	ASTM D6304
Sulfur	mg/kg		15	ASTM D5453
Metals (Al, Ca, Co, Cr, Cu, Fe, K, Li, Mg, Mn, Mo, Na, Ni, P, Pb, Pd, Pt, Sn, Sr, Ti, V, Zn)	mg/kg		0,1 (metal)	ASTM D7111
Halogenates	mg/kg		1	ASTM D7359

Table 11: Jet A-1 specification

Characteristic	Unit	Limits		Norm
		Min	Max	
Aspect		Clear, shiny, free of solid materials and water at ambient temperature		
Total acidity	mg KOH/g	-	0.10	ASTM D3242
Aromatics content	%v/v	8	25.0	ASTM D1319
Total sulphur	%m/m	-	0.30	ASTM D4294
Total mercaptans	%m/m	-	0.003	ASTM D3227
Distillation	ºC			ASTM D86
10% vol	ºC	-	205	
50% vol	ºC	Inform		
90% vol	ºC	Inform		
T50-T10	ºC	15	-	
T90-T10	ºC	40	-	
Final point	ºC	-	300	
Residue	%v/v	-	1.5	
Loss	%v/v	-	1.5	
Inflammation point	ºC	38.0	-	ASTM D56
Density 15ºC	kg/m^3	775	840	ASTM D4052
Freezing point Jet A	ºC	-	-40.0	ASTM D5972
Freezing point Jet A-1	ºC	-	-47.0	ASTM D5972
Kinematic viscosity -20ºC	mm^2/s	-	8.000	ASTM D445
Smoking point	mm	25.0	-	ASTM D1322
Calorific value	MJ/kg	42.80	-	ASTM D4529
Corrosión lámina de cobre (3h a 50ºC)	scale	-	Class 1	ASTM D130
Thermal stability JFTOT (2,5 h T control)				ASTM D3241
Temperature	ºC	325	-	
Pressure drop	mm Hg	-	25	
Clasification				
Anexo A1 VTR, colour code VTR		Lower than 3, without marks or anormal colour deposits		
Anexo A2 ITR o Anexo A3 ETR, nm average area 2,5 mm^2			85	
Existing gums	mg/100 ml	-	7	ASTM D381
Water separation index				ASTM D3948
Without additive antistatic		85	-	
With additive antistatic		70	-	
Electric conductivity	pS/m	50	600	ASTM D2624
Lubricity	mm	-	0.85	ASTM D5001

1.5. BASE CASE ASSUMPTIONS

The main assumptions for the base cases taken for this study are described in Table 12.

The standard technology chosen for e-hydrogen production is alkaline electrolysis, with the only exception of the 2050 Accelerated Technology (AT) scenario, which uses co-electrolysis to produce syngas directly from CO_2 and water steam (see section 1.4.1).

The source of CO_2 is considered available onsite in all cases, from specific sources or combination of sources depending on the time horizon: In 2020 and 2030, a concentrated source, e.g. Steam Reforming (SMR) or Auto Thermal Reforming (ATR) off-gases, is considered as the main CO_2 source. In the 2050 and 2050 AT scenarios, CO_2 from atmosphere via Direct Air Capture (DAC)is taken into account.

Regarding the transportation of the final e-fuels, the assumptions also change for across the timeline: In 2020 and 2030, it is assumed that the transportation modes using liquid fuels (ships and trucks) will consume conventional fossil fuels only, supposing that not enough e-fuels will be available from commercial plants. However, in 2050 we consider that the liquid fuels used will be 100% e-fuels (e-diesel), assuming a big deployment of the technology following stringent directives for road and maritime transport.

Table 12: Base case assumptions

Base case parameter	2020	2030	2050	2050 AT
Electrolysis technology	100% Alkaline	100% Alkaline	100% Alkaline	100% Co-electrolysis
Electrolysis efficiency[2]	66.5%	68%	75%	82% (Sunfire)
Source of CO_2[1]	100% Concentrated source	100% Concentrated source	100% Diluted source (DAC)	100% Diluted source (DAC)
Source of renewable energy for e-fuels production	North EU: Norway renewable mix Central EU: Germany renewable mix South EU: Spain renewable mix MENA: Kingdom of Saudi Arabia (KSA) renewable mix Africa: Morocco			
Source of energy for transport	Truck: Fossil fuels[3] Ship: Fossil fuels + Fuel transported[4]	Truck: Fossil fuels[3] Ship: Fossil fuels + Fuel transported[4]	Truck: e-diesel Ship: 100 % e-fuel transported[5]	

Notes:

[1] Proxies and concentrations for CO_2 sources: See chapter 1.4.9

[2] Based on average values from IEA 2019a

[3] Conventional diesel for trucks, low-sulfur marine gasoil (LSMGO) for ships

[4] For liquid e-H_2, e-Methane (LNG) and e-NH_3, boil-off contributes to ship propulsion (46%, 60% and 29% of total energy respectively)

[5] Only applies for e-H_2, e-CH_4, e-NH_3, e-methanol, e-diesel. Ships use e-diesel for the rest (methanol-to-gasoline, methanol-to-kerosene, e-kerosene, OMEx) assuming that that there will be enough e-fuel for harder-to-abate sectors, including maritime transport in 2050.

(100% use of e-diesel for maritime is aligned to the minimum requirements to meet the IMO's GHG intensity ambition in 2050: 50% total emissions reduction and 70% carbon intensity reduction, based on 2008 CO_2 emissions.

For the first assessments of this study, no optimisation of the size of the fuel synthesis plants, the renewable electricity generation plant (PV or wind) or storage capacities has been taken to ensure that the plant operates continuously. The synthesis fuel plants run at a constant capacity determined by the available full load hours of intermittent renewable energy available for each region (see section 1.5.1). Note that only a limited amount of buffer storage capacity for hydrogen and CO_2 is considered, with the purpose of smoothing the available flow of feedstock to the e-fuels synthesis plants, i.e. reduce ramp rates and thus ensure stable (but not necessarily constant) operating conditions (see section 1.5.2). This buffer storage capacity could be not sufficient in some specific regions, and an optimization model will be developed to assess the optimal storage capacity (to be published in a second report).

1.5.1. Electricity supply

The electricity supply for the e-fuels production in this study comes from renewable sources, more specifically wind offshore/onshore and photovoltaic. It is assumed that a direct connection to the renewable electricity source needs to be installed for the e-fuels production in the form of high voltage transmission systems for all regions for an average distance of 200 km. The sole exception is the particular case of central EU, where we assume that large areas occupied by former lignite power plants will be reallocated to the co-installation of renewable energy plants and fuel synthesis plants not requiring any transmission infrastructure. Large PV/hybrid power plants can be built e. g. in regions with (former) lignite mines in Germany, as suggested in previous analysis of the potential of PV/wind hybrid power plants at multi-GW scale combined with e-fuel plants [IFOK et al. 2018].

There are two important aspects about electricity supply that should be taken into account:

- For renewable fuels in transport, EU RED II regulatory will require new assets for target accounting.
- There are countries that export significant parts of their renewable power production (physical and/or through certificates), such as Norway. The electricity production mix of such regions can be significantly different to its use mix (i.e. including the European attribute mix for exported guarantees of origin).

Figure 4 shows the reference values of carbon intensity (GHG emissions) and Table 13 shows the full load hours (h/a) for the wind and photovoltaic electricity mixes of the different proxy countries covered by the study.

In general, for all kinds of electricity generation, GHG emissions can have three main origins:

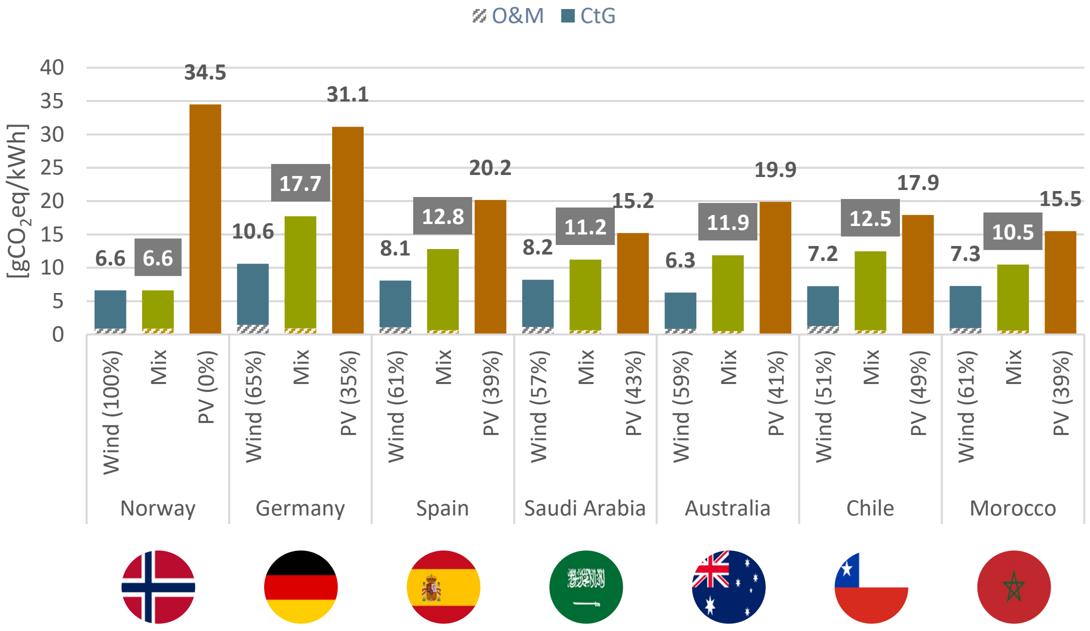
- Direct emissions (Well-to-Wheels, abbreviated as WtW), corresponding to GHG emitted from the energy resources consumed during the use phase. The CO_2 produced from the combustion of fossil-fuelled power plants would fall into this category. Renewable electricity generation has no direct emissions, so its WtW carbon intensity is assumed to be zero.
- Maintenance and replacement of moving parts (abbreviated as M&R) required for the equipment to operate during its use phase. This M&R is particular for wind electricity generation and includes, among other operations: oil changes, mechanical parts lubrication and replacement of one of the wind turbine blades during its lifetime. The value of M&R emissions for wind electricity corresponds to roughly 15% of the total value. M&R emissions for photovoltaic electricity are considered equal to zero, mostly because no moving parts are involved in its operation.
- Infrastructure and equipment emissions (I&E), which include the production and recycling of the equipment (e.g. wind turbines and photovoltaic panels) during the equipment manufacturing and end-of-life phases. For wind turbines, their life cycle inventory includes the rotor (spinner + three blades), nacelle, tower and the foundation of the turbines, as well as the wind system converter.

The models are based on a 300 MW wind park, with a country-specific production capacity and an operational life of 20 years. The values assumed correspond to a mix of power generation from onshore/offshore technologies specific to each country in 2020. [Wind Europe 2020]. For photovoltaic panels, their GHG impact was calculated using a GaBi model based on recent life cycle inventories from the IEA [IEA PVPS 2020] and include module manufacturing, inverter, mounting structure and cables, as well as the construction and transportation of the panels. The values assumed are calculated based on average Global Tilted Irradiation (GTI) for the different locations taken from the EU's Photovoltaic Geographical Information System [PVGIS 2021] and assumed an average technology mix, largely dominated by mono- and multi-crystalline silicon panels (95%) [Fraunhofer 2021]. The end-of-life assumptions considers credits for materials recovered. The GHG impacts of power produced from photovoltaics obtained with our model shown in Figure 4 are roughly 50% lower than those found in the standard GaBi database, as they take into account more recent energy and material consumptions. This reflects the high potential of further reductions due to PV technological progress.

The sum of these three contributions corresponds to the "Cradle-to-Grave" scope of emissions for electricity generation depicted in Figure 4. These reference carbon intensity values also consider the generation plant's own consumption (around 0.4%) and transmission losses related to the distribution of the electricity from the generation site to the production plant (around 5-6%).

The variation of GHG emissions from wind and photovoltaic power generation due to technology progress and energy efficiency improvement from economies of scale have not been considered in this study, but a reduction over time of the cost of the electricity they produce has been assumed in the economic analysis (Part 2).

Figure 4: Average GHG emissions per renewable electricity source (gCO$_2$eq/kWh)



Note: Wind power technology: Mix (country-specific onshore/offshore)
PV power technology: Mix (94% Mono/Multi-Si, 6% CdTe/CIGS). Single-axis tracking
For Norway, 100% wind electricity is considered for this study

Same electricity mixes assumed for 2020, 2030 and 2050. Only the electricity costs vary throughout the years, not the electricity mixes.

The variations observed between countries relate to their specific geographic location and climate conditions, which determines the potential to the full load hours of each type of renewable electricity. As an example. The PV carbon intensity in Norway is higher than in the rest of the regions due to the lower full load hours of PV in Norway. However, the wind carbon intensity is lower than in other areas due to the higher full load hours of wind offshore in Norway.

The values used in our study are comparable to values referenced by Wood Mackenzie [Woodmac 2021], which reports 8 to 11 gCO_2/kWh for onshore and 11-13 for offshore (no reference location specified), and to IPCC AR5 [IPCC 2018], which gives ranges of 7-8/11-12/35-56 gCO_2/kWh for min/median/max values respectively for onshore/offshore sources. The wind renewable CTG emissions are completely dominated by the manufacturing emissions. The contribution of material and manufacturing to the overall emissions in wind energy is around 86.5%. According to Wood Mackenzie, “reducing the wind power’s life-cycle emissions would require using ‘green’ steel and concrete, but that will increase input costs and raise wind’s levelized cost of electricity” [Woodmac 2021].

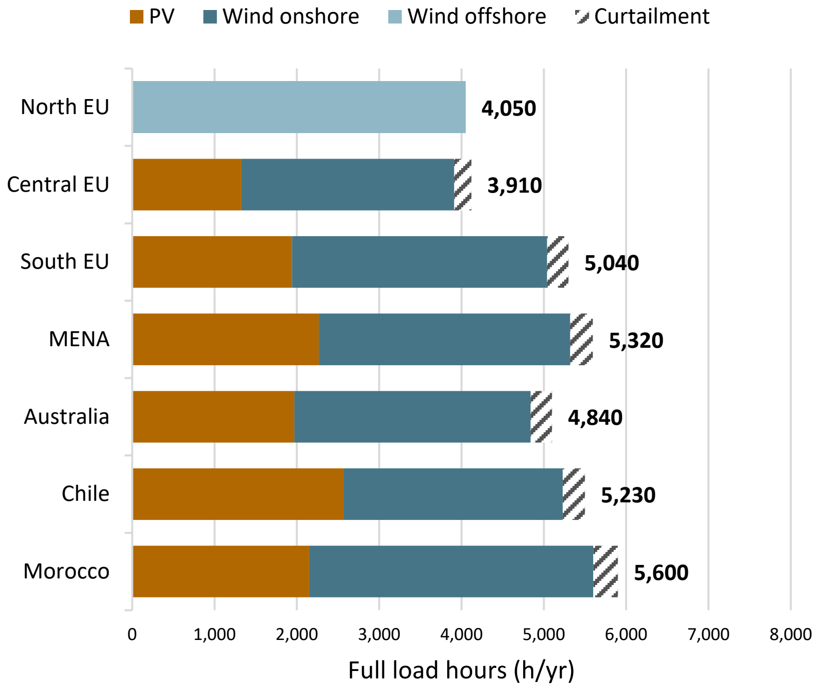
Table 13 and Figure 5 show the equivalent full-load hours estimated for each type of renewable electricity used. The weighted average of full wind and PV electricity based on these full-load hours give the final carbon intensity used for each region in the GHG calculations. The impact of the buffer storage equipment required to counter the effects of wind and solar irradiation intermittence are negligible from a GHG emissions point of view, as the contribution of the storage equipment represents around 0.1% of the lifetime carbon emissions. Buffer storage has a much more significant impact on the cost of fuel production. This is particularly true in the case where batteries are used as electricity buffer storage: The elevated cost of the infrastructure and partial replacement of the equipment has a significant impact on the overall cost(described in Part 2 of the study).

Table 13: Full load hours (h/a) per region

	PV	**Wind onshore**	**Wind offshore**	**Total** (1)
Norway			4,050 (2)	4,050
Germany	1,430 (3)	2,690 (4)		3,910
Spain	2,070 (3)	3,230 (5)		5,040
Saudi Arabia	2,406 (3)	3,190 (3)		5,320
Australia (6)	2,100	3,000		4,850
Chile (7)	2,700	2,800		5,420
Morocco (8)	2,300	3,600		5,600

Sources:
1) Calculation methodology (5% overlap is curtailed) according to [Fasihi 2016]
2) Real plants [BET 2019]
3) Lilley, W. (Aramco), e-mail from 16 June 2021
4) [Deutsche WindGuard 2015]
5) Real plant: [Evwind 2020]
6) Real plants: Darlington Point, PV; Bungala Solar PV Plant, Port Augusta; Daydream, PV; Hornsdale Wind Farm; Sapphire Wind Farm; Collgar Wind Farm; Taltal Wind Farm; Atacama, wind; San Martias, wind
7) Lalackama, PV; Lalackama II, PV; Amanecer Solar CAP plant, PV; Statkraft, wind;
8) Real plants: Noor Quarzazate IV, PV; Noor Laayoune, PV; Noor Boujdour, PV; Tarfaya wind farm; Akhfennir wind farm; Amogdoul wind farm

Figure 5: Full load hours per region including curtailment



As shown in Table 13, the regions with the most renewable energy full-load hours are Morocco, Chile and Saudi Arabia (5,000-5,600 h/a). It is followed by Spain, Australia, Norway (4,000-5,000 h/a), while Germany has the lowest full load hours (3,000-4,000 h/a).

In Norway, 100% of renewable electricity is considered from offshore wind. All the other countries have a mix between PV and wind onshore.

In the calculation methodology, a 5% curtailment is assumed to take into consideration the overproduction of PV and wind power generation that cannot be absorbed by the demand [Fasihi 2016].

The following additional assumptions related to the electricity consumption have been taken:

- Renewable electricity is used to cover the thermal energy requirements of the carbon capture process in the form of electric heaters with an efficiency of 90%.
- For the domestic cases, e-H_2 and e-CH_4 are compressed and transported by pipeline (intraregional transport), and for this it is assumed the use of electricity from the grid mix of the corresponding geographical zone. The composition of the grid mix is based on forecasts of the EU Energy Trend Reports for 2030 and 2050. The 2020 value is based on the of the proxy countries. The carbon intensities of the grid electricity mixes of each scenario have been calculated on the GaBi platform [Sphera 2021] and are presented in Table 14.
- The refuelling in service stations also uses the grid mix of the corresponding geographical zone shown in Table 14.

- CO_2 compression and liquefaction required during the e-fuel production processes (i.e. for CO_2 purification), as well as hydrogen liquefaction for long-distance transport use renewable electricity mix from the corresponding regional proxy, including a premium to a full cost of 25 ct/kWh of auxiliary electricity.
- For electrolysis and e-fuel synthesis, it is always assumed 100% renewable electricity from the corresponding country proxy, same for the 3 timelines (2020, 2030 and 2050).

Table 14: Grid mix GHG emissions per region considered

gCO_2eq/kWh	North EU	Central EU	South EU
2020 (1)	31.5	536.9	404.5
2030 (2)	25.0	539.3	189.5
2050 (2)	20.0	363.3	118.4

Values estimated using GaBi [Sphera 2021] based on electricity mixes.
Sources of the electricity mixes:
1) EU Reference Scenario
2) EU Energy Trends Report

1.5.2. Buffer storage

The buffer storage considered for all the base cases covering multiple geographies and timelines to operate the e-fuels facilities in a continuous basis are:

- H_2 buffer storage: In gaseous state at 10 MPa maximum pressure in natural gas pipeline segments of diameter 48-58):
    - 50 hr of production for compressed hydrogen
    - 50 hr of production for Fischer-Tropsch synthesis
    - 50 hr of production for methanol synthesis
    - 3 hr of production for methanation
    - 3 hr of production for NH_3 synthesis
- CO_2 buffer storage: In liquid state CO_2 at -25°C / 2 MPa pressure, in storage tanks. Conditions taken from [Element Energy 2018].
- Battery storage system

Only the H_2 buffer storage has been considered in the CO_2 emissions cases because of the limited contribution of storage infrastructure emissions, but all three types of buffer storage are included in the economic study.

Disclaimer: The storage capacity will be optimised per region in a next report to be published as a continuation of this one, taking into account that the 50h of storage could not be enough for the Fischer-Tropsch syntesis depending on the region analysed.

1.5.3. Fuel transportation

- Travel itineraries and transport distances

Distances travelled from the different regional zones assessed in the present study (MENA, South America and Australia) are shown in Figure 6, which summarizes the general assumptions of the e-fuels transportation stage. These distances concern both the cases where e-fuels are produced in the continent (domestic supply) and when they are imported into Europe.

While the distance between the electricity production areas and the fuel manufacturing locations is estimated at 200 km (see section 1.5.1), the distance between production sites and international dispatching terminals of the exporting countries is assumed close to zero, hence negligible. We are assuming that the hydrogen production, carbon capture and fuel synthesis sites are collocated or very close to each other, except in the case where H_2 is imported. A similar assumption is held for the distance between the reception terminal in Europe and the distribution nodes from which domestic networks dispatch the products to the local distribution depots. Liquefied hydrogen transported by ship is transferred to the distribution nodes without regasification, with the help of cryogenic pumps. The use of these pumps helps considerably to reduce energy losses related to changes of state, allows the use of a fleet of LH_2 trucks and avoids relying on the implementation of a hydrogen pipeline network. Transporting hydrogen as a pressurized gas would require additional compression and reduce the energy efficiency of the pathway.

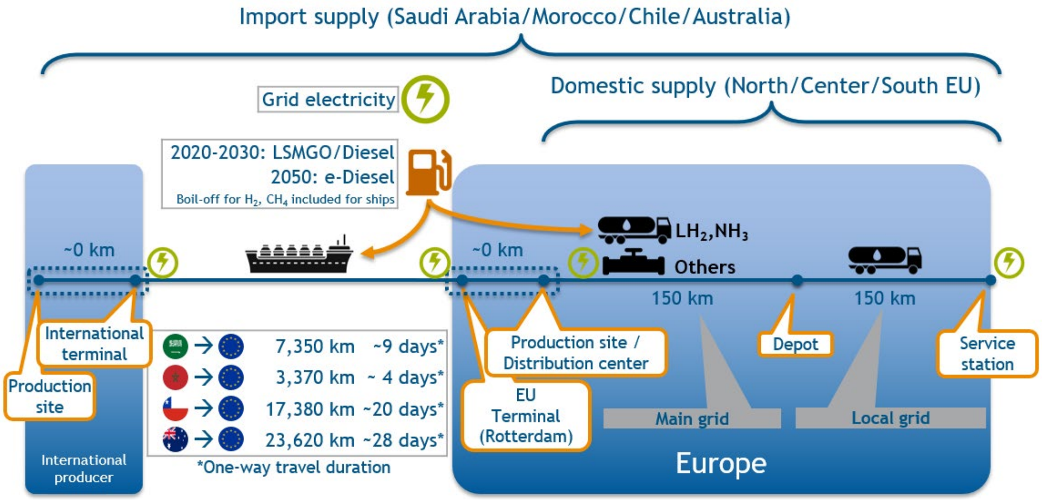
The first domestic distribution network is called the “Main grid”. It is assumed that e-fuels are transported via pipeline in this section of the supply chain, and for a fixed distance of 150 km. The transportation mode is pipeline for all liquid fuels and methane, with the exception of hydrogen and ammonia, which are transported via trucks. The distance of 150 km is based on the average ratio of total distance of pipeline installed in all countries covered in the scope and the total number of service stations.

The second half of the supply network corresponds to the “Local grid”, in which the e-fuels are carried from the depots to the refuelling stations. An average distance of 150 km is also considered for this section. For the transfer of liquefied hydrogen (LH_2) to the refuelling station the LH_2 trailer is connected with the stationary LH_2 tank by a flexible transfer line. The transfer is carried out without a cryogenic pump. A vaporizer mounted at the LH_2 trailer elevates the pressure of the LH_2 in the LH_2 trailer leading to the transfer of the LH_2 to the stationary LH_2 tank [PRESLHY 2019].

During the vehicle tank filling operation, the stored LH_2 is compressed via a cryogenic compressor, vaporized, and subsequently dispensed as CGH_2. A CGH_2 buffer storage with a maximum pressure of 100 MPa is also installed. A description of this concept can be found in [Decker 2019]. The electricity consumption of the hydrogen refuelling station involving high pressure cryogenic pumps was estimated based on the technical specifications provided in the US Drive roadmap [US DRIVE 2017].

The same reference distance (300 km in total) has been considered for the 3 regions in EU (North, Centre and South of EU).

Figure 6: General assumptions for fuel transportation



- Energy for transportation

  Besides the electricity consumption for compression and liquefaction explained in section 1.5.1, long-distance transport (ships) and road-transport (trucks) are assumed to run on fossil fuels (MGO and road diesel respectively) for horizons 2020 and 2030, and 100% on e-fuels for horizon 2050.

  A sensitivity case including the transport in 2050 with 20% fossil fuel is considered in chapter 1.7.5.

  In the case of ship transportation and for all time horizons, the boil-off of gaseous or highly volatile fuels contributes to the energy requirements of the ship. This is the case for liquefied hydrogen, liquefied methane (referred to as LNG, although it is technically not natural gas) and ammonia carriers, whose contribution to the total fuel represents 46%, 60% an 29% of the total fuel respectively. The net fuel consumptions take into account specific requirements to keep these e-fuels at the appropriate transport conditions of pressure and temperature.

- Use of liquid energy carriers for hydrogen transportation

  Section 1.7.4 of this report analyses the impact of producing e-fuels in Europe with hydrogen imported from the MENA region. The long-distance transport of hydrogen can be ensured in three different ways:

  a) As liquefied hydrogen. This pathway would require a highly energy-intensive hydrogen liquefaction stage, representing a consumption of 8 kWh_e/kgH_2 (around 24% of its energy content based on its LHV), taken from a renewable energy mix in the country of origin. Transportation of LH_2 is based on assumptions from [Hank 2020].

  b) As ammonia. The same assumptions of ammonia production described in section 1.4.7 are used for this pathway, and transportation conditions as those for LPG transportation [Wärtsilä 2021b]. Once at destination port, the ammonia is converted back into hydrogen via an ammonia cracking process[3] represented by the reverse Haber-Bosch reaction:

$$NH_3 \rightarrow 1/2N_2 + 3/2H_2$$

Today, only small electric heated NH_3 crackers exists mainly excluding H_2 purification. NH_3 cracking plants at scale are in the stage of design/engineering (TRL = 4).

c) As methanol. The same assumptions of the single-step methanol production described in section 1.4.3 are used for this pathway, and transportation conditions as those for methanol carrier Millennium Explorer as described by Wärtsilä. Once at destination port, the methanol is converted back into hydrogen via steam reforming [Caloric 2021] represented by the reverse reaction of methanol synthesis:

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$$

Because the methanol synthesis uses an unavoidable source of CO_2 as in the base case of methanol synthesis of our study, the CO_2 emissions from this reaction are assumed to have a neutral GHG impact.

d) As methylcyclohexane. This alternative requires the use of toluene as carrier molecule, and its reversible hydrogenation reaction to methylcyclohexane:

$$\text{Toluene} + 5/2H_2 \leftrightarrow \text{Methycyclohexane}$$

Our study assumes transportation conditions as described in [Lanphen 2019], and a hydrogenation/dehydrogenation conditions as described on [EQHHPP 1991].

1.6. BASE CASE RESULTS

1.6.1. Energy balances

1.6.1.1. Synthesis from CO_2 captured from the air via Direct Air Capture (DAC)

Figure 7 shows the power and heat consumptions for each of the e-fuel pathways under the assumption that CO_2 is captured from the atmosphere via a low temperature direct air capture (DAC) technology. The time horizon is 2050, for which the alkaline electrolyser efficiency is estimated at 75%.

The energy consumption (equal to the energy expended plus the energy contained in the fuel) is in all cases vastly dominated by electrolysis, counting for 58% (OME_{3-5}) to 97% (NH_3) of the total energy consumption (74% to 78% for drop-in liquid e-fuels). This share is responsible for the high dependency of power carbon intensity and costs on the values calculated for the e-fuels that will be explained in the following sections.

The study assumes heat integration implemented between the fuel synthesis and carbon capture plants, meaning that the thermal energy produced from the exothermic synthesis reaction and light ends burning (shown as negative

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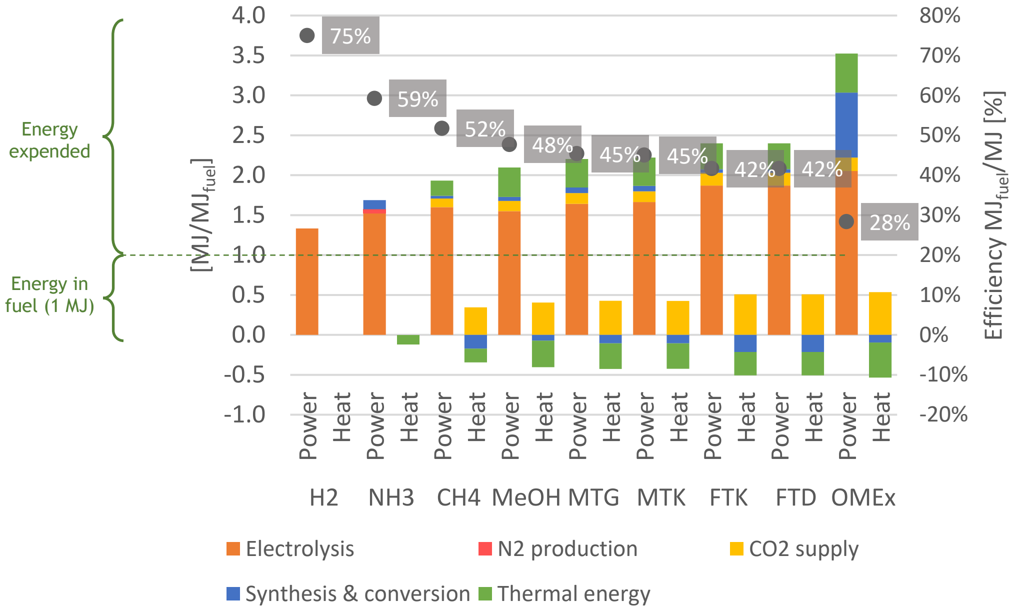
[3] For NH_3 cracking, a 1.2507 MJ NH_3 per MJ of H_2 and 0.1446 MJ electricity per MJ of H_2 is required according to [Jackson et al. 2019].

consumptions on the Heat columns of each fuel) is transferred to the carbon capture facilities to be used for the CO_2 desorption operations. The heat requirements of the DAC units are only partially covered, so additional heat needs to be produced. Contrary to what happens to other synthesis processes, the heat produced in the ammonia synthesis is considered as not recovered and therefore not counted for its energy efficiency. This is because we assumed that recovered heat is used for the desorption stage in the carbon capture process, which is not relevant for ammonia production.

To limit the impact on greenhouse gas emissions, the supplementary heat is produced from electric heaters as described in section 1.5.1. This additional power consumption for heating purposes is represented in Figure 7 in a separate category "Thermal Energy". The heat produced heaters is also shown with similar pattern as a negative consumption (production) of Thermal energy.

The energy efficiencies values can be read in the right axis of the graph. The energy efficiency is defined as the ratio between the energy contained in the fuel and the energy consumed to produce the fuel. It can be observed that as the fuel molecules increase in size and complexity from left to right, they show higher energy consumptions and lower energy efficiencies. Drop-in quality e-fuels compatible with the existing fleet being larger and more complex, this means that their compliance comes at a higher energy expense.

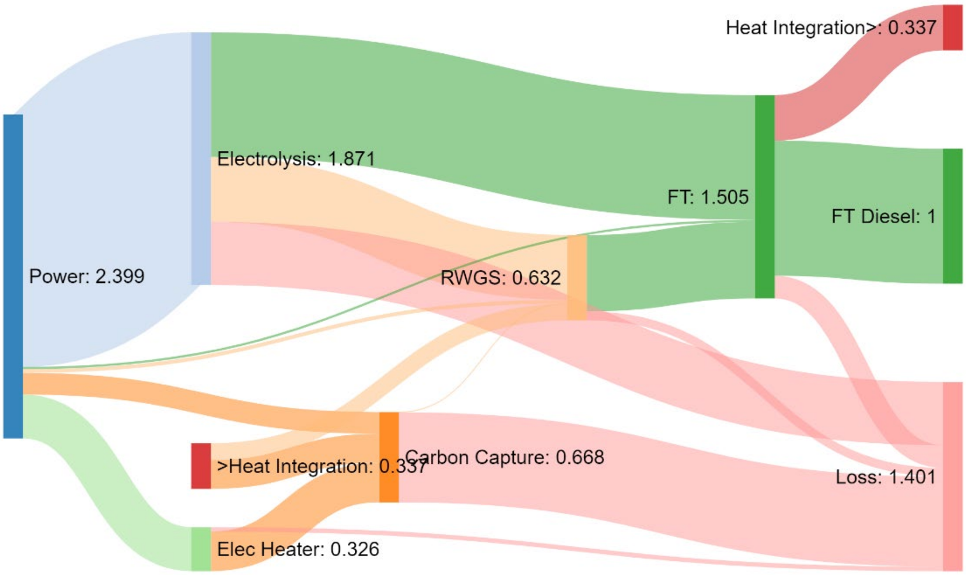
Figure 7: Power and heat consumption for the production of different e-fuels with CO_2 from Direct Air Capture (DAC) (Timeline: 2050)



Note: List of acronyms available in the Glossary and section 0. Thermal energy potentially recovered from NH_3 synthesis not included in its energy efficiency

To better understand the energy flows throughout the process, a Sankey diagram is shown in Figure 8 for the FT Diesel case using CO_2 from a diluted source (reference year: 2050) as an example. The Sankey diagrams for the rest of the pathways are shown in Annex 7.2.

Figure 8: Energy consumption to produce 1 MJ of FT e-diesel via Direct Air Capture (DAC)



In this diagram, the width of the arrows is proportional to the energy carried between the successive stages of fuel production, with losses represented explicitly with separate arrows. The values are all expressed in MJ for the production of 1 MJ of fuel based on its lower heating value. The net power consumption compared with the energy contained in the fuel produced defines the e-fuel energy efficiency. For the efficiency calculation, the energy consumption of the process is taken at the entrance of the different plants (electrolysis, carbon capture, RWGS, Fischer-Tropsch). Therefore, the efficiency excludes the efficiency of the power plants and any potential transmission losses.

The sole source of energy to produce FT e-diesel is electricity. The largest part of this electricity is required by the electrolyser, which produces hydrogen for both the RWGS and the FT reactions. Losses from the electrolysis in the form of low temperature heat are represented as a red band going to the Loss node. The rest of the electricity is consumed by the Carbon Capture (DAC) process, both by direct consumption as indirectly via an electric heater of 90% efficiency. Additional consumptions by the RWGS and FT reactions are observed, but they remain marginal compared to the others.

The Carbon Capture stage is the largest heat consumer across the production pathway, as it requires thermal energy to desorb the CO_2 captured. The electric heater and the heat released from the downstream synthesis processes provide this thermal energy, as shown in the diagram via the two “Heat Integration” nodes. The electricity consumption of the Carbon Capture stage is mostly used for compression and CO_2 liquefaction, as part of its purification process. All the energy provided to the Carbon capture to desorb and liquefy is assumed to be a loss as the CO_2 stream does not carry any heating value.

The RWGS converts H_2 and CO_2 into CO and H_2O by consuming heat and electricity. All the heat for this process is provided by the FT reactor downstream via the Heat Integration node. This heat is at a very high temperature required for the RWGS reaction, as it is generated from the burning of light ends produced during the FT and hydrocracking process. The CO stream, carrying some heating content, is sent to the FT node.

The FT step converts the syngas produced by the electrolyser and the RWGS into FT Diesel, releasing an important amount of energy from both the exothermic reaction, in the form of steam, and the burning of light ends, producing flue gases at very high temperature. The latter part is the one used for the RWGS reaction and the rest for the Carbon Capture step.

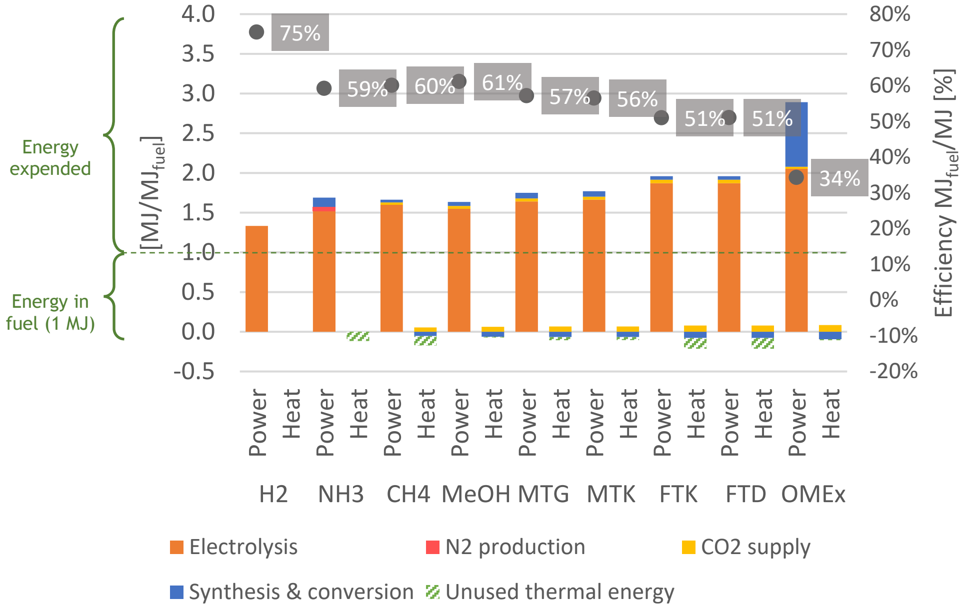
To further improve the overall energy efficiency of the FT e-diesel it could be envisaged to recover part of the low temperature heat produced at the electrolysis. This option is not analysed in the base cases, which use with low-temperature (LT) electrolysis. However, high-temperature (HT) electrolysis is included in the specific sensitivity case called "Advance Technologies". HT electrolysis uses heat, thus reducing the electricity demand. The energy consumptions for this sensitivity case are derived from Sunfire data for SOEC co-electrolysis with and analysed in section 1.7.1.

1.6.1.2. Synthesis from CO_2 captured from a high concentration point source

Figure 9 shows a variation of the previous case, now supposing that the CO_2 used for the fuel synthesis is extracted from a concentrated point source, like Steam Methane Reformer (SMR) or Autothermal Reforming (ATR) pre-combustion off-gases.

In this case the higher CO_2 concentration requires less energy for its separation and purification. For all the e-fuel pathways, the heat from fuel synthesis is enough to cover the thermal requirements of the carbon capture process, so no external electric heating is needed. Efficiencies of all pathways fed with CO_2 (all except e-hydrogen and e-ammonia) go up by about 10 percent points. This increase is based on the assumption that all the excess heat produced from the fuel synthesis exothermic reactions is a waste and does not provide any energy credits. The part of energy that is wasted is shown in Figure 9 as “Unsued thermal energy”.

Figure 9: Power and heat consumption for the production of different e-fuels with CO_2 from a concentrated point source (Timeline: 2050)



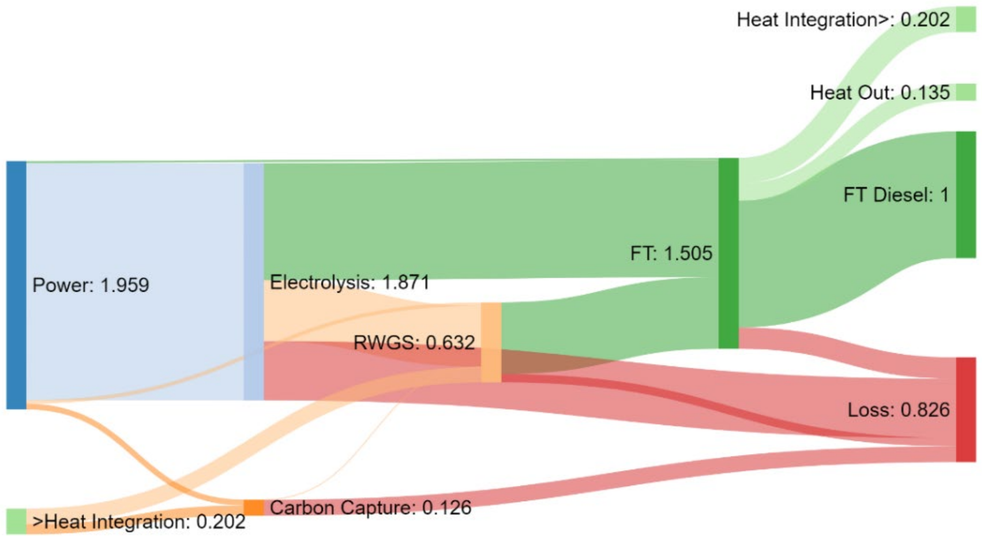
The former assumption implies that energy efficiencies could be further improved if excess heat was, for example, converted into high pressure (HP) steam and used in a process nearby, like in the case of an e-fuels plant integrated with a refinery. This would not only increase the energy efficiency of the e-fuel pathway but also have an impact on the carbon intensity and costs, as it could generate CO_2 and cost credits depending on the type of energy it would substitute. The impact of this additional energy saving is discussed in section 1.6.2,

As in the case of air-captured CO_2, we still confirm that the complexity of the chemical structure of the fuel molecules is inversely proportional to the efficiency. However, the advantage of ammonia over methane observed in the previous case is lost because the change of the source of carbon is only relevant for the latter.

A Sankey diagram was also generated for the FT e-diesel case under these conditions in Figure 10. The size of the carbon capture node is smaller than in Figure 8, consistent with the lower energy required to capture the CO_2, which is around seven times lower than in the DAC case, as reported in Table 9.

The routing of the energy flows is the same as in the previous case, expect that now the heat released by the FT reactor is split in two parts: One effectively recycled to RWGS and Carbon Capture, marked as Heat Integration, and another that is left available of other process out of the pathway, marked as Heat Out.

Figure 10: Energy consumption to produce 1 MJ of FT e-diesel via Direct Air Capture (DAC)



KEY MESSAGES – ENERGY BALANCES

The energy consumption in the e-fuels production stage increases depending on the length and complexity of the synthesised molecules. The simplest molecules, like hydrogen, require less energy consumption than the more complex ones. As an example, for fuels synthesised from air-captured CO_2, 1 MJ of FT e-diesel requires 2.1 times the energy needed to produce 1 MJ of e-hydrogen, while 1 MJ of the more complex molecule e-OME_{3-5} needs 2.7 times that amount.

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. More complex molecules like FT e-diesel or FT e-kerosene have an energy efficiency of 42%. The lowest efficiency corresponds to the e-OME_{3-5}, estimated at 28%. These values correspond to a carbon capture from DAC and 2050 timeline. If the carbon capture is from a concentrated source, the FTD and FTK efficiencies increase up to 51%, and in OMEx to 34%.

The energy losses in the e-fuel production processes are mainly originated from the electrolysis and the carbon capture steps. These losses are higher when fuels use CO_2 captured from the air than when they contain CO_2 from a concentrated point source (1.401 MJ/MJ_{fuel} versus 0.826 MJ/MJ_{fuel} respectively for a FT e-diesel), due to the energy required to concentrate the carbon (45% by volume of CO_2 in the concentrated source versus 0.04% CO_2 concentration in the air).

The study assumes heat integration between the fuel synthesis and carbon capture by default, with an electric heater producing any additional requirements. Heat integration differentiated by temperature level has been taken into account derived from literature.

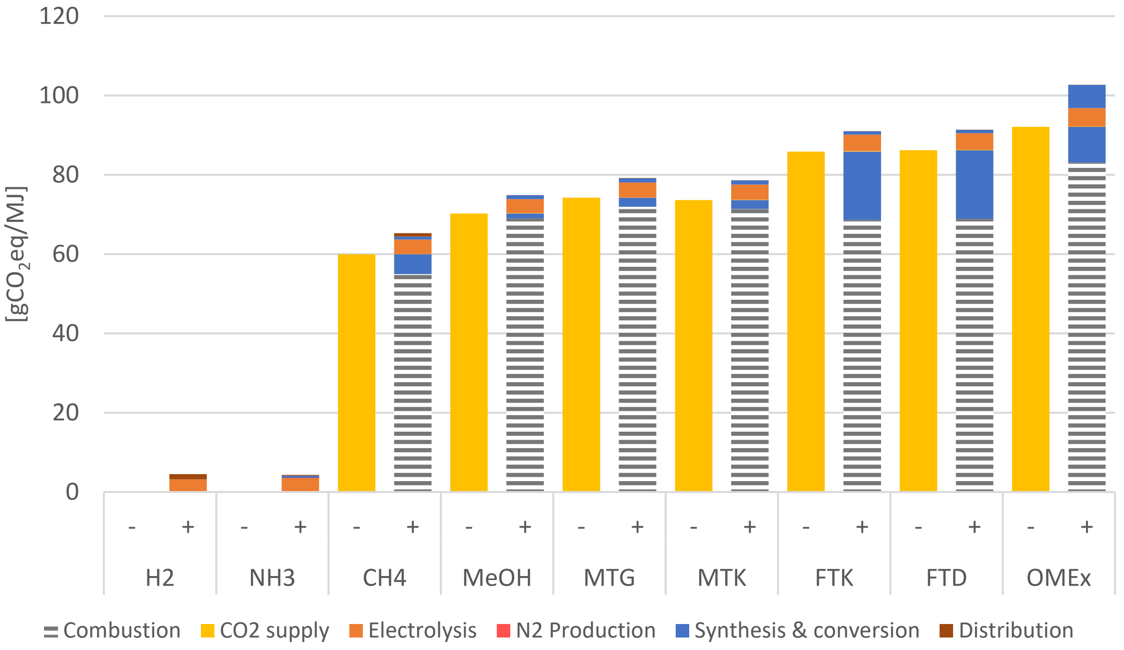
A major criticism of any e-fuels scheme is the “wastage” of renewable electricity. A part of this waste could be reduced if part of the waste heat in electrolysis was used for the carbon capture or any other endothermic stage, increasing the total efficiency.

The energy and mass balances and the Sankey diagrams for all the e-fuels pathways are shown in the annexes 7.1 and 7.2 respectively.

1.6.2. GHG emissions

Figure 11 shows the balances of captured CO_2 versus emitted CO_2 for each of the e-fuels pathways (production, distribution and combustion) for the timeframe 2050 in Northern Europe (Norway). This timeframe implies a high electrolysis efficiency and a mix of CO_2 sources as described in Table 12. The results are calculated on a Cradle-to-Grave basis, including all the burdens described in 1.3.2.

Figure 11: CO_2 captured vs CO_2 emitted [gCO_2/MJ] by different e-fuels pathways (Case: North EU, 2050)



Note: The extra CO_2 captured/emitted in MTG or MTK vs MeOH is coming from the MTG and MTK synthesis step (from methanol to gasoline/distillates), which emits additional CO_2 because of the burning of a small quantity of light ends in the synthesis phase, to a much lower extent than the FT processes though.

The carbon credits and carbon emissions are displayed in separate columns for each fuel marked with a minus (-) and a plus (+) sign respectively. The graph can be read as follows:

- The yellow bars show the amount of CO_2 captured per MJ of fuel produced and distributed. This amount carbon captured is not just dependent on the carbon content of the final fuel, but also includes the CO_2 emitted during the synthesis stage. e-Hydrogen and e-ammonia do not have any carbon capture contribution as they do not have any carbon atom in their structure.
- The striped grey bars correspond to the CO_2 emitted during the fuel combustion. This estimation excludes the impact of the engine efficiency, so it is calculated purely as an emission factor on an energy basis. Note that only CO_2 production is considered in this analysis - no other greenhouse gases (CH_4,

N_2O) that could be present in the combustion exhaust are taken into consideration.

- The dark blue bars show the CO_2 emitted during the fuel synthesis. Some examples are the burning of light ends produced during the Fischer-Tropsch reaction (see section 1.4.8) or the oxidation of part of the intermediate reactant formaldehyde in the OME_{3-5} synthesis process (see section 1.4.4). Also included in this category are indirect emissions from any resources used during the production phase, like oxygen for the OME_{3-5} synthesis or emissions from waste water treatment. As in the previous category, only emissions of CO_2 are considered in this category – no assumptions of CH_4 or N_2O leaks have been considered for the fuel synthesis stage. This is justified by the lack of information currently available on specific pollutants from the processes.
- Other bar colors indicate emissions associated to hydrogen and nitrogen production, and the transport and distribution stage.

It can be observed that the emissions from combustion (striped grey) and the emissions from synthesis (dark green) balance with the captured carbon (yellow). This is equivalent to saying that the CO_2 emissions from burning the e-fuels and the CO_2 directly emitted by the synthesis plants could be assumed to be zero, as they benefit from credits of the CO_2 recovered from the air or the waste streams. This credit is the main reason why e-fuels produced from renewable energy sources are considered as low carbon fuels. From now on and for the rest of the analysis, these major contributing categories to the total CO_2 emissions (between 89% and 94%) will be excluded from the analysis. This will allow for a deeper interpretation of the remaining categories.

KEY MESSAGES – GHG EMISSIONS

The majority of the emissions (> 89%) are balanced between the ones emitted in the process and e-fuel combustion in the tailpipe of the vehicle, and the ones captured (eg: 86 gCO_2 eq/MJ for FT diesel), so they can be neglected in terms of net emissions.

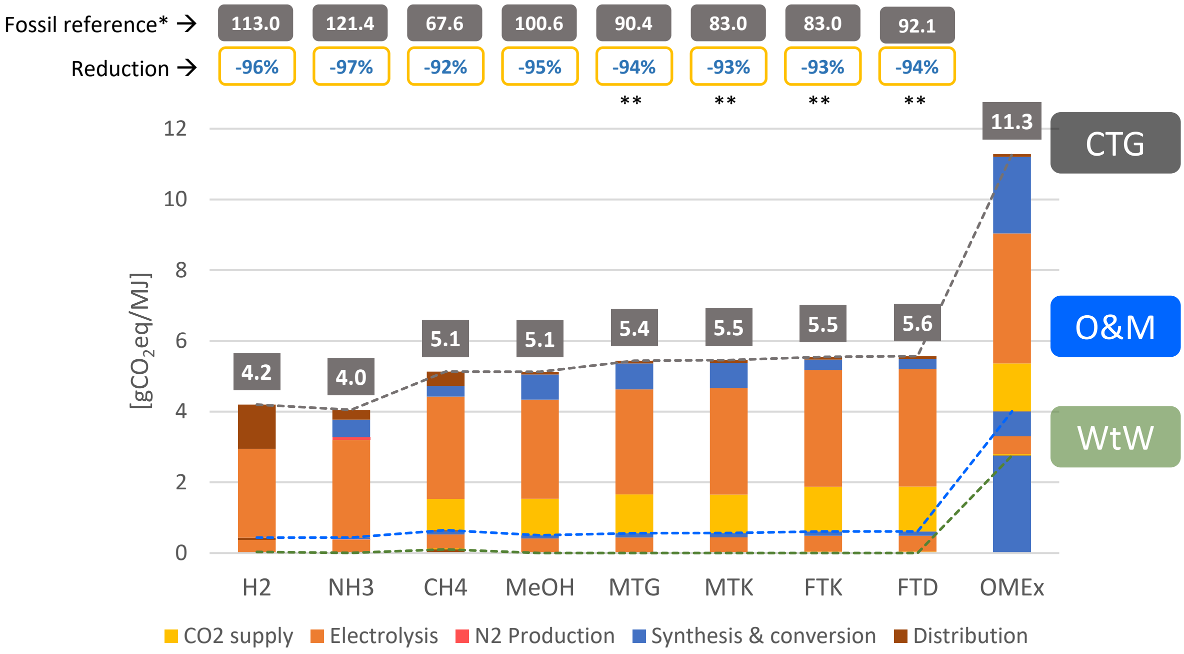
The remaining net emissions are < 10% (around 5.5 gCO_2 eq/MJ for the majority of e-fuels routes except from the OME_{3-5}.

Figure 12 shows the Cradle-to-Grave net GHG emissions, expressed in gCO_2eq/MJ of the different pathways, in Well-to-Wheel (WTW), Operation & Maintenance (O&M) and Cradle-to-grave (CTG) basis. The definitions of these categories are described in section 1.3.2 and Figure 1:

- WtW includes direct emissions of the fuel synthesis stage as well as feedstock and energy production and fuel transportation.
- O&M refers to emissions related to equipment maintenance for both fuel production and electricity generation. This includes manufacturing of spare mechanical parts and their end-of-life.
- CTG includes infrastructure building and manufacturing of equipment facilities necessary for the plants (synthesis plants, electrolysers, power farms) including the end of life. Carbon capture infrastructure is not included in the GHG analysis (see section 1.3.2).

The contributions of different steps of the fuel life cycle are differentiated by colours, segregated by scope.

Figure 12: Cradle-to-grave GHG emissions of different e-fuel pathways (Case: North EU, 2050)



Based on these results, the fuels can be divided in three categories from the standpoint of GHG emissions:

- The group of hydrogen and lighter molecules (H_2, NH_3, CH_4 and MeOH), with values ranging between 4 and 5 gCO_2/MJ.
- The group of drop-in liquid fuels (MTG, MTK, FTK, FTD), with carbon intensities fluctuating around the value of 5.5 gCO_2/MJ.
- The molecule of OME_{3-5} (OMEx), with a carbon intensity of almost twice the value of drop-in liquid fuels. This fuel is deemed to be used only blended with diesel-like fuels (see section 1.4.4).

In all groups without exception, we can observe the biggest contribution of the net GHG emissions for e-fuels: The hydrogen production, mostly dominated by the power consumption of this stage. Moreover, the largest share of H_2-related emissions comes from the infrastructure required for power generation. Also significant in the particular case of e-hydrogen is the weight of the distribution stage, which requires large amounts of (renewable) electricity to liquefy and transport it. Well-to-Wheels emissions for this category are originated from the utilization of grid electricity for distribution operations at service operations (compression at service station, dispensing) and, in the case of CH_4, also compression for the pipeline distribution network using grid electricity. Marginal contributions from the distribution infrastructure can be observed in the CTG level, mostly from hydrogen storage installation.

The drop-in fuels present all comparable contribution shares. The energy consumption required for the carbon capture stage does not contribute significantly to the total value, as it comes from renewable energy. Liquid fuel distribution does not contribute with more than 0.1 gCO_2/MJ to the total GHG emissions thanks to the assumption of generalized use of e-fuels for the fleet of trucks transporting it.

However, the analysis of the sensitivity to the technology progress (subsection 1.6.2.2) will show some impact from road transport distribution.

The particular case of OME_{3-5} is explained by mainly two factors: The very high energy requirements of the synthesis process compared to other fuels, and the utilization of a specific carbon-intensive resource, oxygen. The impact of oxygen is displayed under the WTW category, making it the only noticeable contribution of this scope.

KEY MESSAGES – GHG EMISSIONS

For Northern Europe, the net GHG emissions of the different e-fuels pathways in a CTG basis are around 5.5 gCO_2 eq/MJ (except from the e-OME_{3-5}) and around 0.5 gCO_2eq/MJ if we only count emissions from Operation & Maintenance only. The WTW emissions are almost zero because of the use of renewable energy for all operations except power for distribution. These values are similar in all the e-fuels pathways, because e-fuels that are less energy-intensive to produce (such as e-hydrogen) are more energy-intensive to transport.

The emissions from Operation & Maintenance (O&M) emissions represent around 10-15% of the total Cradle-to-grave (CTG) emissions. This means that 85-90% of the total emissions are associated to the infrastructure required.

All the e-fuels pathways comply with the RED II limit for ReFuNoBio (28.2 gCO_2eq/MJ) on a CTG basis, which determines a minimum 70% reduction in GHG versus the fossil reference defined in the RED II: 94 gCO_2eq/MJIt 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 manufacturing solar panels or wind turbines are excluded, the GHG reduction would be even higher.

Drop-in fuels, such as Methanol-to-Gasoline (MTG), Methanol-to-Kerosene (MTK), Fischer-Tropsch Kerosene (FTK) and Fischer-Tropsch Diesel (FTD), have slightly more CTG emissions (around 5.5 gCO_2eq/MJ) than non-drop in fuels, such as methanol (MeOH), at 5.1 gCO_2 eq/MJ, even if the infrastructure for transport, storage, delivery, etc is already available. This is because the energy efficiency is the main driver of the drop-in e-fuel GHG emissions, even if their transport, storage and dispensing infrastructures are already available.

e-OME_{3-5} GHG emissions are around 11.3 gCO_2eq/MJ. The emissions are significantly higher than for the rest of e-fuels due to the higher complexity of the process that requires more energy consumption. However, OME_{3-5} presents other benefits when blending with diesel components such as the low soot and NOx emissions.

In the case of carbon source coming from a concentrated source, a quick sensitivity can demonstrate the potential benefits that could be obtained by using this excess heat as high-pressure (HP) steam (0.135 MJ). The energy credits obtained would represent an increase in efficiency from 51% to 53% in the FTK pathway. Furthermore, assuming the e-fuels plant is associated to a crude oil refinery, potential CO_2 credits could be attributed for avoided fuel gas burned if accounting for 74 gCO_2/MJth x 0.135 MJth/MJ = 10 gCO_2/MJfuel. This estimation considers an average thermal energy from gas in EU of 74 gCO_2/MJth (GaBi database).

1.6.2.1. Impact of geographic locations

Figure 13 shows the e-fuels GHG emissions in three different regions of Europe in 2050. The WTW values are very similar among regions for all the e-fuels pathways, with very low values reflecting the emissions from distribution. The only exception is OMEx, with high WTW emissions coming from the supply of oxygen feedstock for the process.

At a CTG scope, the results appear lower in North Europe, followed by South and finally Central Europe. This is directly related to the carbon intensity of the renewable mix in the different regions (see Figure 4). In the case of South Europe (Spain), despite the higher full load hours (5,040 h/a), the carbon intensity due to the PV component is higher resulting in higher GHG emissions than in the North Europe (Norway). As in the base cases, the emissions related to hydrogen production are dominant for all the cases.

Figure 13: Cradle-to-Grave GHG Emissions from e-fuels production by region in Europe in 2050

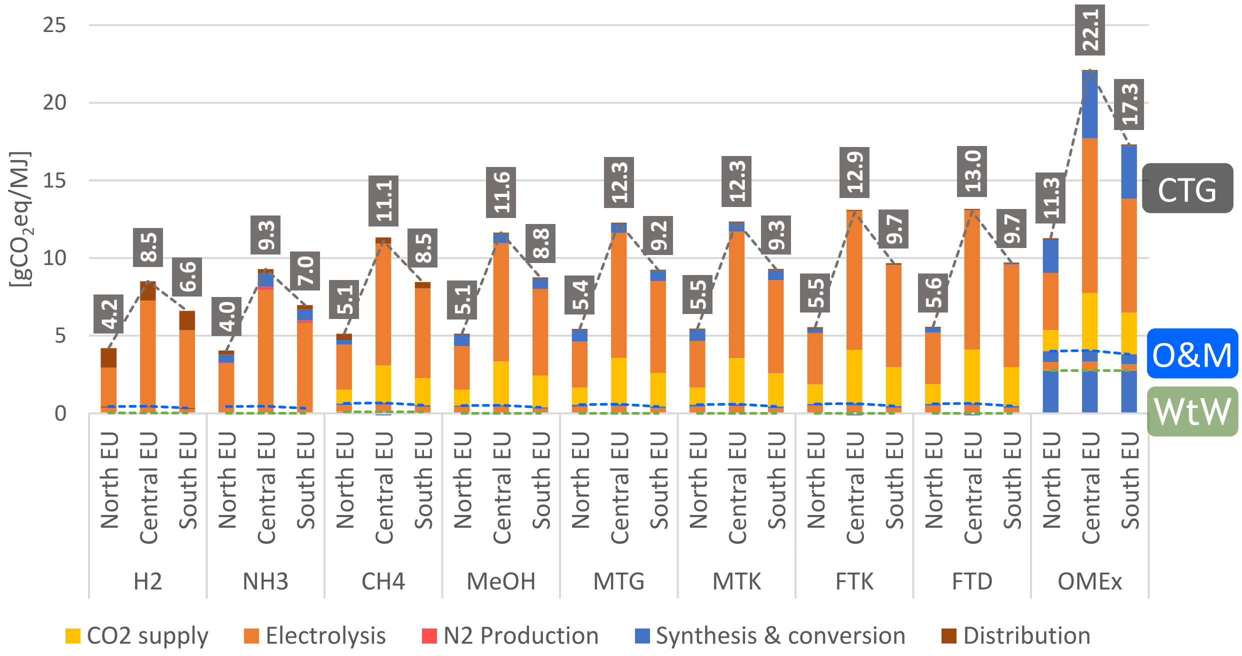


Figure 14: Comparison of GHG Emissions from e-fuels produced in Southern Europe and Middle East in 2050

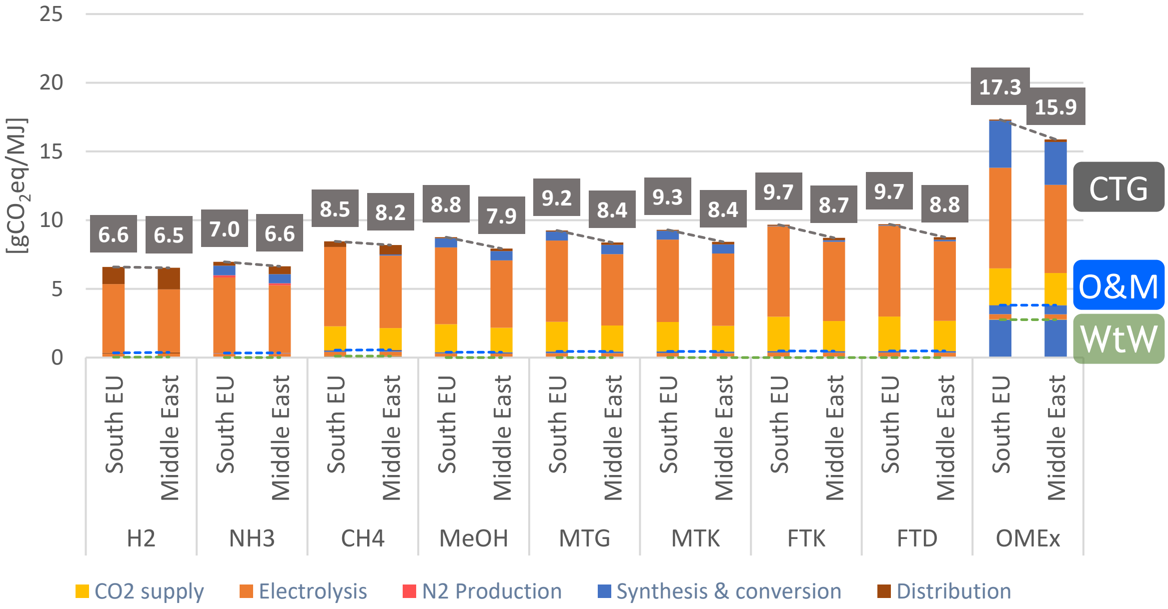


Figure 14 compares the emissions from producing e-fuels either in the South of Europe or in Middle East. This implies a change in the electricity mix but also in the distribution, adding supplementary steps to the supply chain (shipping over a distance of over 5,000 km + unloading). The results show little impact from this additional step, as in 2050 ships are fueled with e-diesel, so their GHG impact is marginal. Even in the case of hydrogen, the impact is barely noticeable (around 0.2 gCO$_2$eq/MJ). The results suggest that the carbon intensity of the electricity used in the synthesis process is the dominant factor even when including long distance transport.

KEY MESSAGES – IMPACT OF GEOGRAPHIC LOCATION

The GHG emissions from Operation & Maintenance are very similar among regions for all the e-fuels pathways in 2050 (around 0.5 gCO$_2$eq/MJ). However, the CTG GHG values show lower levels in North Europe (around 5.5 gCO$_2$eq/MJ), followed by South (around 9 gCO$_2$eq/MJ) and Central Europe (around 12.5 gCO$_2$eq/MJ) in 2050. This is due to the differences in carbon intensity (defined by the lower full load hours of renewable electricity and the contribution of PV versus wind renewable electricity, as PV presents a higher CTG carbon emission).

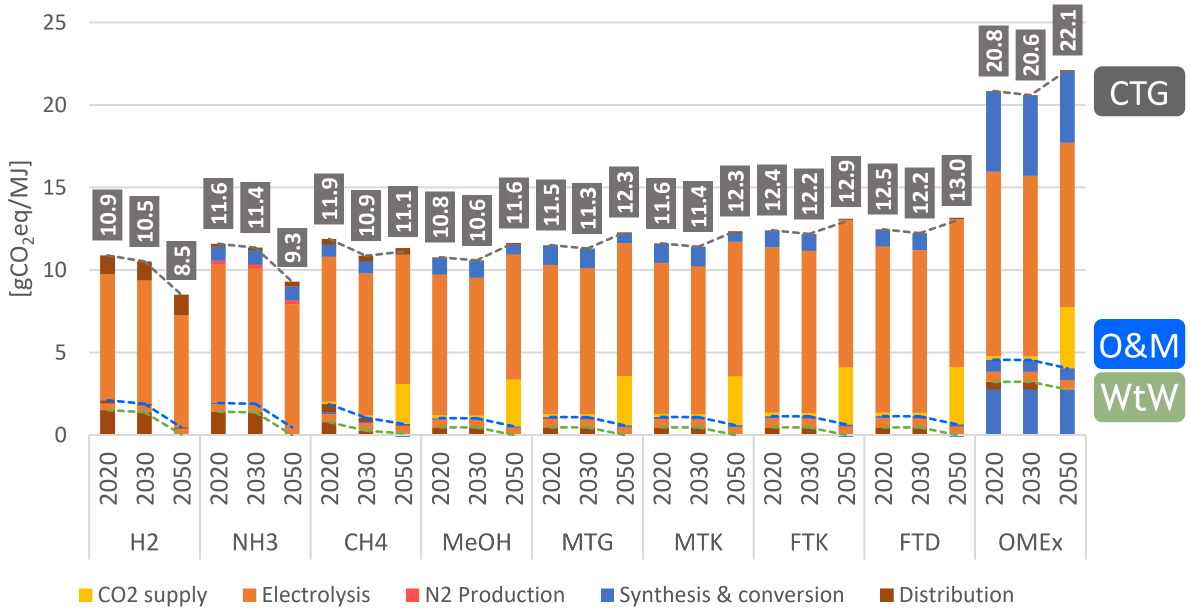
Long distance transport of fuels is not expected to increase significantly the GHG emissions of e-fuels. The carbon intensity of the electricity used will still be the most dominant factor.

1.6.2.2. Impact of technology progress over time

The technology progress assumptions for the three timeframes evaluated in the study have been defined in chapter 1.5, Table 12. These include the increase in electrolyser efficiency, increase share of DAC versus concentrated source and use of e-fuels (e-diesel) for truck and ship transportation.

Figure 15 shows the GHG emissions over time in Central Europe for all the different e-fuel pathways. 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 FT Kerosene the CTG GHG emissions in gCO_2eq/MJ for the FT Kerosene go from 12.4 in 2020 down to 12.2 in 2030 and then up to 12.9 in 2050. This is due to opposite effects overlapping: On one side, an improvement in electrolyser efficiencies and the generalization of the use of e-fuels for maritime and truck transport, which favour a decrease over time of H_2 supply and distribution emissions. On the other hand, the displacement of concentrated sources of CO_2 by the use of DAC, which requires more energy-intensive operations to capture CO_2 from the atmosphere and results in a net increase of emissions by 2050. The contribution of Operation & Maintenance remains stable over time (around 0.2 gCO_2eq/MJ for FT kero) until 2050. The WTW GHG emissions drop steadily until 2050 for all fuels as the emissions from the additional renewable electricity required for DAC is assumed to be 0 on a WTW basis.

Figure 15: Cradle-to-Grave GHG Emissions from e-fuels production in Central Europe in 2020, 2030 and 2050



KEY MESSAGES - IMPACT OF TECHNOLOGY PROGRESS OVER TIME

A progressive reduction is observed over time for hydrogen and ammonia, but not for carbon-based e-fuels on a CTG basis (from 12.4 to 12.9 gCO_2eq/MJ for FT kerosene between 2020 and 2050) because of the use of Direct Air Capture for CO_2 supply. The Operation & Maintenance emissions remain similar over time (0.5 gCO_2eq/MJ for FT kerosene) until 2050 where the generalized use of e-fuels for maritime and truck transport is assumed.

1.7. SENSITIVITY ANALYSES OF KEY TECHNICAL FACTORS

1.7.1. Advanced Technology scenario (co-electrolysis)

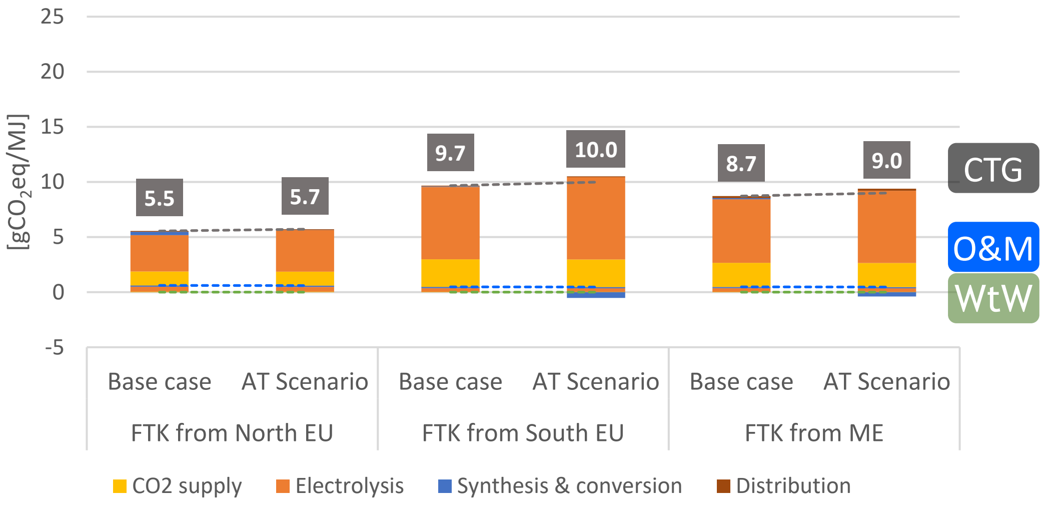
As indicated in Table 12, the Advanced Technology Scenario applied to the 2050 base cases implies the use of a different H_2 production technology known as co-electrolysis, with higher energy efficiency.

The co-electrolysis technology proposed by Sunfire for the Fischer-Tropsch pathways combines high temperature electrolysis (Solid Oxide Electrolysis Cells, also known as SOEC) with RWGS, producing syngas directly in one single step from water and a CO_2 stream (pure CO_2), evolving from a 3- to a 2-stage process. Sunfire claims higher energy efficiency for this configuration, increasing by 15% points in the Fischer-Tropsch pathway and by 10% points in the methanol pathway [Sunfire 2019]. As a caveat, it is important to clarify that this basis is according to the technology developer estimation and should be verified when the first plant will be in operation.

The results in Figure 16 show the differences between the base case production of 2050 and the Advanced Technology (AT) Scenario. The AT cases show a slight increase of 3-4% of the CTG GHG emissions.

This non inutitie result resides in the assumptions around cogeneration and the heat balance taken as a reference. The higher energy efficiency expected from the combination of electrolysis and RWGS applies to a case with no heat integration. In our study we have assumed already that the heat from the fuel synthesis processes can be used to cover part of the energy requirements from carbon capture. Co-electrolysis relies on a process that becomes more efficient at a higher temperature, which is translated into a net increase of the thermal energy demand. With no surplus energy available from the synthesis, this supplementary heat supply is covered with an increase of electricity consumption that increases the burden even further. The use of co-electrolysis would show actual benefits in a system where there is idle energy going to waste, like in the case where 100% concentrated CO_2 is used (see section 1.7.3).

Figure 16: Comparison of GHG emissions between the base case and the Advanced Technology scenario in 2050



KEY MESSAGES – ADVANCED TECHNOLOGY SCENARIO

The Advanced Technology (Co-electrolysis) cases show an increase of CTG GHG emissions. The reason is that the higher energy efficiency expected from the combination of electrolysis and RWGS applies to a case with no heat integration. Our study assumes already that the heat from the fuel synthesis processes can be used to cover part of the energy requirements from carbon capture. Co-electrolysis relies on a process that becomes more efficient at a higher temperature, which is translated into a net increase of the thermal energy demand. With no surplus energy available from the synthesis, this supplementary heat supply is covered with a supplement of electricity consumption that increases the burden even further. The use of co-electrolysis would show actual benefits in a system where there is idle energy going to waste, like in the case where 100% concentrated CO_2 is used.

1.7.2. Electricity source

- 100% wind source

  Figure 17 shows the results of the GHG sensitivity analysis for four types of e-fuels when switching from a mixed power in Central Europe to a 100% onshore wind power source.

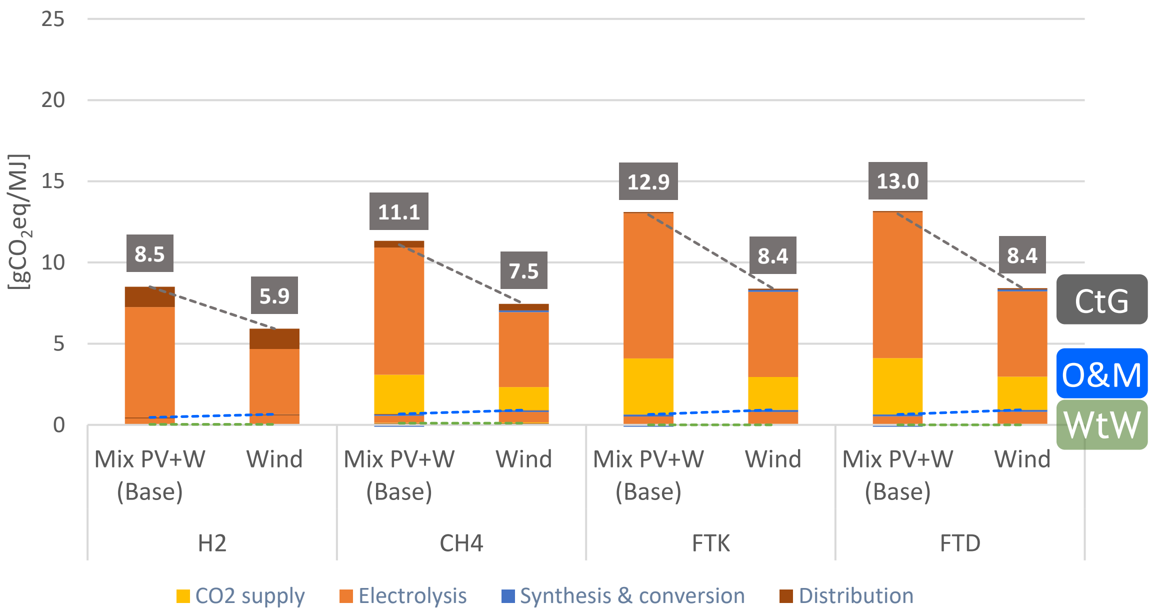
  General trends show a decrease of GHG emissions when a full wind source is used exclusively, in accordance with Figure 4. The same trend applies for any of the regions studied and puts in evidence the advantage of wind over a mix of photovoltaic power when the electricity production emissions are indicated on a Cradle-to-Grave basis. The impact of the additional buffer storage operation is negligible for CO_2 emissions (less than 0.2 gCO_2eq/MJ, included in the H_2 production category), as explained in section 1.5.1, but not necessarily for the cost.

KEY MESSAGES – ELECTRICITY SOURCE (100% wind)

Cradle-to-Grave emissions show an advantage for the use of 100% wind onshore electricity (8.4 versus 12.9 gCO_2eq/MJ in FT kero, equal to 28% GHG emissions reduction).

Operations & Maintenance emissions increase only very slightly in this case (from 0.2 to 0.3 gCO_2eq/MJ in FT kero) because of the impact of the maintenance of wind turbines compared to the negligible operating emissions from the photovoltaic panel farms.

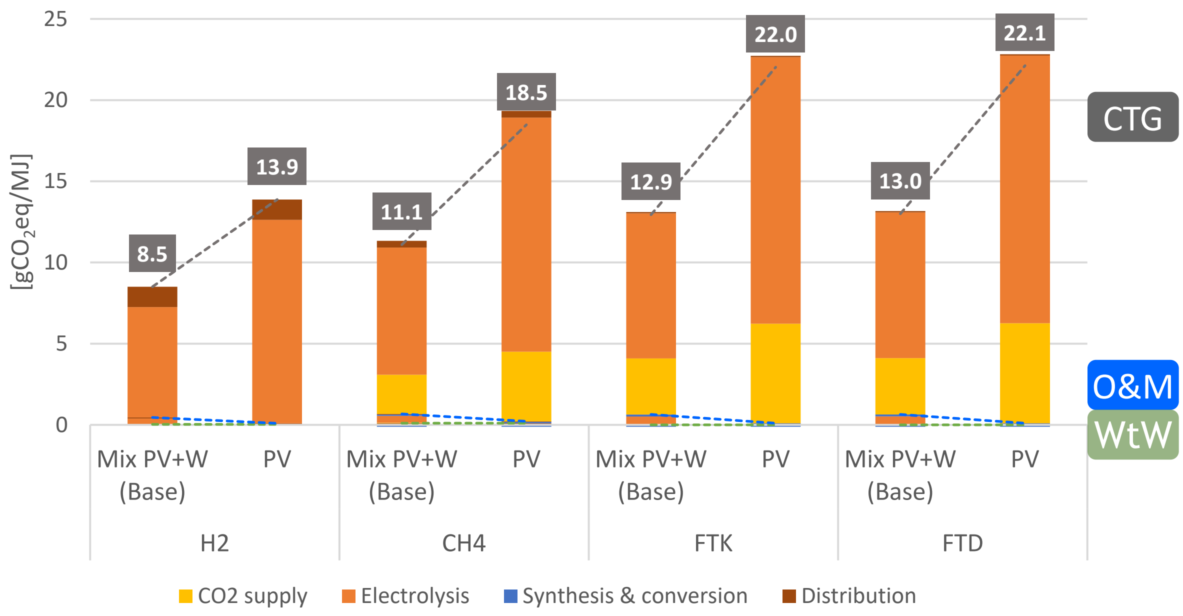
Figure 17: Comparison of GHG Emissions in Central Europe between a mixed and 100% wind power source



- 100% PV source

  Figure 18 shows the results of the GHG sensitivity analysis for four types of e-fuels when switching from a mixed power in Central Europe to a 100% photovoltaic (PV) power source. General trends show a significant increase of GHG emissions on a CTG basis when a full PV source is used exclusively, in accordance with Figure 4. This effect is directly related to the bigger impact of solar panels manufacturing compared to wind turbines, due to the use of more energy intensive materials (silicon wafer) and a more energy intensive process in general. Contrary to what is observed for a switch to 100% wind, the impact on an O&M (WtW + maintenance) scope is actually lower than the renewable mix because of the very limited maintenance required during the lifetime of solar panels compared to wind turbines. Like in the case of wind turbines, the cost of additional hydrogen storage capacity is two orders of magnitude lower and remains marginal for GHG emissions.

Figure 18: Comparison of GHG Emissions in Central Europe between a mixed and a 100% photovoltaic power source



KEY MESSAGES - ELECTRICITY SOURCE (100% PV)

Cradle-to-Grave emissions show a disadvantage for the use of 100% PV electricity (22.0 versus 12.9 gCO_2eq/MJ in FT kero, equivalent to a 70% GHG emissions increase) instead of a mix of renewable energy sources.

Well-to-Wheels-and-Maintenance emissions decrease in this case (from 0.4 to 0.6 gCO_2eq/MJ in FT kero) because there is little maintenance in the photovoltaic panel farms.

- Sensitivity to other renewable sources

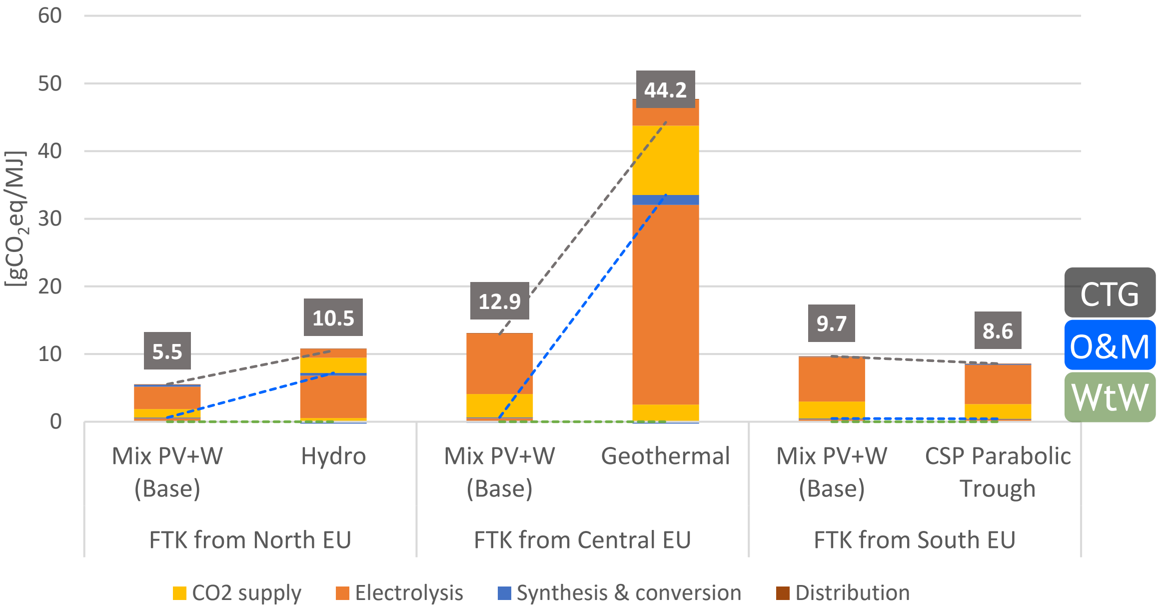
Figure 19 shows the results of the GHG sensitivity analysis of Fischer-Tropsch kerosene in 2050 three additional types of renewable energy in regions where they are particularly relevant: Hydropower in Northern Europe (14.1 gCO_2eq/kWh), Geothermal in Central Europe (64.8 gCO_2eq/kWh) and Concentrated Solar Power (CSP) using Parabolic Trough technology in Southern Europe (11.2 gCO_2eq/kWh). The carbon intensity values for hydropower and geothermal power are taken from the GaBi databases [Sphera 2021]. The value for CSP was calculated from a GaBi model based on NREL's System Advisory Model (SAM) [NREL 2020].

The results show a net increase of GHG emissions for the the first two types of energy on a CTG basis and a decrease for Concentrated Solar Power, consistent with the power carbon intensities shown in Figure 4. With hydropower, the impact almost doubles for Northern Europe; for geothermal power it more than triples in Central Europe, and for CSP it is reduced by more than 11% in Southern Europe.

The reasons for these increased impacts lie on specific characteristics of each one of these renewable energies and the level of technology progress considered. The hydropower and geothermal energy pathways all show important additional contributions in the Well-to-Wheel scope, corresponding to direct emissions from the plant operations. Examples of this include methane produced at the bottom of hydropower reservoirs, where oxygen is low (anaerobic conditions) and bacteria decompose organic material [Deemer 2016] and CO_2 carried by fluids drawn from deep earth to produce geothermal power [Bonafin 2019]. For hydro and geothermal power, the increase with respect to a wind and PV mix also concerns the impacts related to energy and materials involved in infrastructure building (dams, drilling, rotating equipment, etc.)

In the case of concentrated Solar Power plants, the Parabolic Trough CSP pathway shows even lower CTG emissions than the mixed PV+Wind base case because of the lower energy requirements in its infrastructure compared to photovoltaic panels. The increasing efficiency of the solar technologies, along with higher steel recycling potentials will draw the carbon intensity of CSP to lower levels in the future, significantly reducing the impacts of fuels produced from it.

Figure 19: Comparison of GHG Emissions of fuels produced with various renewable energy sources



1.7.3. Use of alternative carbon dioxide sources

Figure 20 shows the results of a sensitivity analysis made on the use of different CO_2 source concentrations. The base case assumption, as described in Table 12, is the exclusive use of Direct Air Capture where CO_2 is at a very low concentration (0.04%). Three alternative scenarios were tested: One relying exclusively on a highly concentrated source (SMR off-gas), another on an average concentrated source (NGPP flue gas) and a third one using an equal part of each DAC, SMR and NGPP sources.

The difference between the two extreme cases (100% concentrated source and 100% diluted source of CO_2) represent a gap of 0.7 gCO_2eq/MJ for North EU and even 1.3 gCO_2eq/MJ for a fuel produced in Middle East. The variation is proportional to the carbon intensity of the electricity used in each region. It can be observed that emissions from the CO_2 capture stage are the main source of variation between each scenario. While for the DAC case the emissions from this stage represent 20 to 24% of the total, they have no impact in the SMR case because of the absence of makeup heat production, as the heat available from the fuel synthesis reaction is enough to cover all the thermal energy requirements of CO_2 supply. The scenario with a mix of CO_2 sources is comparable to the average concentration case (NGPP).

Figure 20: Comparison of GHG Emissions from Fischer-Tropsch kerosene production from different CO_2 sources and different production locations

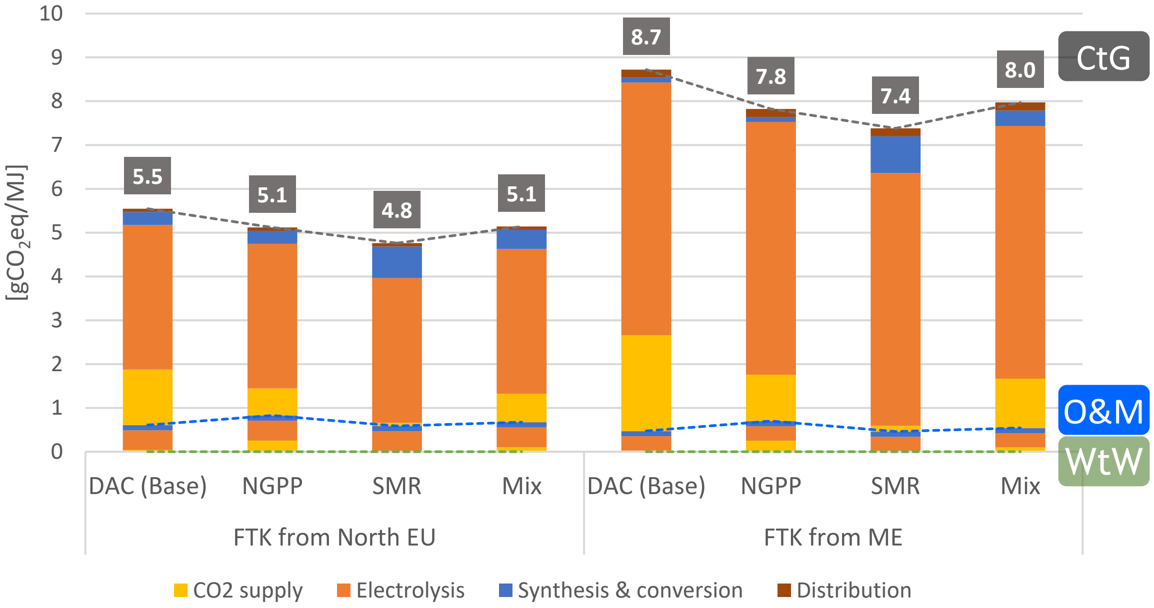


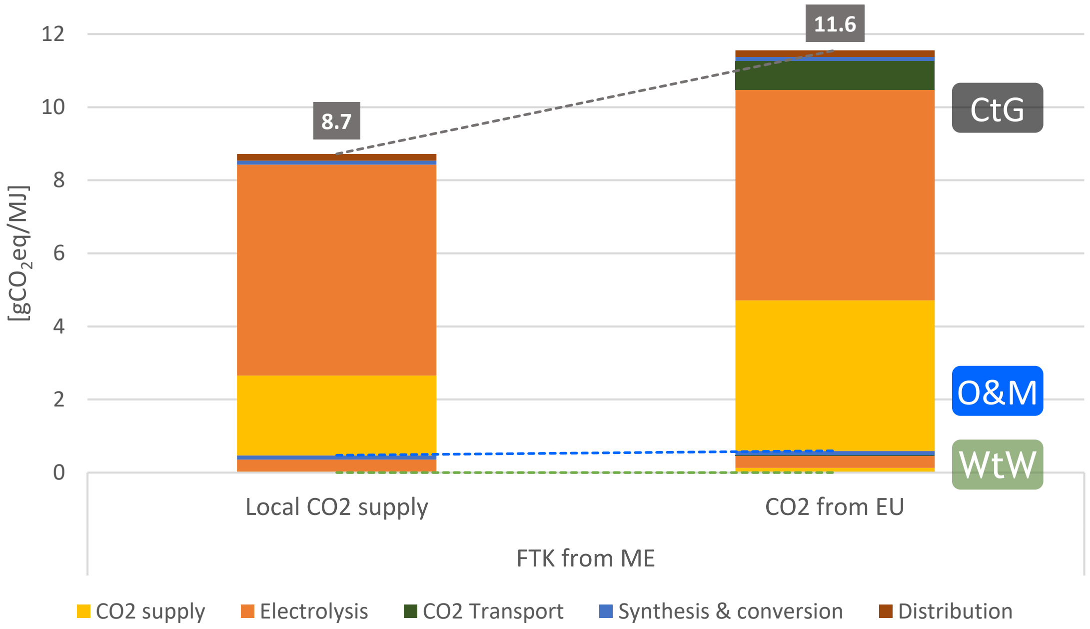
Figure 21 shows a particular case in which fuels are produced in Middle East, but instead of capturing CO_2 onsite and dispatching the fuels to Europe, the process uses CO_2 that is captured in Southern Europe, liquefied, and transported by ship to the synthesis plant in Middle East. This scenario intends to represent a hypothetical situation in which European regulations require e-fuel producing countries outside the region to use CO_2 captured in Europe to comply with the requirement of utilization of certified unavoidable CO_2.

The consequences of such additional step in the supply chain represent an increase of about 33% of total GHG emissions on a Cradle-to-Grave bases in 2050, reflected in the larger size of the CO_2 Capture & Transport bar in both electricity plant maintenance and electricity plant infrastructure categories. This rise can be attributed to two factors:

- The absence of heat integration under this new configuration, since the thermal energy produced during the fuel synthesis cannot be used in the carbon capture process. This implies supplementary emissions from the electricity used to produce this missing energy in Europe. This is reflected as an increase of the Maintenance and Infrastructure contribution proper to renewable electricity.

- The additional maritime emissions linked to the liquefied CO_2 transport, from the e-fuels used to fuel the vessel. This is reflected as an increase of WtW emissions.

Figure 21: Comparison of GHG emissions of FT e-kerosene produced in South EU with H_2 from Middle East



KEY MESSAGES - CO_2 SOURCE

Cradle-to-Grave emissions from Fischer-Tropsch (FT) kerosene reach the lowest level when using a concentrated source of CO_2, a decrease of about 15% respect to the base case diluted source (DAC).

The use of CO_2 captured in Europe and transported to Middle East for the production of e-fuels represents an increase of the carbon intensity of FT kerosene of about 33%, mostly related to the lack of heat integration and the use of supplementary e-diesel for shipping liquefied CO_2.

1.7.4. Use of alternative carriers for H_2 import to feed synthesis processes

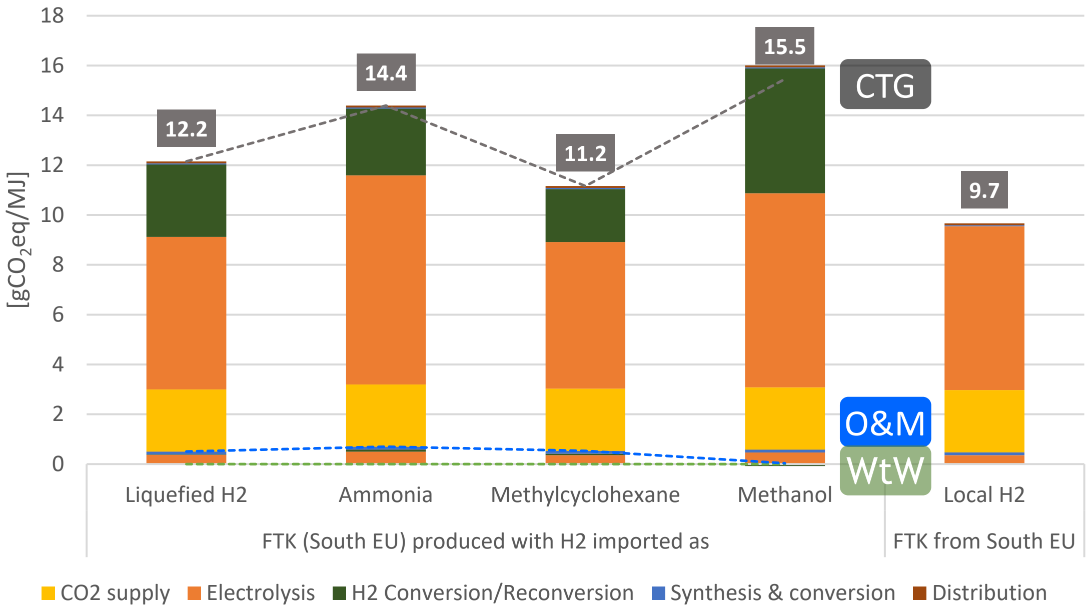
Figure 22 shows the results of a sensitivity analysis on the particular case where Fischer-Tropsch Kerosene is produced in Southern Europe with hydrogen imported from Middle East in various forms: As liquified hydrogen, as ammonia (from reaction between hydrogen and nitrogen), as methycyclohexane (from reaction between hydrogen and toluene) and as methanol (from a process identical to the production of e-methanol). It is assumed that in all these cases, the hydrogen is liquefied or added to the molecule carrier in Middle East and reconverted into hydrogen back at arrival in Europe at a centralized plant located next to the FT plant.

The impact is mainly dependent on the energy consumption and material losses in the process of conversion to and reconversion from carriers in each case. The process of reconversion (cracking) of ammonia into hydrogen considered in the present study assumes the use of ammonia itself as the main source of thermal energy, implying autoconsumption of 30% of the ammonia input. This explains its disavantage compared to hydrogen liquefaction or methylcyclohexane (LOHC) pathway, in which there is no destruction of the molecule carrier (toluene used to produce methylcyclohexane can be recycled) or the energy required in the process is low or taken from an external power source instead of the feedstock itself. A similar observation can be made on the methanol carrier pathway, where the losses in the conversion and reconversion processes increase the penalty from the conversion/reconversion stage. The emissions from electrolysis also increase because of the additional hydrogen production required to cover for the losses in the processes.

The Liquefied H_2 case assumes the use of a Saudi Arabia renewable energy mix for the most energy intensive stage of the hydrogen supply chain. The results for this pathway are highly sensitive to the type of electricity used. For instance, switching to conventional power from fossil sources would increase the impact of this pathway by more than 7.5 times.

Further assessments need to be taken to consider multiple ways of increasing the effiency of the different processes, but in general the advantages of carrying hydrogen in the form of a stable liquid under standard conditions does not compensate in terms of GHG emissions the high penalty of using intermediate conversion and reconversion processes that reduce the energy efficiency of the supply chain.

Figure 22: Comparison of GHG emissions of FT e-kerosene produced from Middle East hydrogen transported via different carrier modes



KEY MESSAGES - USE OF ALTERNATIVE H_2 CARRIERS

Cradle-to-grave emissions increase by 15 to 60% when hydrogen for the production of FT kerosene is imported in liquid form or via a liquid carrier from MENA. The additional burden is caused by a reduction of the energy efficiency and an increase of material losses.

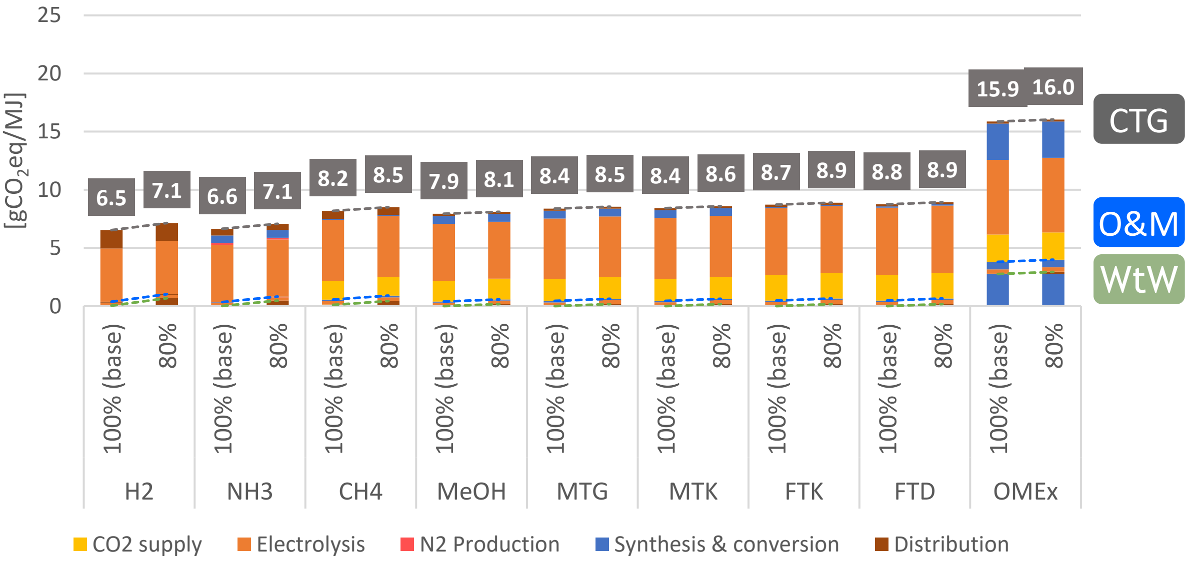
The results are highly dependent on the source of electricity used, in particular for hydrogen liquefaction. Technology progress could reduce the material losses from the reconversion processes and diminish the estimated impact.

1.7.5. Use of marine transport using only 80% e-diesel (2050)

Figure 23 shows the impact of a change on the marine transport default assumptions, which consider the use of 100% e-diesel in this time horizon when e-fuels are produced in the Middle East and are then transported by ship to Europe. The sensitivity tests the use of a blend of 80% e-diesel and 20% fossil marine gasoil, expected to be the minimum requirement to comply with the carbon reduction objectives of the IMO.

The consequences of this change affect more significantly pathways that have higher consumption of marine fuel per kg of fuel transported. For hydrogen, ammonia and methane the increase represents around 9%, 7.5% and 3.5% respectively under the conditions set in the study. For the rest of liquid fuels, the increase is only limited to about 2%.

Figure 23: Comparison of GHG emissions from Middle East imported fuels with different contents of e-diesel in marine fue*l*



KEY MESSAGES - USE OF MARINE TRANSPORT USING ONLY 80% E-DIESEL (2050)

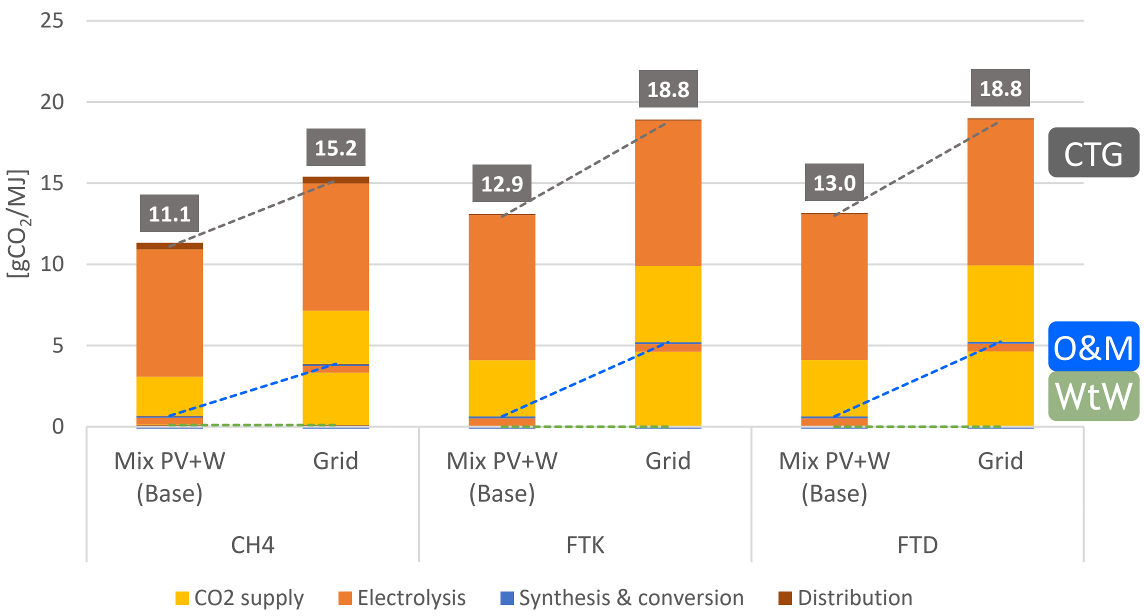
The consequences of this change affect more significantly pathways that have higher consumption of marine fuel per kg of fuel transported. For hydrogen, ammonia and methane the increase represents around 9%, 7.5% and 3.5% respectively under the conditions set in the study. For the rest of liquid fuels, the increase is only limited to about 2%.

1.7.6. Use of grid electricity for carbon capture

Figure 24 shows the impact of switching the type of electricity used in the carbon capture stage produced in Central Europe in 2050. The change affects the direct power consumption only and the electricity consumed in the electric furnaces to supply heat to the process.

Sensitivity cases were run for three different fuels: Methane, Fischer-Tropsch kerosene and Fischer-Tropsch diesel. In all the cases a net increase of emissions is observed, with higher increase rates for the fuels with higher requirements of CO_2 for producing 1 MJ of fuel. The use of electricity from the grid affects in particular the contribution of the WtW emissions, caused by the presence of fossil-powered plants with direct emissions in the mix.

Figure 24: Comparison of GHG emissions from fuels produced in Central EU with different power sources (renewable versus grid) for Carbon Capture



The use of grid electricity for generating supplementary heat for the carbon capture stage already increases the GHG emissions on a CTG basis by 37% to 46% for the three cases studied. If grid electricity were used for all the processes involved, water electrolysis for hydrogen production included, the GHG intensity of the e-fuels would rocket to levels comparable or even higher to their fossil equivalents: 82.8 gCO_2/MJ for methane, 101.8 gCO_2/MJ for FT kerosene and 102.2 gCO_2/MJ for FT diesel.

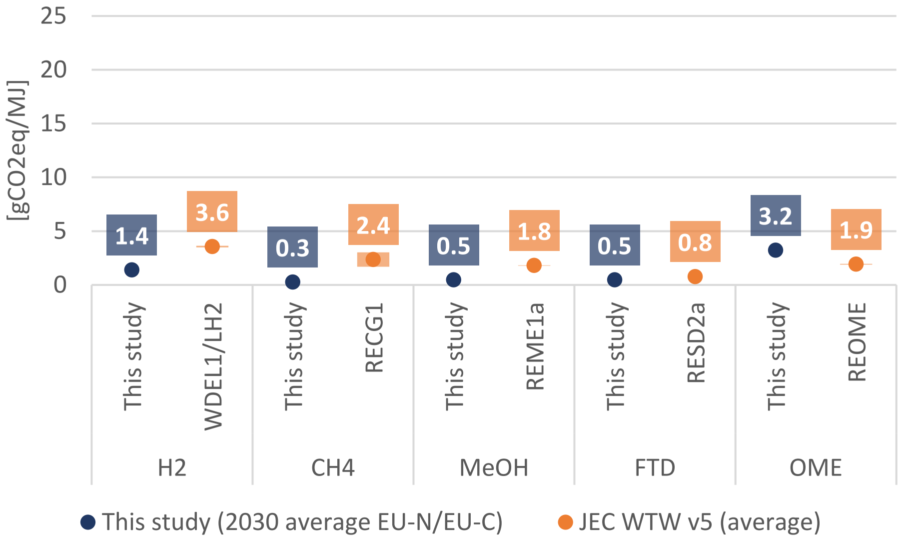
KEY MESSAGES - USE OF GRID ELECTRICITY FOR CARBON CAPTURE

Sensitivity cases were run for three different fuels: Methane, Fischer-Tropsch kerosene and Fischer-Tropsch diesel. In all the cases a net increase of GHG emissions between 37% and 46% is observed, with higher increase rates for the fuels requiring larger inputs of CO_2 per MJ. The use of electricity from the grid affects in particular the contribution of the WtW emissions, caused by the presence of fossil-powered plants with direct emissions in the mix.

1.8. GHG EMISSIONS VALUES COMPARISON WITH JEC WTW V5 STUDY

The base case results of our study were compared to the GHG emissions values of the JEC WTT study [JEC 2020] for five of the e-fuels of their scopes in common: Hydrogen, methane, methanol, syndiesel (FT diesel) and OME$_x$. To ensure alignment of general conditions, the base case values from our study were taken from the 2030 timeframe instead of the default 2050. Also, the WTW emissions are shown instead of the CTG ones indicated in the data labels of all graphs. The comparison is displayed in Figure 25.

Figure 25: Comparison of average e-fuel GHG emissions (WTW 2030) of this study with JEC WTW v5



Note:
WDEL1/LH2: Electricity from wind energy, central electrolysis, H_2 liquefaction, liquid H_2 road transport to retail site, H_2 cryo-compression into vehicle tank (35 MPa).
RECG1: Synthetic methane (as CNG) from renewable electricity, CO_2 from flue gases
REME1a: Renewable electricity to methanol, CO_2 from flue gases
RESD2a: Renewable electricity to synthesised diesel via high temperature electrolysis based on SOEC and FT route, CO_2 from flue gases
REOME: Renewable electricity to OME via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis, CO_2 from biogas upgrading

Several differences in the assumptions must be taken into account to explain the disparities. Some examples of assumptions taken in the JEC WTW study compared to this study are:

- The electricity used for hydrogen liquefaction is assumed to come from the grid, while this study considers the use of renewable electricity instead (grid electricity is used for other operations like compression and dispensing).
- Road transport for hydrogen is assumed at 35 MPa, instead of 50 MPa in this study, which has an impact on the amount of hydrogen that can be transported and its GHG impact and cost.

- Energy consumption rates for H_2 liquefaction and CH_4 compression/dispensing are considered higher than the values used in this study (example: hydrogen liquefaction consumes 0.24 MJ_e/MJ_{H2} in this study and 0.30 MJ_e/MJ_{H2} in the JEC WTW study). The reasons for these differences are explained by the scope of the JEC WTW study, which uses current technology values, while this study anticipates when possible technology progress by the base case year 2050.
- The source of CO_2 is flue gases, while this study assumes the use of a concentrated source (SMR pre-combustion gases) that require less energy.
- The electrolysis technology used for diesel synthesis (SOEC) is different from the one used in this study (alkaline).
- Emissions from O_2 production, necessary for OME_x synthesis are not taken into account.

2. ECONOMIC ASSESSMENT

2.1. ECONOMIC MODELLING OF SELECTED E-FUELS PATHWAYS

Table 15 shows the list of base case pathways executed in this study.

Table 15: Overview of e-fuel pathways investigated in this study

N°	Fuel	Supply	Pathway code
1	e-Hydrogen	Europe (N)	H2EU-N
2	e-Methane	Europe (N)	CH4EU-N
3	e-Methanol	Europe (N)	MeOHEU-N
4	e-OMEx	Europe (N)	OMExEU-N
5	e-Gasoline (MTG)	Europe (N)	MTGEU-N
6	e-Kerosene (MTK)	Europe (N)	MTKEU-N
7	e-Ammonia	Europe (N)	NH3EU-N
8	e-Kerosene (FT)	Europe (N)	FTKEU-N
9	e-Diesel (FT)	Europe (N)	FTDEU-N
10	e-Hydrogen	Europe (C)	H2EU-C
11	e-Methane	Europe (C)	CH4EU-C
12	e-Methanol	Europe (C)	MeOHEU-C
13	e-OMEx	Europe (C)	OMExEU-C
14	e-Gasoline (MTG)	Europe (C)	MTGEU-C
15	e-Kerosene (MTK)	Europe (C)	MTKEU-C
16	e-Ammonia	Europe (C)	NH3EU-C
17	e-Kerosene (FT)	Europe (C)	FTKEU-C
18	e-Diesel (FT)	Europe (C)	FTDEU-C
19	e-Hydrogen	Europe (S)	H2EU-S
20	e-Methane	Europe (S)	CH4EU-S
21	e-Methanol	Europe (S)	MeOHEU-S
22	e-OMEx	Europe (S)	OMExEU-S
23	e-Gasoline (MTG)	Europe (S)	MTGEU-S
24	e-Kerosene (MTK)	Europe (S)	MTKEU-S
25	e-Ammonia	Europe (S)	NH3EU-S
26	e-Kerosene (FT)	Europe (S)	FTKEU-S
27	e-Diesel (FT)	Europe (S)	FTDEU-S
28	H2 (liquid)	MENA by ship	H2ME-Liq
29	e-Methane (LNG)	MENA by ship	NGME-Liq
30	e-Methanol	MENA by ship	MeOHME
31	e-OMEx	MENA by ship	OMExME
32	e-Gasoline (MTG)	MENA by ship	MTGME
33	e-Kerosene (MTK)	MENA by ship	MTKME
34	e-Ammonia	MENA by ship	NH3ME
35	e-Gasoline (FT)	MENA by ship	FTGME
36	e-Kerosene (FT)	MENA by ship	FTKME
37	e-Diesel (FT)	MENA by ship	FTDME
38	e-Kerosene (FT)	MENA by ship as e-crude	FTKMEe-crd
39	e-Kerosene (FT)	Europe (S) with H_2 from MENA by ship	FTKME-H2ex
40	e-Diesel (FT)	Europe (S) with H_2 from MENA by ship	FTDME-H2ex

2.1.1. Approach and economic modelling

The focus of the study are e-fuels production and distribution (Well-to-tank approach). Vehicles/fuel use combination (tank-to-wheel) is not part of the scope.

In line with the study objective of fundamental comparison of different e-fuels and pathways, a full cost assessment from the renewable power production to the final e-fuel dispensing has been carried out. Hence, no business case analysis, no net present value (NPV), or return on invest (ROI) have been calculated. Therefore, neither taxes/levies nor exemptions thereof, and no inflation have been taken into account (cost figures are given in today’s purchasing power). Learning curves have been considered for technologies with potential for cost reductions from series production.

CAPEX is converted to an Equivalent Annual Cost via the Excel ‘PMT’ function using discount rate (baseline: 8%) and the depreciation time (process-specific lifetime). Annual costs for maintenance and repair are added. The resulting annual costs divided by average annual production volume result in the specific product costs (€/kWh electricity supply, €/t CO_2 supply, €/kWh intermediary product supply, etc.). The specific costs are aggregated according to pathway definition and expressed in € per unit of final energy.

All facilities, such as plants for power generation, synthesis and conversion/upgrading, are newly built (from scratch) and depreciated over their lifetime (in many cases some 25 years). The same applies for vehicles used for the transport of the final fuel. Conversion and upgrading are included in the economic assessment, aligned with the LCA asssement in the previous section of this report.

In case of cost data from earlier publications, these are converted to today’s costs via Chemical Engineering Plant Cost Index (CEPCI)[4]. Inflation is not taken into account for future costs.

Costs for spare parts are part of annual O&M costs, i.e. no investment/discount rate is assumed for overhauls/spare parts.

New plants are assumed for each time horizon (Today, 2030, 2050), thus capturing the picture of cost reduction potentials over a series of projects over time.

2.1.2. Economic assumptions

For a description of the e-fuels pathways and plants investigated in this report, as well as the detailed CAPEX and OPEX assumptions, see ECONOMIC ANNEX 8.

Basic assumptions:

- For the base case, a nameplate capacity of 1 million t of e-diesel equivalent[5] per year or about 114 t/h has been assumed (1,370 MW of final e-fuel, based on the LHV).
- Discount rate: 8%
- Depreciation period: Lifetime (specified in Annex 8)

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[4] The CEPCI is a dimensionless number used to calculate the CAPEX of chemical plants from one period to another. The CEPCI consists of a composite index assembled from a set of four sub-indexes: equipment, construction labour, buildings, engineering, and supervision [Chemical Engineering 2022].

[5] Based on fuel properties of conventional diesel EN 590

- The fuel demand of trucks and ships except gas carriers for the transport and distribution of the final fuel is met by conventional fuels (except for time horizon 2050 where 100% e-fuels are assumed in the e-fuel transport in the base case). Table 16 shows the cost assumptions for diesel and low sulphur marine gas oil (LSMGO).

Table 16: Costs of conventional fuels, natural gas, and fossil CO_2 emissions

	Unit	2020	2030	2050	Reference
Diesel	€/l	0.30	0.60	0.80	EC/Concawe*
	€/GJ	8.4	16.7	22.3	EC/Concawe*
LSMGO	€/t	306	613	843	EC/Concawe*
	€/GJ	7.1	14.3	19.7	EC/Concawe*
Natural gas	€/GJ	3.3	5.7	9.0	EU COM 2020
CO_2 price	€/t (base case)	25	130	250	IEA 2021
	€/t (sensitivity)	60			EC/Concawe*

*Crude-oil prices taken from the European Commission Impact Assessment [EU COM 2020] and extrapolated by Concawe using historical factors

Throughout the supply chain there are electricity consumers which are not connected with the PtX plant such as refuelling stations and compressors within a hydrogen pipeline grid. Table 17 shows the cost assumptions for electricity and low and medium voltage level for the different regions inside Europe. Based on [Eurostat 04/2022] and [Eurostat 10/2022], the electricity prices for household (low voltage, LV) and non-household consumers (medium voltage, MV) are assumed to 25 ct/kWh$_e$ and 10 ct/kWh$_e$, respectively.

Table 17: Costs of electricity for electricity consumers not connected with the PtX plant (€/kWh)

	Voltage level	2020	2030	2050
North EU (Norway)	LV	0.25	0.25	0.25
	MV	0.10	0.10	0.10
Central EU (Germany)	LV	0.25	0.25	0.25
	MV	0.10	0.10	0.10
South EU (Spain)	LV	0.25	0.25	0.25
	MV	0.10	0.10	0.10

The electricity demand of the PtX plants is met by 100% renewable energy. For North Europe offshore wind farms are assumed, for the other locations electricity from photovoltaic (PV) and wind power plants. In the regions assessed in this study wind power and photovoltaic are complementary. The electricity yield of PV is high in times when the yield of wind power is low and vice versa. A 5% overlap according to [Fasihi et al. 2016] has been assumed to be curtailed[6], as the integration costs of the last 5% of excess power typically exceed the gain from using it (economic

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[6] The 5% overlap means that 5% of the annual electricity generation is curtailed

curtailment). The overlap varies from region to region. Therefore, for selected pathways 10% curtailment has been assumed for sensitivity.

The rated capacity of the PV/wind hybrid plant consists of 50% PV and 50% wind. The capacity of the PV plant is adjusted to the capacity of the connected e-fuel plant.

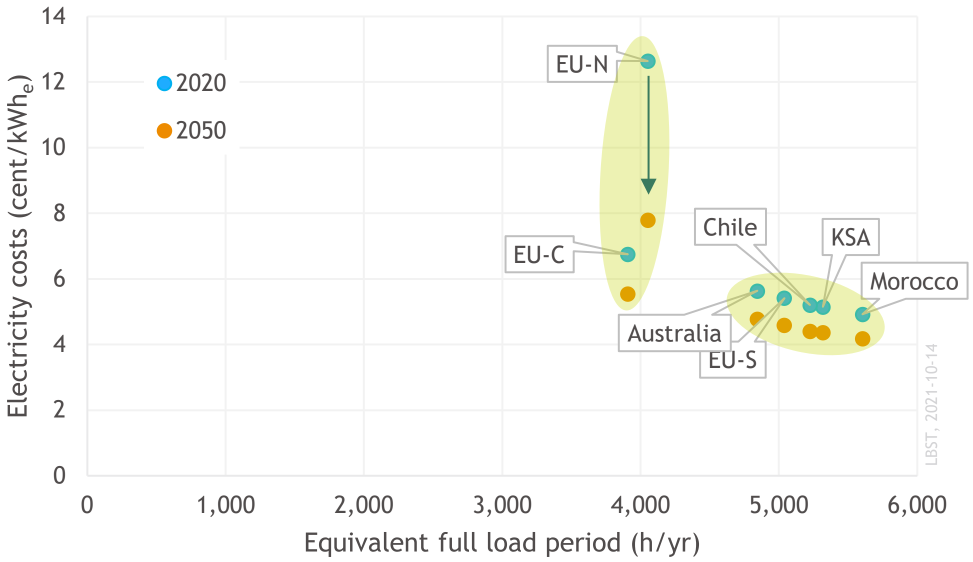
- If the electricity input of the e-fuel conversion plant amounts to e. g. 2,000 MW the rated capacity of the PV plant will be 2,000 MW and the capacity of the wind farm will be 2,000 MW. As base case, a H_2 buffer storage has been applied. For e-hydrogen, e-methanol, e-OME_x, e-gasoline, e-kerosene, and e-diesel the capacity of the buffer storage is assumed to be 50 hours of full load operation in the base case (see ECONOMIC ANNEX 8.4.1, 8.4.3, 8.4.4, 8.4.5, 8.4.7). The level of storage is dependent of the location. Note that in this section, the same capacity of storage was assumed for all regions for simplicity. This storage capacity is region specific, a detailed cost minimisation model using time series of renewable power supply will be developed to assess the required storage capacity per region (report to be published). For e-methane and e-ammonia, the capacity of the buffer storage is assumed to be 3 hours of full load operation because the methanation plant is more flexible and methane and ammonia can be stored easier than hydrogen (see ECONOMIC ANNEX 8.4.2 and 8.4.6). The hydrogen buffer storage consists of underground buried steel pipes with a diameter of 1,485 mm and a maximum pressure of 10 MPa. The CO_2 buffer storage consists of tanks where the CO_2 is stored at a temperature of -41°C.
- The costs of renewable electricity shown in Table 18 have been calculated based on CAPEX, OPEX, and the equivalent full load period of photovoltaic (PV) and wind power plants in the different regions. The calculation of the renewable electricity costs including the references is described in ECONOMIC ANNEX 8.2.

Table 18: Costs of renewable electricity in the different regions (€/kWh)

	2020				2030				2050			
RE source / Region	PV	Wind onshore	Wind offshore	Σ	PV	Wind onshore	Wind offshore	Σ	PV	Wind onshore	Wind offshore	Σ
Northern Europe (NO)			0.126	0.126 (4050 h/a)			0.084	0.084 (4050 h/a)			0.078	0.078 (4050 h/a)
Central Europe (DE)	0.055 (1430 h/a)	0.069 (2690 h/a)		0.067 (3910 h/a)1)	0.043 (1430 h/a)	0.065 (2690 h/a)		0.060 (3910 h/a)1)	0.037 (1430 h/a)	0.061 (2690 h/a)		0.055 (3910 h/a)1)
Southern Europe (ES)	0.038 (2070 h/a)	0.047 (3230 h/a)		0.054 (5040 h/a)1)	0.030 (2070 h/a)	0.044 (3230 h/a)		0.049 (5040 h/a)1)	0.025 (2070 h/a)	0.042 (3230 h/a)		0.046 (5040 h/a)1)
MENA (KSA)	0.032 2) (2410 h/a)	0.047 2) (3190 h/a)		0.051 (5320 h/a)1)	0.026 2) (2410 h/a)	0.045 2) (3190 h/a)		0.047 (5320 h/a)1)	0.022 2) (2410 h/a)	0.042 2) (3190 h/a)		0.044 (5320 h/a)1)
Australia	0.037 2) (2100 h/a)	0.050 2) (3000 h/a)		0.056 (4840 h/a)1)	0.030 2) (2100 h/a)	0.047 2) (3000 h/a)		0.051 (4840 h/a)1)	0.025 2) (2100 h/a)	0.045 2) (3000 h/a)		0.048 (4840 h/a)1)
Chile	0.029 2) (2700 h/a)	0.053 2) (2800 h/a)		0.052 (5230 h/a)1)	0.023 2) (2700 h/a)	0.050 2) (2800 h/a)		0.047 (5230 h/a)1)	0.019 2) (2700 h/a)	0.048 2) (2800 h/a)		0.044 (5230 h/a)1)
Morocco	0.034 2) (2300 h/a)	0.043 2) (3600 h/a)		0.049 (5600 h/a)1)	0.027 2) (2300 h/a)	0.040 2) (3600 h/a)		0.045 (5600 h/a)1)	0.023 2) (2300 h/a)	0.038 2) (3600 h/a)		0.042 (5600 h/a)1)

1) 5% overlap (curtailed) analogous [Fasihi et al. 2016] and including HVDC in Southern Europe and regions outside Europe; 2) Electricity cost without HVDC, 200 km (0.008 €/kWh for KSA, Chile, and Morocco, 0.009 €/kWh for Australia and Southern Europe)

Figure 26: Costs of renewable electricity in the different regions (€ct/kWh_e)



- In North Europe there is a large potential for offshore wind. Therefore, in case e-fuels are produced in North Europe, the electricity generated by the offshore wind farm is transported via a sea cable to the coast (~80 km) where the e-fuel plant is located.
- In North Europe, 100% wind off-shore has been considered. While there is a high contribution of renewable electricity generated from hydropower today, new additional renewable power generation at large in future may rely on wind power. Besides, we wanted to explore the case of 100% wind off-shore to see how it compares versus PV/wind onshore in the rest of the regions in EU.
- In Germany, the installation of large-scale PV/wind hybrid power stations at former lignite mining regions are proposed. Therefore, in case e-fuels are produced in Central Europe, the e-fuel plant is located nearby the PV/wind hybrid power station.

  Southern Spain, the Kingdom of Saudi Arabia (KSA), Australia, Chile, and Morocco are arid regions where water is scarce. Seawater desalination is required for water supply. New export-oriented PtX plants will likely to be located at the coast [Sasol 2021]. For e-fuels produced in Southern Europe, KSA, Australia, Chile and Morocco, it has been assumed that the renewable electricity is transported to the e-fuel plant at the coast via a high voltage direct current (HVDC) transmission line over a distance of 200 km.
- Concerning technical assumptions for PtX plants, respective CO_2 sources and transport modes, see Table 12 in chapter 1.5.

In 2050 the ships for the marine transport of final fuel are powered by 100% e-fuels. In the case of FT kerosene imported from MENA (pathway FTKME), the marine transport from Kingdom of Saudi Arabia to South Europe contributes to about 0.7 € per GJ of final fuel (1.4% of the total costs of fuel supply) if e-diesel is used for ship propulsion. If fossil fuel (LSMGO) were used, the cost for marine transport from Kingdom of Saudi Arabia (KSA) to South Europe will amount to about 0.5 € per GJ of final fuel (or about 1.0% of total costs of fuel supply).

Table 19: Baseline electricity supply – Resulting equivalent full load period

	PV (h/yr)	Wind onshore (h/yr)	Wind offshore (h/yr)	Σ Equivalent full load period$^{1)}$ (h/yr)
Northern Europe (Norway)	-	-	4050 $^{2)}$	4050
Central Europe (Germany)	1430 $^{3)}$	2690 $^{4)}$	-	3910
Southern Europe (Spain)	2070 $^{3)}$	3230 $^{5)}$	-	5040
MENA (KSA)	2410 $^{3)}$	3600 $^{3)}$	-	5600

1) Calculation methodology (5% overlap of annual electricity generation is curtailed) according to [Fasihi et al 2017]

2) Real plants: [BET et al. 2019] BET, Fichtner, Prognos: Vorbereitung und Begleitung bei der Erstellung eines Erfahrungsberichts gemäß § 97 EEG – Teilvorhaben IIf – Windenergie auf See; Juli 2019

3) Lilley, W. (Aramco), e-mail from 16 June 2021

4) [Deutsche WindGuard 2015, p30] Deutsche WindGuard: Kostensituation der Windenergie an Land in Deutschland – Update; Dezember 2015

5) Real plant: Evwind – Wind energy in Andalusia, Naturgy wind farm; 11 January 2020; https://www.evwind.es/2020/01/11/wind-energy-in-andalusia-naturgy-wind-farm/73011

- Although a hydrogen and CO_2 buffer storage is assumed to bridge rapid load changes of the electrolysis plant, the same equivalent full load period has been assumed for downstream processes, like Fischer-Tropsch synthesis. The hydrogen buffer storage consists of underground buried pipes with a diameter of 1,485 mm and a maximum pressure of 10 MPa. The CO_2 is liquefied and stored in tanks at a temperature of -41°C.
- In regions where water is scarce e. g. in Middle East seawater desalination is required for the supply of water for the electrolysis plants. However, the impact of water desalination on the overall electricity consumption and the costs of e-fuel supply is low. Aquatech, a manufacturer of seawater desalination plants based on seawater reverse osmosis (SWRO) indicates an electricity consumption of less than 3 kWh per m^3 of desalinated water [Aquatech 2018].

  The water requirement for hydrogen production via water electrolysis amounts to about 0.27 kg per kWh of hydrogen based on the LHV. As a result, the electricity requirement for seawater desalination will be 0.00081 kWh per kWh of hydrogen based on the LHV.

  For 2020 we assume an efficiency of 66.5% for the production of hydrogen via water electrolysis which leads an electricity consumption of 1.503759 kWh/kWh of hydrogen based on the LHV. Adding water desalination would lead to 1.504569 kWh/kWh and to an efficiency of 66.46%, still 66.5% if rounded. The additional electricity consumption for water desalination is below the accuracy of the indicated efficiency of the electrolysis plant.

  The CAPEX for a large water desalination plant based on SWRO located in Saudi Arabia is estimated at 1.5 million US$ per million l of water per day [Almar 2016]. For the supply of hydrogen via liquid hydrogen (LH_2) imported from KSA, the capacity of the water electrolysis plant would amount to about 1,470 MW of hydrogen based on the LHV. The water demand amounts to about 0.27 l of water per kWh of hydrogen based on the LHV. Then, the required capacity of the water desalination plant would amount to about 9.5 million l of desalinated water per day. Adjustment of the CAPEX to today's values via the CEPCI and conversion to € would lead to about 14.3 million € or about 10 €/kW of hydrogen for the water desalination plant (<1% of the CAPEX of the electrolysis plant). Including the costs of renewable electricity in KSA and costs for maintenance and labour the water costs would amount to about 1.0 € per m^3 of water or 0.0010 € per l of water or <1% of total fuel production and supply costs.

Other sources report a large bandwidth for the CAPEX (0.36 to 1.65 million US$ per million l of water per day) for large SWRO plants in Israel [ACWA 2019] (no techno-economic data for SWRO plants are presented for KSA; therefore, locations in Israel have been used as proxy). Application of the same assumptions used for KSA in this study leads to water costs of 0.46 to 1.07 € per m^3 (Table 20). [Saudi Gazette 2019] indicates a CAPEX of 700,000 US$ for a SWRO plant with a capacity of 600,000 m^3 of water per day (1.17 million US$ per million l of water per day) leading to about 0.79 € per m^3 of water.

Table 20: Water cost for water from seawater reverse osmosis (SWRO) plants

		Israel				KSA	
	Unit	Askelon	Hadera	Soreq	Ashdod	Rabigh 3	Reference
Award	-	2003	2007	2010	2011	2018	ACWA 2019; Saudi Gazette 2019
Capacity	m^3/d	330,000	368,000	540,000	274,000	600,000	ACWA 2019; Saudi Gazette 2019
	m^3/h	13,750	15,333	22,500	11,417	25,000	
CAPEX	US$/($m^3/d$)	360	1155	741	1653	1167	ACWA 2019; Saudi Gazette 2019
	€/(m^3/d)*	486	1193	730	1531	1049	
	million €	160	439	394	419	630	
Equivalent full load period	h/yr	5319					Assumption
Electricity consumption	kWh/m^3	3.5					ACWA 2019
Electricity costs	€/kWh	0.051					ANNEX 8.2.2
Lifetime	yr	30					Assumption
Discount rate	-	8%					Assumption
O&M	-	4% of CAPEX/yr					Assumption
Water costs	-	0.46	0.87	0.60	1.07	0.79	

*Adjusted to €$_{2019}$ via the CEPCI and conversion from US$ to €

According to Almar Water Solutions, the water costs for seawater desalination via seawater reverse osmosis (SWRO) in the Arabian Gulf amount to 1.35 US$ per m^3 of water and in the Red Sea 1.38 US$ per m^3 of water. For the Mediterranean Sea, the cost of water supply is even lower (0.98 US$/$m^3$) [Almar 2016]. [ACWA 20WA 2019] indicates water costs of 0.53 to 0.70 US$/$m^3$ based on bids for the Rabigh 3 SWRO plant. The reasons for the deviation to the calculated water costs depicted in Table 20 can be different assumptions for the discount rate, different equivalent full load periods, different electricity costs, and different assumptions for O&M costs.

In the EU the water prices range between 1.5 (Netherlands) and 2.0 (Germany) € per m^3 [Lauruschkus et al. 2015], although no seawater desalination is required. On the other hand, the water pipeline grid is included in these figures, which is not required if a seawater desalination plant is located onsite the electrolysis plant. As a rough estimate, the costs for water have been assumed to be 1.5 € per m^3 for all regions.

- In our calculations the use of water recycling has not been considered. Possible sources of reclamation include by-product water from chemical synthesis reactions and water captured from the air by DAC. Direct air capture of CO_2 leads to extraction of water from air as by-product. Up to 1 kg of water can be extracted per kg of CO_2 or about 3.8 kg per kg of liquid transportation fuel leading to a positive water balance.
- We have assumed very large (GW-scale) electrolysis plants and we assume high market penetration of e-fuels leading to huge amounts of oxygen which exceed the industrial oxygen demand. Therefore, no credit has been taken into account for the by-product oxygen as a conservative approach for the purpose of this study (covering very different fuels, suited for very different applications, and stretching over a far time horizons). There may be local opportunities for the use of by-product oxygen which is a topic for site-specific business-case analyses (out of scope of this study).
- For the electrolysis plants, all auxiliaries such as transformer, AC/DC converter, pumps, blowers, and storage tanks are included. Same for costs for civil and engineering work.
- The costs of CO_2 supply via extraction from flue gases and direct air capture (DAC) have been calculated. The costs of CO_2 going into the CO_2 extraction plant is zero as it is considered as waste. The calculation is described in the TECHNICAL ANNEX chapter 7).

The assumptions including learning curves and references for the calculation of CAPEX and OPEX are described in the ECONOMIC ANNEX chapter 7.

Generally, the costs are indicated per GJ of final fuel (1 GJ = 1,000 MJ). Table 21 shows a set of factors to convert GJ to other units.

Table 21: Conversion table

	MJ	kWh	kg H_2	Nm^3 H_2	kg CH_4	Nm^3 CH_4	kg methanol	kg NH_3	l diesel	kg diesel
1 MJ	1	0.278	0.00834	0.0926	0.0200	0.0279	0.0502	0.0535	0.0279	0.0232
1 kWh	3.6	1	0.0300	0.333	0.0720	0.1005	0.181	0.1925	0.100	0.0835
1 kg H_2	120.0	33.32	1	11.1	2.40	3.35	6.02	6.42	3.34	2.78
1 Nm^3 H_2	10.80	3.00	0.090	1	0.216	0.301	0.542	0.577	0.301	0.250
1 kg CH_4	50.0	13.89	0.417	4.63	1	1.40	2.51	2.67	1.39	1.16
1 Nm^3 CH_4	35.82	9.95	0.299	3.32	0.716	1	1.797	1.915	0.998	0.830
1 kg methanol	19.93	5.54	0.166	1.85	0.398	0.556	1	1.066	0.555	0.462
1 kg NH_3	18.7	5.19	0.156	1.73	0.374	0.522	0.938	1	0.521	0.434
1 l diesel	35.9	9.97	0.299	3.32	0.718	1.002	1.801	1.919	1	0.832
1 kg diesel*	43.13	11.98	0.360	3.99	0.862	1.204	2.164	2.306	1.202	1

* Conventional diesel based on EN 590; FT diesel: 44.0 MJ/kg, 0.783 kg/l

2.1.3. Base case results from economic assessment

For 2020 and 2030 a concentrated source with a CO_2 concentration of 45% (flue gas from SMR plants as proxy) has been assumed for CO_2 supply. For 2050, Direct Capture of CO_2 from air has been assumed as base case both for e-fuels produced in Europe and in MENA (Kingdom of Saudi Arabia as proxy in the base case), assuming that Direct Air Capture will be technically developed and anything else may not recognized by the EU regulations.

Sensitivities to the CO_2 source have been included in chapter 2.2.4.

2.1.3.1. E-fuels produced in Europe by zone

Figure 27 shows the base case results for e-fuels produced within Europe by zone (North, Central, South) for time horizon 2020.

Figure 27: Costs of e-fuels produced inside Europe by zone in 2020

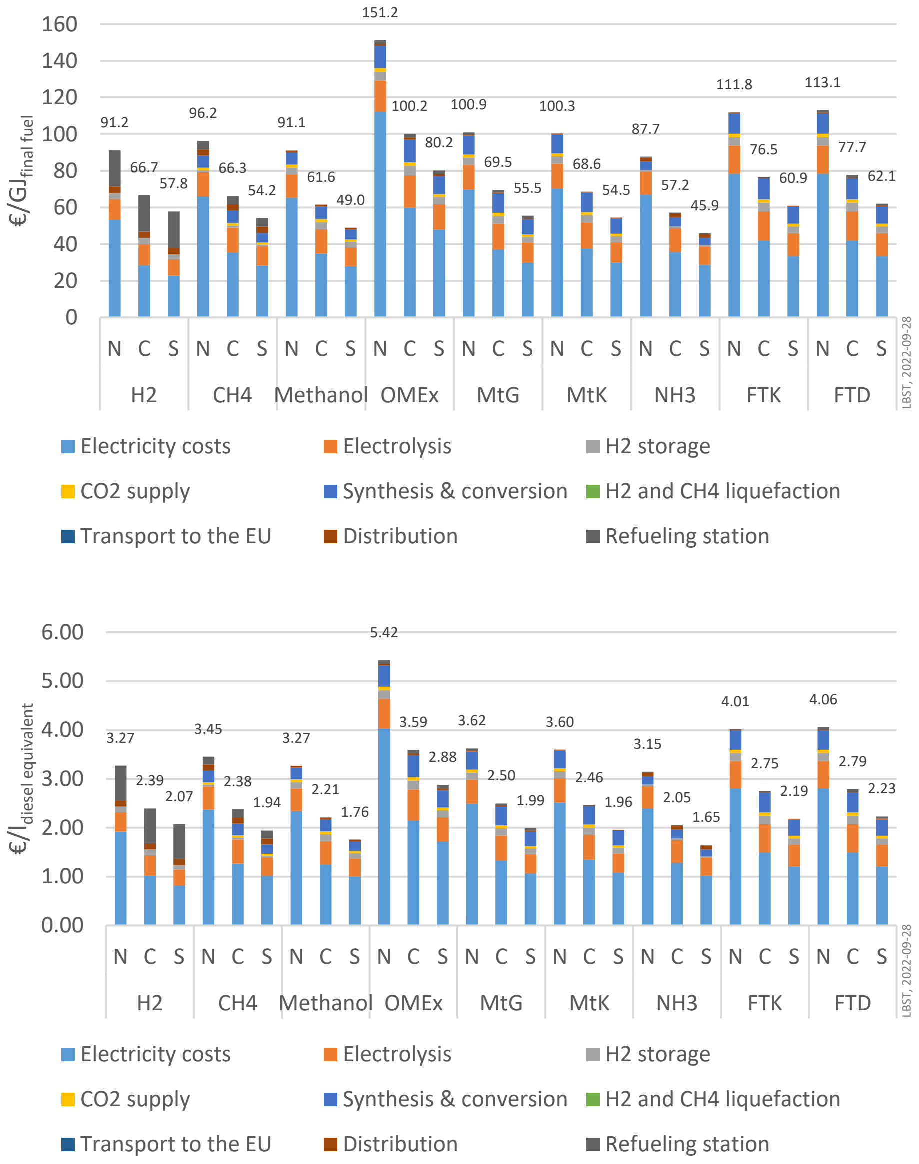


Figure 28 shows the base case results for e-fuels produced within Europe by zone (North, Central, South) for time horizon 2030.

Figure 28: Costs of e-fuels produced inside Europe by zone in 2030

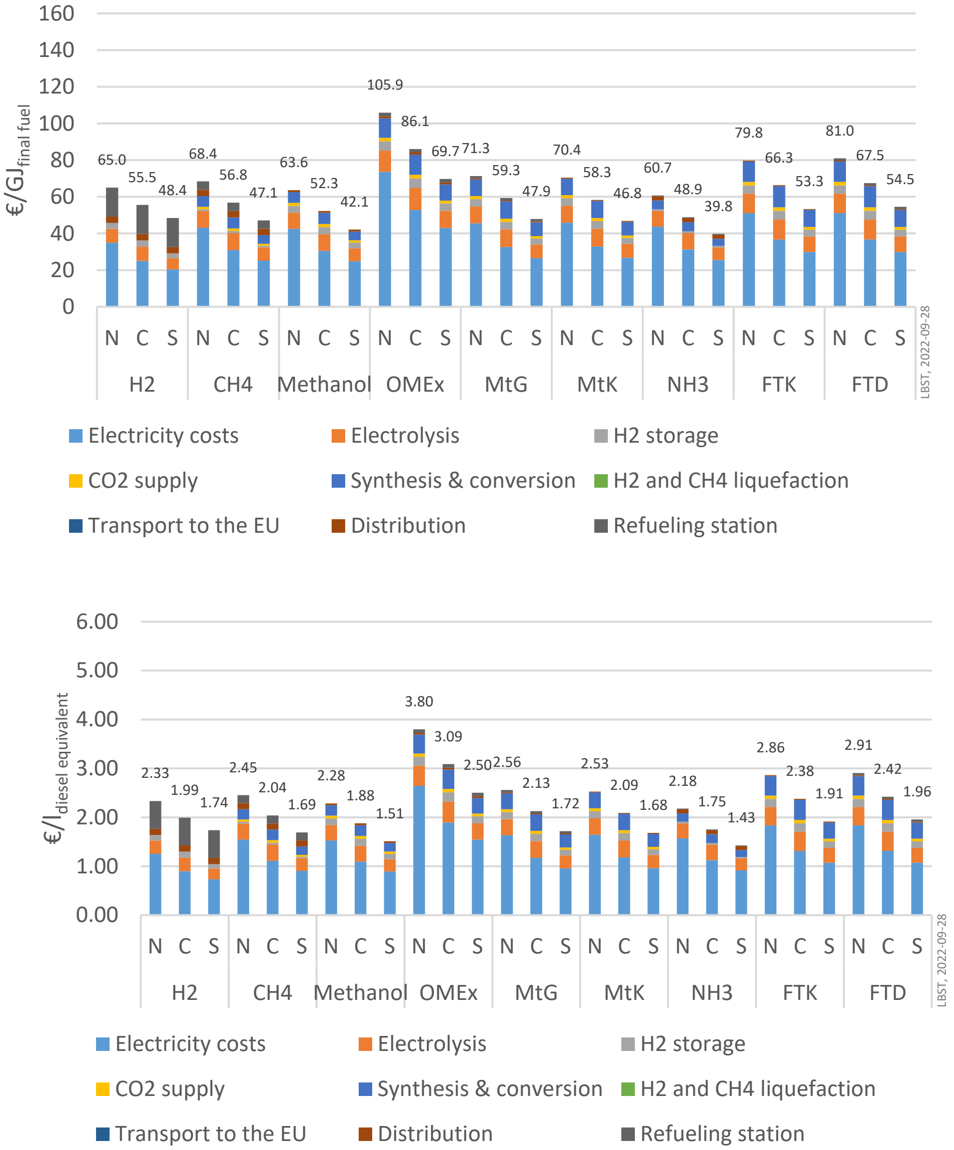
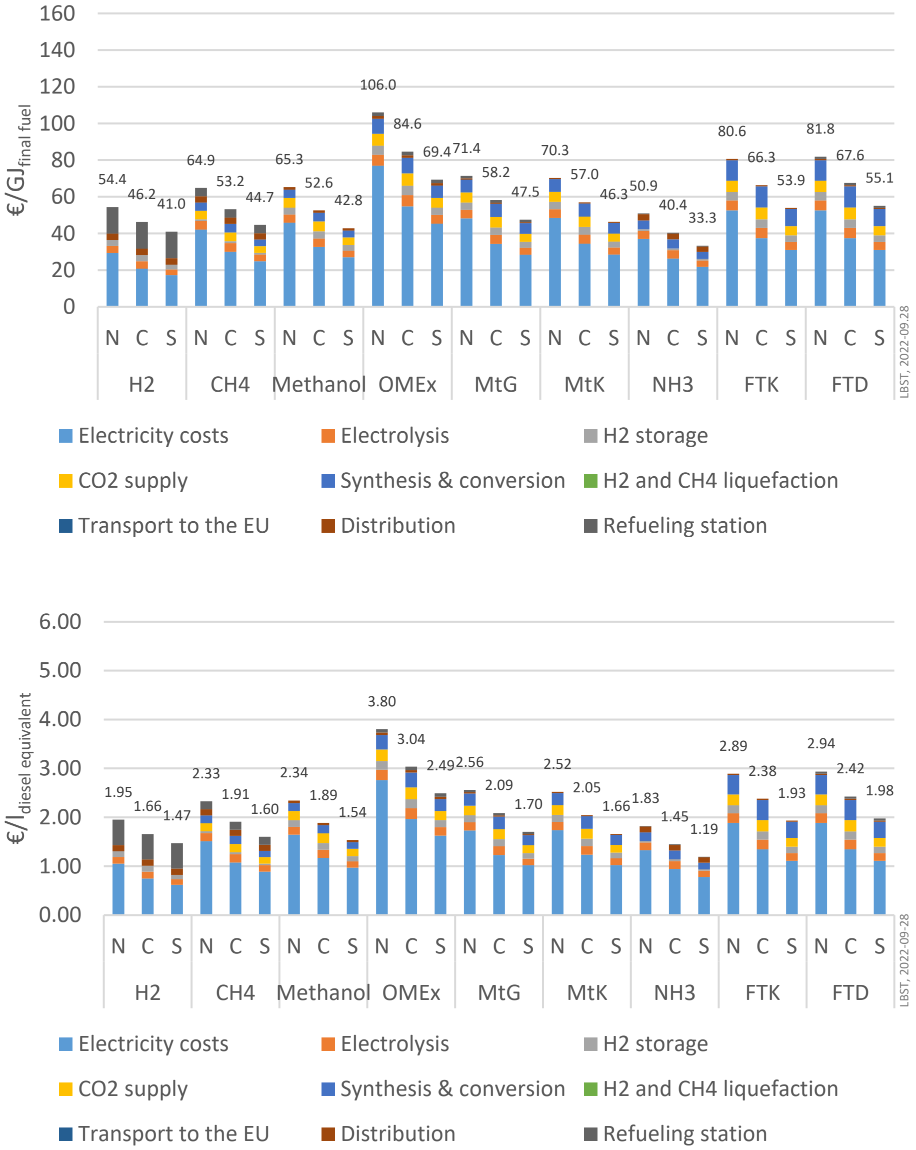


Figure 29 shows the base case results for e-fuels produced within Europe by zone (North, Central, South).

Figure 29: Costs of e-fuels produced inside Europe by zone in 2050



The electricity costs (blue bar) include the electricity consumed by the whole power-to-fuel plant including electrolysis, CO_2 supply and the further processing to final fuel. The costs for the other process steps of the power to fuel plant include CAPEX and OPEX (e. g. maintenance and repair). The cost for electricity has the highest share of the overall costs of fuel supply (up to around 70%) except in case of compressed gaseous hydrogen (CGH_2) in South Europe (around 40%). The reason is that the capital costs per unit of final fuel for the refuelling station dispensing CGH_2 is higher than for other fuels.

Due to the low efficiency of the fuel supply chain the supply of OME_x leads to the highest fuel costs per unit of final fuel.

The costs of fuel supply for kerosene generated via MTK process is lower than for kerosene generated via the FT route because the efficiency of the power-to-kerosene plant involving the MTK process is higher (~50% versus ~45%). It has to be noted that the TRL of the MTK process is lower than that for the production of kerosene via the FT route, so its estimate is less precise and will have to be confirmed with the first units in operation.

2.1.3.2. E-fuels produced in Europe by year

Figure 30 shows the base case results for e-fuels produced in North Europe by year.

Figure 30: Costs of e-fuels in North Europe by year

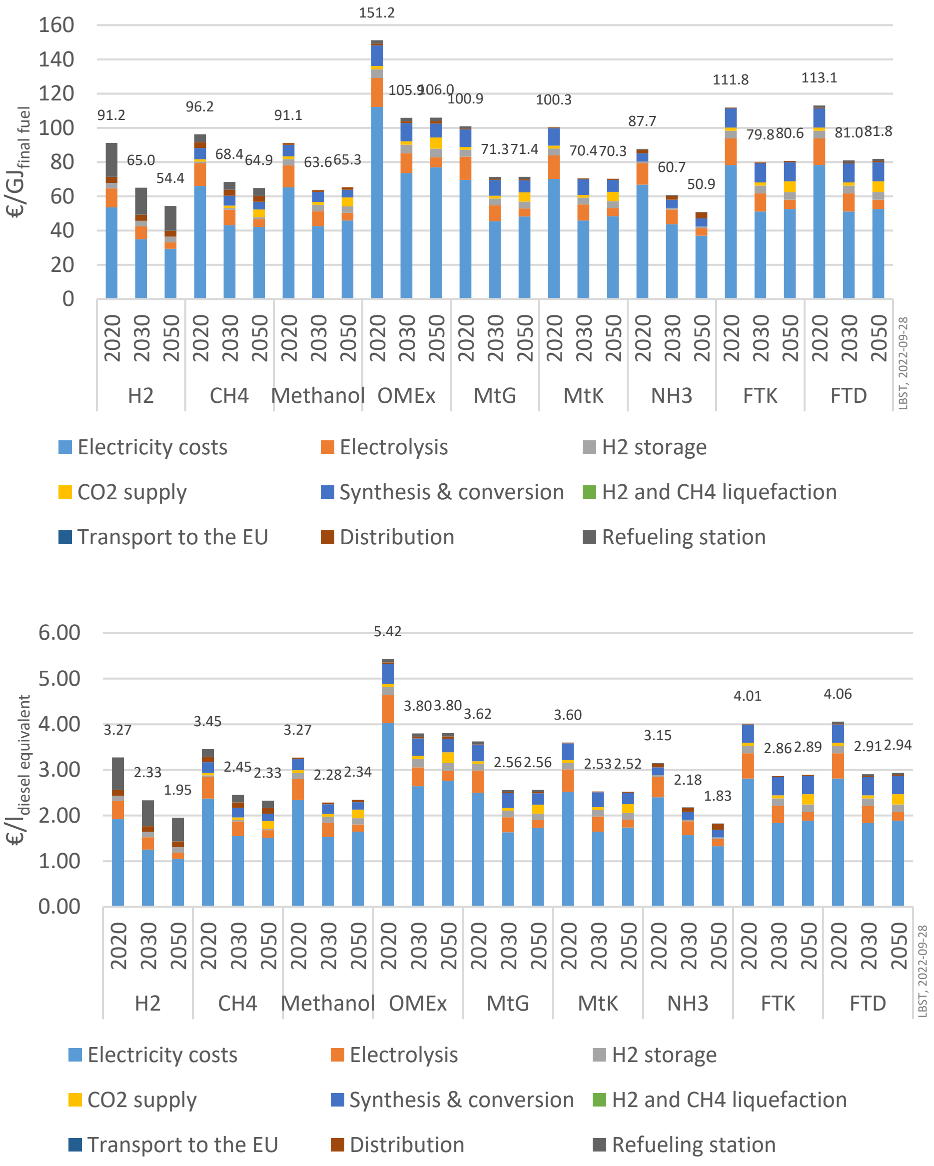


Figure 31: Costs of e-fuels in Central Europe by year

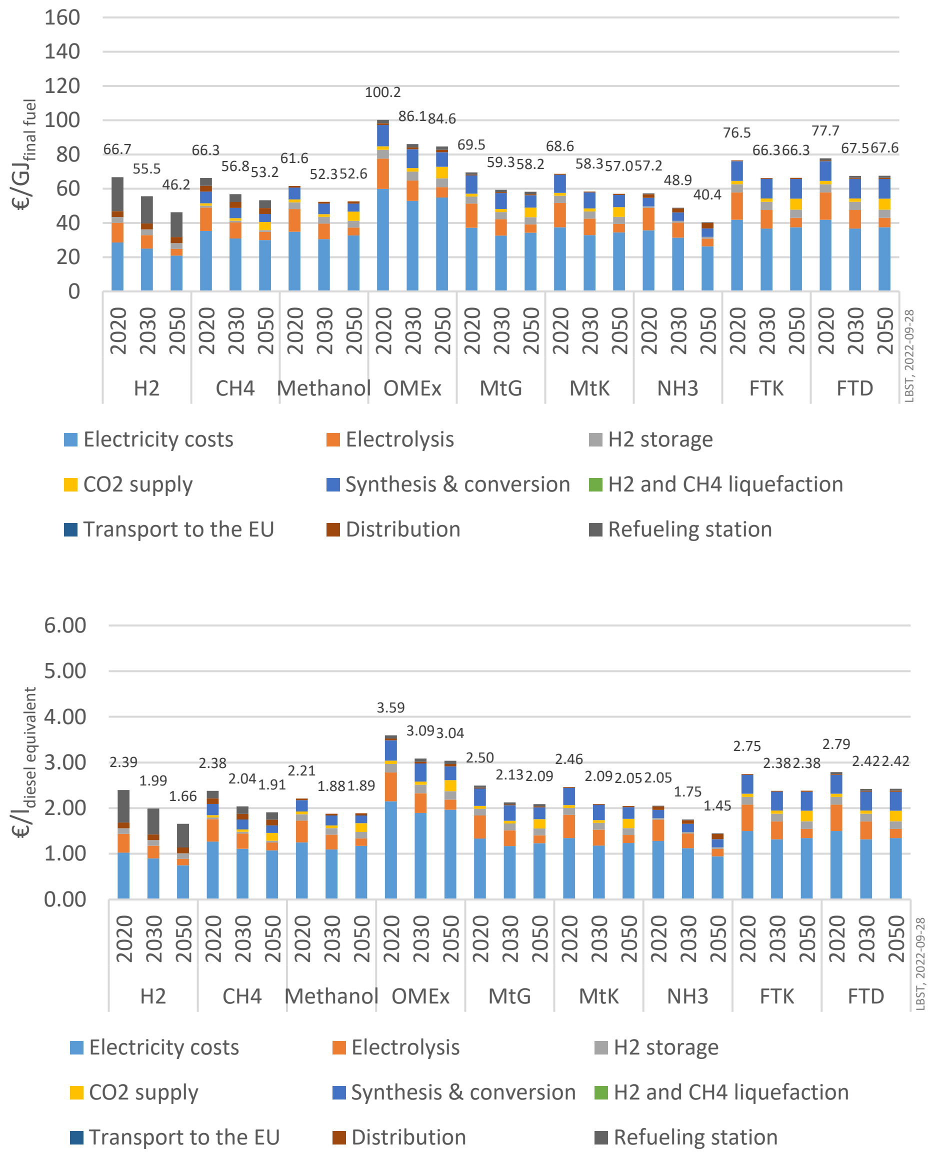
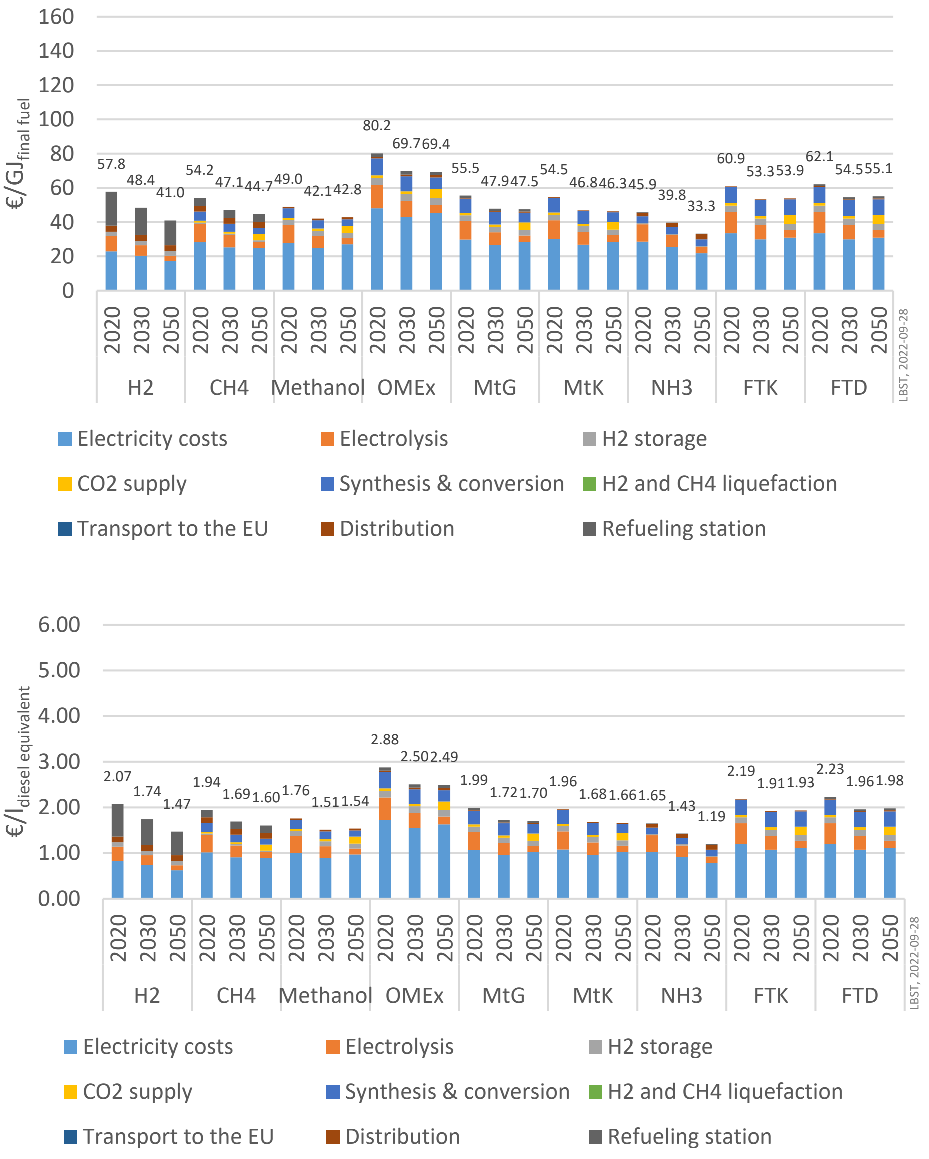


Figure 32 shows the base case results for e-fuels produced in South Europe by year.

Figure 32: Costs of e-fuels in South Europe by year



Decreasing costs of renewable electricity, learning curves and reduction in CAPEX of electrolysers despite the less concentrated CO_2 sources leads to significant lower costs of fuel supply in 2050 versus 2020 (20-30% decrease) and 2030 (10-15% decrease).

2.1.3.3. E-fuels produced in MENA and consumed in Europe

The Kingdom of Saudi-Arabia (KSA) is used as proxy region for a location in MENA. Figure 33 and Figure 34 show the costs for fuels produced in MENA and exported to South Europe (Spain).

Figure 33: Costs of e-fuels imported from MENA by year (€ per GJ)

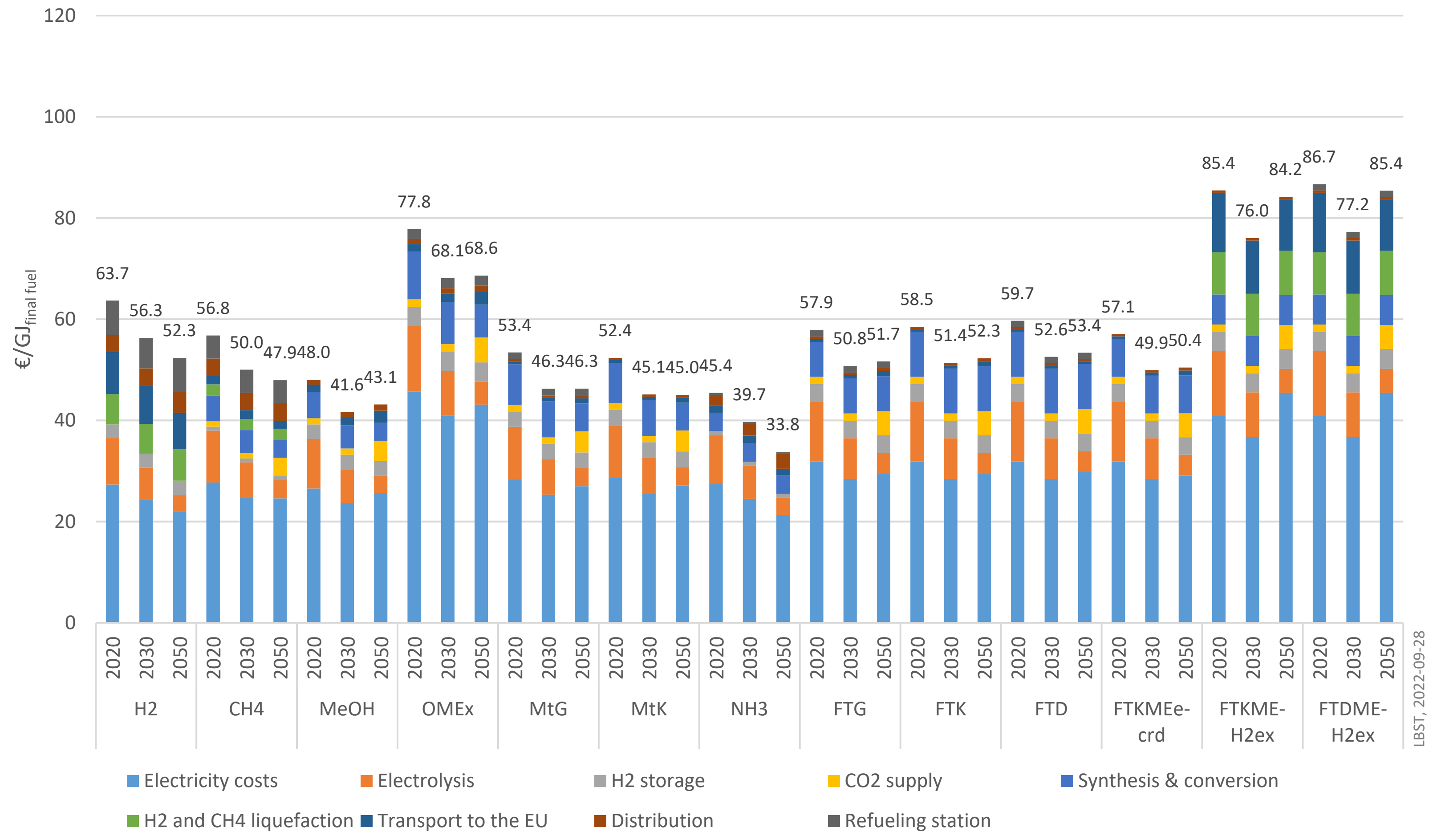
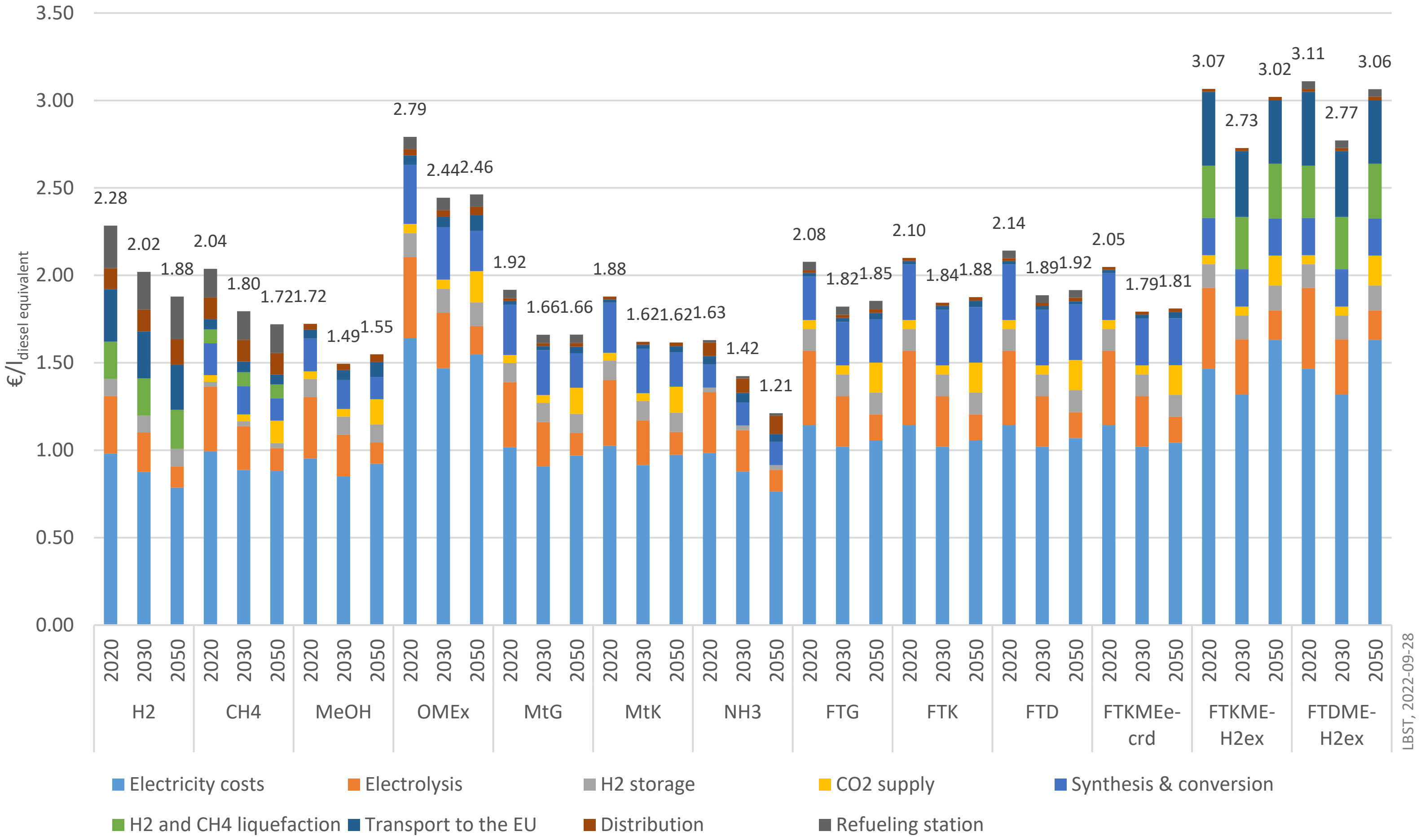


Figure 34: Costs of e-fuels imported from MENA by year (€ per l of diesel equivalent)



The supply of carbon containing fuels show no improvement because of the use of a diluted CO_2 source (DAC) instead of a purely concentrated source. Fischer Tropsch pathways using imported hydrogen from MENA (pathways FTKEME-H2ex and FTDME-H2ex) show an increase between 2030 and 2050. This is because of the use of a diluted CO_2 source (air) instead of a purely concentrated source, as well as the use of 100% H_2 for ship propulsion in 2050. This leads to a higher electricity demand for producing the additional H_2 requirements, and a higher CAPEX for CO_2 supply, which partly reduces the benefit of lower specific electricity costs and lower CAPEX for e-fuel plants in 2050.

2.1.3.4. E-fuels produced in EU and MENA by zone

Figure 35 and Figure 36 shows the base case results for e-fuels produced by zone (North, Central, South, MENA) for time horizon 2050.

Figure 35: Costs of e-fuels by zone in 2050 (€ per GJ)

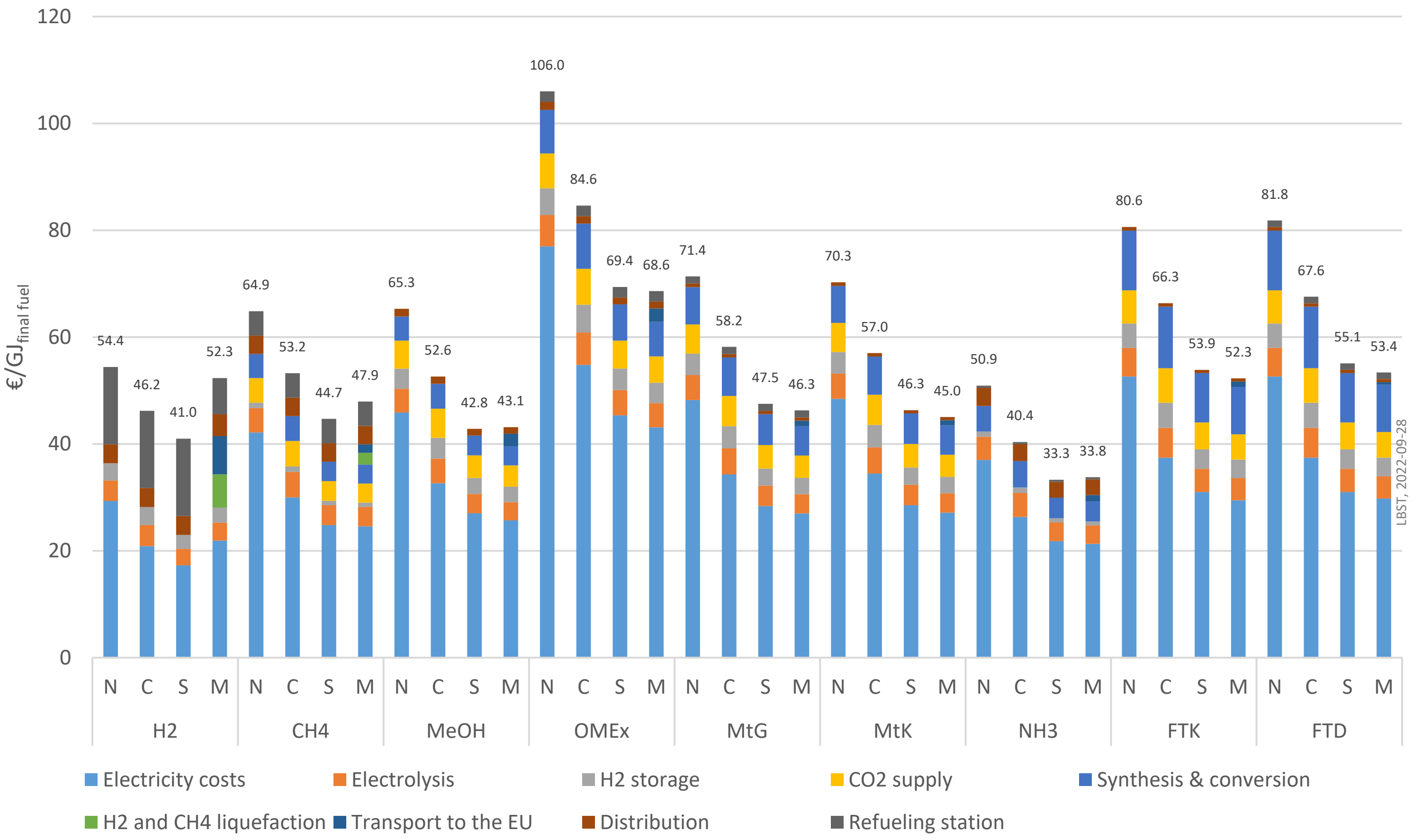
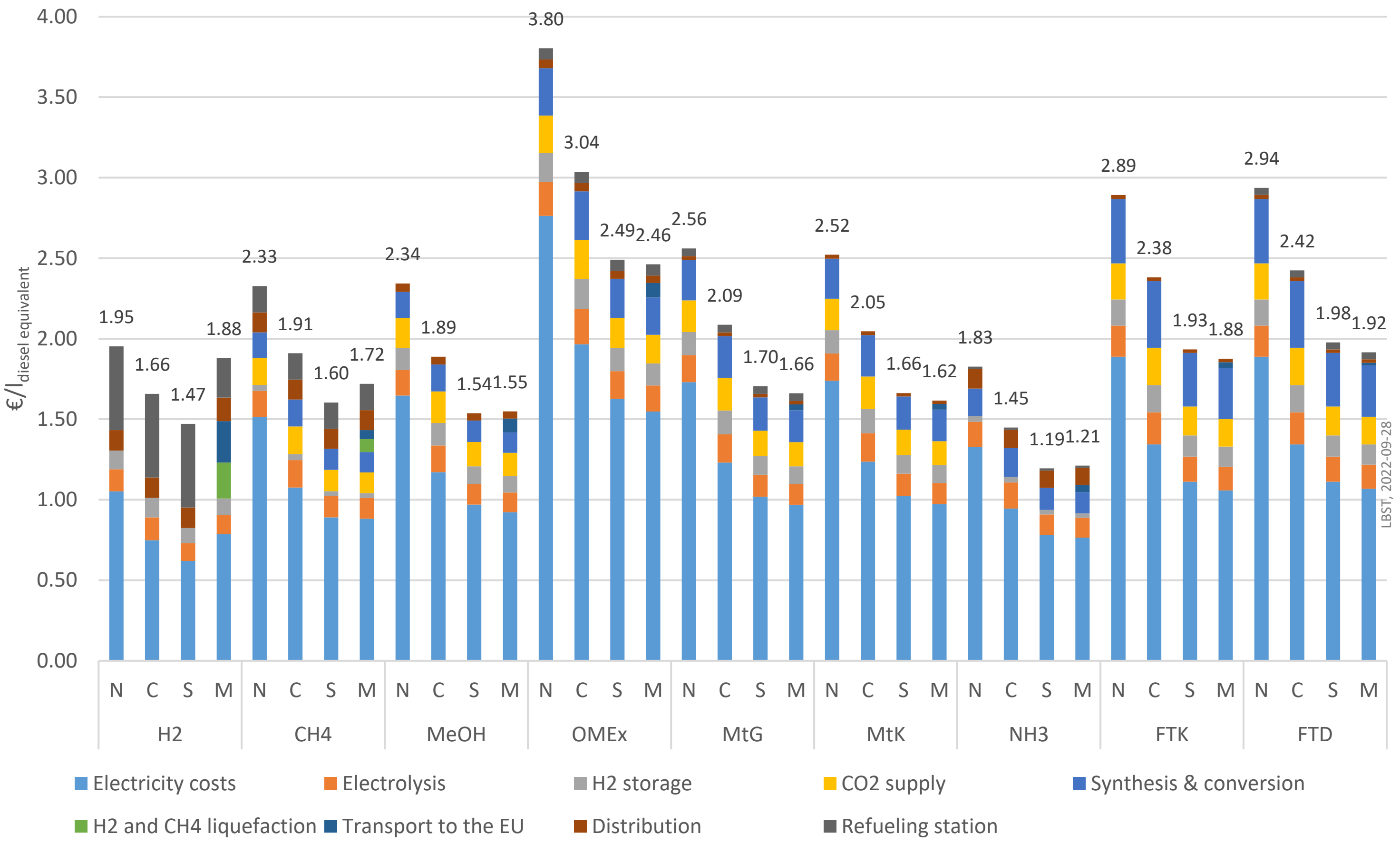


Figure 36: Costs of e-fuels by zone in 2050 (€ per l of diesel equivalent)



The supply of OME_x leads to the highest costs of final fuel because the efficiency of this fuel supply chain is lower than for the other e-fuels.

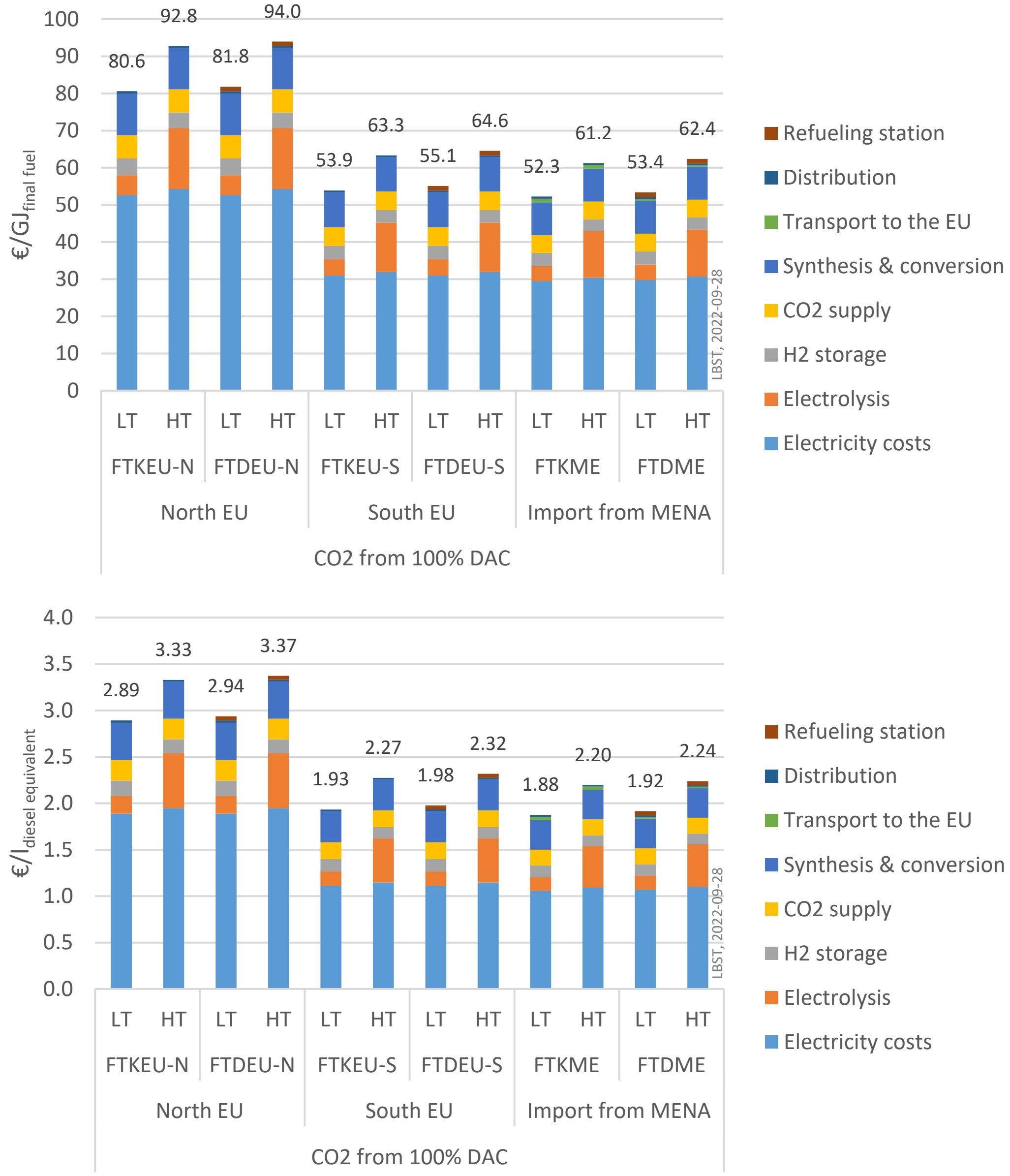
In the case of hydrogen produced inside Europe, the hydrogen is distributed via a hydrogen pipeline grid, compressed at the refuelling station and dispensed to the vehicles. In case of hydrogen produced outside Europe and transported to Europe as liquefied hydrogen (LH_2) the LH_2 is distributed inside Europe by truck. At the refuelling station, the LH_2 is compressed via a cryogenic pump, then vaporized and dispensed as compressed hydrogen (CGH_2) to the vehicles.

The contribution of the refuelling station in the H_2 pathway is lower in the MENA case than in the case where hydrogen is generated in Europe. The reason is that in the case of H_2 delivery via LH_2, both the CAPEX of the H_2 refuelling station and the electricity consumption per unit of dispensed hydrogen are significantly lower than for the case where the H_2 refuelling stations benefit from H_2 delivery via pipeline.

2.1.3.5. E-fuels produced via co-electrolysis versus alkaline electrolysis

Figure 37 shows the costs of fuel supply for selected pathways involving high-temperature co-electrolysis via solid oxide electrolysis cells (SOEC) compared to those involving alkaline electrolysis.

Figure 37: Cost of fuel supply of selected pathways involving co-electrolysis via SOEC compared to those involving alkaline electrolysis in 2050 (CO_2 from DAC)

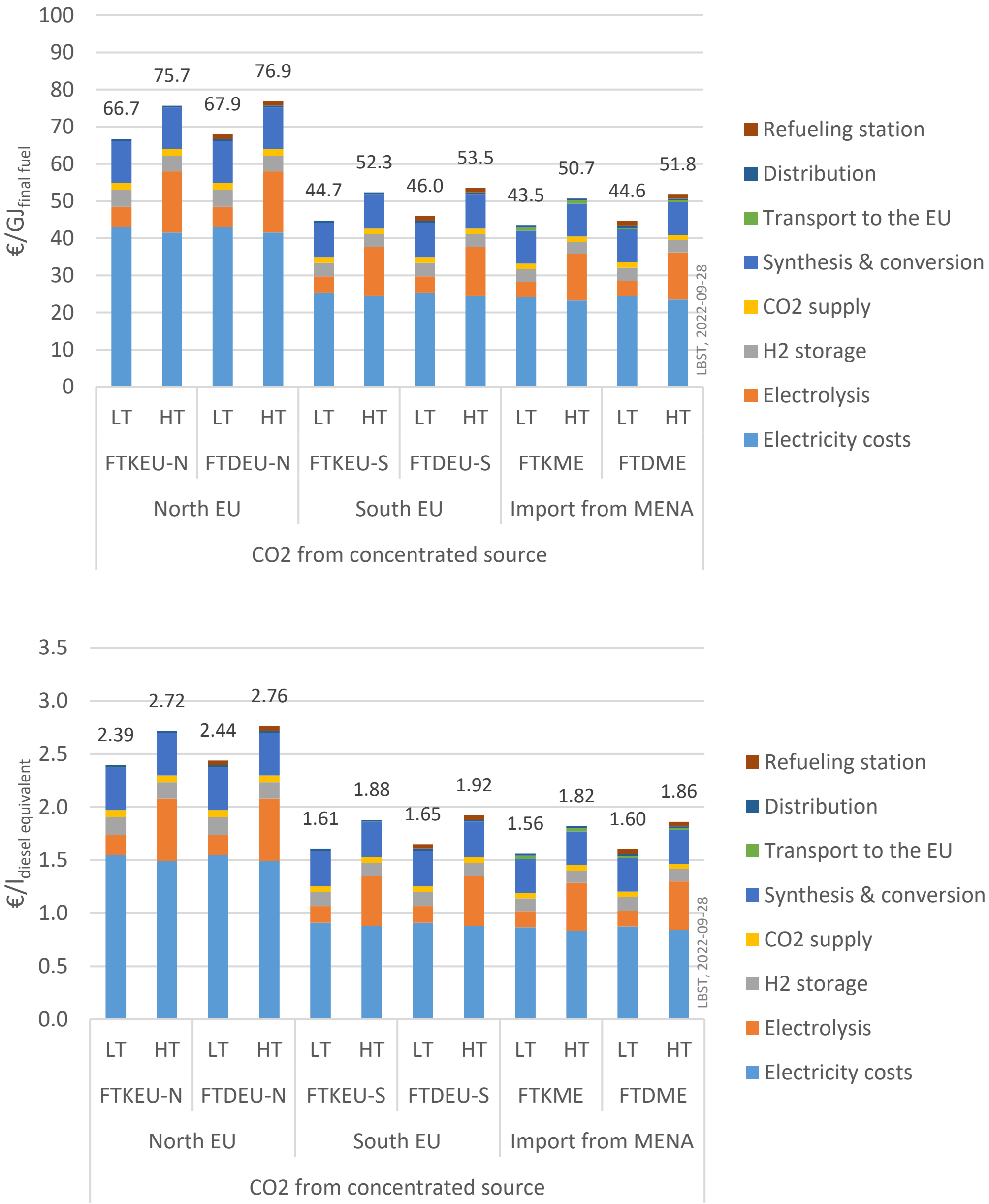


Based on the available data, high temperature co-electrolysis via SOEC has no advantage compared to low temperature electrolysis.

One reason is that the CAPEX for SOEC is significantly higher (see ECONOMIC ANNEX chapter 8.3). Another reason is that in the case SOEC is combined with direct air capture (DAC), large amounts of heat are already required for the DAC. Additional high temperature (>100°C) heat for the steam supply for SOEC has to be generated by electrically heated steam generation. The total efficiency of co-electrolysis including steam supply amounts to 71.5% (efficiency based on the electricity input alone: 82.1%), which is lower than the efficiency assumed for alkaline electrolysis in 2050 (75%).

If CO_2 from concentrated sources is used, the electricity requirement for the whole PtL plant decreases but cannot compensate the higher CAPEX of the SOEC (Figure 38).

Figure 38: Cost of fuel supply of selected pathways involving co-electrolysis via SOEC compared to those involving alkaline electrolysis in 2050 (CO_2 from concentrated source)



LBST, 2022-09-28

KEY MESSAGES – BASE CASE COST RESULTS

There is a strong correlation between energy efforts for fuel production and associated costs. E-fuels that are less energy-intensive to produce generally lead to lower costs of fuel production. The cost for electricity has the highest share of the overall costs of fuel supply (up to around 70%).

Based on the assumptions taken, this economic assessment of e-fuels towards 2050 shows that fuel supply costs range between 1.6 and 4.1 € per litre of diesel-equivalent in the short and between 1.2 and 2.9 € per litre of diesel equivalent in the long term if the outlier OMEx is excluded. For OMEx, the fuel supply costs range between 2.8 and 5.4 € per l of diesel equivalent in the short term and between 2.5 and 3.8 € per l of diesel equivalent in the long term.

E-fuels that are less energy-intensive generally lead to lower costs of fuel supply. Fuel costs per car-km for H_2 are lower than for conventional liquid fuels because Hydrogen fuel cell electric vehicles (FCEV) show a significantly lower fuel consumption due to a factor ~2 higher power-train efficiency. However, the powertrain analysis is out of the scope of this report.

2.2. SENSITIVITY ANALYSES OF KEY ECONOMIC FACTORS

For some selected pathways, a sensitivity analysis to key economic factors is carried out (Table 22). The pathways are described briefly in Table 15 in chapter 2.1 and detailed in the ECONOMIC ANNEX chapter 8.4. Note that similar parameter variations have been grouped together in case of few pathways (see below).

Table 22: Matrix of pathways and sensitivities analysed

	Pathway code	4.1: Different electricity price scenarios	4.2: Different discount rate	4.3: Electricity source: 100% Wind electricity	4.3: Electricity source: 100% PV electricity	4.4: CO_2 source: 100% DAC	4.4: CO_2 source: 100% SMR	4.4: CO_2 source: 100% NGCC	4.4: Use of CO_2 captured in EU for synthesis in MENA	4.5: Use of NH3 as H2 carrier to feed synthesis processes	4.5: Use of MCH as H_2 carrier to feed synthesis processes	4.5: Use of MeOH as H_2 carrier to feed synthesis processes	4.6: Longer transportation distance inside Europe	4.6: Other transport types inside Europe (truck, ship)	4.7: Long haul from North Africa (distance + CO_2 origin)	4.7: Long haul from Australia, Chile (distance only)	4.8: Larger/smaller e-fuels plant size
1	H2EU-N	X	X										X	X			X
2	CH4EU-N	X	X										X	X			X
3	MeOHEU-N	X	X														X
4	OMExEU-N	X	X														X
5	MTGEU-N	X	X														X
6	MTKEU-N	X	X														X
7	NH3EU-N	X	X														X
8	FTKEU-N	X	X	X	X	X	X	X					X	X			X
9	FTDEU-N	X	X														
28	H2ME-Liq	X	X												X	X	X

	Pathway code	4.1: Different electricity price scenarios	4.2: Different discount rate	4.3: Electricity source: 100% Wind electricity	4.3: Electricity source: 100% PV electricity	4.4: CO_2 source: 100% DAC	4.4: CO_2 source: 100% SMR	4.4: CO_2 source: 100% NGCC	4.4: Use of CO_2 captured in EU for synthesis in MENA	4.5: Use of NH3 as H2 carrier to feed synthesis processes	4.5: Use of MCH as H_2 carrier to feed synthesis processes	4.5: Use of MeOH as H_2 carrier to feed synthesis processes	4.6: Longer transportation distance inside Europe	4.6: Other transport types inside Europe (truck, ship)	4.7: Long haul from North Africa (distance + CO_2 origin)	4.7: Long haul from Australia, Chile (distance only)	4.8: Larger/smaller e-fuels plant size
29	CH4ME-Liq	X	X													X	X
30	MeOHME	X	X														X
31	OMExME	X	X														X
32	MTGME	X	X														X
33	MTKME	X	X														X
34	NH3ME	X	X														X
35	FTGME	X	X														
36	FTKME	X	X	X	X	X	X	X	X						X	X	X
37	FTDME	X	X														
38	FTKMEe-crd	X	X														X
39	FTKME-H2ex	X	X							X	X	X					X
40	FTDME-H2ex	X	X														X

Sensitivities have been calculated for the years 2020, 2030, and 2050. In this chapter, results are depicted for the year 2050. For the years 2020 and 2030, refer to respective sub-chapters 8.5 in the ECONOMIC ANNEX.

2.2.1. Different electricity cost scenarios

Two electricity cost variants have been assessed in this study:

- Optimistic (-50% of current assumptions)
- Pessimistic (+50% of current assumptions)

Figure 39, Figure 138, and Figure 139 show the results for different electricity price scenarios for 2020, 2030, and 2050 with CO_2 from concentrated source (flue gas from SMR as proxy) in 2020 and 2030, and CO_2 from a mix of sources in 2050. The result charts for the year 2050 is depicted hereunder. For the years 2020 and 2030, refer to ECONOMIC ANNEX chapter 8.5.1.

Figure 39: Sensitivity to different renewable electricity costs by region for 2050 (CO_2 from diluted CO_2 source)

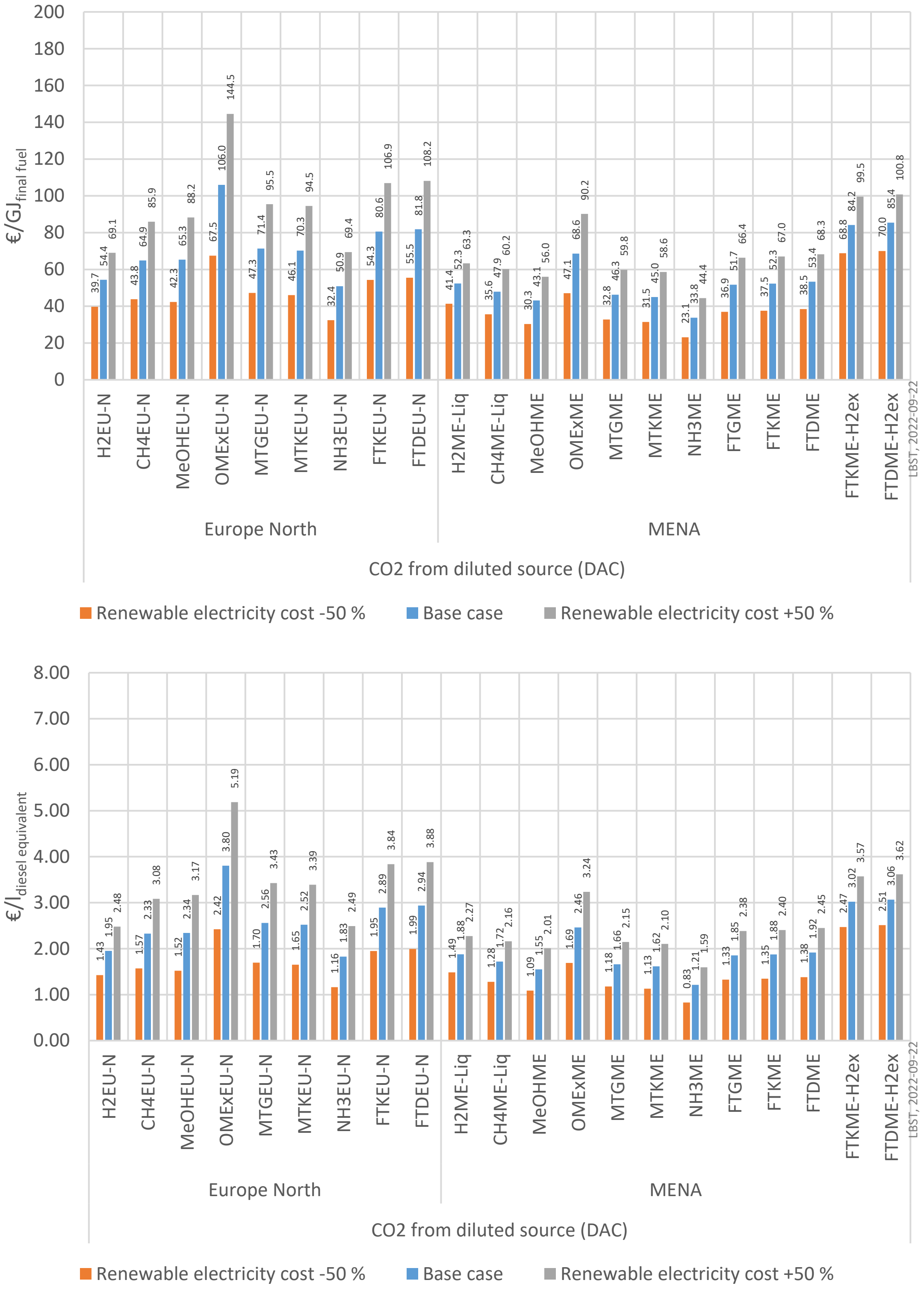


Figure 40 and Figure 41 show the sensitivity to different renewable electricity costs by year for selected fuels produced and consumed in North Europe.

Figure 40: Sensitivity to different renewable electricity costs by year for CGH_2 in North Europe (H2EU-N)

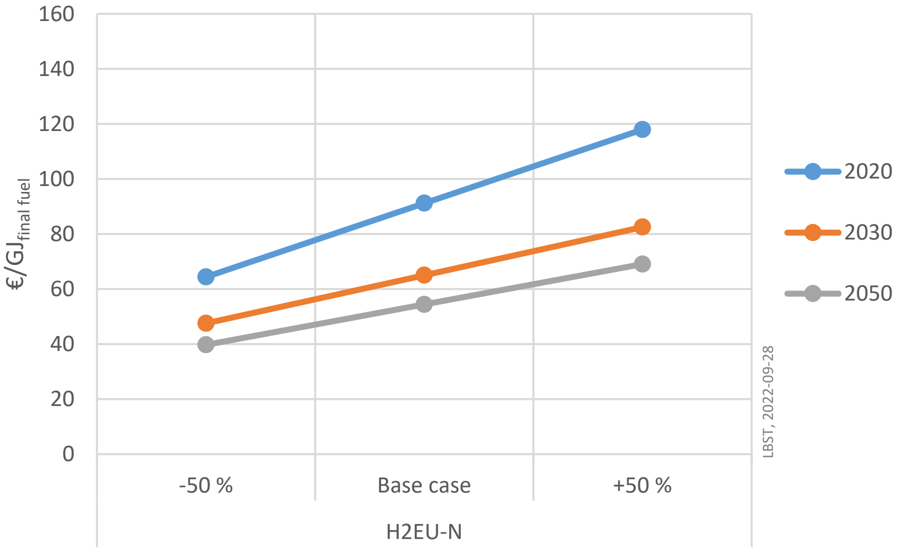


Figure 41: Sensitivity to different renewable electricity costs by year for Kerosene in North Europe (FTKEU-N)

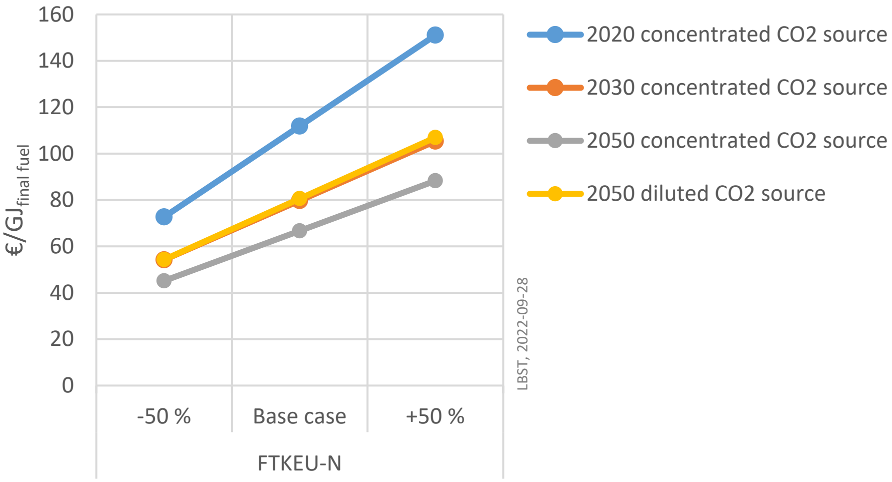


Figure 42, Figure 43, Figure 44, and Figure 45 show the sensitivity by different renewable electricity cost by year for the supply of selected fuels imported from MENA and consumed in in South Europe.

Figure 42: Sensitivity to different renewable electricity costs by year for LH_2 imported from MENA and dispensed as CGH_2 (H2ME-Liq)

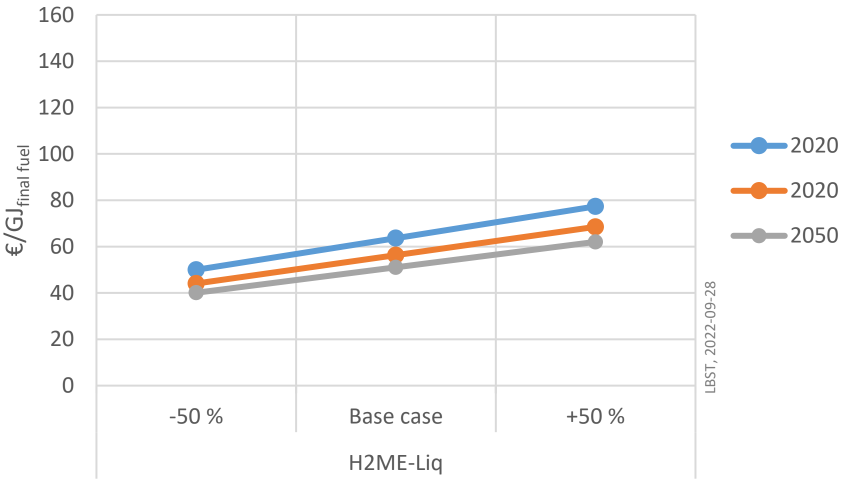


Figure 43: Sensitivity to different renewable electricity costs by year for FT gasoline imported from MENA (FTGME)

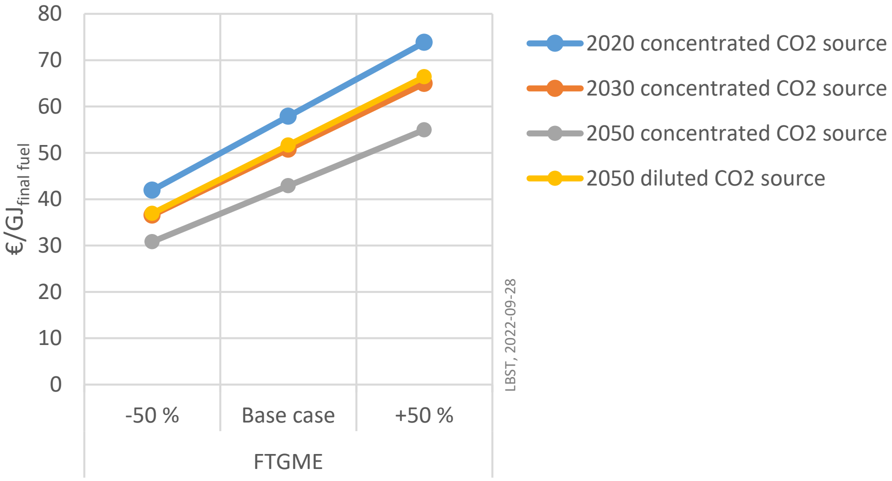


Figure 44: Sensitivity to different renewable electricity costs by year for FT kerosene imported from MENA (FTKME)

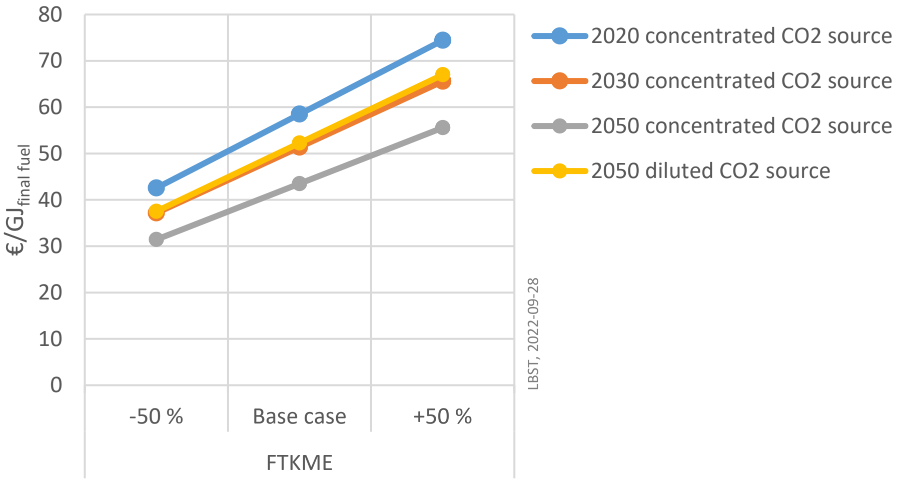
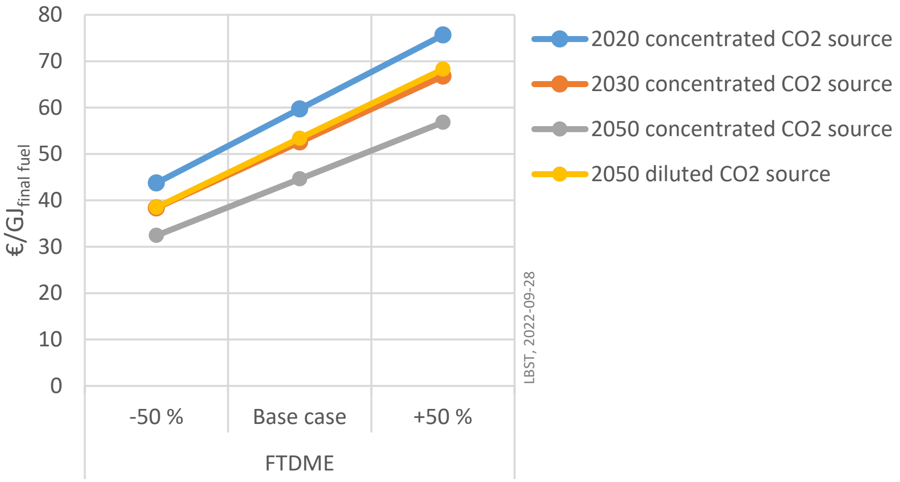


Figure 45: Sensitivity to different renewable electricity costs by year for FT diesel imported from MENA (FTDME)



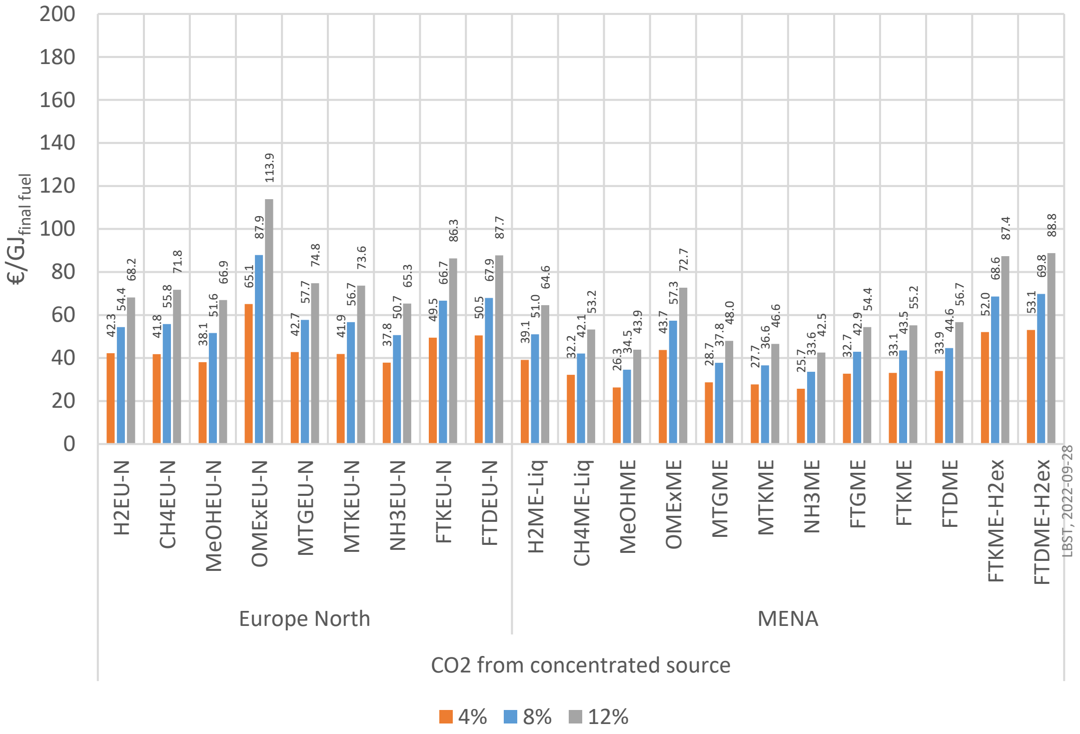
Variation of the electricity costs have a high impact on the overall cost of e-fuel supply.

2.2.2. Different discount rate

Two discount rate variants are compared to the baseline assumptions (8%):

- High (12%)
- Low (4%)

Figure 46: Sensitivity to different discount rates by region for 2050 (CO_2 from concentrated source)



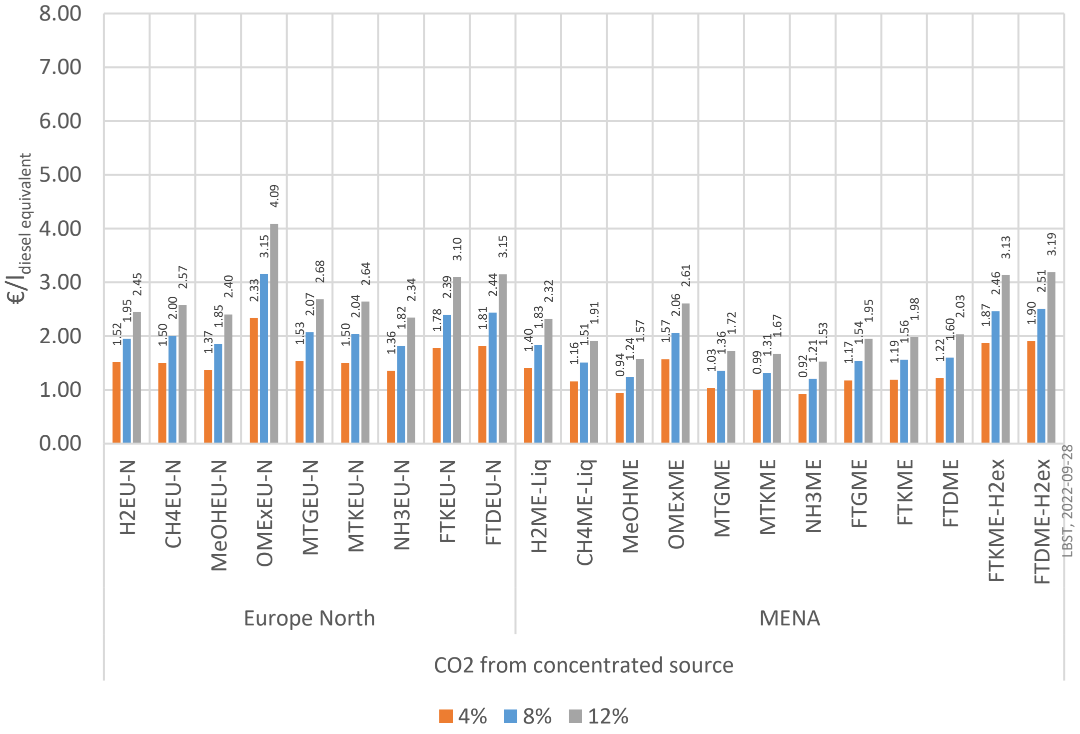


Figure 47: Sensitivity to different discount rate by region for 2050 (CO_2 from diluted source)

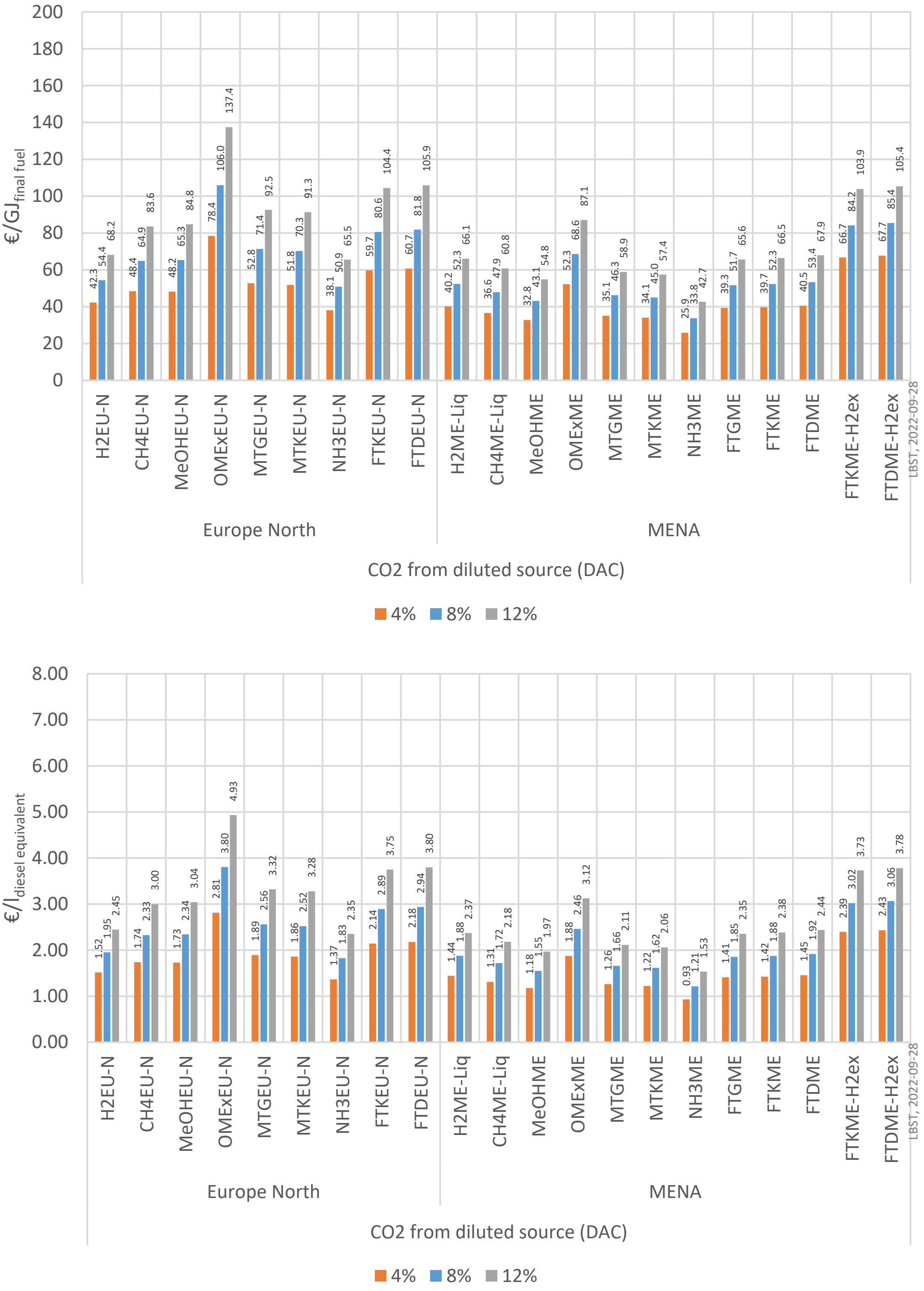


Figure 48 and Figure 49 show the sensitivity to different discount rates by year for selected fuels produced and consumed in North Europe.

Figure 48: Sensitivity to different discount rates by year for CGH_2 in North Europe (H2EU-N)

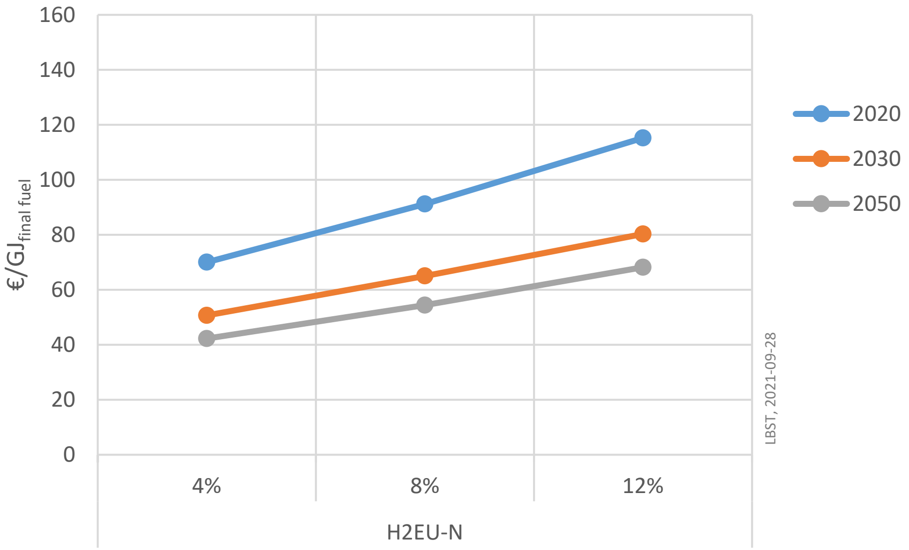


Figure 49: Sensitivity to different discount rates by year for kerosene in North Europe (FKEU-N)

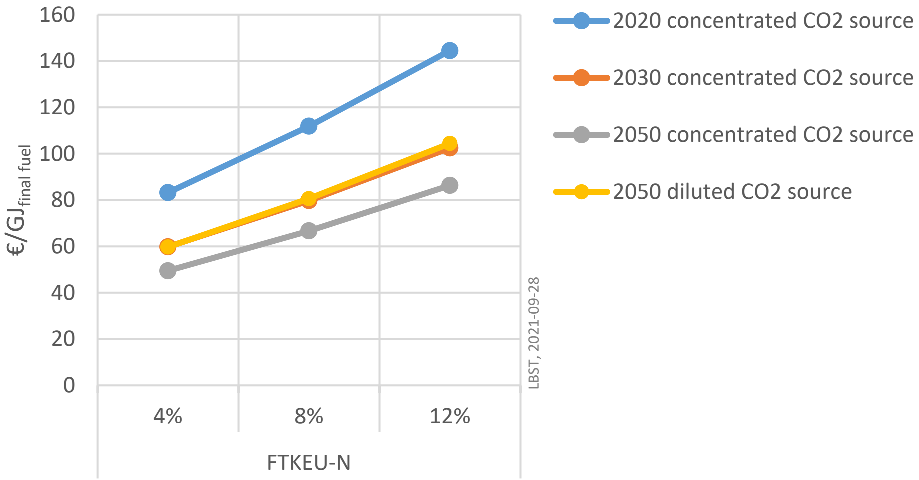


Figure 50, Figure 51, Figure 52, and Figure 53 show the sensitivity to different discount rates by year for the supply of selected fuels imported from MENA and consumed in in South Europe.

Figure 50: Sensitivity to different discount rates by year for LH_2 imported from MENA and dispensed as CGH_2 (H2ME-Liq)

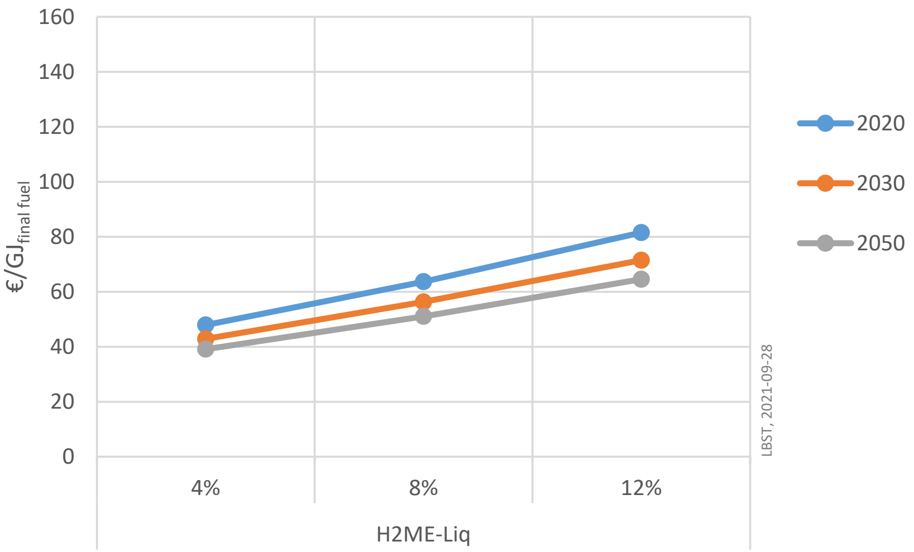


Figure 51: Sensitivity to different discount rates by year for FT gasoline imported from MENA (FTGME)

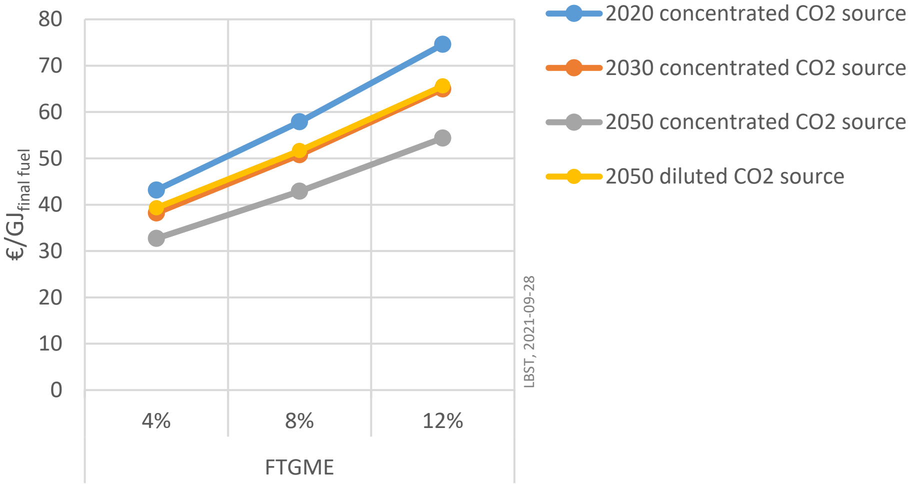


Figure 52: Sensitivity to different discount rates by year for FT kerosene imported from MENA (FTKME)

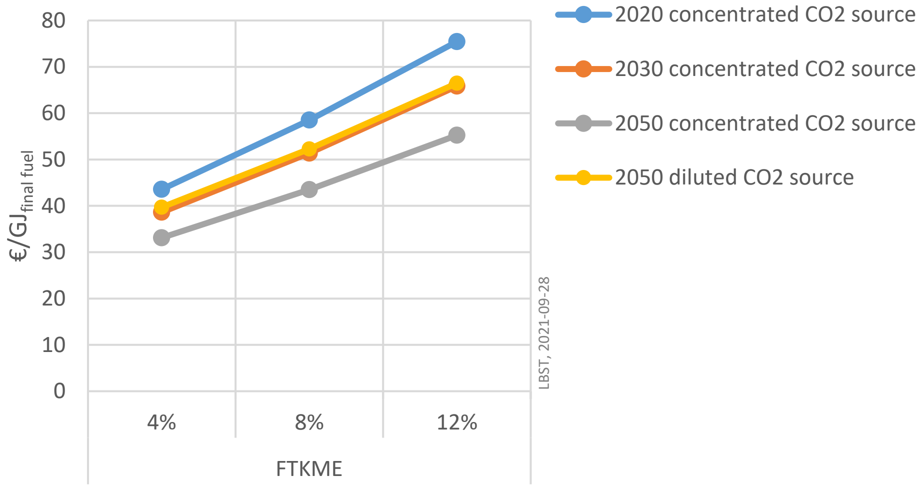
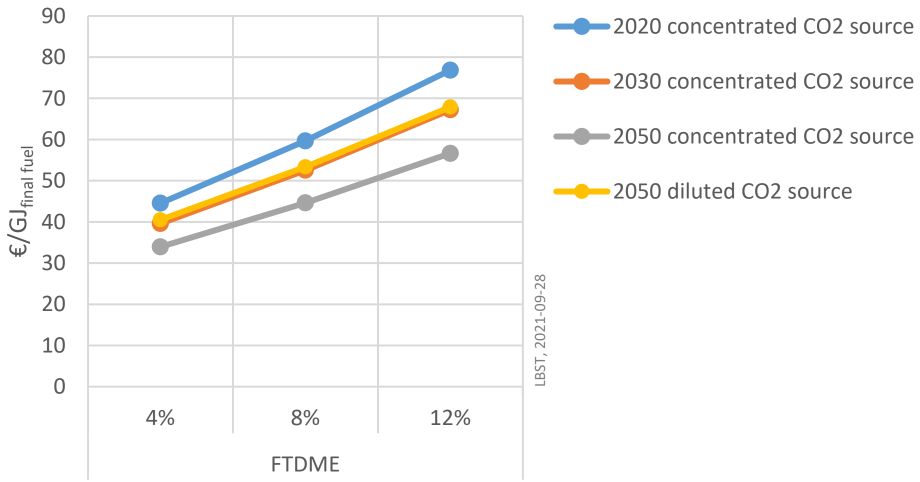


Figure 53: Sensitivity to different discount rates by year for FT diesel imported from MENA (FTDME)



Variation of the discount rate has a high impact on the overall cost of e-fuel supply, leading to similar results to the variation of the electricity cost in chapter 0.

2.2.3. Electricity source

For this sensitivity analysis, the electricity source has been changed for selected pathways (FT kerosene produced in North Europe and in MENA):

- 100% Wind electricity
- 100% PV electricity

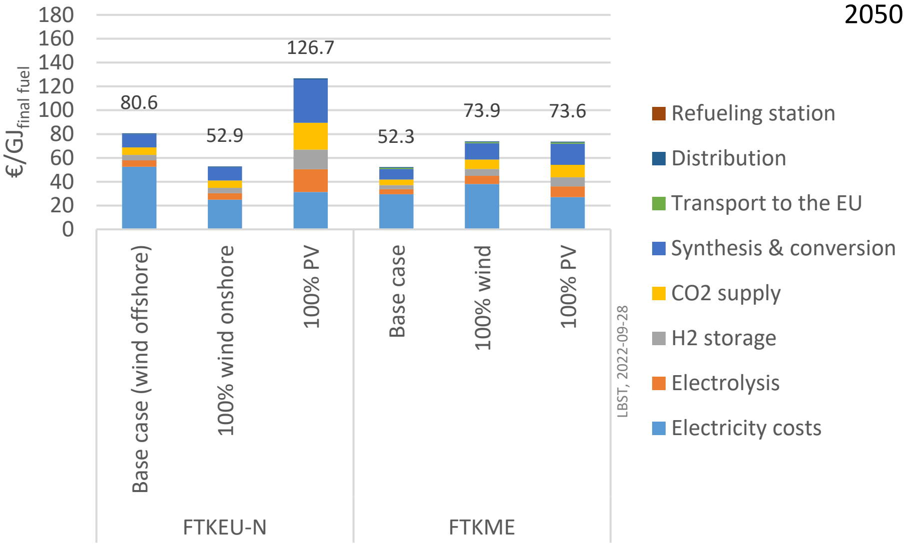
In case of North Europe, offshore wind farms are used as electricity source in the base case. For sensitivity by electricity source, 100% onshore wind has been used as electricity source both for North Europe and MENA.

The references and a detailed description of the assumptions are presented in the ECONOMIC ANNEX, chapter 8.2.3.

Table 23: E-fuel costs in 2050 depending on electricity source

	FTKEU-N			FTKME		
	Base case (wind offshore)	**100% wind (onshore)**	**100% PV**	**Base case (PV/wind hybrid)**	**100% wind**	**100% PV**
€/GJ$_{\text{final fuel}}$						
Electricity costs	52.6	24.9	31.4	29.5	38.1	27.1
Electrolysis	5.4	5.4	19.0	4.1	6.8	8.9
H_2 storage	4.6	4.6	16.5	3.5	5.8	7.7
CO_2 supply	6.2	6.2	22.6	4.7	7.9	10.5
Synthesis & upgrading	11.2	11.2	36.4	8.9	13.7	17.7
Transport to the EU	0.0	0.0	0.0	1.0	1.0	1.0
Distribution	0.7	0.7	0.8	0.6	0.6	0.6
Refuelling station	0.0	0.0	0.0	0.0	0.0	0.0
Total	**80.6**	**52.9**	**126.7**	**52.3**	**73.9**	**73.6**
€/l$_{\text{diesel equivalent}}$ (based on conventional diesel EN 590)						
Electricity costs	1.89	0.89	1.13	1.06	1.37	0.97
Electrolysis	0.19	0.19	0.68	0.15	0.24	0.32
H_2 storage	0.16	0.16	0.59	0.12	0.21	0.28
CO_2 supply	0.22	0.22	0.81	0.17	0.28	0.38
Synthesis & upgrading	0.40	0.40	1.31	0.32	0.49	0.64
Transport to the EU	0.00	0.00	0.00	0.04	0.04	0.04
Distribution	0.02	0.02	0.03	0.02	0.02	0.02
Refuelling station	0.00	0.00	0.00	0.00	0.00	0.00
Total	2.89	1.90	4.55	1.88	2.65	2.64

Figure 54: E-fuel costs in 2050 depending on electricity source for FT Kerosene produced in North Europe and MENA



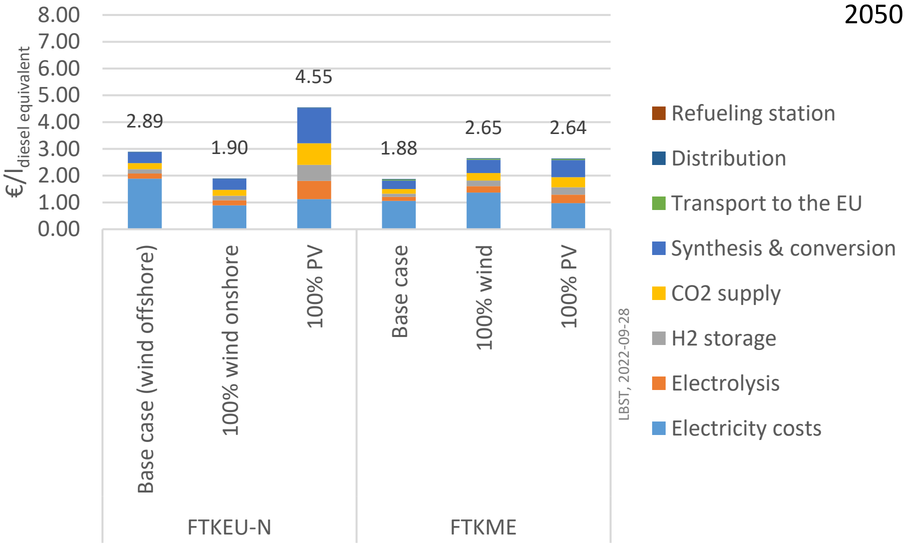


Figure 55 and Figure 56 show the costs of FT kerosene in North Europe and the costs of FT kerosene imported from MENA depending on the electricity source by year.

Figure 55: Costs of FT e-kerosene in North Europe depending on the electricity source by year

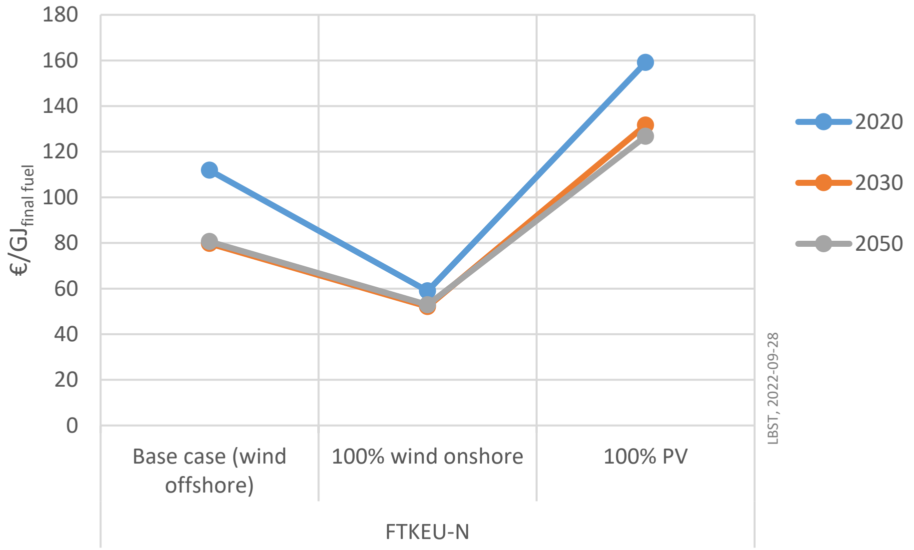
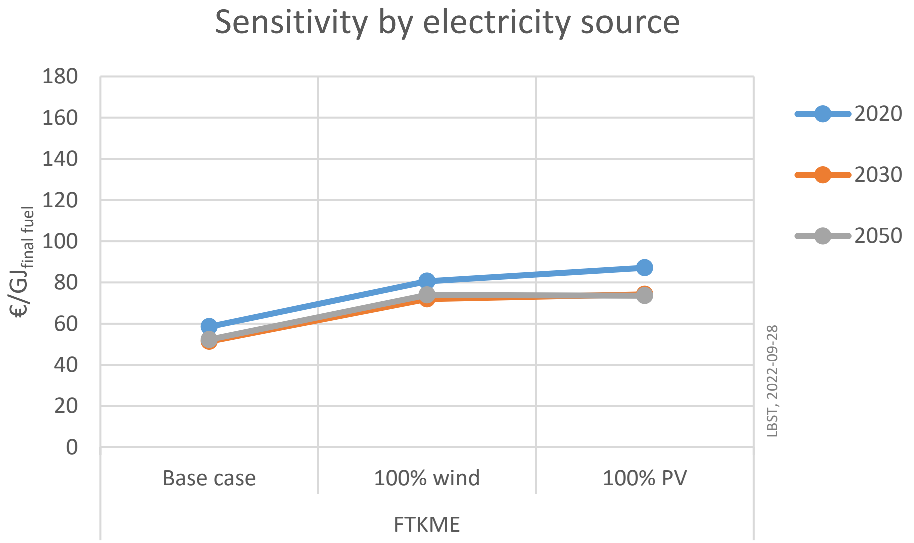


Figure 56: Costs of FT e-kerosene imported from MENA depending on the electricity source by year



For North Europe, 100% wind offshore is assumed. The costs of electricity from offshore wind power are higher than those for onshore wind power. Based on the available data, the CAPEX and the OPEX for offshore wind are higher than those for onshore wind (see ECONOMIC ANNEX, chapter 8.2.1). The higher equivalent full load period cannot compensate the higher CAPEX and OPEX. Using hydropower with an equivalent full load period of 8000 h/yr would lead to lower costs of fuel supply, provided that the CAPEX for the hydropower plant is not significantly higher and as a result overcompensates the higher equivalent full load period. However, at least in Europe, the potential for hydropower is already largely exploited. Furthermore, the social acceptance for the construction of new large hydropower plants in the GW-scale is low.

For MENA, a PV/wind hybrid power station is assumed. Wind and PV are complementary. High wind speeds often occur in periods where the solar irradiation is low and vice versa. As a result, the equivalent full load period of the power-to-fuel plant is higher in the base case in MENA. Wind only or PV only leads to a lower equivalent full load period of the power-to-fuel plant leading to higher capital costs and production costs.

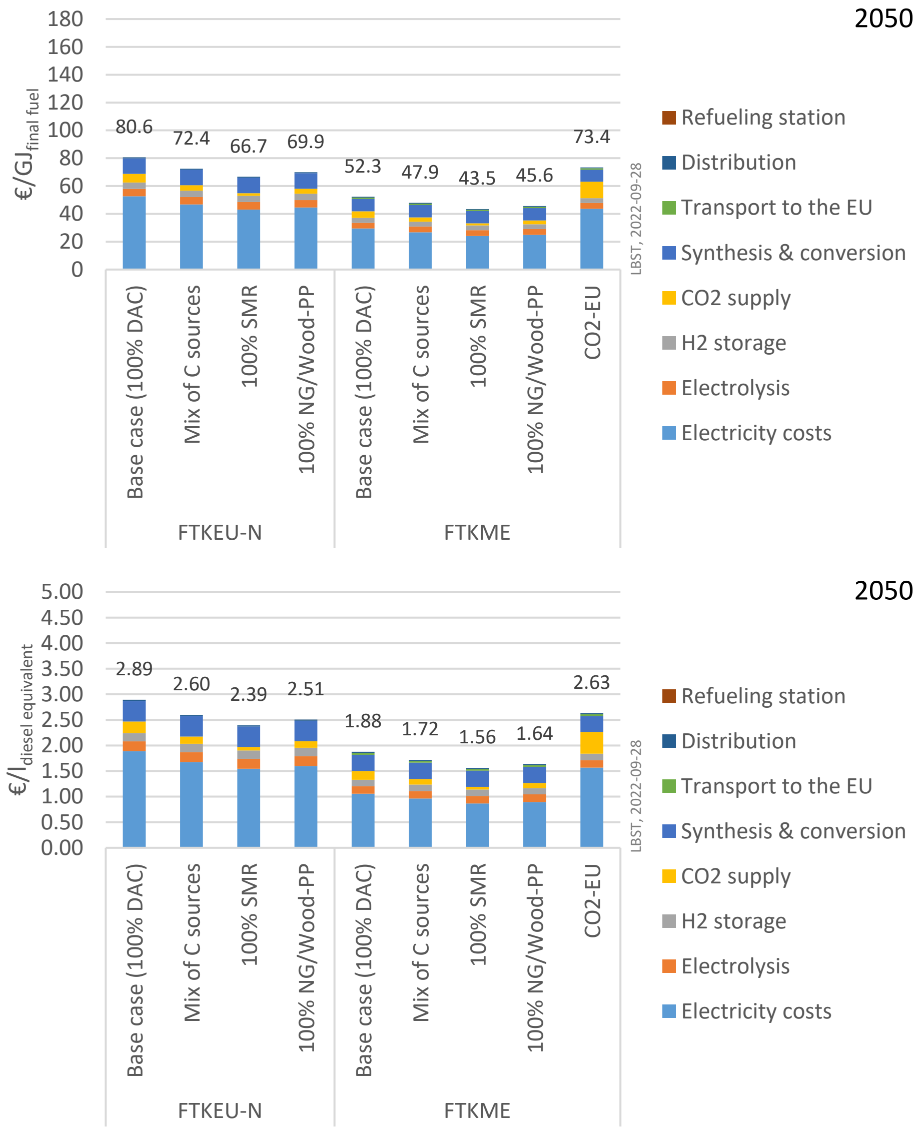
2.2.4. CO_2 source

In the base case, a concentrated CO_2 source with a CO_2 concentration of 45% (SMR as proxy) has been used for 2020 and 2030. For 2050, CO_2 from direct air capture has been used for e-fuels produced both in Europe and in MENA in the base case.

The following CO_2 sources have been assumed for sensitivity analysis:

- A mix of one third CO_2 from SMR, one third CO_2 from a mix of natural gas and lignocellulosic biomass fuelled power plants, and one third CO_2 from direct air capture for e-fuels produced in Europe. A mix of 50% concentrated source and 50% from DAC for fuels produced in MENA
- 100% concentrated CO_2 source (Steam methane reforming (SMR) or Autothermal reforming (ATR)) as proxy)
- 100% flue gas from of a mix of 50% natural gas and 50% wood fuelled power stations
- Use of CO_2 captured in EU (100% concentrated CO_2 source in 2020 and 2030, mix of CO_2 sources in 2050) for synthesis in MENA (pathway: CO_2-EU).

Figure 57: E-fuel costs in 2050 depending on CO_2 source for FT kerosene produced in North Europe and MENA



The electricity costs include the whole amount of electricity consumed by the power-to-liquid plant including electrolysis, hydrogen compressors, and CO_2 capture. If the CO_2 for the FT plant in MENA is captured in the EU (pathway 'CO_2-EU), electricity from the electricity grid in Southern Europe is used for CO_2 capture, leading to higher electricity costs for this process step.

Figure 58 shows the summarised e-fuel costs for FT kerosene produced and consumed in North Europe. Figure 59 shows the e-fuel costs for FT kerosene produced in MENA and consumed in South Europe. For 2020 and 2030 CO_2 from concentrated source has been assumed for the base case and CO_2 from diluted source (DAC) for sensitivity. For 2050 CO_2 from DAC has been assumed as base case and CO_2 from a mix of C sources for sensitivity.

Figure 58: E-fuel costs for FT kerosene in North Europe depending on CO_2 source by year

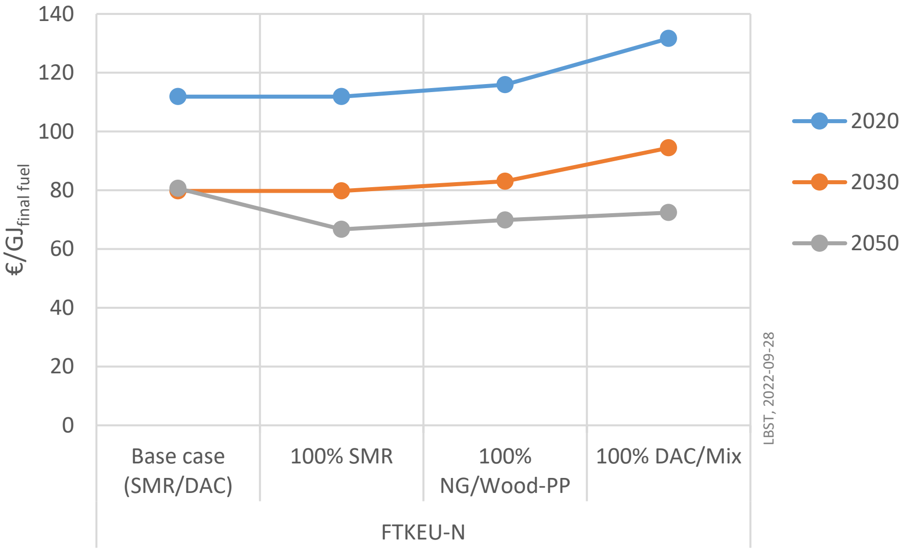
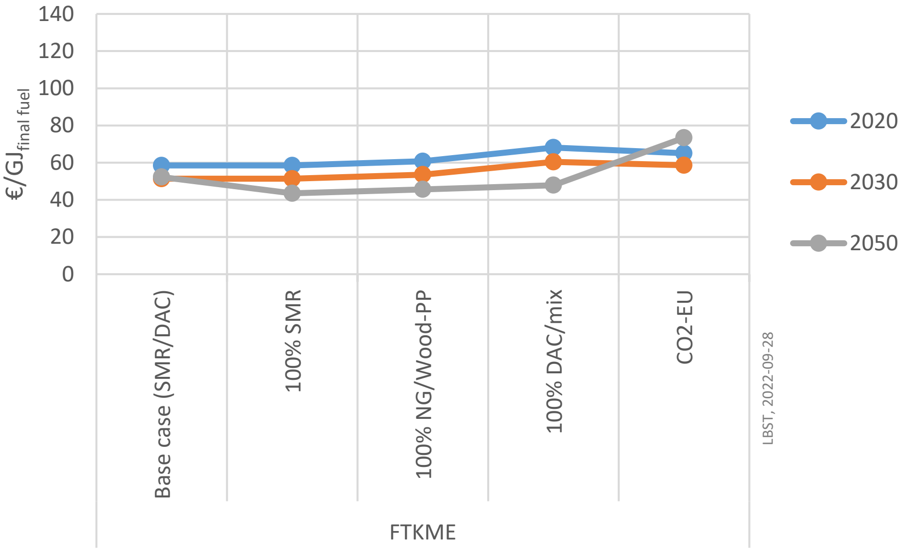


Figure 59: E-fuel costs for FT kerosene produced in MENA and consumed in South Europe depending on CO_2 source by year



The lowest e-fuel cost can be achieved with CO_2 from a concentrated source (SMR). CO_2 from direct air capture (DAC) leads to the highest fuel costs due to higher energy demand for the extraction of CO_2 from air and the higher CAPEX of the DAC plant.

For FT kerosene produced in MENA, the differences between the CO_2 sources are lower because the costs of renewable electricity are lower. CO_2 captured in the EU from concentrated CO_2 sources (SMR) and exported to MENA has only minor advantage compared CO_2 from a DAC plant in MENA for the time horizons 2020 and 2030. For 2050, the e-fuel costs for CO_2 captured in the EU from direct air capture (DAC) and exported to MENA even leads to the highest costs of e-fuel supply. One reason is that in 2050 the ships for the transport of CO_2 and the transport of final fuel to South Europe are fuelled with e-diesel (pathway FTKME). Another reason is that a mix of CO_2 sources has been assumed for CO_2 capture in South Europe in 2050 instead of 100% direct air capture.

The CO_2 capture plant is integrated. Depending on the CO_2 source the heat demand is partly (CO_2 from a mix of natural gas and wood fueled power plants and CO_2 from DAC) or fully (CO_2 from concentrated sources such as SMR) supplied by the downstream FT synthesis. Table 24 shows the costs attributed to CO_2 supply per t of CO_2. Cost of renewable electricity, capital, and maintenance are included. The net heat demand of CO_2 capture (gross heat demand minus heat supplied by downstream FT syntheses) is also supplied by electricity.

Table 24: Costs attributed to CO_2 supply for different CO_2 sources (€/t_{CO2})

	CO_2 source	2030	2050
FTKEU-N	100% SMR	33	32
	100% NG/wood PP	69	67
	100% DAC	191	182
FTKME	100% SMR	23	22
	100% NG/wood PP	47	46
	100% DAC	121	116
	CO_2 from EU*	104	174

* CO_2 captured from a concentrated source in the South Europe and transported to MENA via ship

CO_2 from concentrated CO_2 sources shows the lowest costs, CO_2 from DAC shows the highest costs of CO_2 supply except in case of CO_2 from EU transported to MENA in 2050. The reason for the increasing costs for CO_2 from EU transported to MENA is, that in 2050 the fuel demand for ship propulsion is fully met by e-diesel.

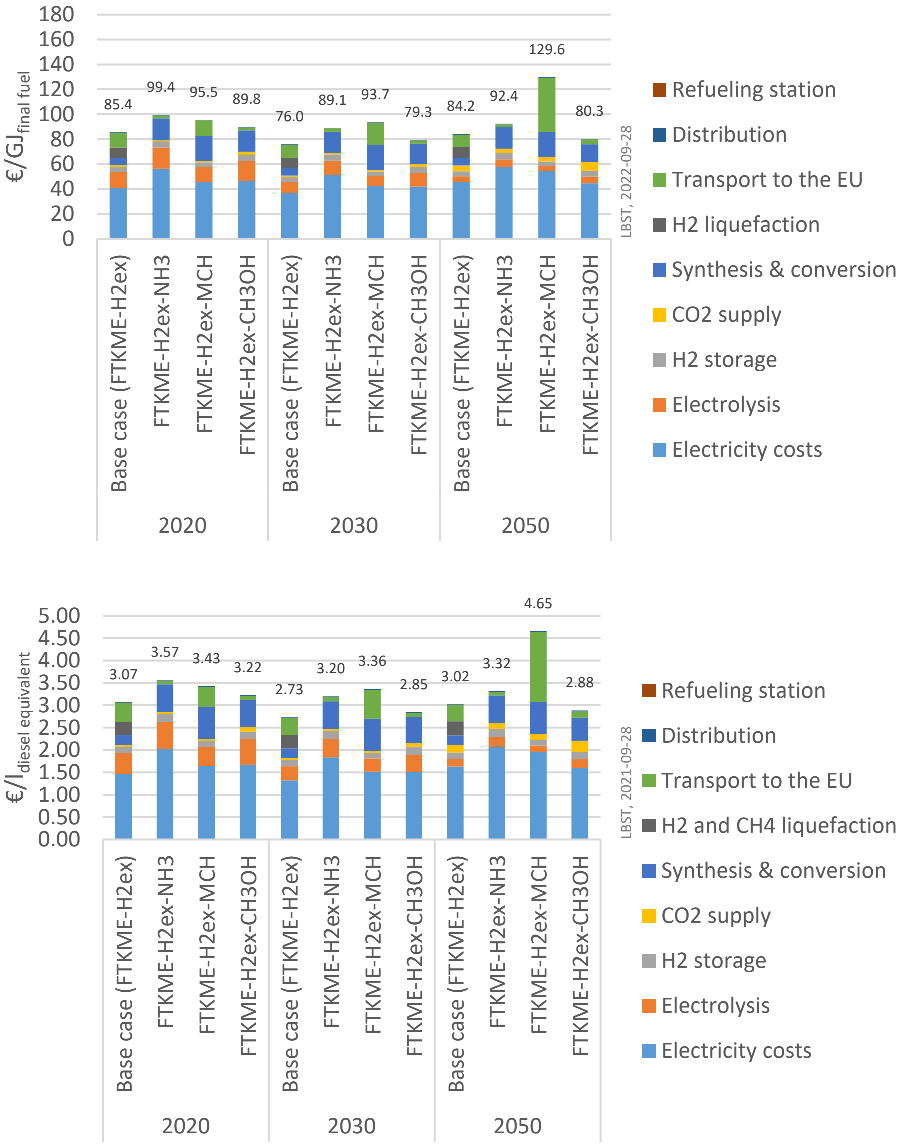
2.2.5. Use of Alternative carriers for H_2 import to feed synthesis processes

For these cases, South Europe (Spain) is used as destination proxy associated with:

- Use of ammonia (NH_3) as H_2 carrier to feed synthesis processes
- Use of methylcyclohexane (MCH) as H_2 carrier to feed synthesis processes
- Use of methanol (MeOH) as H_2 carrier to feed synthesis processes

Figure 60 shows the e-fuel costs for alternative carriers for hydrogen transport to feed synthesis processes in South Europe.

Figure 60: Fuel costs depending on the use of alternative carriers for H_2 import to feed FT e-kerosene synthesis process



'H2ex' means that H_2 is transported to South Europe as liquefied hydrogen (LH_2), ammonia (NH_3) or methylcyclohexane (MCH) or methanol (CH_3OH).

The synthesis of ammonia, the transport of ammonia, the reconversion of ammonia back to hydrogen, and finally the synthesis of FT kerosene leads to high energy losses, leading to high costs of the final fuel.

The reason for the increasing costs of fuel supply for pathway FTKME-H2ex-MHC is that renewable diesel from power-to-liquid via FT synthesis is used as fuel for ship propulsion. The low energy density of MCH increases the impact of higher costs for diesel for ship propulsion.

It has to be noted that today, there are no available or known processes to decompose ammonia at large-scale plant with a capacity of e. g. 200 t of hydrogen per day. Most commercially available solutions offer an electric-based furnace solution at a production capacity ranging from 1 to 2 t of hydrogen per day [Jackson et al. 2019].

In case of methylcyclohexane (MCH) as hydrogen carrier, the low energy density (hydrogen content 6.16% by mass at a density of 0.77 t/m^3 leads to 5.69 GJ of hydrogen per m^3 bound in MCH) leads to high costs for MCH transport.

Methanol as hydrogen carrier approximately also leads to higher costs of the final fuel than the transport of the liquefied hydrogen.

It also has to be noted that the electricity requirement for NH_3 cracking, MCH dehydrogenation, methanol steam reforming, the CO_2 supply, and the FT plant in Southern Europe is met by grid electricity (~0.10 €(kWh). As a result, the costs of electricity per GJ of final fuel do not necessarily correlate with the efficiency of the whole fuel supply chain. The reason for this approach is that the processes located in South Europe are located at the port and not nearby the renewable power stations.

2.2.6. Variation of transportation inside Europe

- Longer transportation distance inside Europe
  - Liquid fuels and LH_2 imports: truck 300 km (base case: 150 km)
  - Gaseous fuels: wider-meshed pipeline grid (double pipeline distance per refuelling station compared to base case)
- Other transport types inside Europe (truck, ship)
  - Sensitivity on 2050 pathways, distance kept constant
  - Transport of gaseous fuels via CGH_2 / CNG trailer
  - Transport of liquid fuels via inland ship (barge)

2.2.6.1. Longer transportation distance inside Europe

The cost assumptions for the transport and distribution of the final fuel such as CAPEX and OPEX for pipelines, trucks, and ships are described in the ANNEX chapter 8.

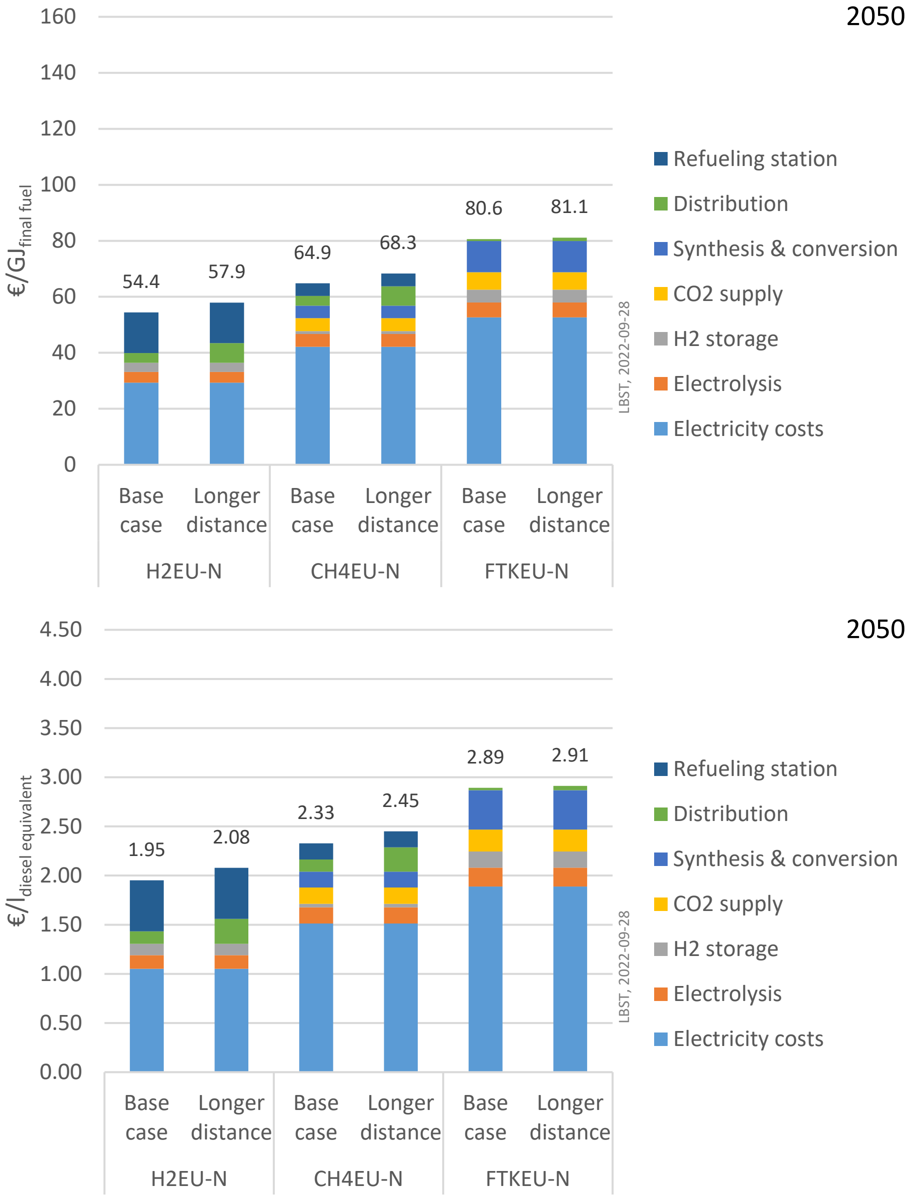
For e-hydrogen and e-methane, a wider pipeline grid for the same amount of final fuel has been assumed (double km per refuelling station). For liquid e-fuels, the distance for the transport via product pipeline and truck has been doubled (Table 25).

Table 25: Transport distances inside Europe for selected pathways

	Transport mode	Base case	Sensitivity
H2EU-N	H_2 pipeline grid	5.5 km/station	10.9 km/station
CH4EU-N	CH_4 pipeline grid	5.9 km/station	11.7 km/station
FKEU-N	Pipeline + truck	150 km + 150 km	300 km + 300 km

Figure 61 shows the influence of longer transportation distances inside Europe for 2050 (for 2020 and 2030, see Figure 146 and Figure 147 in ECONOMIC ANNEX chapter 8.5.5).

Figure 61: Influence of longer transport distance inside Europe on the fuel costs in 2050



The influence of longer transport distance on the fuel costs is low, especially in case of liquid fuels.

2.2.6.2. Other transport types inside Europe (truck, ship)

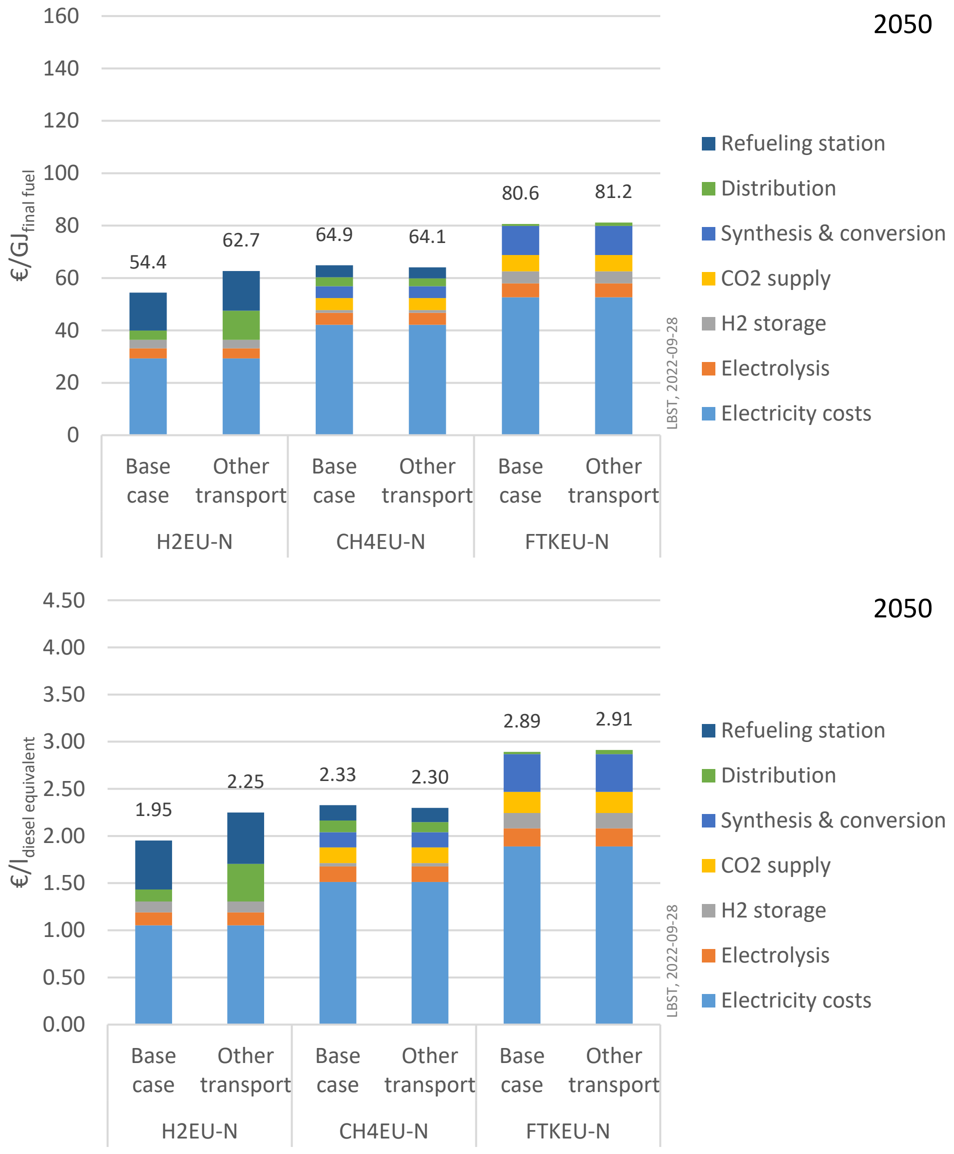
For this sensitivity analysis, e-hydrogen and e-methane are distributed via CGH_2 or CNG trailer respectively, instead of via pipeline grid. In the case of e-kerosene, the product pipeline has been replaced by inland navigation. A distance of 500 km has been assumed because transport via ship is typically applied for longer distances.

Table 26: Transport modes inside Europe for selected pathways

	Base case	Sensitivity
H2EU-N	H_2 pipeline grid 5.5 km/station	CCH_2 trailer 150 km
CH4EU-N	CH_4 pipeline grid 5.9 km/station	CNG trailer 150 km
FKEU-N	Pipeline 150 km + truck 150 km	Ship 500 km + truck 150 km

The CGH_2 is transported at a pressure of about 50 MPa leading to a transport capacity of 1.1 t of hydrogen (132 GJ related to the LHV). The CNG is transported at a pressure of 25 MPa leading to a transport capacity of about 9.55 t of methane (478 GJ related to the LHV).

Figure 62: Influence of other transport types inside Europe on the fuel costs in 2050



Except in case of pathway H2EU-N, the influence of other transport types inside Europe is low. The reason is the lower energy density of hydrogen leading to higher costs if distributed via CGH_2 trailer.

2.2.7. Long-haul from other potential sweet spots worldwide

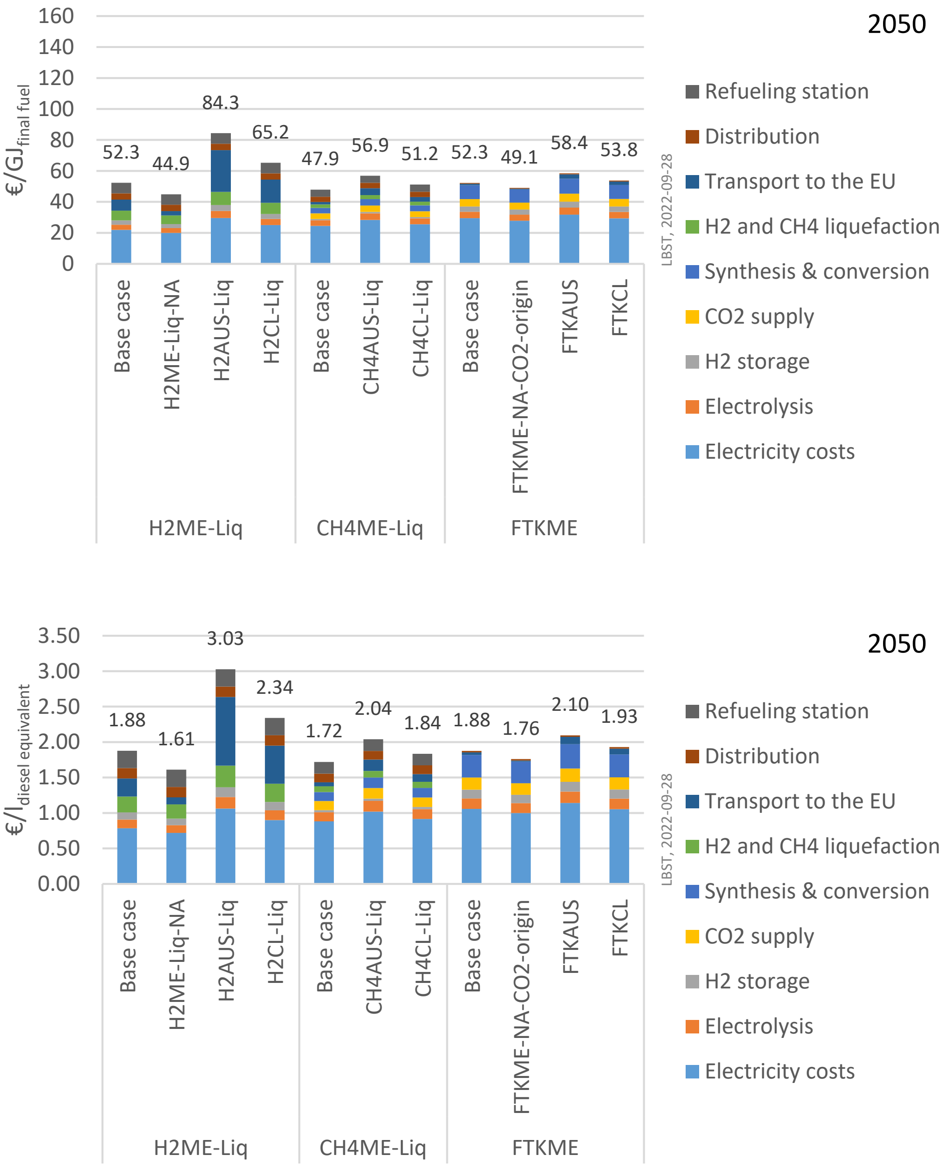
Rotterdam in the Netherlands as representative for the ARA (Amsterdam-Rotterdam-Antwerp) region is used as destination proxy.

The calculation approach made assumptions for CAPEX and OPEX to calculate the renewable electricity generation costs as with MENA (Saudi Arabia), but used equivalent full load hours adjusted to the country of origin (see ECONOMIC ANNEX, chapter 8.2.3).

- North Africa – NA (variation of distance)
  - Morocco as proxy country
  - Equivalent full load hours of hybrid renewable electricity generation (PV and 50% wind onshore with same nameplate capacity each): ~5,600 h/a
  - CO_2 origin: same as for KSA (100% DAC)
  - Transport distance from Morocco to ARA region: ~3,370 km
- Australia - AUS
  - Equivalent full load hours of hybrid renewable electricity generation (PV and 50% wind onshore with same nameplate capacity each): ~4,800 h/a
  - Transport distance from Australia to ARA region: ~23,620 km
  - CO_2 origin: same as for KSA (100% DAC)
- Chile - CL
  - Equivalent full load hours of hybrid renewable electricity generation (PV and 50% wind onshore with same nameplate capacity each): ~5,200 h/a
  - Transport distance from Chile to ARA region: ~17,380 km
  - CO_2 origin: same as for KSA (100% DAC)

Figure 63 shows the influence of long-haul marine transport from potential other sweet spots worldwide on the fuel costs for 2050 (for 2020 and 2030, see Figure 150, and Figure 151 in ECONOMIC ANNEX chapter 8.5.6).

Figure 63: Influence of long-haul marine transport from potential other sweet spots worldwide on the fuel cost in 2050



Long distance transport of LH_2 (e. g. from Australia) significantly increases the costs of e-fuel supply because of the boil-off losses resulting from longer days at sea. In case of liquid e-fuels, even very long transport distances lead to minor changes of fuel supply costs only.

2.2.8. Larger/smaller e-fuels plant size

For the base case, a nameplate capacity of 1 million t of e-diesel equivalent[1] per year or about 114 t/h has been assumed (1,400 MW of final e-fuel, based on the LHV). Two nameplate capacity variants have been assumed for sensitivity analysis:

- 0.2 million t per year (~23 t/h)
- 4 million t per year (~457 t/h)

The real amount of final e-fuel produced per year depends on the equivalent full load periods in the different regions. The amount of final fuel per year only depends on the electricity supplied per year minus some electricity curtailment for technical reasons.

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[1] Based on conventional diesel EN 590

Figure 64 shows the influence of variation of the capacity of the e-fuels plants for 2050 (for 2020, see Figure 152 in ECONOMIC ANNEX chapter 8.5.7).

Figure 64: Influence of larger/smaller e-fuels plant capacity in 2050

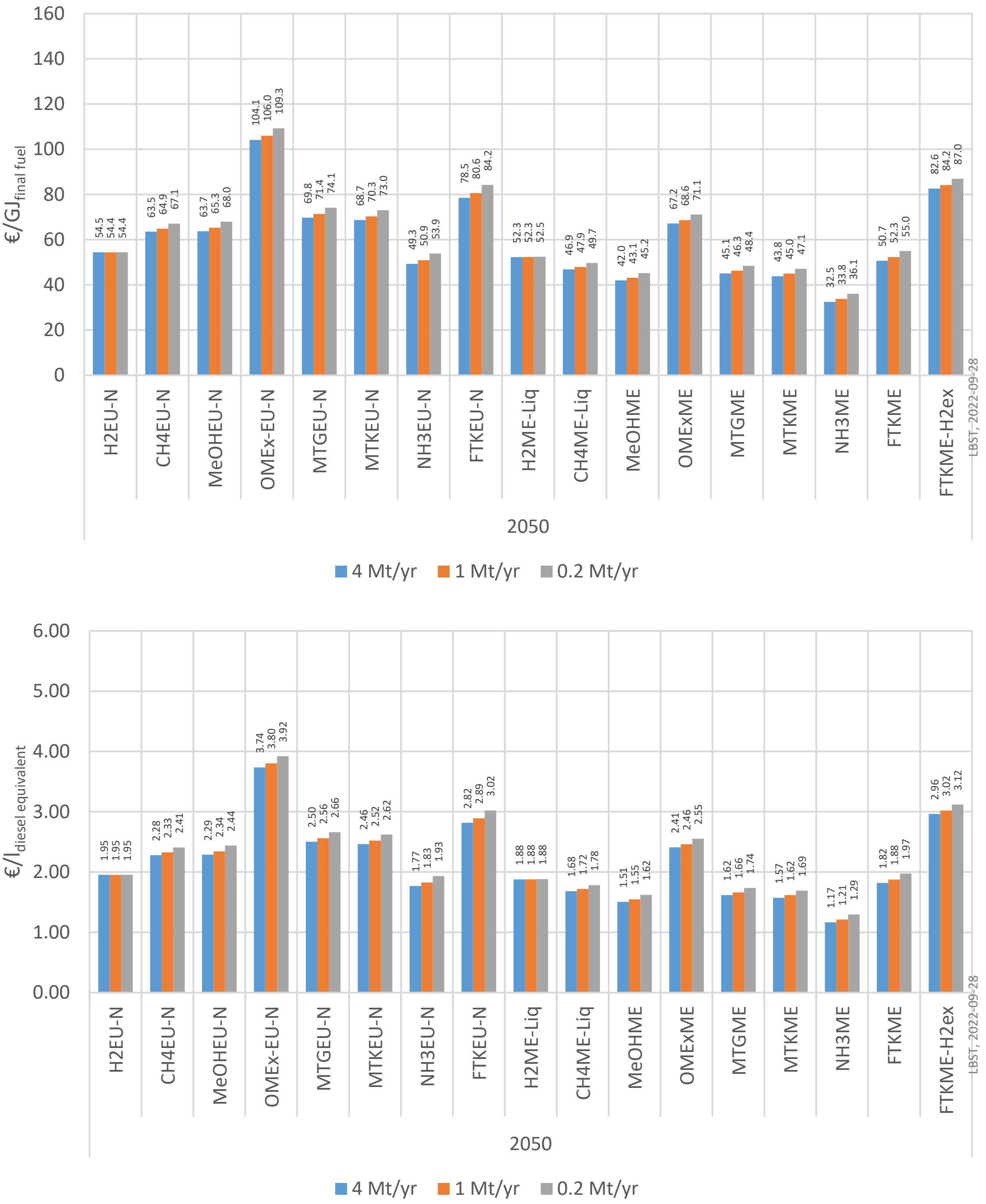
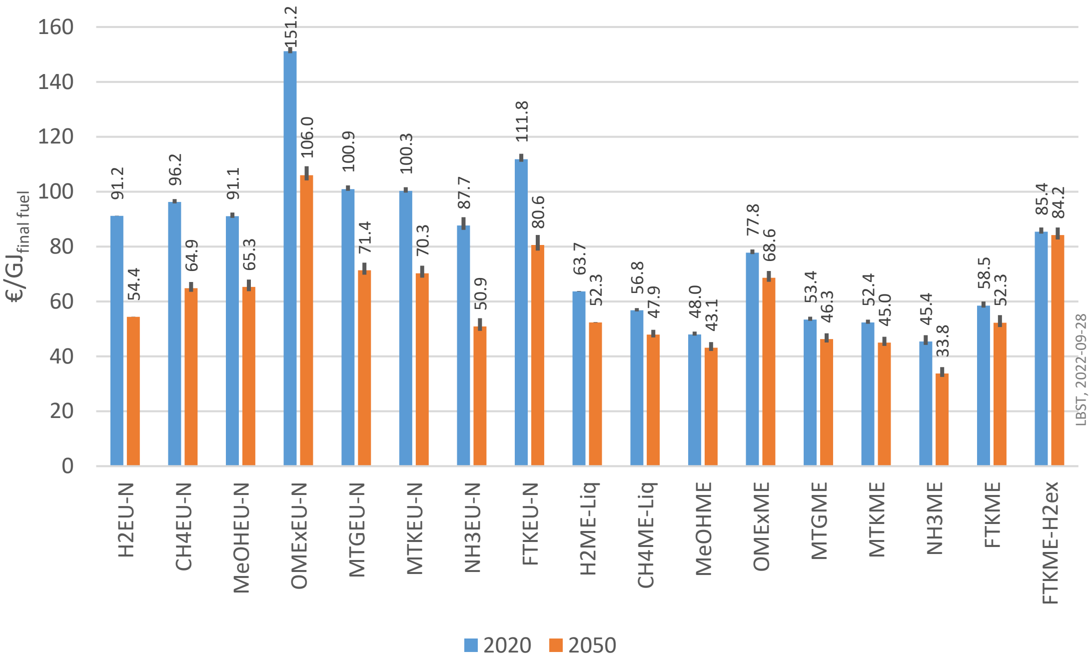


Figure 65 shows the influence of variation of the capacity of the e-fuels plant as uncertainty bars for the base case.

Figure 65: Influence of larger/smaller e-fuels plant capacity shown as uncertainty bars



LBST, 2022-09-28

The impact of larger/smaller e-fuels plant capacity is low for the capacities assumed in this study. Even the 0.2 million t per year plant requires an electrolysis plant with a capacity of between 365-570 MW of electricity input, which is already very large. No further decrease of specific CAPEX is expected for electrolysis plants above 100 MW$_e$. Electrolysis is a surface-related technology like PV panels. The decrease of specific CAPEX is only caused by the cost of auxiliary equipment such as converters and transformers.

Scaling by capacity has been applied for the DAC plant, the NH_3 synthesis plant, and some components of the FT synthesis plant such as the reverse water gas shift, pressure swing adsorption, and hydrocracking units (see ECONOMIC ANNEX, Table 101 in chapter 8.4.7).

2.2.9. Variation of PV/wind overlap (curtailed electricity)

The renewable electricity for e-fuel production is generated by photovoltaic (PV) and wind power hybrid power plants, except in case of Norway where the electricity is generated by offshore wind power.

In the regions assessed in this study, wind power and solar photovoltaic power are complementary. The electricity yield of PV is high in times when the yield of wind power is low and vice versa. In the base case, a 5% overlap of annual electricity generation according to [Fasihi et al. 2016] has been assumed to be curtailed, as the integration costs of the last 5% of excess power typically exceed the gain from using it (economic curtailment). For this sensitivity analysis, 10% curtailed electricity is assumed.

Figure 66 shows the results for the base case and Figure 67 shows the results if 10% of the electricity is curtailed.

Figure 66: FTK produced in selected regions: 5% PV/wind electricity curtailment (base case)

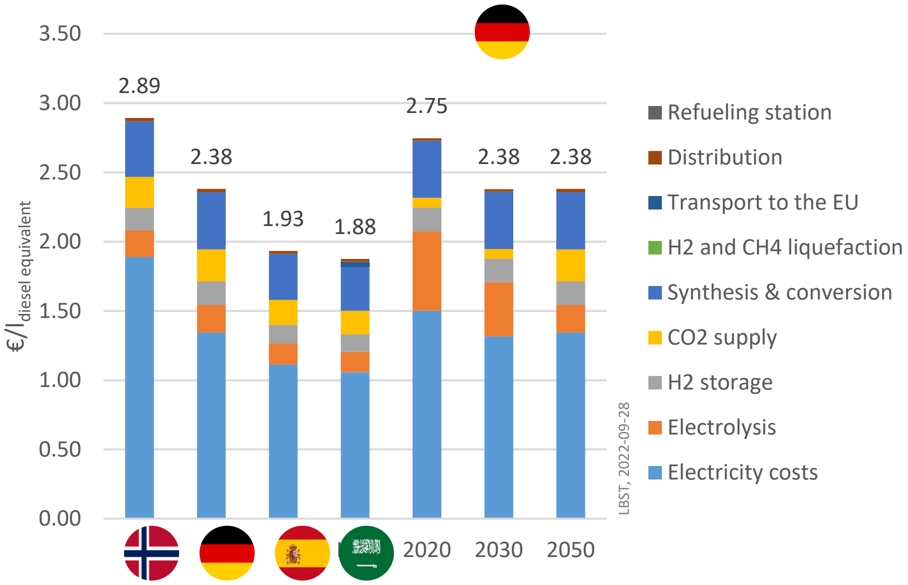
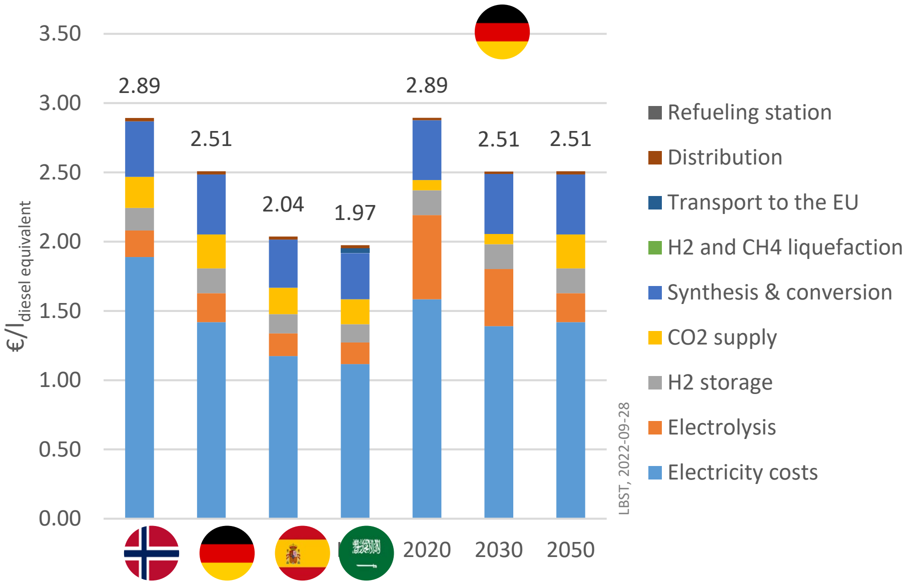


Figure 67: FTK produced in selected regions: 10% PV/wind electricity curtailment (sensitivity)

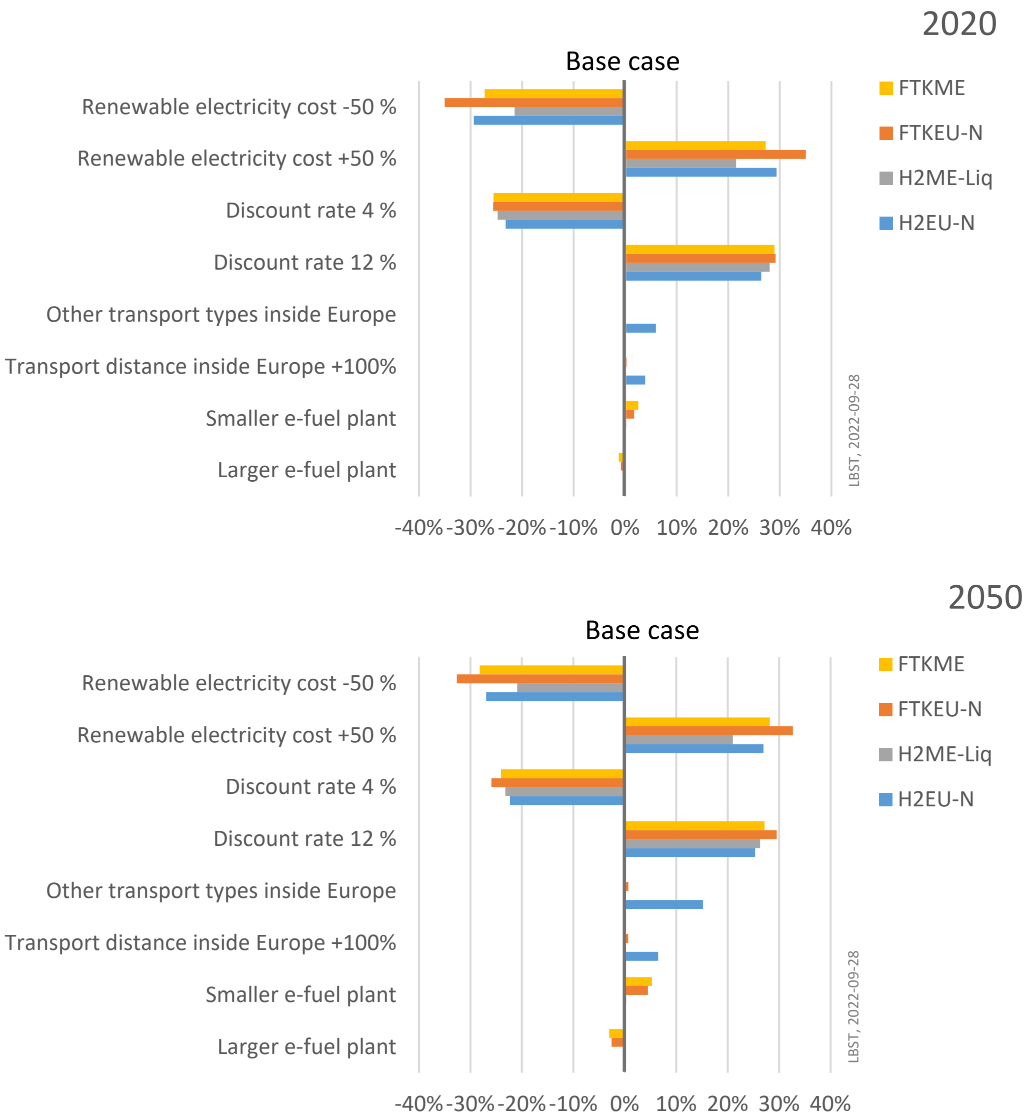


Increase of the PV/wind curtailment from 5% to 10% leads to an increase of the fuel costs by about 5% for all regions where electricity from PV/wind hybrid power plants are used for e-fuel production.

2.2.10. Summary sensitivity analysis

Electricity costs and the discount rate have a significant impact on overall fuel supply costs. A 50% change of the electricity supply costs or the discount rate assumptions resulted in a change of about 25% of the supply cost. Other factors investigated, such as transport type and distance inside Europe or e-fuel plant size, have only marginal impacts (single-digit percentage points). The cost impacts relative to the final production costs are very similar for 2020 and 2050. The sensitivities and impacts are shown for 2050 in Figure 68.

Figure 68: Sensitivity: impact of variation of selected parameters



Another sensitivity analysis is the variation of the curtailment due to PV/wind overlap. Increase of the PV/wind overlap from 5% to 10% leads to an increase of the fuel costs by only about 5% for all regions where electricity from PV/wind hybrid power plants are used for e-fuel production.

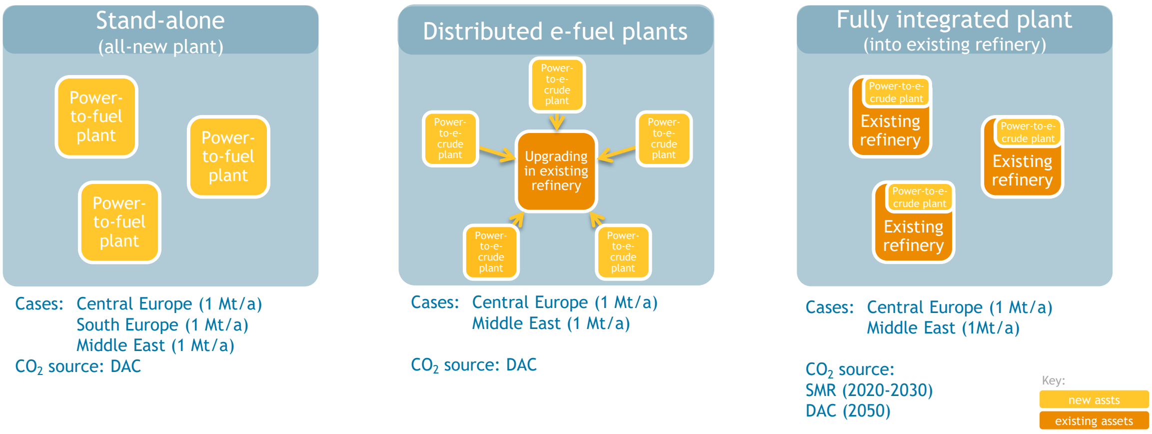
KEY MESSAGES - SENSITIVITY ANALYSIS

Electricity costs and discount rate have a significant impact on overall fuel supply costs. 50% change of electricity supply costs or discount rate assumptions resulted in about 25% supply cost. Other factors investigated, such as transport type and distance inside Europe, e-fuel plant size or PV/wind overlap (curtailed electricity), have only marginal impacts (single-digit percentage points).

2.3. STAND-ALONE PLANTS VERSUS DISTRIBUTED E-CRUDE PLANTS VERSUS FULLY INTEGRATED PLANTS

The motivation to look at this topic is to assess the potential role of existing refineries in e-fuel value chains. The use of existing refinery assets reduces the CAPEX and allows the transformation of incumbent energy industries. To assess this, three archetype supply chains as depicted in Figure 69 have been compared.

Figure 69: Distributed versus stand-alone/integrated plants



Cases: Central Europe (1 Mt/a)
South Europe (1 Mt/a)
Middle East (1 Mt/a)
CO_2 source: DAC

Cases: Central Europe (1 Mt/a)
Middle East (1 Mt/a)
CO_2 source: DAC

Cases: Central Europe (1 Mt/a)
Middle East (1Mt/a)
CO_2 source:
SMR (2020-2030)
DAC (2050)

The **stand-alone** e-fuel **plant** (left box in Figure 69) consider all-new integrated plants for hydrogen production, synthesis to e-crude, and final upgrading as assumed in the base case in this study. In case of **distributed e-fuel plants** (middle box in Figure 69) new hydrogen production and synthesis to e-crude units, and e-crude upgraded in existing refineries. In case of the **full integrated e-fuel plant** (right box in Figure 69) the hydrogen production, synthesis to e-crude, and final upgrading is all fully integrated into an existing refinery

Existing **refineries** can play a facilitating role in the energy transition to e-fuels. These 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. Furthermore, the existing refining assets can, in part, be used to upgrade Fischer-Tropsch syncrude, allowing an efficient use of existing investments. Since refineries are complex, have diverse configurations, and differ in terms of supply infrastructure and products mix, refinery-specific feasibility studies are recommended to assess opportunities in the field.

For the stand-alone plant and the distributed e-fuel plant direct air capture (DAC) of CO_2 is assumed as CO_2 source. A concentrated CO_2 source (proxy: SMR) is used for the fully integrated plant into an existing refinery for 2020 and 2030. For 2050 DAC is also assumed for the e-fuel plant integrated into an existing refinery. The rational is that if an e-fuel plant is integrated into an existing refinery, the most logical CO_2 source to use is a concentrated source from SMR on-site a refinery for example as it is already available in an existing refinery. The use of a concentrated CO_2 source is less energy demanding and cheaper than using more diluted sources, such as DAC. Concentrated CO_2 is considered as waste. It has to be noted that the use of fossil CO_2 does not result in lower fossil CO_2 emissions in the refinery. Refinery fossil CO_2 emissions are not avoided and as a result the existing refinery still would have to pay for it. Otherwise, the e-fuel plant has to pay for it and these fossil CO_2 has to be taken into account in the e-fuel LCA part.

Looking at the concept of distributed e-fuel plants, there is a problem with e-crude stability (to be stabilised after synthesis by removing the light ends), corrosivity (due to the oxygenates) and viscosity for pathways with long-distance e-crude transport. Therefore, still some further processing via stabilization and mild hydrocracker is required at the e-crude plant site.

Refineries are typically highly complex processing plants that have been optimised over years or even decades to efficiently convert specific sorts of crude-oil into a portfolio of products. Thus, no refinery is like another. The level of analysis in this study does not allow for detailed analysis of different refinery configurations and their specific adaptability to use e-crude up to 100% of refinery oil input.

There are significant differences between Fischer–Tropsch (FT) syncrude and crude oil that in principle allows syncrude refining to be more efficient than crude oil refining.

FT syncrude consists of multiple product phases, has a high oxygen content, a high alkene content, high concentration of linear products, and little cyclic components. There are no sulphur and nitrogen compounds but some metal carboxylates. Therefore, additional processes for feedstock treatment to eliminate compound classes that are not compatible with the technology in existing refineries (e. g. hydrocrackers). As a consequence, modifications of the hydrocracker and fractionation technology could be required to deal with FT syncrude properties [de Klerk 2011].

A detailed analysis of the impact on existing refineries is outside the scope of this study.

Table 27 shows the case definitions and the assumptions behind. In case of stand-alone plants (base case) all components have to be built new with the associated CAPEX. In case of the distributed e-crude plants the e-crude plant requires mild hydrocracking including the associated CAPEX. Transport of e-crude to the existing refinery via pipeline has been assumed. For the process at the existing refinery site such as hydrocracking, fractionation, and utilities no CAPEX is required because these processes are already available at the existing refinery. Only maintenance and repair are taken into account.

In case of a fully integrated e-fuel plant into an existing refinery no mild hydrocracking is required. For hydrocracking, fractionation, utilities, and logistics no CAPEX is required because these processes are already available at the existing refinery. Only maintenance and repair are taken into account.

Table 27: Distributed versus standalone/integrated plants: Case definitions

	Standalone plant	**Distributed e-crude plant** (if far from refinery, example: MENA)	**Fully integrated plant** (into an existing refinery)
Concept	E-fuels plants as standalone/ independent entities, ensuring the whole process from hydrogen and CO_2 capture (if needed) up to quality upgrading. These are all-new plants that produce fuels ready to be commercialised.	E-fuels plants that depend on an existing oil refinery, with some form of synergy implemented (by-product utilization, sharing of upgrading units, utilities systems). Products from these plants are not ready to be commercialized (e-crude, off-spec, etc.). The plants could be physically next to or far from the refineries.	
Plant size	There is no difference between the plant sizes any of the configurations (contrary to a biorefinery)		
Representation			
Processes involved **Legend** new existing (at the refinery)	DAC Electrolysis Synthesis Hydrocracking Fractionation/(Upgrading) Utilities & logistics	DAC Electrolysis Synthesis Mild hydrocracking ======================== E-crude transport ======================== Hydrocracking Fractionation/(Upgrading) Utilities & logistics	2020-2030: Concentrated source (SMR as proxy) 2050: DAC Electrolysis Synthesis ======================== Hydrocracking Fractionation/(Upgrading) Utilities & logistics

The difference between stand-alone and fully integrated plant into a refinery is that there are no capital costs for hydrocracking, fractionation (upgrading), utilities, and logistics in case of the fully integrated plant. Only OPEX is taken into account for these processes.

The CAPEX for the stand-alone FT plant without H_2 and CO_2 supply amounts to about 1500 million € including indirect cost. The CAPEX for the distributed FT e-crude plant without H_2 and CO_2 supply amounts to about 1100 million €. The CAPEX of the FT plant fully integrated into an existing refinery without H_2 and CO_2 supply amounts to about 800 million € (see ECONOMIC ANNEX, chapter 8.4.17).

The OPEX of the stand-alone FT plant amounts to about 88 million €/yr. In case of the distributed FT e-crude plant the OPEX including the OPEX share of the existing refinery for further processing amounts to about 97 million €/yr (slightly higher than for the stand-alone FT plant due to additional mild hydrocracker at the e-crude plant). The OPEX of the fully integrated FT plant including the OPEX share of the existing refinery amounts to about 88 million €.

Table 28 and Figure 70 show the results for the sensitivity for stand-alone e-fuel plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2020.

Table 28: Stand-alone e-fuel plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2020

No.	Pathway code	Stand-alone PtL plant (CO_2 from DAC)	Distributed e-crude plant (CO_2 from DAC)	Fully integrated plant into existing refinery (CO_2 from SMR)
€/GJ of final fuel				
17	FTKEU-C	89.3	88.0	73.3
18	FTDEU-C	90.4	89.2	74.5
26	FTKEU-S	71.0	-	-
27	FTDEU-S	72.2	-	-
36	FTKME	68.1	67.2	56.2
37	FTDME	69.2	68.3	57.3
38	FTKMEe-crd	-	67.2	-
€/l of diesel equivalent				
17	FTKEU-C	3.20	3.16	2.63
18	FTDEU-C	3.25	3.20	2.68
26	FTKEU-S	2.55	-	-
27	FTDEU-S	2.59	-	-
36	FTKME	2.44	2.41	2.02
37	FTDME	2.49	2.45	2.06
38	FTKMEe-crd	-	2.41	-

Figure 70: Stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2020

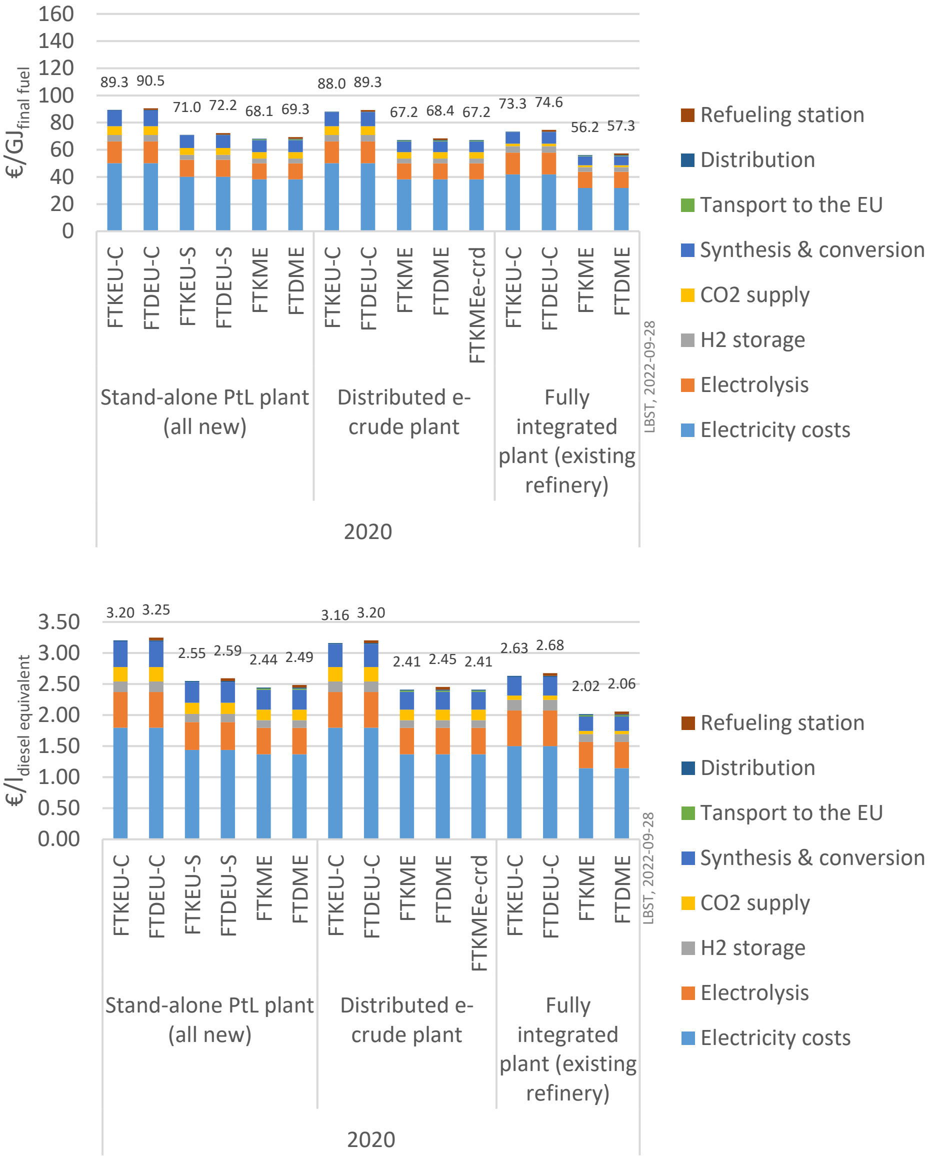


Table 29 and Figure 71 show the results for the sensitivity for stand-alone e-fuel plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2030.

Table 29: Stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2030

No.	Pathway code	Stand-alone PtL plant (CO_2 from DAC)	Distributed e-crude plant (CO_2 from DAC)	Fully integrated plant into existing refinery (CO_2 from SMR)
€/GJ of final fuel				
17	FTKEU-C	78.2	76.9	63.1
18	FTDEU-C	79.4	78.2	64.3
26	FTKEU-S	62.8	-	-
27	FTDEU-S	64.1	-	-
36	FTKME	60.4	59.5	49.0
37	FTDME	61.6	60.7	50.2
38	FTKMEe-crd	-	59.5	-
€/l of diesel equivalent				
17	FTKEU-C	2.81	2.76	2.26
18	FTDEU-C	2.85	2.80	2.31
26	FTKEU-S	2.25	-	-
27	FTDEU-S	2.30	-	-
36	FTKME	2.17	2.14	1.76
37	FTDME	2.21	2.18	1.80
38	FTKMEe-crd	-	2.13	-

Figure 71: Stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2030

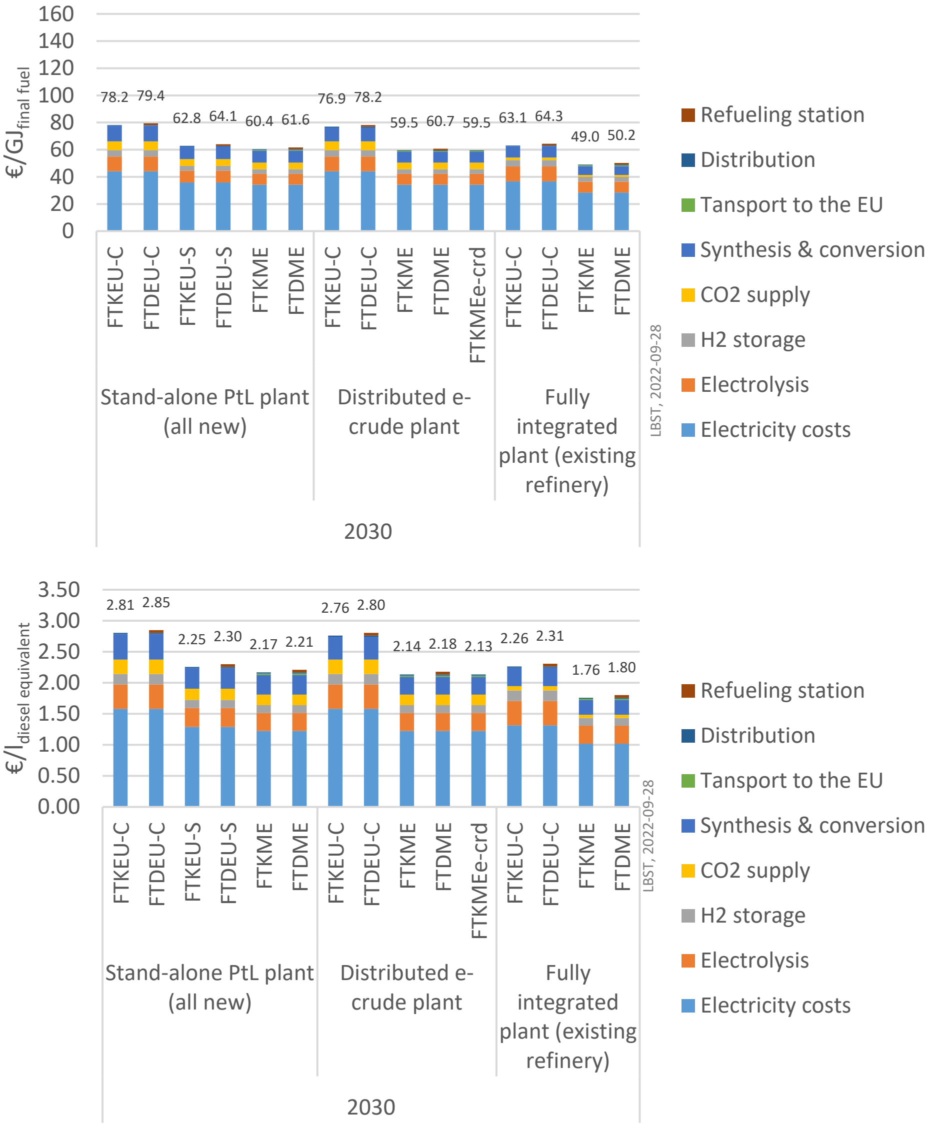


Table 30 and Figure 72 show the results for the sensitivity for stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2050.

Table 30: Stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2050

No.	Pathway code	Stand-alone PtL plant (CO_2 from DAC)	Distributed e-crude plant (CO_2 from DAC)	Fully integrated plant into existing refinery (CO_2 from DAC)
€/GJ of final fuel				
17	FTKEU-C	66.3	65.1	63.1
18	FTDEU-C	67.6	66.3	64.4
26	FTKEU-S	53.9	-	-
27	FTDEU-S	55.1	-	-
36	FTKME	52.3	51.3	49.9
37	FTDME	53.3	52.4	51.0
38	FTKMEe-crd	-	51.3	-
€/l of diesel equivalent				
17	FTKEU-C	2.38	2.34	2.27
18	FTDEU-C	2.42	2.38	2.31
26	FTKEU-S	1.93	-	-
27	FTDEU-S	1.98	-	-
36	FTKME	1.88	1.84	1.79
37	FTDME	1.91	1.88	1.83
38	FTKMEe-crd	-	1.84	-

Figure 72: Sensitivity stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2050

Concentrated CO_2 source for fully-integrated plants existing refinery has the highest contribution to cost reduction compared to stand-alone and distributed e-crude plants. Lower CAPEX due to use of existing refineries has a low contribution to cost reduction under the assumption given. The reason for the cost reduction is the combination of both the lower CAPEX and lower cost of CO_2 supply. In the long-term (2050) diluted CO_2 source also is used for fully integrated e-fuel plants. Then the difference between the stand-alone e-fuel plant and the fully integrated e-fuel plant into an existing refinery is low.

In the short to medium term there may be advantages in utilizing existing refineries to minimize capital expenditure. There is a potential advantage of co-processing in the early e-fuel development. The lower the CAPEX, the higher the probability for a company to invest, aiming to have a return of invest in a shorter time. In the long-term (2050), when diluted CO_2 sources are also used for fully integrated e-fuel plants, then the difference between the stand-alone e-fuel plant and the e-fuel plant fully integrated into an existing refinery is low.

KEY MESSAGES – STAND-ALONE VS. DISTRIBUTED VS. INTEGRATED E-FUEL PLANTS

The analysis of a **stand-alone e-fuel plant** (all-new integrated plants for hydrogen production, synthesis to e-crude, and final upgrading) versus a **distributed e-fuel plants** (new hydrogen production and synthesis to e-crude units, and e-crude upgraded in existing refineries) versus a **full integrated e-fuel plant** (the hydrogen production, synthesis to e-crude, and final upgrading is all fully integrated into an existing refinery) have been conducted.

The difference between stand-alone and fully integrated plant into a refinery is that there are no capital costs for hydrocracking, fractionation (upgrading), utilities, and logistics in case of the fully integrated plant. Only OPEX is taken into account for these processes. However, these capital cost elements in the total e-fuel production costs have a low contribution (~5%). Concentrated CO_2 source for plants fully integrated into an existing refinery (instead of CO_2 from direct air capture (DAC)) has the highest contribution to cost reduction compared to stand-alone and distributed e-crude plants.

In the short to medium term there may be advantages in utilizing existing refineries to minimize capital expenditure. There is a potential advantage of co-processing in the early e-fuel development. The lower the CAPEX, the higher the probability for a company to invest, aiming to have a return of invest in a shorter time. In the long-term (2050), when diluted CO_2 sources are also used for fully integrated e-fuel plants, then the difference between the stand-alone e-fuel plant and the e-fuel plant fully integrated into an existing refinery is low.

3. COMPARISON OF RENEWABLE E-FUEL PRODUCTION COSTS VERSUS FUELS PRODUCED FROM NUCLEAR ELECTRICITY AND BIOFUELS

3.1. RESULTS FROM NUCLEAR ELECTRICITY VERSUS RENEWABLE E-FUEL PRODUCTION COSTS

The costs of nuclear electricity have been calculated based on a new nuclear power station based on the European Pressurized Water Reactor (EPR). Based on the assumptions taken, the costs for nuclear electricity amount to about 94 € per MWh of electricity for all time horizons (see chapter 8.4.19 in the annex) taking into account a new nuclear plant. The charts show that nuclear electricity (based on a new nuclear plant) results in higher production costs than Norwegian offshore wind (based on new installations) in 2050.

In section 2.1.3., it was shown that e-fuel production in Norway (offshore wind) results in higher cost than in other regions (Germany, Spain, MENA) (mix of PV/wind onshore). Therefore, it can be concluded that e-fuels produced from nuclear electricity, based on a new nuclear plant, results in higher production costs than with renewable electricity for all the regions by 2050.

However, electricity produced from nuclear long-term operation by lifetime extension, instead of from a new nuclear plant, could be as low as 25 to 34 € per MWh, subject to CAPEX and full load hour assumptions taken in [IEA 2020b]. Further details are given in ECONOMIC ANNEX chapter 8.4.19.

Figure 73 and Figure 74 show the fuel costs for e-fuels from new nuclear plant electricity compared to the costs of e-fuels from renewable electricity from new offshore wind power in North Europe in 2050.

Figure 73: Costs of e-fuels from new nuclear plants electricity compared to e-fuels from new renewable electricity installations in 2050 - per GJ of final fuel

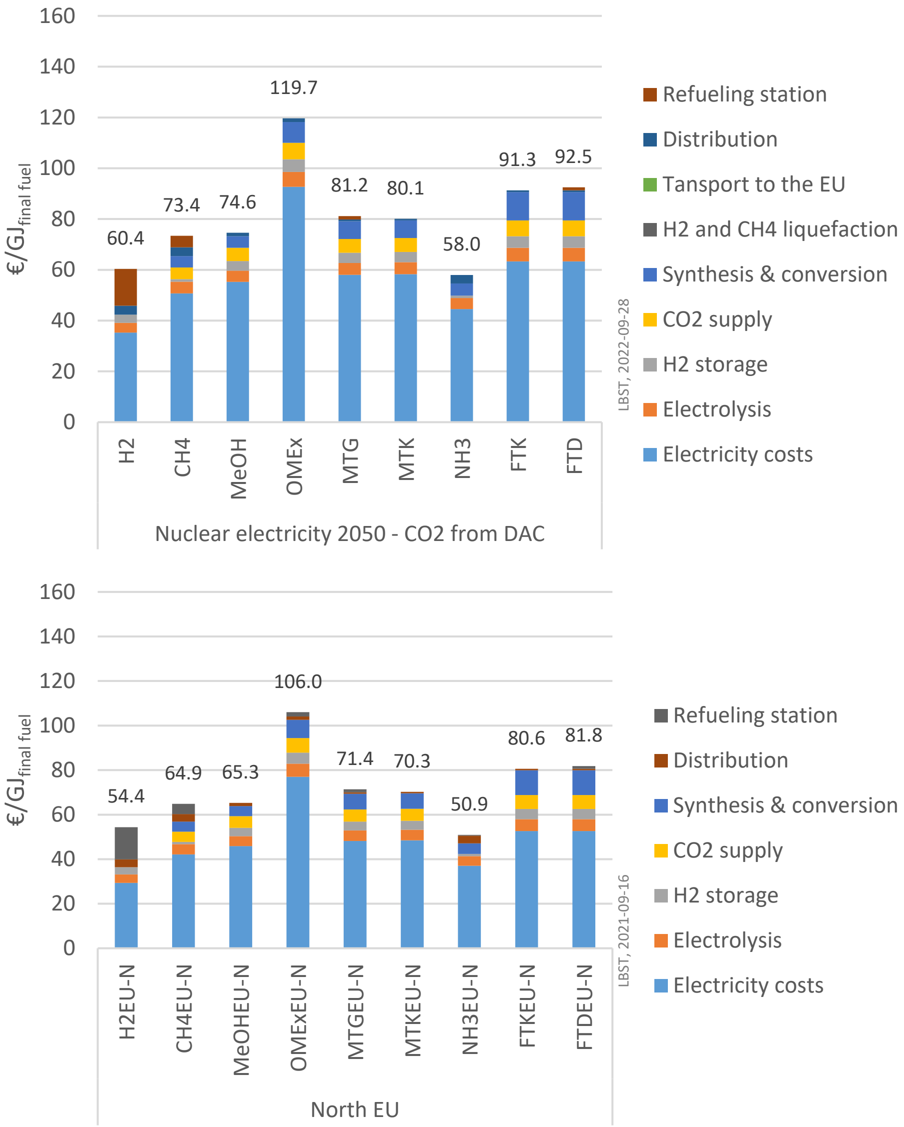
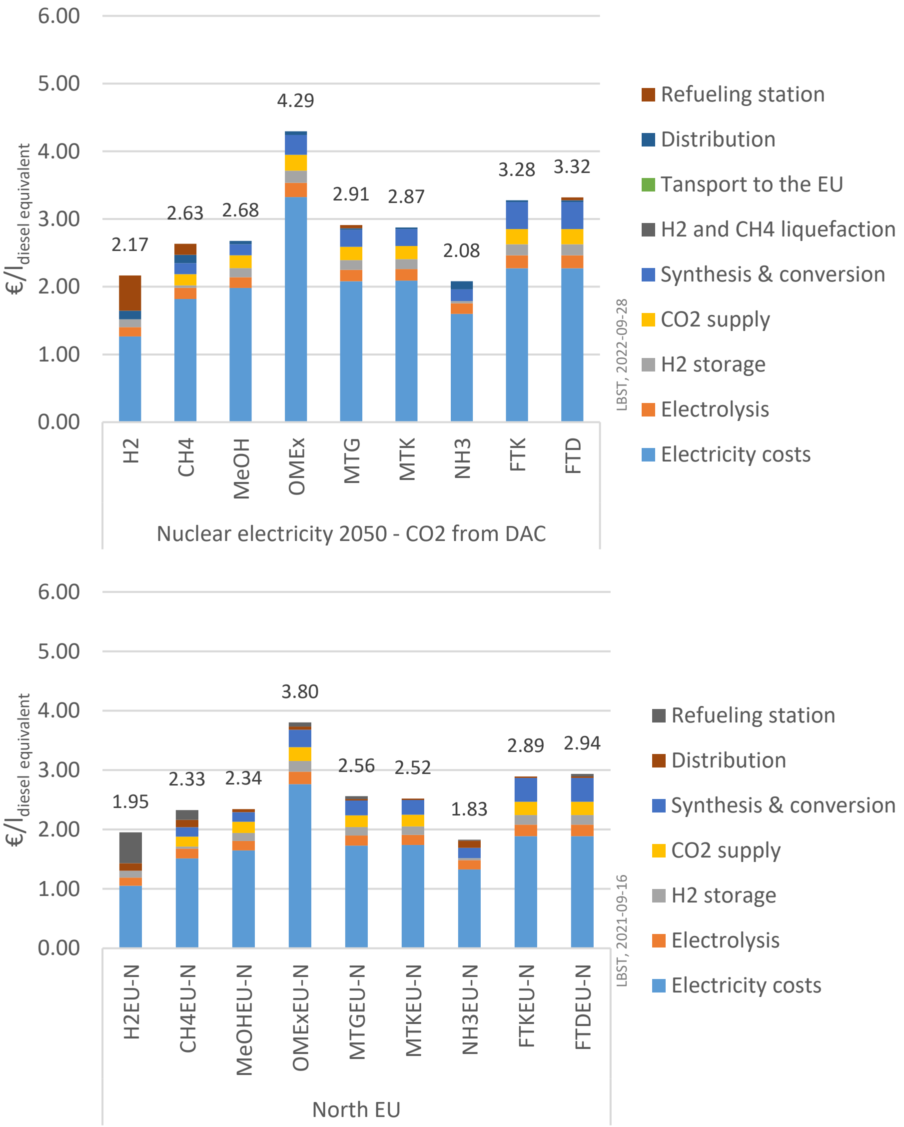


Figure 74: Costs of e-fuels from new nuclear plants electricity compared to e-fuels from new renewable electricity installations in 2050 – per l of diesel equivalent



It has to be noted that abatement costs refer to fuel supply (including embedded carbon), i.e. without use efficiencies. Fuel cell electric vehicles (FCEV) have a higher efficiency than vehicles with internal combustion engine (ICE), leading to lower fuel costs per km. However, the powertrain evaluation (TTW) is out of the scope of this project.

3.2. PRODUCTION COSTS AND ABATEMENT COSTS OF E-FUELS VERSUS BIOFUELS

The greenhouse gas (GHG) production costs and abatement costs of selected e-fuels have been compared with those of selected biofuels.

For biofuel costs in 2020, the focus is on waste based feedstocks produced with a well-established technology and 1st of a kind plant (FOAK). For biofuel costs in 2050, the focus is on biofuel feedstock with highest long-term potential and nth of a kind plant (NOAK).

Table 31 shows the costs of biofuels assumed in this study and which are based on [IEA 2020] representing global biofuel costs where e.g. climatic conditions allow for feedstock cultivation. For 2020, the data labelled as 'current costs' has been used. For 2050, the lower and upper values have been derived from the medium-term data for 'Lower cost of capital' indicated in [IEA 2020] because the bandwidth depicted for medium-term costs are already wide, covering a significant additional learning at the lower end. The medium-term costs in [IEA 2020] are based on 8% discount rate and a lifetime of 20 years which fits well with economic assumptions taken in this study for e-fuels.

Table 31: Costs of biofuels

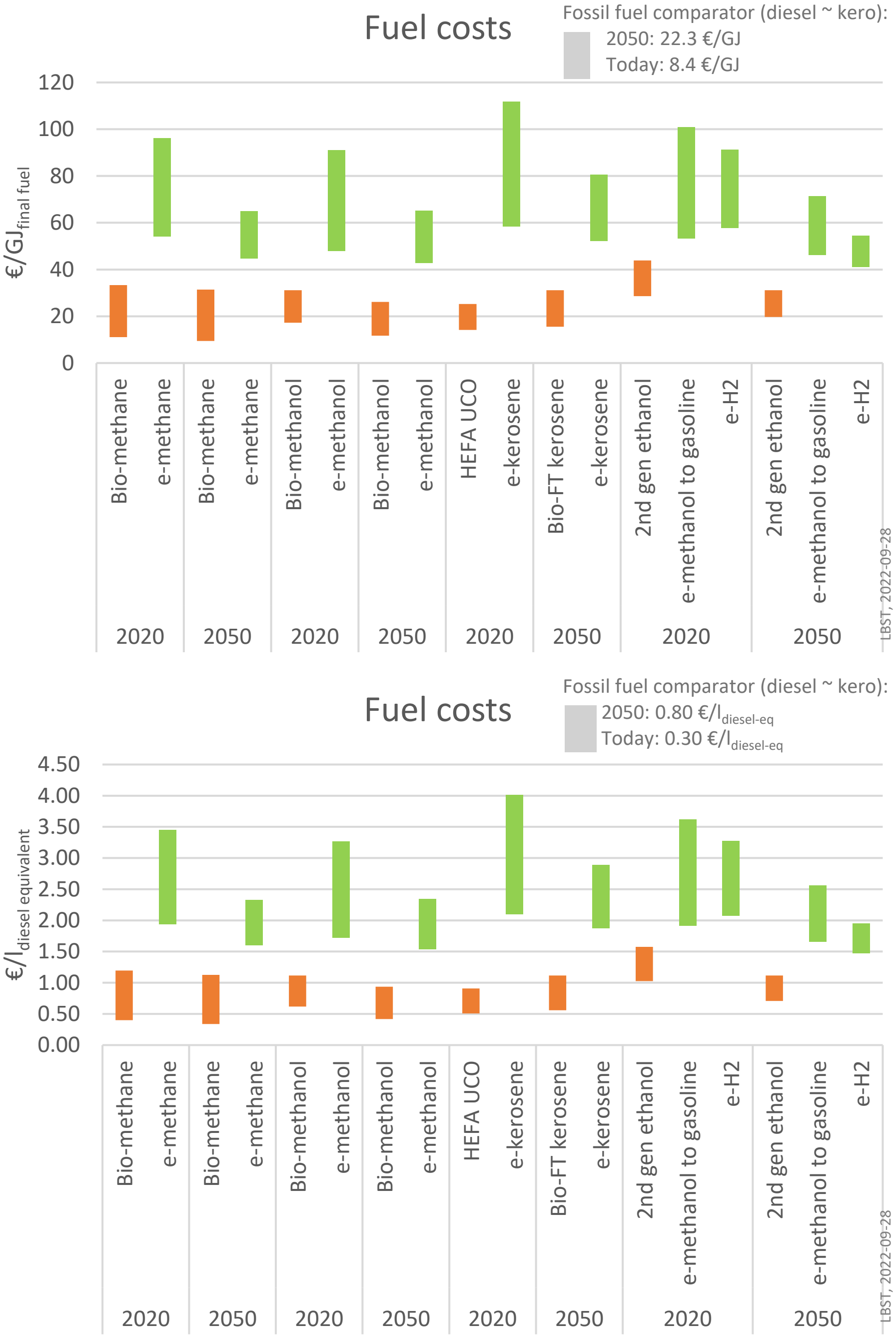
E-fuel route	Biofuel comparators	2020	2050	Reference
e-methane	Bio-methane from anaerobic digestion	11.1-33.3 €/GJ 0.40-1.19 €/Nm^3 9.4-22.0 CO_{2eq}/MJ (waste)	9.4-31.4 €/GJ 0.34-1.12 €/Nm^3 9.4-22.0 CO_{2eq}/MJ (waste)	IEA 2020 JEC WTT v5
e-methanol	Biomass gasification + synthesis	17.2-31.1 €/GJ 343-620 €/t 18.6 g CO_{2eq}/MJ (farmed wood)	11.7-26.1 €/GJ 232-520 €/t 18.6 g CO_{2eq}/MJ (farmed wood)	IEA 2020 JEC WTT v5
e-gasoline	2nd generation bio-ethanol*	28.6-43.9 €/GJ 0.61-0.93 €/$l_{ethanol}$ 17.8-22.8 g CO_{2eq}/MJ (wheat straw, waste wood)	19.7-31.1 €/GJ 0.42-0.66€/$l_{ethanol}$ 17.8-22.8 g CO_{2eq}/MJ (wheat straw, waste wood)	IEA 2020 JEC WTT v5
e-kerosene	HEFA/HVO (2020) Biomass gasification + synthesis (2050)	14.2-25.3 €/GJ 625-1115 €/t 11.1-16.1 g CO_{2eq}/MJ (UCO)	15.6-31.1 €/GJ 686-1372 €/t 17.6 g CO_{2eq}/MJ (farmed wood)	IEA 2020 JEC WTT v5

*Blend wall applies, i.e. no full drop-in capability with gasoline fuel

For the calculation of the greenhouse gas abatement costs, a fossil fuel comparator of 94 g/MJ as indicated in the actual Renewable Energy Directive of the EU [RED 2018] has been applied. The costs of fossil fuel are assumed to be 8.4 €/GJ (diesel as proxy, see Table 16 in chapter 2.1.2).

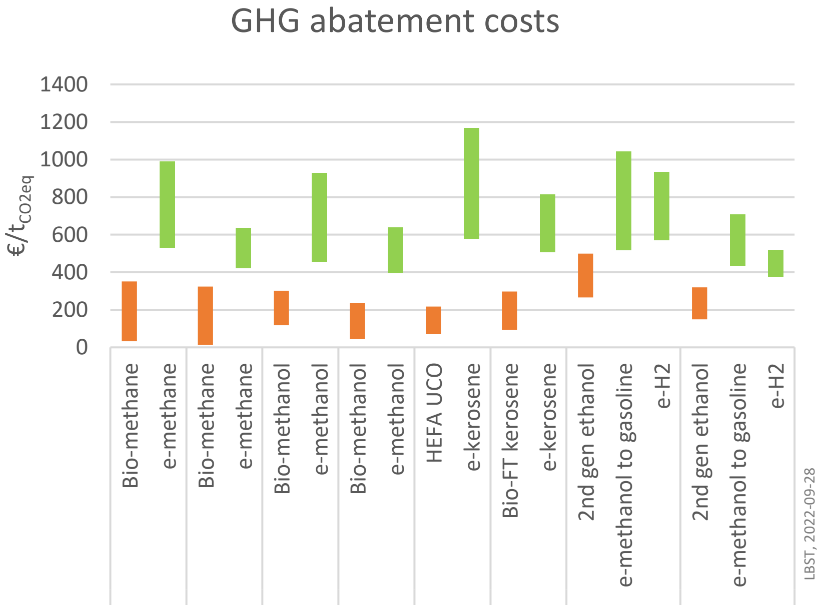
Figure 75 shows the costs of selected e-fuels (minimum and maximum costs of each energy product across regions and CO_2 sources within one timeframe) compared with selected biofuels (minimum and maximum costs as per Table 31) leading to the greenhouse gas production costs and abatement costs shown in Figure 76. Note that current biofuel *prices*, e.g. for hydrotreated vegetable oils (HVO) from wastes (UCO) with some 1900 US$/t in spring 2021 [Argus 2021], are more than twice the costs indicated in Figure 75 because of renewable fuel quotas, constrained supply base (wastes and residues), and ramp-up pace.

Figure 75: Cost bandwidths of selected e-fuels from this study (EU domestic and imports) compared with selected biofuels (global for suitable areas) derived from literature [IEA 2020] – per GJ final fuel and per litre diesel-equivalent



Based on the assumptions taken, the ranges of fuel production costs for biofuels reported in [IEA 2020] are lower than those for e-fuels calculated in this study.

Figure 76: GHG abatement costs for selected biofuels (derived from IEA) and e-fuels (this study)



Based on the assumptions taken, the GHG abatement costs for biofuels are lower than those for e-fuels. The GHG abatement costs for e-fuels are decreasing from about 450-1170 in 2020 to some 370-810 €/t of avoided CO_2-equivalent in 2050.

The decrease of the upper limit over time is higher than that of the lower limit of GHG abatement costs because the upper limit represents e-fuels from offshore wind farms where the cost decrease is higher than for onshore wind. Offshore wind power is at an earlier stage of development than onshore wind power. The lower limit represents e-fuel from MENA where the electricity costs are already rather low today.

The costs of e-fuels using renewable electricity are compared with fuels derived from natural gas with CCS is also analysed in Section 8.6.)

KEY MESSAGES - COMPARISON OF E-FUELS PRODUCED FROM NUCLEAR ELECTRICITY AND BIOFUELS

1. E-fuels from nuclear electricityThe costs of nuclear electricity have been calculated based on a new nuclear power station based on the European Pressurized Water Reactor (EPR). Based on the assumptions taken, the costs for nuclear electricity amount to about 94 € per MWh of electricity for all time horizons (see chapter 8.4.19 in the annex) taking into account a new nuclear plant. The charts show that e-fuels produced from nuclear electricity (based on a new nuclear plant) results in higher production costs than from Norwegian offshore wind (based on new installations) in 2050.

In section 2.1.3., it was shown that e-fuel production in Norway (offshore wind) results in higher costs than in other regions (Germany, Spain, MENA) (mix of PV/wind onshore).

Therefore, it can be concluded that e-fuels produced from nuclear electricity, based on a new nuclear plant, results in higher production costs than with renewable electricity for all the regions by 2050.

2. BiofuelsThe production costs and GHG abatement costs for biofuels are lower than those for e-fuels, based on the assumptions taken. In 2050 the costs of e-fuels supply ranges between 1.5 € per l of diesel equivalent for e-methanol in the best case and 2.9 € per l of diesel equivalent for FT kerosene in the worst case.

In 2050 the costs of biofues range between 0.3 € per l of diesel equivalent (lower limit for bio-methane) and 1.1 € per l of diesel equivalent (upper limit for bio-methane, Bio-FT kerosene, and 2nd generation ethanol). The GHG abatement costs for e-fuels are expected to decrease from about 460-1170 in 2020 to some 380-810 €/t of avoided CO_2-equivalent in 2050. The GHG abatement costs for biofuels are expected to decrease from 30-500 €/t of avoided CO_2 equivalent in 2020 to some 10-320 €/t of avoided CO_2 equivalent in 2050. The higher cost of abatement for e-fuels is attributable primarily to the cost of green hydrogen production as compared with biomass gasification. Taking FT liquid production, for example, 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. 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.

Therefore, it can be concluded that biofuels result in lower production costs than e-fuels by 2030 and 2005. However, biofuels have other issues related to sustainability and land/water requirements to be analysed (out of the scope of this study).

4. CONTEXT OF E-FUELS IN THE FUTURE OF EUROPE – POTENTIAL DEMAND, FEASIBILITY, OPPORTUNITIES AND CHALLENGES

This chapter explores the context into which e-fuels may play in the future. For this, additional aspects are analysed to identify aspects such as potential demand, feasibility, opportunities and challenges for using e-fuels, and conditions that allow for e-fuel business cases.

4.1. POTENTIAL E-FUEL DEMAND IN EUROPE, CAPEX, LAND AREA AND ELECTRICITY REQUIREMENTS

The e-fuels explorative scenarios for 2050 were developed based on final energy demand data in the transport sector reported in the IEA World Energy Outlook Net Zero by 2050 [IEA 2021] scenario. This study includes a comprehensive analysis of how to transition to a net zero energy system by 2050, and includes a portion of synthetic hydrogen-based liquid fuels (e-liquids) and e-hydrogen in the global energy demand in 2050 for the transportation sector. The dataset provides a breakdown of the total energy demand in transport (1911 MTOE) by fuel at a global level.

Since no regional breakdown for Europe is provided by IEA World Energy Outlook, the European energy demand for transport was estimated to be 12% of the global data reported by IEA, based on shares derived from MESSAGEix-GLOBIOM 1.1 Net Zero 2050[2] and GCAM5.3_NGFS Net Zero 2050[3]. It was further assumed that the share by fuel in Europe would be the same as at a global level, on the basis that by 2050 an equilibrium position should have been reached across the globe.

Explorative scenarios in term of final energy demand (Table 32) were built considering two cases:

- **Low scenario:** in line with IEA expectations for e-fuels take-up
- **High scenario:** As above but with IEA shares of biofuels and oil shifted to e-liquids and biomethane shifted to e-methane.

The total e-fuels demand including e-liquids (e-gasoline, e-diesel, e-kerosene), e-hydrogen and e-methane represents 29% and 56% of the total EU final energy demand in transport in the low and high scenario respectively. **It should be emphasised that these are not intended to be forecasts of future e-fuels demand in transport but rather to provide a plausible envelope within which e-fuels demand could fall.** The demand level actually reached will be dependent on multiple factors including policy settings and technical developments across production and end use applications.

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[2] https://www.iamcdocumentation.eu/index.php/MESSAGE-GLOBIOM

[3] https://data.ene.iiasa.ac.at/ngfs/#/workspaces

Table 32: EU energy demand for transport: explorative scenarios for 2050 [IEA 2021]

Fuel category	Low scenario	High scenario	Notes
	MTOE	MTOE	
Electricity	100	100	For transport
e-liquids	**29**	**86**	**e-fuels**
e-methane	**0**	**6**	**e-fuels**
Biofuels	32	0	Shifted to e-liquids in high scenario
Oil	26	0	Shifted to e-liquids in high scenario
Biomethane	6	0	Shifted to e-methane in high scenario
e-hydrogen	**37**	**37**	**e-fuels**
Natural gas	0	0	
Total e-fuels	**66**	**129**	
Total	229	229	

The renewable energy (in TWh) required to produce the e-fuels demand indicated by the explorative scenarios was estimated using an average conversion efficiency for each fuel category (Table 33), using data already contained in Chapter 3.2 of this report.

Table 33: Efficiencies used for evaluating the electric energy required for e-fuels in 2050

E-fuels category	Efficiency	Notes
	%	
e-liquids	42	via FT synthesis and CO_2 from DAC
e-methane	52	with CO_2 from DAC
e-hydrogen	75	on-site production

The electricity generation capacity (in GW) was calculated by applying capacity factors in three distinct locations and energy mixes designed to evaluate a range of possibilities for e-fuels production in EU (Table 34). The chosen scenarios for renewable energy production were: PV in South Europe (lowest capacity factor), PV/wind hybrid in Central Europe (note that this is very similar to Wind offshore in North Europe) (central capacity factor) and PV/wind hybrid in South Europe (highest capacity factor).

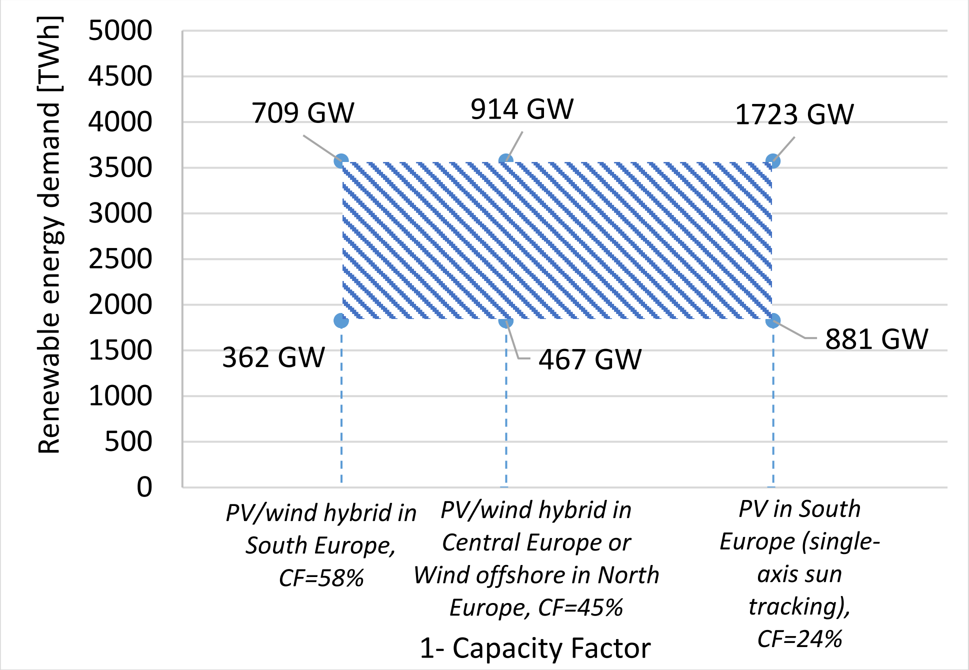
Table 34: Capacity factors selected for evaluating the electric capacity required for e-fuels in 2050

Category	Capacity factors		Notes
	h/year	%	
PV in South Europe (single-axis sun tracking)	2073	24	Worst case scenario
PV/wind hybrid in Central Europe or Wind offshore in North Europe	3908	45	Central case scenario
PV/wind hybrid in South Europe	5039	58	Best case scenario

Depending on location (South, Central, and North EU) and renewable generation mix (PV or PV/wind hybrid), a plausible envelope of renewable energy demand and electricity generation capacity required to meet the potential e-fuels demand was estimated as reported in the chart in Figure 77. The results show that the renewable energy demand ranges from 1825 TWh (low scenario) to 3571 TWh (high scenario) while the electricity generation capacity ranges from 362-881 GW (high capacity factor case) and 709-1723 GW (low capacity factor case) depending on the demand scenario. According to this explorative analysis, the actual required generation capacity could plausibly lie within the shaded envelope in Figure 77, depending on the final location of e-fuels plants in 2050 and the level of demand.

Comparing this estimation with the current situation, the renewable energy supply from wind, solar and hydro in 2019 in Europe was about 1500 TWh [IEA 2019c], representing between one quarter and one half of the predicted renewable energy needed for transport in 2050 in the low and high scenarios respectively. Meanwhile the current installed renewable generation capacity in Europe was 500 GW in 2020, with the IEA forecasting this to increase to 800 GW in 2030 [IEA-RES 2021]. The build out rate implied by this forecast is of a similar order of magnitude to what would be required to meet the e-fuels demand in the scenarios in this study, i.e. in the hundreds of gigawatt range. However, there will be competing demands for renewable electricity and meeting e-fuels demand is likely to require additional renewables deployment over and above what is forecast by IEA.

Figure 77: Electricity generation capacity requirements depending on capacity factors (location/renewable energy type) and renewable energy demand for e-fuels in EU in 2050



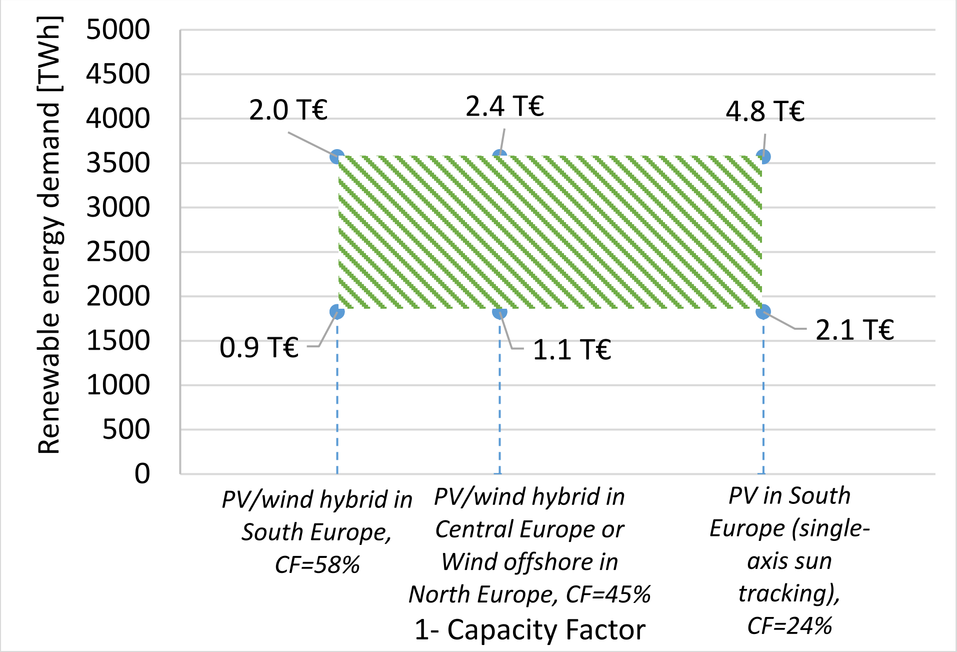
Combining the energy demand data and the CAPEX for each fuel category (already estimated in this report and summarized in table Table 35 in €/kW$_{\text{final fuel}}$), the overall required investment was calculated for each boundary of the scenarios, as depicted in Figure 78. The explorative scenario analysis shows that the total investment by 2050 for e-fuels in transport lies between €0.9 and 2.1 trillion in the low scenario, and between €2.0 and 4.8 trillion in the high scenario.

Table 35: CAPEX in €/kWh$_{\text{final fuel}}$ in the three locations selected for evaluating the overall scenario

E-fuels category	CAPEX		
	South Europe	Central Europe	South Europe
	PV in South Europe (single-axis sun tracking)	PV/wind hybrid in Central Europe*	PV/wind hybrid in South Europe
	€/kWh$_{\text{final fuel}}$	€/kWh$_{\text{final fuel}}$	€/kWh$_{\text{final fuel}}$
e-liquids	3.77	1.93	1.55
e-methane	2.81	1.41	1.16
e-hydrogen	1.97	0.98	0.81

* only the Central Europe case was analyzed for the total investment in the central scenario

Figure 78: Total investment in trillion € required depending on capacity factors (location/renewable energy type) and renewable energy demand for e-fuels in EU in 2050



The average annual investment over the period (assuming constant annual levels) ranges from €32 - 71bn/year if plants are built in the most favourable location and from €75bn - €171bn/year in the least favourable location. By way of comparison, this represents approximately 0.2 – 0.5% (best case) and 0.5 - 1% (worst case) of the current GDP in the European Union (€15 trillion [World Economic Outlook Database]). This level of investments is typical for major infrastructure. For example, according to [VDI 2019] the cost of a new generation of telecommunication infrastructure is estimated between €300 - €500 billion for European coverage with 5G mobile network. Similarly, the cost of a new greenfield 400,000 bbl/day refinery is estimated at $ – 10 billion [EIA 2015], making the annual investment for e-fuels equivalent to roughly 3 - 5 new refineries per year (considering the investment cost if all plants built in the most favourable location).

Assuming a standard e-fuels plant capacity in this study of 3.3GW[4], it equates to an output of ~600ktoe per annum in the most favourable locations and 250ktoe per annum in the least favourable locations. In the low case scenario, the e-liquids demand estimate would require the construction of 2 plants per year in each year to 2050. This would rise to 12 plants per year in the high case. The required effort is significant but would be spread over multiple countries reducing the pressure on the supply chain in individual countries. In addition, an annual build out rate of between 13 GW and 62 GW of renewable capacity would be required. To put this into perspective, Europe added 15 GW of new wind capacity in 2019 while global solar capacity additions reached over 100 GW in 2020.

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[4] The plant size used is the one referred to as the base case in Section 2.2.8 (1000 kt/y of final e-fuel). This plant has a nameplate capacity of 1.4GW of final efuel which equates to 3.3GWe based on the assumed 42% efficiency. In the best location the capacity factor (CF) is 58% so the output would be 580kt e-fuel, and in the less good location CF is 24%, meaning 240 kt e-fuel.

In order to frame the e-fuels scenarios investment boundaries in a larger context, according to McKinsey's study, the overall capital expenditure required to reach net zero is expected to be approximately €24 trillion over the next 30 years in EU-27 across all sectors, with 43% (€10 trillion) predicted to be on transportation only [McKinsey 2020]. Therefore, the e-fuels ranges predicted in this report represent about 8-20% (low scenario) and 20-50% (high scenario) of the overall investment required in the transportation sector. Higher investment levels still have been predicted by the EU Commission, with annual investment of €1.4 trillion required by the transportation sector [EC 2018], representing a total investment of roughly €40 trillion in the next 30 years. In this case, e-fuels may represent a percentage of 2-5% (best case) and 5-11% (worst case).

The gross area required for the generating capacity to meet the e-fuels demand in 2050 was estimated by considering averaged data of 2.5-5 MW/km^2 for wind farms [IRENA 2019b], and 30-36 MW/km^2 for solar PV [NREL 2018]. No additional land requirement was assumed for the e-fuels plants or DAC since these are small relative to renewable generation and can more likely use repurposed land.

The data shows a maximum gross area requirement of roughly 250,000 km^2 (high demand scenario and wind offshore in North Europe) and a minimum requirement of roughly 30,000 km^2 (low demand scenario and PV in Southern Europe). The average value across all the scenarios and renewable energy location and type combination is around 100,000 km^2. By way of comparison, between 50 and 170,000 km^2 would be required to produce the e-liquids portion of demand from rapeseed crop [ICCT 2018] although this figure would vary widely according to crop type, location and intensity of farming, and its net area occupancy would be ~100% of the gross area. Once again, to put these expected area requirements into perspective, the area of the North Sea is approximately 570,000 km^2, of which roughly half is non-usable (owing to shipping routes, military exclusion zones, etc.), while the inland area of South Europe (Spain, Italy, Greece and Portugal and the Balkans) is 1.3Mkm^2 [World Bank]. The total European land area is about 4.6 million km^2. (this is based on 3.99 million km^2 for EU to which has been added the UK (0.24 million km^2), Switzerland (0.04 million km^2) and Norway (0.37 million km^2) giving 4.64 million km^2), with urban areas representing on average 10% of the total land area [World Bank]. This suggests that between 2 and 3% of the total land area would need to be shared with renewables.

Table 36: Area required for e-fuels demand in 2050 in EU, depending on the renewable energy location and source

Renewable energy and location	Scenario	km^2 x 10^3			
		e-liquids	e-methane	e-hydrogen	Total
PV in South Europe (single-axis sun tracking), CF=24%	Low	12		15	27
	High	35	2	15	52
PV/wind hybrid in Central Europe, CF=45%	Low	30		39	69
	High	90	6	39	136
Wind offshore in North Europe, CF=45%	Low	54		70	125
	High	162	11	70	244
PV/wind hybrid in South Europe, CF=58%	Low	23		30	54
	High	70	5	30	105
Average		*60*	*3*	*39*	*101*
Max		*162*	*11*	*70*	*244*
Min		*12*	*0*	*15*	*27*

KEY MESSAGES - POTENTIAL E-FUEL DEMAND IN EUROPE, CAPEX, LAND AREA AND ELECTRICITY REQUIREMENTS

The challenge involved in meeting e-fuels demand in both the high and low scenarios is significant. Vast amounts of investment are required and sizable amounts of resource must be mobilised but these are consistent with other major infrastructure investment.

High and low **scenarios for e-fuels developed** for this project suggest that demand for e-fuels in Europe could be in the range between 66 and 129 million tons of oil-equivalents. This would require the deployment of anywhere between 362 and 1,723 GW of new renewable generation capacity depending on the geographic distribution, generation mix and demand scenario chosen. This compares with an installed renewables capacity today of around 500 GW which is still a small fraction of technical renewable power generation potential in Europe (see chapter 4.2.1.1).

The capex required to deliver this amount of e-fuels process plant and associated renewables would lie in the range €1 – 5 trillion or the equivalent of an annual investment of between 0.2 and 1% of EU GDP. This level of expenditure is consistent with other estimates of the investment required to achieve net zero and must be set against the operating cost benefits of switching to renewables (high capex but low opex cost profile) not to mention the benefits in terms of energy security. It is also comparatively low considering that the cost of a new generation of telecommunication infrastructure is estimated between €0.3 - 0.5 trillion in the case of European coverage with 5G mobile network.

While gross land use requirements are significant, being around 0.1 million km^2, this represents a proportion of some 2% of the total usable European land area. The challenge involved in meeting e-fuels demand while significant is spread over a large region, mitigating the pressure on the supply chain.

The investment required must be set against the reduction in operating costs that would result from shifting away from fossil fuels as well as the costs of climate change, e.g. adapting to a significant rise in global temperatures. No absolute show-stopping concerns was identified but consideration must be given to whether e-fuels represent the desired way to achieve net-zero ambitions where other alternatives, such a direct use of electricity is an alternative. Deployment of e-fuels plant and especially electricity generating capacity may have to be handled in a sensitive way recognising that there can be societal concerns over aspects such as changes in the visual landscape.

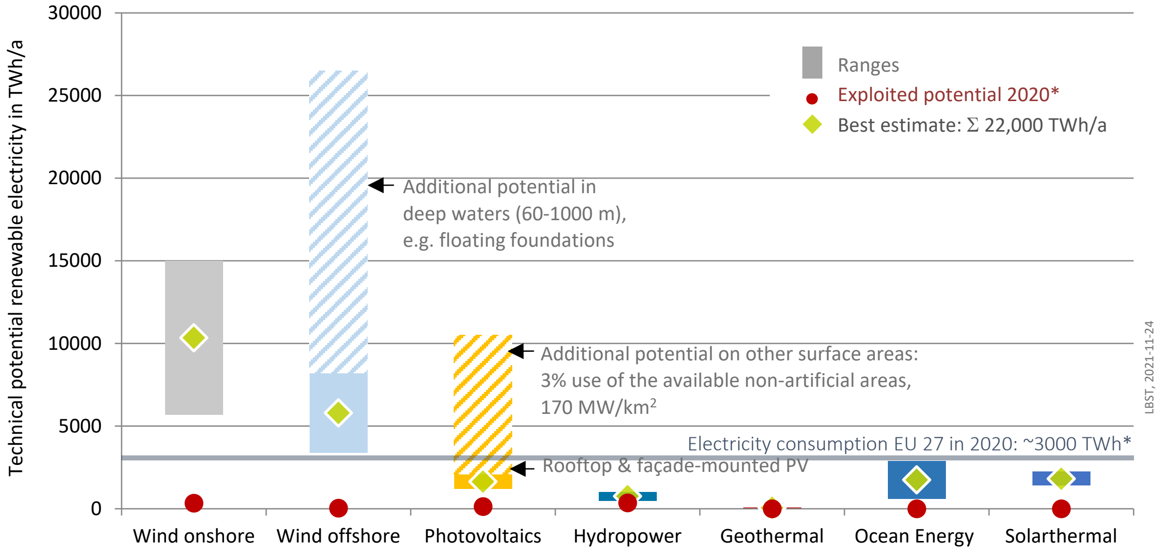
4.2. TECHNICAL AVAILABILITY AND POTENTIAL OF FEEDSTOCKS

The previous chapter explored the potential demand for e-fuels and what that represents in terms of required electricity and e-fuels supply capacity. This chapter explores the theoretical supply potential and whether there are any constraints which might limit the expansion of e-fuels.

4.2.1.1. Technical renewable electricity potentials

Figure 79 depicts the technical renewable electricity production potentials for **Europe** derived from a literature review. The bars indicate bandwidths of assumptions taken in literature e.g. for specific area demand and future power plant performance data.

Figure 79: Technical renewable electricity production potentials for Europe (Source: LBST based on literature review)



Data: [Brauner 2019], [Caglayan et al. 2019], [EEA 2009], [Elavarasan 2019], [JRC 2019], [Ruiz et al. 2019], [LBST 2016], [Magagna 2019]
*2020 data: [Eurostat 06/2021], [IEA Data Services 10/2021]

Summing up the bandwidth averages results in 22,000 TWh/a of renewable power production potential. Hence, conservative assumptions of European technical renewable power production potentials are sufficient to cover at least seven times today's electricity consumption. For comparison:

- If **today's transport fuel demand** of EU 28+ was completely provided with PtL (worst and **unrealistic case**, but just to put figures in perspective), this would result in a renewable electricity demand of ~12,000 TWh_e/a, thereof ~1,600 TWh_e/a for aviation.
- Assuming a **range of scenarios using 100% renewable energy use in all transport** for BEV charging, e-hydrogen, e-methane, and e-liquids in EU27+UK by 2050, according to [FVV 2021, p69ff] this would result in 2,570 to 10,880 TWh_e/a of renewable electricity demand.

The main limitation on exploiting the significant renewable electricity potentials in Europe may be social acceptance of mass deployment of wind and solar power plants.

Table 37 gives the techno-economic/'realistic' renewable electricity production potentials for PtX plants in the Middle East/North African regions derived from the PtX Global Potential Atlas[5].

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[5] https://maps.iee.fraunhofer.de/ptx-atlas/

Table 37: Techno-economic/'realistic' renewable electricity production potentials for PtX plants MENA

TWh_e/a	**Hybrid (c.)**	**Hybrid (i.)**	**PV (c.)**	**PV (i.)**	Region SUM
Algeria	-	370	-	599	969
Morocco	743	-	131	-	875
Tunisia	436	79	60	-	575
Saudi Arabia	1330	48	2419	196	3993
UAE	-	-	967	-	967
Tech. TOTAL	2509	497	3578	794	**7378**

Hybrid: suitable for wind & solar
c.: along the coastline
i.: along inland waters

According to the *PtX Global Potential Atlas*, the techno-economic/'realistic' potentials of e-H_{2_gas} production in the MENA region is ~5000 TWh_{H2} or 150 million t_{H2} per year. This is a very conservative estimation as it incorporates infrastructure restrictions, such as limiting the distance to the coast, and restricting transport to inland waterways and existing pipeline infrastructures. Assuming a 67% conversion efficiency, the hydrogen production potential translates into renewable electricity supply potentials of 7378 TWh_e per year. The main limitation to exploit this potential may be **political and energy security risks**, e.g. impacting discount rates for investment which are typically region and project specific.

According to [Bond et al. 2021], the share of solar & wind potential of Africa and Middle East is ~40% and ~8% of global technical potential, respectively, i.e. huge. The share of Europe is estimated to be ~3%, i.e. still huge compared to current and prospective renewable electricity demand.

High potentials of renewable electricity are available in South Europe (Spain), MENA, Australia, and Chile. However, there are also some regions in Central Europe e. g. at the Lusatia lignite mining region in Germany where large-scale PV-wind hybrid power could be installed for the supply of electricity for e-fuels. On the other hand, in density populated regions with cold winters like Germany there is an increasing electricity demand of other sectors especially due to expansion of electrically driven heat pumps for heat supply. Therefore, for **liquid e-fuels where transport costs are low, less-densely populated regions with high renewable electricity potential such as the MENA region are an option. The most cost-effective transport of gaseous e-fuels is via pipeline where topography allows for this option.**

4.2.1.2. Availability of concentrated CO_2 sources

The CO_2 source is an important determinant of the greenhouse gas balance of carbon containing e-fuels. Today, early in the deployment phase, there is a notion to utilize the most concentrated CO_2 sources that are available and unavoidable to save on process energy demands, reduce plant complexity, and lower asset investment. However, CO_2 emissions from fossil sources will be reduced towards 2050 and other

CO_2 sources will be required: direct air capture (DAC) of CO_2 from air, CO_2 from biogas upgrading, biomass fermentation to alcohols, and exhaust gas CO_2 from biomass fueled heat and power plants (biomass complying with sustainability criteria). Sustainability safeguards are necessary to avoid unintended collateral damage (e.g. prolonging the life of fossil plant) and to reduce risks for stranded investment in future. Table 38 depicts the different sustainability aspects for exemplary concentrated CO_2 sources.

Table 38: Sustainability and perspectives of different CO_2 sources

CO_2 sources	Renewability	Environmental sustainability	Alternative CO_2 uses	Towards carbon-neutrality; Risks
Extraction from air	🟩	Subject to renewable energy		
Biogas upgrading	🟩	Subject to feedstock & process	Power-to-methane	Other land or sustainable biomass uses
Solid biomass fired heat (and power) plants	🟩	Subject to feedstock & process	Bio-CCS	
Fermentation to alcohols	🟩	Subject to feedstock & process	Beverage industry	
Geothermal sources	🟨	Subject to geo-phys. CO_2 cycle	CO_2 re-injection (closed-loop)	Hot dry rock a potential no-go
Cement, burnt lime or glass production	🟥	Short-term exemptions?	Power-to-chemicals	Shift to alternative materials, recycling; Technology lock-in
Steel production	🟥	Short-term exemptions?	Top-gas for heating and reduction	Shift to direct reduction with H_2, recycling, alternative materials; Technology lock-in
Fossil fuel firing	🟥		CCS	Phase-out; Technology lock-in

The potential of concentrated CO_2 sources such as biogas upgrading and biomass fueled combined heat and power stations is limited due to limited sustainable bioenergy potential. Furthermore, bioenergy plants are too small to supply CO_2 for e-fuel plants with capacities envisaged here and are sometimes not located in regions with high solar irradiation and wind speeds like the MENA region.

CO_2 is also avoidable in other ways. Primary steel plants can be converted from blast furnace to direct reduction iron (DRI) technology using renewable hydrogen and avoiding CO_2 emissions from primary steel production in the future. In case of CO_2 from geothermal plants it is subject to the geo-physical cycle. A closed water loop including re-injection of the CO_2 can avoid these CO_2 emissions.

By contrast, CO_2 from cement production often is considered unavoidable. In the Kingdom of Saudi-Arabia (KSA) about 43 million t of clinker[6] was produced in 2019 [KAPSARC 2020]. Approximately 560 kg of CO_2 can be captured per t of clinker [Gardarsdottir et al. 2019]. As a result, the potential for CO_2 from cement production for e-fuels in KSA would amount to about 24 million t per year sufficient for about 10 PtL plants with a capacity of 114 t of diesel equivalent/h based on Fischer-Tropsch synthesis in KSA generating about 273 PJ of final fuel per year (~6 million t/yr, see Table 39).

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[6] Clinker is a pre-product for cement production

Table 39: Potential for CO_2 from cement production

	Unit	MENA (KSA)	MENA (Morocco)
Clinker production 2019	million t	43	3.1
Potential CO_2 captured	kg $CO_2/t_{clinker}$	559	559
	million t/yr	24.0	1.73
CO_2 demand FT synthesis	kg/$MJ_{final\ fuel}$	0.0880	0.0880
Potential fuel production	PJ/yr	273	19.7
	million t/yr	6.33	0.457
Equivalent full load period PtL plant	h/yr	5319	4560
Capacity PtL plant	$MW_{final\ fuel}$	1368	1368
	t/h	114	114
Number of PtL plants		10.4	0.9
Domestic demand gasoline, kerosene, diesel	PJ/yr	2267	243

The potential for CO_2 from clinker production in Morocco is much lower and the CO_2 potential from clinker production in both KSA and Morocco is insufficient to meet the local demand of transportation fuel (2267 PJ/yr in 2019 based on [KAPSARC 2021] and 243 PJ/yr in 2017 based on [IEA 2019b] respectively).

Furthermore, in the case of cement production using renewable energies in the future to meet the Paris Agreement, the remaining CO_2 released by the chemical reaction from the calcination of limestone for clinker production can be avoided via

- returning demolished concrete to the cement production process and thus closing the CO_2 loop [Heidelberg Cement 2021],
- increasing use of alternative construction materials, or
- avoiding cement production via extending the use-phase of concrete-made structures (e. g. renovation instead of dismantling and new construction).

Table 39 shows an overview of CO_2 from cement production.

According to a literature review by [Concawe 2019, p 46f], the CO_2 available from large point sources in 2030 seems to be sufficient to cover the foreseeable demand from the production of electricity-derived synthesised fuels and chemicals. Supply from concentrated CO_2 sources could be more constrained in the mid to long-term horizon (2050), subject to the sustainability assessment of large point sources (supply side) and scenarios for synthesised e-fuels production (demand side).

4.2.1.3. Availability of water

The availability and sustainability of water that can be further processed to demineralized process water is subject to local conditions. Large point consumption such as for agriculture, beverage bottling or industry uses usually require an environmental impact assessment to achieve construction and operation authorisation.

Regions with high solar irradiation such as Southern Europe, North Africa and KSA often are affected by water scarcity. Seawater desalination will likely be required to supply water in a sustainable way in these regions for the various aspects of e-fuels production. Climate change is also increasingly felt in Central Europe with changing patterns of precipitation and water storage (snow, ice).

However, the water demand for the cleaning of PV panels is low. For MENA the water demand is indicated with 0.04 kg per kWh of electricity for PV power plants in 2020. It is expected that the water demand for the operation of PV power plants decreases to 0.03 kg per kWh until 2050. Dry cleaning of PV panels also is possible [SolarClean 2021] and considered a must in dry regions [PI Berlin 2018]. The water demand for wind power is negligible [DLR et al. 2021]. For water electrolysis about 0.27 kg of water per kWh of hydrogen is required (~75 kg per GJ of hydrogen). Furthermore, direct air capture (DAC) of CO_2 also extracts about one kg of water from the air per kg of CO_2. As a result, a large fraction of the water demand of the e-fuel plant can be supplied by the DAC plant. Water is also released by the methanol and Fischer-Tropsch (FT) synthesis.

While water demand may be necessary for cooling, the cooling water demand of the Qatar GTL plant is met by the water released by the FT reaction [Shell 2021] and no water is imported and no water is exported. Furthermore, dry cooling towers can reduce the water demand for cooling.

Table 40: Water demand e-fuel plants

		H_2	MTK	FTK
H_2 demand for synthesis & further processing	$MJ/MJ_{final\ fuel}$	-	1.241	1.404
Water demand water electrolysis	$kg/kWh_{final\ fuel}$	0.268	0.333	0.376
	$m^3/GJ_{final\ fuel}$	0.074	0.092	0.105
CO_2 demand	$kg/MJ_{final\ fuel}$	-	0.074	0.088
Water extracted from air by DAC plant	$kg/kgCO_2$	-	1	1
	$m^3/GJ_{final\ fuel}$	-	0.074	0.088
Net water demand e-fuel plant	$m^3/GJ_{final\ fuel}$	0.074	0.019	0.017
	$l/l_{diesel\ equivalent}$	2.673	0.678	0.594

In case of H_2 generated in KSA, the annual water demand would amount to about 2.0 million m^3 per year for a water electrolysis plant with a capacity of 1368 MW of hydrogen based on the LHV. By contrast, in the case of MTK and FTK with a capacity of 1368 MW of final fuel the annual net water demand would amount to about 0.4 to 0.5 million m^3 per year if the e-fuel plant were located in KSA. This compares to current water consumption in KSA, which exceeded 8 million m^3 per day (> 2920 million m^3 per year) in 2019 [USSBC 2021].

In regions with water scarcity the net water demand of the e-fuel plant has to supplied by seawater desalination plants. There are already seawater desalination plants operational and under construction in MENA. The CAPEX for the seawater desalination plant would amount to less than 1% of the CAPEX of the electrolysis plant (see chapter 2.1.2) and as a result, less than 1% of the total CAPEX of the e-fuel plant.

The water demand of e-fuel plants can be compared with capacity of current water desalination projects to give an idea about the scales this study is talking about. In Casablanca in Morocco a large seawater desalination plant with a capacity of 300 million m^3 of drinking water per year is under construction. The plant will be operational by end of 2027 [MLN 2021]. Existing seawater desalination plants are located Laayoune, Boujdoor, Tan-Tan, and Sidi Ifni. Other seawater desalination plants are under construction including one in Agadir (144 million m^3 per year), one in Al Hoceima, one in Safi, and one in Dakhla [MLN 2021]. The capacity of current water desalination projects is significantly higher than the water demand of individual large e-fuel plants. Water scarcity is a major problem in KSA, with around 40% of the water demand in 2019 being met by extraction of water from deep groundwater sources where far more water is extracted than recharged naturally. About 60% of the water demand is met by seawater desalination and only a small amount of the water comes from surface water and reclaimed waste water [USSBC 2021]. As a result, expansion of seawater desalination is required regardless of large-scale e-fuel plants will be built in KSA in the future.

Practical implementation examples

Suitable locations for e-fuel plants in North Europe are at the coast connected with high voltage direct current (HVDC) electricity transmission cables from large offshore wind power plants. For example, the company Nordic Blue Crude is just building a pilot plant for the production of synthetic jet fuel and other products in Herøya in Porsgrunn, 160 km South West of Oslo in Norway. Another pilot plant is the KEROSyN100 project at the Heide refinery in Germany nearby the North Sea coast (and nearby offshore wind farms) where synthetic kerosene will be produced.

It is also possible to build large-scale water electrolysis offshore nearby the offshore wind farms and transport the hydrogen via pipeline to the coast. From there the hydrogen can be distributed via a hydrogen pipeline grid. No active projects of this type as yet exist although a number of developers are studying offshore wind to hydrogen solutions, e.g. the Dolphyn Project [ERM 2022].

Former lignite mining regions e. g. in Bulgaria, Czech Republic, Germany, Greece, Poland, Romania may also be suitable locations for large scale onshore projects. These have the added benefit of providing these regions with welcome economic activity after the complete phasing out of brown coal.

KEY MESSAGES - Technical **potentials for renewable power production** in Europe (>22,000 TWh/yr) is a factor of seven of today's (~3000 TWh/yr) electricity demand and thus exceeds the foreseeable energy demand for all energy uses in a carbon-neutral future, in principle. However, exploiting this renewable power potential is subject to social acceptance of the significant infrastructure that would have to be built. The technical potentials in other regions of the world is even greater, but can be associated with geopolitical and energy security risks.

The use of concentrated (point) **CO_2 sources** lead to lower overall fuel costs, notably in the short-term when technologies for direct air capture are not yet available at-scale and are early in the learning curve but have higher emissions. The potential from industrial CO_2 sources, such as from steel production or cement, is set to decrease with novel production pathways, increased recycling efforts, and a general move towards a more circular economy.

Specific **water** demand for electricity-based fuels is negligible compared to water demand for energy crops. However, for regions that are prone to, or already face, water-supply stress, use of dry cooling towers and/or closed-loop water cycling is recommended (where needed) to minimise net water demand. Some direct air capture technologies also provide water that can reduce the net water demand from PtX plants. Despite the low specific water footprint, PtX production plants at-scale are significant point water consumers. Diligent assessment of water supply, demand, and reservoir characteristics are a relevant part in the preparation of environmental and social impact assessments (ESIA) accompanying plant approval processes. In the absence of sufficient fresh water supplies, desalination of sea water may be required but this adds marginally to the overall cost of the fuels.

4.3. AVAILABILITY OF EXISTING INFRASTRUCTURE

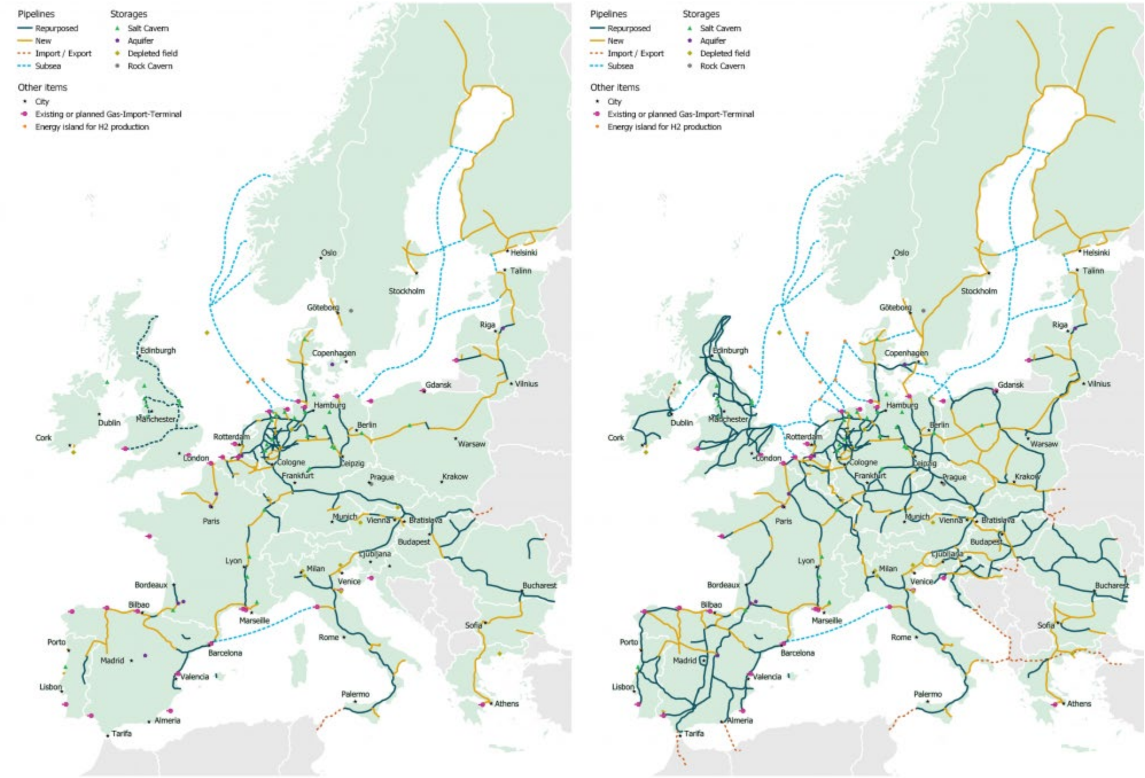
4.3.1.1. Availability of hydrogen pipeline grids

There are several projects for the implementation of a hydrogen pipeline grid in Europe. Within the GET H_2 initiative a hydrogen pipeline backbone grid is planned in Germany [GET H2 2021]. The length of the hydrogen pipeline backbone grid will reach 130 km by 2023, 452 km by 2026, 1294 km by 2028, and 5900 km by 2030. The steps to realising this goal include:

- 2024: GET H2 Nukleus
- 2025: Connection to The Netherlands
- 2026: Inclusion of a hydrogen storage and start of operation in Salzgitter
- 2030: Connection of elements

GET will form part of the European Hydrogen Backbone described in [Guidehouse 2021]. In [Guidehouse 2021] a roadmap for the development of a European hydrogen pipeline grid is described. The length of the hydrogen pipeline grid may reach 11,600 km by 2030 and 39,700 km by 2040 covering 21 European countries. The majority of the hydrogen pipeline grid would consist of repurposed natural gas pipelines as this was found technically feasible and more economical than building new pipelines. Since 2021, the European Union's REPowerEU and several national initiatives were brought forward which are reflected in an updated proposal for an European hydrogen backbone infrastructure as depicted in Figure 80 for 2030 (left map) and 2040 (right map).

Figure 80: Hydrogen backbone pipeline grid 2030 (left map) and 2040 (right map)



Source: EHB 2022

4.4. SAFETY, ENVIRONMENTAL AND SOCIAL CONSIDERATIONS

Safety and environmental regulations for drop in e-fuels (e-liquids and e-methane) are well established and it is not anticipated that any particular additional regulation will be required. Similarly, the regulatory picture for large scale production of hydrogen, ammonia and methanol are all subject to stringent regulation. Hydrogen also has a well-established set of norms for its use in transportation with clear requirements for hydrogen refuelling stations and fuel cell vehicles. Some further work will be required to deal with the specifics of hydrogen use in trucks but its use in buses is now relatively commonplace, mainly in China[7]. By contrast the use of both ammonia and methanol in distributed downstream applications is much less developed and the safety and environmental considerations for the use of both these fuels would need careful consideration. Ammonia, in particular, is highly toxic and harmful to life and, in addition, can result in major environmental damage if released.

Table 41 provides an overview of the toxicity and safety considerations associated with selected e-fuels.

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[7] In their technology status report for 2020, NREL considered fuel cell-electric buses to be around technology readiness level (TRL) 7-8 [NREL 2021]. Up to September 2021, fuel cell buses have been accumulating 13 million km in operation in the European Union [HE & WaterstofNet 2022]. More than 1000 units of FCEV buses are shipped each year worldwide [E4tech 2021]. Following a first wave of battery-electric buses China has started rolling out fuel cell-electric buses with a fleet stock of about 4300 buses in 2020 [IEA 2020c].

Table 41: Toxicity classification of selected fuels and safety issues

	Methanol	**Hydrogen (gas, liquefied)**	**Methane (gas, liquefied**	**Ammonia (gas, liquefied)**
Chemical formula	CH_3OH	H_2	CH_4	NH_3
Acute toxicity (oral, dermal)	Category 3	-	-	
Acute toxicity (eyes, central nervous system)	Category 1	-	-	
Acute toxicity (inhalation)		-	-	Category 3
Serious egy damage		-	-	Category 1
Skin corrosion/irritation		-	-	Category 1B
Carcinogenicity	-	-	-	-
Persistence	Readily biodegradable	Biodegradeable	Biodegradable	Readily biodegradable
Aquatic environment (acute)		-	-	Category 1
Aquativ environment (long term)		-	-	Category 2
Safety issues		Compressed gas, cryogenic burns	Compressed gas, cryogenic burns	Compressed gas
Flammable gases/liquid	Category 2	Category 1	Category 1	Category 2
				

In 2019 about 17.5 million t of NH_3 was transported by 71 NH_3 carriers worldwide. The energy content of these transported NH_3 amounts to 325 PJ based on the LHV. NH_3 is e.g. proposed as fuel for ship propulsion. According to [IEA 2015] 204.84 million t of oil equivalent or 8577 PJ of fuel were consumed by international navigation that year. If the fuel demand of the marine ships were substituted by NH_3 the amount of NH_3 handled worldwide and the associated risks would be increased by a factor of 26.

Further energy applications are being discussed to potentially use ammonia in future, such as NH_3 as a long-distance carrier of hydrogen (power to hydrogen to ammonia to hydrogen), NH_3 as fuel for inland waterway vessels, or for electricity generation via NH_3-fuelled gas turbines. Expanding the use of NH_3 beyond today's use as feedstock for fertiliser and chemicals entails increasing today's risk surface potentially by several orders of magnitudes. Following the root-cause-principle, minimising the risk surface would require the production and storage of ammonia as close (site and time) as possible to its use. This principle, however, contradicts with today's notion for long-distance transport and storage of bulk NH_3 volumes.

Human safety considerations in the use of ammonia

Ammonia has been in use globally for over 100 years resulting in an accumulation of safety experience, a mature set of international laws and regulations, and a sophisticated support sector providing ammonia users and first responders with safety equipment, training, and education.

Ammonia is toxic, causing irritation to humans at low concentrations and can be life threatening at high concentrations. Early detection at low concentrations is feasible through human smell and automated gas detection, even at low ppm levels is effective. However, the immediate consequences of ammonia spills can be more damaging, e.g. through skin impacts, dissolution in bodies of water will be toxic to aquatic life and in the worst case, can cause death by inhalation. Ammonia is flammable and when stored under pressure (<17 bar) presents an explosion risk but its low reactivity means high temperatures are required for ignition and it has a low flammability range in air.

A 2019 study by TU Delft and C-JOB provides a technical assessment of ammonia as a marine fuel and suggests that its risk profile is comparable to other marine fuels e.g. it is less flammable than LNG and is no more toxic to aquatic life than marine oil. Other studies suggest that safety and risk concerns for ammonia are comparable to those for petrol and diesel and lower than for LPG so the associated challenges may not be an obstacle to the implementation of ammonia fuel technologies. However, none of these studies take worst-case scenarios (unintended or intended incidents) into account that fully explore the potentially very high impacts.

In [Keinan 2017] the consequences of an accident or a terrorist attack of a NH_3 carrier at Haifa in Israel has been described based on a report carried out by several scientists and engineers. Rupture of the studied ammonia ship would create a deadly cloud of ammonia, which could reach the entire metropolitan area of Haifa (Israel) and beyond. All the metropolitan areas of Haifa and its suburbs are within the range of a deadly NH_3 cloud, even if the attack occurred when the ship was within the waiting area in the centre of the bay, i.e. away from the port. 600,000 inhabitants would have to be quickly evacuated, which is considered impossible due to the many affected people and paralyzed drivers blocking the roads [Keinan 2017]. After publication of the report, the Haifa Local Affairs Court ruled to empty the existing 12,000 t NH_3 tank in Haifa [Jerusalem Post 2017]. The study also found that road accidents with NH_3 laden trucks with a release of 20 tons of NH_3 gas in urban area also can be disastrous [Keinan 2017].

The Haifa case study shows a number of adverse aspects in a single case. Each of these aspects raises concerns if the production, storage, transport, and use of ammonia is to be significantly further expanded in the future to also serve as a bulk energy carrier and fuel in the energy sector.

Environmental considerations

Air pollutants arising from ammonia use need to be managed in line with air quality strategies. The UK Governments Clean Air Strategy noted ammonia as one of the five most damaging air pollutants. Nitrogen oxides (NO_x) play a major role in climate change, as they have a greenhouse warming potential (GWP) almost 300 times that of CO_2. The GWP of N_2O is even higher than that of NO_x and the effects of its release are not well understood. Thermal NOx emissions are produced on combustion of all fuels but the combustion of ammonia has the potential for higher NOx emissions due to the additional nitrogen content of ammonia itself. Unburnt ammonia ‘slip’ can also arise in the exhaust. Ammonia itself is not a greenhouse gas but NOx will react with ammonia emissions to form particulate matter ($PM_{2.5}$) which is an important secondary air pollutant that can cause respiratory and cardiovascular issues.

The IMO regulates emissions of air pollutants from shipping MARPOL. Emission standards are commonly referred to as Tier I, II and III, and vessels must comply with NOx limits in Emission Control Areas. Where possible, engine designers try to comply with NOx emission regulations through improved combustion technology and exhaust gas recirculation, as aftertreatment systems increase complexity and cost. However, all modern combustion engines are required to operate Selective Catalytic Reduction (SCR) systems in which ammonia stored in a urea solution (commonly marketed as “AdBlue”) is used to reduce NOx to nitrogen and water vapor and these can decrease emissions by over 90%. It is possible the SCR system could be modified to operate with the same ammonia used on board as fuel. NOx is also eliminated if ammonia is used in a fuel cell, as is particulate matter.

Current and required safety and environmental regulation

Health, safety, risk and the environment will all be critical considerations in the deployment of ammonia as an energy vector. Existing legislation varies in different parts of the world and necessary legislative changes and standardization will represent a major challenge. Currently, no jurisdiction has a legal approach that fully addresses both environmental and health and safety concerns in all applications although REACH has gone some way to setting out a harmonised approach [ECHA].

The US is highly dependent on ammonia as a feedstock for e.g. fertiliser and has thus established regulations and legislations focused on occupational safety, public security and transportation. In the US, the EPA (Environment Protection Agencies) and OSHA (Occupational Safety and Health Administration) are the main federal agencies with performance standards for environment and safety that apply to the use and consumption of toxic and explosive materials i.e. ammonia and ammonium nitrate, respectively. The EPA develops risk management programs (RMP) and are concerned with environmental impacts and health and safety of the public outside facilities, and the main regulation is RMP-40CFRPart68. The General Duty Clause is the threshold quantity above which prompts the enforcement of the RMP and this is 10,000 lbs (around 4.5 tonnes) for ammonia. This legislation will not apply e.g. to a fuel tank exemplifying the fact that new standards are required for expanded use of ammonia. OSHA is focused on process safety management and applies to workers and technicians within the bounds of facilities and the main regulation is PSM-OSHA 1910.119. ANSI (American National Standards Institute) has collaborated with the IIAR (International Institute of Ammonia Refrigeration) to establish rules and issue standards outlining good engineering and operating practices in the ammonia refrigeration industry. IIAR have 9 ANSI approved ammonia standards and have published the ‘ammonia data book’ and other guidelines and handbooks covering practical and technical information relating to the use of ammonia.

The EU has developed legislation and regulations surrounding the production, storage, mobility, and use of ammonia and the European Chemicals Agency (ECHA) has set workplace exposure limits for ammonia via directives such as EH40/2005. In the EU, the Gothenburg Protocol was implemented in 1999 to reduce acidification, eutrophication, and ground-level ozone and sets emission ceilings for Member States and includes control measures for reducing ammonia emissions from agriculture. Chinese regulations are heavily concerned with the impact that ammonia can have in bodies of water which is regulated by the GB 13458-2013 standard issued by the China’s Ministry of Ecology and Environment (MEE). In the EU, rail and waterway transport is favoured over road given the more effective risk mitigation.

Standards for ammonia synthesis, cracking and end use are all important and should be consistent with existing standards and common throughout the value chain and across all regulated industries. Many ammonia standards exist for current feedstock markets e.g. training, regulatory, safety, handling, environmental, emissions and product standards. However currently there is not a recognised fuel standard, and this will require a new set of components to facilitate its acceptance. These will include standards for purity testing and handling in fuel applications, as the current regulatory and permitting landscapes are not clear. The Ammonia Energy Association (AEA) Fuel Standard Committee has developed a draft product specification to facilitate the acceptance of ammonia as a fuel which would mirror the industry standards today for C-grade (Commercial grade/Agricultural grade) ammonia which has 99.5% purity. This is the most consumed grade worldwide and would be of sufficient purity for use as a fuel and in power generation.

Due to ammonia's toxicity and reactivity, in marine settings the IGC Code specifies strict requirements on the materials that can be used to contain ammonia onboard as well as on design features required to minimize the risk of exposure. Double walled piping must be used in enclosed spaces in accordance with the IGF code, a ventilation system would have to be installed and the fuel tank located to be safe from grounding and away from areas with high risk from fire or mechanical damage. Given the rapid development in ammonia engine technology, IMO and ISO will need to develop applicable codes and safety standards as the use of ammonia as a fuel and the operation of ammonia-based engines are currently precluded under existing regulation. This will be a critical focus if, as some predict, use of ammonia as a marine fuel becomes widespread.

Societal acceptance of e-fuels

One critical benefit from the use of liquid e-fuels is that it minimises the need for change on the part of the end-use. E-gasoline, e-kerosene and e-diesel can be produced as drop-in fuels and obviate the need for changes to end use applications using internal combustion engines. By contrast, gaseous e-fuels such as hydrogen will require a process of education in order to familiarise end-users with their safe use. That said, the use of hydrogen has been extensively tested in locations such as Asia, Europe and the USA where significant fleets of FCEV are seen. Similarly, fuel cell buses are now relatively commonplace and have seen general acceptance by the public from the very beginning [AcceptH$_2$ 2005].

Attitudes to the widespread use of ammonia as an energy vector has been researched by [Guati-Rojo et al 2021]. This revealed that perceptions of green ammonia among participants in both the UK and Mexico were surprisingly positive but the authors add a note of caution to the results given the novelty of the concept. This would be a valuable avenue of future research.

KEY MESSAGES - SAFETY, ENVIRONMENT AND SOCIAL CONSIDERATIONS

Safety regulations are well established for "drop-in" fuels such as e-kerosene and a well-established standard for the handling of hydrogen has been in place in industry for decades. However, ammonia, in particular, is highly toxic and harmful to human life as well as presenting risks to the environment through its toxicity to aquatic life.

The use of ammonia and, to a lesser extent methanol, in distributed settings, densely populated areas or outside confined industrial spaces will therefore require significant changes to safety, security and environmental regulations. Public reluctance may exist and prove difficult to overcome, although recent academic research suggests that public acceptance may be higher than expected.

4.5. NEW TECHNOLOGIES AVENUES FOR E-FUELS

A number of additional routes for the production of e-fuels, both liquid and gaseous, are being investigated but are not as well developed as the ones analysed in this report. Many of these new routes could be described as hybrid systems, combining hydrogen produced from electricity with carbon resulting from biological processes or integrating solar-thermal heat into the PtX plant. This includes some relatively high TRL process like Lanzatech’s steel gas fermentation reactor which can be operated with or without supplementary electrolytic hydrogen to produce ethanol (TRL = 9 according to [AECOM & Fichtner 2021, p120]). Despite the relatively high TRL this process has only been demonstrated at quite small scale and will need to prove its ability to scale-up. Other processes remain at low TRL and small scale, such as hydrogen from photo-electrocatalytic (PEC) water splitting, despite this having been the subject of decades of research. Other processes like power-to-hydrogen coupled with biological methanation offer promise, too, but may suffer from poor heat integration owing to the absence of high temperature elements in the production chain.

Elsewhere, significant effort is being invested in industrialising electrolyser manufacture to bring costs down. This is considered a more important area for research than seeking fundamental technology breakthroughs as a robust foundation of technologies to proceed has been achieved over the past few decades. Thus, incremental improvements to existing electrolyser designs are being investigated and these may help to reduce costs or improve performance such as reducing platinum loadings in PEM electroysers. This type of applied research benefits and goes hand-in-hand with technology deployment as could have been observed with e.g. photovoltaics and wind technology.

Novel electrolyser technologies are being investigated, notably anion exchange membrane (AEM) electrolysers, and some firms such as Enapter are already seeking to commercialise their designs. The principal benefit to AEM technology is cost given the absence of noble metal catalysts but with research at an early stage and performance still below that achievable with more established technologies, much research is still required.

With up-scaling and mass deployment of energy conversion technologies, the need for design-for-recyclability and considerations regarding materials and material loadings shift into focus. This area is driving research and innovation including breakthroughs also in existing technology domains.

Another strain of technology development with e-fuels is improved system integration. This may range from better heat integration (such as including external renewable heat sources like solar-thermal plants), use of storage (see chapter 1.5.2 on Buffer storage) and process integration (formerly several process steps are included in a single process step, such as high-temperature co-electrolysis).

Catalytic methanation has been assumed for the e-methane pathways in this study. An alternative approach is biological methanation which is being proposed in combination with CO_2 from biogas upgrading today. In the case of biological methanation specialised microorganisms (archae) convert H_2 and CO_2 to methane. This technology was successfully implemented at a first power-to-gas plant of that kind in the year 2015. Generally, biological methanation can be carried out in-situ within a fermenter for biogas generation or ex-situ in a separate reactor. If the CO_2 comes from a source other than biogas the biological methanation always would be carried out in a separate reactor. The biological methanation is carried out at a temperature of 65°C and a pressure of 0.1 MPa [MicrobEnergy 2020]. The technology is commercially available (TRL = 9).

A technology with low TRL of between 2 and 5 consists of photo-electrochemical cells (PEC). PEC combine photovoltaic electricity generation and electrolysis in a single process (integrated system). A photo-electrochemical cell has similarities to a photovoltaic cell (PV). A PV cell separates electrons and holes in the semiconductor material while the electric current via external loads recycles the electrons. The PEC device separates anode and cathode via an electrolyte; it consumes the free electrons at the solar irradiated cathode by the formation of neutral hydrogen molecules from positive protons (H^+), which are attracted by the cathode during the water splitting process. Negative oxygen ions (usually bound in negatively charged OH^- ions) are attracted by the anode where they are transformed in neutral oxygen molecules by stripping off their surplus electrons at the anode. A current recycles the electrons back to the anode. One general disadvantage of hydrogen production via PEC is that hydrogen has to be collected from the panels via an extensive grid consisting of a huge number of small diameter pipelines. It is challenging to keep this hydrogen collection grid tight. For small energy streams, as it is the case on panel area level, it is easier to collect electricity than to collect hydrogen. [JRC 2019b]

Ethanol can be generated by microbial fermentation of a mixture of CO, CO_2 and H_2 by bacteria. The process is capable to use a wide range of gas compositions. Even pure CO can be used as feedstock but also a mixture of CO_2 and H_2. A pilot plant has been built in New Zealand in 2008. Pre-commercial plants have been built at Baosteel in China in 2012, at Capital Steel in China in 2013, and at WBT in Taiwan in 2014. A commercial plant had been built in Shougang in China in 2018. Further commercial plants are under construction at AcelorMittal in Belgium, at Indian Oil in India, at Aemetis in the USA, and in Swayana in South Africa [LanzaTech 2018]. The TRL is 9. The ethanol can be processed further to jet fuel via the alcohol-to-jet (ATJ) process.

Twelve (former Opus 12) together with Emerging Fuels Technology (a developer of Fischer-Tropsch synthesis plants) develops a polymer electrolyte membrane (PEM) based electrolysis process, i.e. an integrated low-temperature co-electrolysis process, where CO and H_2 is formed which are processed further to jet fuel. In summer 2021, the US Air Force tested and qualified jet fuel produced in this way [Twelve 2022] [Business Wire 2021]. However, lifetime is still an issue for co-electrolysis applying PEM [Weber 2021].

Another approach is to convert e-methane to syngas via dry reforming ($CH_4 + CO_2 \rightarrow 2\ CO + 2\ H_2$) and convert this syngas to liquid hydrocarbons via FT synthesis (and some additional H_2 to get the adequate H_2/CO ratio). Dry reforming is still at an early stage of research and development, especially the catalyst development [hte 2022].

KEY MESSAGES - CONTEXT OF E-FUELS IN THE FUTURE OF EUROPE. POTENTIAL DEMAND, FEASIBILITY, OPPORTUNITIES AND CHALLENGES

While some **new hybrid e-fuels routes**, combining e-hydrogen with bio-sources of CO_2 and/or solar-thermal heat are under development, most of these have not been proven yet at scale. Similarly, some alternative electrolyser technologies e.g. anion exchange membrane, are being developed but none of these has yet been commercially deployed. Much of the research effort in PtX is going into process optimisation, such as integration of low-temperature heat from electrolyser operation or coupling with solar-thermal heat plants, and industrialisation aimed at bringing down manufacturing costs.

Novel technology avenues that are currently pursued for the production of electricity-based fuels include photo-electrochemical cells (PEC) for hydrogen production, microbial fermentation of a mixture of CO, CO_2 and H_2 to ethanol, co-electrolysis of water and CO_2 using polymer electrolyte membranes (PEM) and biological methanation. The technology readiness levels range between 2 to 5 and 9 for biological methanation, respectively.

4.6. POTENTIAL BARRIERS TO E-FUELS DEPLOYMENT AND RISK MATRIX ASSESSMENT

As part of this study, a structured assessment was carried out of the high-level supply side and demand side barriers preventing or hindering an increase in the supply of e-fuels to the level required to meet potential future demand in the agreed timescale. This took into account considerations relating to resource availability (including CO_2), technology, economics, infrastructure, regulation, policy and market. The process followed is described below:

Brainstorm risks and barriers: Identified the largest possible number of potential risks and barriers "offline" from the project delivery group and the Technical Steering Committee members. This was developed into a risk register containing the group's initial proposals for key barriers and risks.

Initial grouping and prioritisation: E4tech conducted a thematic grouping of the ideas generated in preparation for a workshop involving the stakeholders mentioned above.

Workshop: During a workshop, the themes, priorities and specific risks / barriers were reviewed, with the objective of arriving at a broad consensus on the scope of risks and barriers that were surfaced and to assign an impact and likelihood measure assessment based on stated or proposed policies for each risk / barrier, then discuss what interventions or mitigating actions could be employed to address each. These were grouped according to a PESTLE framework which breaks down issues into groups: Political, Economic, Social, Technical, Legal and Environmental.

The risk / barrier register developed is included in ECONOMIC ANNEX 8, while the most significant risks and barriers are replicated below. Table 42 shows the high impact factors, while Table 43 shows the high probability factors. Note that H indicates high, M indicates medium and L indicates low.

Table 42: High impact factors

Category	Risk / Barrier Description	Impact	Likelihood	Mitigating actions
Political	No, or weak political support for e-fuels	H	H for road, L for aviation	Encourage appropriate level of support, consistency of support
	Insufficient renewables capacity made available for e-fuels production because policy supports it's use for electricity first (note: separate issue from technical generation potential, technical deployment rate of generation capacity, and social acceptance issues)	H	H	Encourage support for e-fuels in appropriate sectors - i.e. those that are hard to abate - which could include heavy duty road
Economic	Failure to achieve cost reductions	H	L	Support projects and R&D as appropriate to ensure cost reductions are realised
	Efuels higher production cost versus biofuels or fossil fuels	H	H for road, L for aviation	Need to combine efforts on lobbying for support policies and investments to reduce costs (see above). Could focus efforts in those sectors where benefits are likely to be greatest, e.g. aviation, and take advantage of possible "trickle down" into other sectors, e.g. HD road
Technological	Unable to optimise processes	H	L	Support projects and R&D as appropriate to ensure technology issues are overcome
	Inability to get high enough CO2 capture rates	H	H for CO2 based fuels, L for non-CO2 based	Support projects and R&D as appropriate to ensure technology issues are overcome
	Unknown ramp-up potential for electrolysis, carbon capture, fuel synthesis	H	M	Support projects and R&D as appropriate to ensure technology issues are overcome
Legal	Planning processes too complicated / time consuming	H	H for road, L for aviation	Work with regulators / policymakers to ensure regulations are fit for purpose recognising the benefits of e-fuels
	Lack of initiative for ASTM-approval of methanol route for PtL jet fuel	H	L	Work closely with ASTM and other relevant stakeholders (e.g. engine makers) from an early stage to get routes into the approval process

H = High, M = Medium; L = Low

Table 43: High probability factors

Category	Risk / Barrier Description	Impact	Likelihood	Mitigating actions
Political	No, or weak political support for e-fuels	H	H for road, L for aviation	Encourage appropriate level of support, consistency of support
	Lack of support to policies not aligned with the current green trend (ICE ban, push for EVs, etc.)	M	H for road, L for aviation	Encourage support for e-fuels in appropriate sectors - i.e. those that are hard to abate - which could include heavy duty road
	Prioritization of renewable power capacities for other sectors	M	H	Make argument that all sectors need to decarbonise and some (e.g. aviation) have few alternatives to e-fuels
	Insufficient renewables capacity made available for e-fuels production because policy supports it's use for electricity first (note: separate issue from technical generation potential, technical deployment rate of generation capacity, and social acceptance issues)	H	H	Encourage support for e-fuels in appropriate sectors - i.e. those that are hard to abate - which could include heavy duty road
	Efuels higher production cost versus biofuels or fossil fuels	H	H for road, L for aviation	Need to combine efforts on lobbying for support policies and investments to reduce costs (see above). Could focus efforts in those sectors where benefits are likely to be greatest, e.g. aviation, and take advantage of possible "trickle down" into other sectors, e.g. HD road
	Reluctance of the population to have wind turbines, carbon capture units "in their yards"	M	H for renewables, low for industrial site, H for power transmission	Provide transparent information on the potential benefits of e-fuels in the sectors where they are anticipated for use, e.g. through independent studies and programme of "education"
	Inability to get high enough CO2 capture rates	H	H for CO2 based fuels, L for non-CO2 based	Support projects and R&D as appropriate to ensure technology issues are overcome
Legal	Planning processes too complicated / time consuming	H	H for road, L for aviation	Work with regulators / policymakers to ensure regulations are fit for purpose recognising the benefits of e-fuels

H = High, M = Medium; L = Low

The following key themes emerged from the workshop:

- There was a perceived need to distinguish between liquid e-fuels, which have CO_2 as an input, and hydrogen or ammonia since the treatment of different sources of CO_2 is likely to be a critical factor in market development.
- Similarly, it will be important to distinguish between sectors which are particularly hard to abate, e.g. aviation and shipping, and those where alternative solutions to e-fuels can be more readily used, e.g. heavy and light-duty road.
- Lack of strong policy measures is perhaps the most important potential barrier to e-fuels development but strong support is expected in aviation and shipping. The proposed changes to RED and ReFuelEU Aviation Regulation (see following section) provide specific support for e-fuels. However, these are yet to be ratified.
- Regulation and chain of custody of both CO_2 and electricity are likely to be critical factors and a lack of a clear regulatory framework would deter investment – again this issue is more likely to be resolved in aviation / shipping than in other transport sectors. The delegated acts (see following section) relating to CO_2 sources are yet to be ratified but will provide clarity on the sources that can be used in the production of e-fuels.
- A significant risk is posed by a lack of social acceptance of more renewable electricity generation and transmission capacity – this may tend to weaken support for e-fuels since lower efficiency implies greater required capacity.
- Failure to achieve cost reductions would deter e-fuel capacity build out but strong cost reductions are expected - if cost reductions are achieved and policy support is strong, a compelling business case for e-fuels is expected to emerge. A similar view to this was expressed with respect to overcoming technical challenges.
- Mitigating actions are expected to include providing input to the development of policy / regulatory support and programme of “education” on the benefits of e-fuels in addition to efforts to bring down costs and secure chains of custody.

KEY MESSAGES – POTENTIAL BARRIERS TO E-FUELS DEPLOYMENT

Perhaps the biggest **barrier** to e-fuels development would be a lack of sufficient policy support, although support is expected to be forthcoming for the hard to abate sectors such as aviation or; in other sectors, support is likely to be weaker given the availability of alternatives, notably more direct electrification solutions. A wide package of policy support mechanisms exists already, e.g. REDII, but these have not historically supported e-fuels explicitly. However, as discussed in the next section, RED III, the Fit for 55 package, ReFuelEU Aviation and FuelEU Maritime aim to address these shortcomngs.

This barrier could be somewhat mitigated through a programme of education and support to put the case for e-fuels relative to alternatives, leading to better policy incentive. Other barriers to e-fuels use include failure to achieve the necessary cost levels relative to both fossil fuels and biofuels, ability to scale up production fast enough to meet demand, as well as regulatory barriers such as chain of custody for electricity / CO_2 source and planning arrangements. Once again, policies to support demonstration projects as well as fundamental R&D are helping to break down cost barriers and regulations should be examined to ensure a level playing field for e-fuels relative to alternatives.

4.7. CONDITIONS FOR POTENTIAL BUSINESS CASES

The emergence of compelling business models for e-fuels will be dependent, at least in the short to medium term, on the policies in place to support their deployment. In the absence of strong policy, advanced sustainable fuel, including e-fuels, is unlikely to develop beyond the pilot or demonstration phase as the technology might not be competitive. Over the long term the relative economics of e-fuels compared with alternative low carbon solutions is one of the criteria that will ultimately determine which fuels are favoured. In the following section, the supporting policy and financing mechanisms are presented with particular reference to how they could impact the emergence of e-fuels.

Policy and regulation

Renewable Energy Directive (RED)

The **main legislation supporting the transition in the EU away from fossil fuels and towards low carbon alternatives is the RED**, now in its second iteration (RED II), with **further amendments (sometimes referred to as RED III) at the proposal stage**. RED sets an overall target for countries to provide 32% of their energy supply from renewable sources by 2030 and includes a sub-target of 14% renewables in road and rail transport. A revision to RED II was proposed in 2021, and future renewable energy targets are expected to be reinforced in light of the new EU minimum 55% GHG reduction target by 2030 vs. 1990s level. Member States independently adopt national frameworks and policies to comply with EU targets. Most of these frameworks are technology agnostic, meaning, for instance, that hydrogen is supported as well as other technologies such as batteries and biofuels.

At present, the transport sectoral target within RED II is the only substantial piece of legislation that specifically supports the use of hydrogen. In addition to the overall target, it sets thresholds and limitations for certain types of renewable energy sources. Key items of note are:

- A cap on the use of waste oils and fats, which must not exceed 1.7% of energy supplied and is designed to limit the dependence on these sources;
- A floor on advanced biofuels which must represent at least 3.5% of energy supplied and seeks to encourage development of these new fuels; and
- A cap on the use of conventional biofuels derived from food or feed crops of 7%, aimed at limiting competition between food and fuel land uses.

RED II has no specific synthetic fuels targets, and so does not drive widespread uptake in its current form. Electricity-based hydrogen and derivative fuels (termed “renewable fuels of non-biological origin” or RFNBOs) fall into ‘the rest’ category. However, it should be emphasised that hydrogen-based fuels compete with conventional and advanced biofuels, which have significantly lower costs.

This puts e-fuels at a disadvantage to both:

- Advanced biofuels, which have their own sub target and double count. MSs are putting the sub-targets into their own policies, which may have an impact on the prices of these fuels.
- Biofuels from waste oils and fats can double count towards the target (but are capped).

Nevertheless, some countries have gone beyond RED II's provisions and have set policies which support synthetic fuels further, e.g. NL, DE or the UK (now outside of the EU).

It is possible that RFNBOs could receive additional support in future legislation.

In September 2020, the Commission launched a consultation on the revision of RED II to align it with the European Green Deal, which is ultimately targeting climate neutrality by 2050. RED III is expected to be adopted in 2023 after the trilogue negotiation, which might drive changes to the proposal from the Commission. The proposed directive requires majority agreement for adoption.

RED III switches from a renewable energy target to a GHG intensity reduction target, requiring a 13% GHG reduction for 2030 for transportation fuels. RED III proposes to introduce a new 2.6% (energy basis) minimum sub-target by 2030 for RFNBOs which includes hydrogen and synfuels used directly in transport, and a minimum of 50% hydrogen produced from renewable electricity used in industries (excluding the hydrogen used in refineries for the production of conventional fuels). While multipliers for Annex IX and renewable electricity are proposed to be deleted (i.e. no more double counting for advanced biofuels or used cooking oil/tallow), the 1.2 multiplier for Annex IX A and RFNBO in aviation and maritime is retained.

The Fit for 55 package would provide a further set of policy incentives for reducing emissions.

European Trading System

While the transport sector is not currently covered by the EU emissions trading scheme except for intra-EU aviation, changes to EU ETS are proposed for aviation to phase out free-allocation and shipping to be gradually included from 2023 (incl. all intra-EU and half of extra-EU shipping emissions). A new ETS covering road transport and building has been proposed by the Commission.

European Taxation Directive

There is also potential for tax exemptions for SAF under Energy Taxation Directive proposals, the value of which will increase to 2030. The proposed taxation rates are given in Annex I, Tables A & D, with the fossil kerosene tax proposed at €10.75/GJ (~$559/tonne) by 2033 and 2G biofuels and RFNBOs tax proposed at €0.15/GJ (~$8/tonne). Low-carbon hydrogen and related fuels will also benefit from that same rate for a transitional period of 10 years.

ReFuelEU Aviation

A new legislative instrument, ReFuelEU Aviation, was proposed in July 2021 and is designed to increase the share of sustainable aviation fuel (SAF) in aviation, placing a mandate on both airlines and fuel suppliers. The proposed target is split between two sub-mandates- (1) advanced biofuels and biofuels from waste oils and lipids, and (2) synthetic fuels produced with renewable energy sources. Synthetic fuels are not currently proposed to be obligated before 2030. Assuming an EU aviation demand of around 43 Mt in 2030, a 0.7% mandate would represent a dedicated PtL jet market of ~300 ktonnes. Note, the proposal does not have a linear increasing obligation each year between these quoted dates. ReFuelEU Aviation is a regulatory obligation, which, as proposed by the Commission, does not allow trading between parties or carry over from one year to the next.

SAF supplied under ReFuelEU also counts towards MS targets under the proposed REDIII (with the RED 1.2 multiplier as explained above).

Note that ReFuelEU Regulation allows aircraft operators to claim once (and once only) in a separate GHG scheme ("a scheme granting benefits to aircraft operators for the use of sustainable aviation fuels"), e.g. SAF reported under ReFuelEU can be claimed under EU ETS, and possibly under CORSIA.

ReFuelEU Maritime

ReFuelEU Maritime sets out a regulation for a well to wake GHG target for ships. The scope covers:

- Vessels over 5,000 gross tonnage starting or ending journeys in the EU, excluding inland vessels, fishing, naval and government vessels. Small and medium size vessels below 5,000GT represent approx. 40% of the fleet but only 10% of the total emissions in the EU.
- Voyages that the regulation applies to are EU-to-non-EU port and non-EU-to-EU port for 50% of the energy consumed, as well as EU-to-EU port for 100% of the energy consumed (i.e anything arriving or departing from EU port rather than just intra-EU).

The regulation sets targets for GHG intensity of energy used on board which need to decrease by 2% by 2025; 6% by 2030; 13% by 2035; 26% by 2040; 59% by 2045; 75% by 2050. Shipping companies are responsible for monitoring and reporting.

Additionally, containerships and passenger ships will be required to connect to onshore power when at berth from 2030, unless covered by a set of exceptions, one of which is that they are already using zero carbon technologies (fuel cells, electricity, microgeneration with renewable and low carbon fuels). There is also an exemption proposed around availability of shore power at berth and incompatibility of shore power connections.

Delegated Acts

In addition, crucial rules that affect power-to-liquids on renewability and additionality of the renewable electricity used, and on eligible sources of CO_2 are currently under discussion.

The delegated act will make some further provisions with respect to the conditions for renewable hydrogen, notably:

RED II currently states that grid mix electricity should be assumed for RFNBOs unless the electrolyser is directly connected to a renewable energy installation which was built after or at the same time as the electrolyser, plus the electrolyser is not connected to the grid or has not taken electricity from the grid.

Rules for operators using renewable electricity via the grid, for example with a power purchase agreement, are being developed through a delegated act. This will define rules to ensure that there is a temporal and geographical correlation between the electricity production unit and the electrolyser.

The delegated act will also consider additionality, ensuring that use of electricity for hydrogen production does not divert low carbon electricity from other users (with the increased demand met by higher carbon options), rather than incentivising new low carbon power generation.

Supply side factors

Ultimately, the viability of e-fuels will be determined by the ability to drive down their cost to the levels discussed in earlier sections of the report. In order for e-fuels to become competitive, significant cost reductions will need to be achieved. In the end it is likely to be a deployment at scale that will allow cost reductions to be achieved, although technological breakthroughs could potentially have an impact.

A variety of policy initiatives exist to support the roll out of capital projects and for research and development into technological and process improvements. These policies include the Important Project of Common European Interest (IPCEI) framework, which enables state aid funding for large cross-border projects. The European Hydrogen Strategy foresees the use of the IPCEI framework for hydrogen-related projects. Among the principal funds that support demonstration projects are the EU Innovation Fund and InnovFin which provide support to projects that deliver carbon reductions.

Supporting research and development aim to accelerate the process of bringing technologies to market and bridging the gap to commercial deployment by proving technologies in the field. **The EU has led the way in this area, and we focus here on the mechanisms that have been put in place by the EU to support research, development and demonstration projects in renewable energy, many of which include hydrogen and in some cases are dedicated to hydrogen**. Two of the principal mechanisms for research and development projects are the Fuel Cell & Hydrogen Joint Undertaking (FCH-JU) and the Horizon 2020 (H2020) programme.

KEY MESSAGES

A strong package of measures already exists to support low carbon fuels in transport under RED II, but these make very modest provisions for e-fuels, specifically. However, these are yet to be agreed upon and the details will be incorporated in the delegated acts still under discussion. The proposed RED III and associated legislation such as ReFuelEU Aviation aim to address this and contain specific targets for e-fuels (“RFNBOs”).

A variety of mechanisms are in place to support project development and to motivate players to develop value chain. A large number of pilots and demonstration projects have been announced but few have reached FID as yet.

In the absence of strong policy, any advanced sustainable fuel, including e-fuels, are unlikely to develop much beyond the pilot or demonstration phase by lack of competitiveness.

5. GLOSSARY

AEC	Alkaline Electrolysis
ARA	Amsterdam-Rotterdam-Antwerp
Boe	Barrels of oil equivalent
CAPEX	Capital expenditure
CC	Carbon capture
CCS	CO_2 Capture & Storage
CCU	CO_2 Capture & Utilisation
CEPCI	Chemical Engineering Plant Cost Index
CGH_2	Compressed gaseous hydrogen
CH_3OH	Methanol
CH_4	Methane
CNG	Compressed Natural Gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation
CTG	Cradle-to-grave
DAC	Direct Air Capture
EPR	European pressurized reactor
ETS	Emission Trading System
EU MRV	EU monitoring, reporting and verification
EU	European Union
FAME	Fatty acid methyl ester
FC	Fuel Cell
FCEV	Fuel cell electric vehicle
FCH-JU	Fuel Cell & Hydrogen Joint Undertaking (now: Clean Hydrogen JU)
FID	Final Investment Decision
FT	Fischer-Tropsch
FTD	Fischer-Tropsch diesel
FTK	Fischer-Tropsch kerosene
GHG	Greenhouse Gas(es)
GJ	Gigajoule (1 GJ = 1000 MJ, 1 kWh = 3.6 MJ)
GtL	Gas-to-liquid
GW	Gigawatt (1 GW = 1000 MW)
H_2	Hydrogen
HP	High pressure

HT	High temperature
HVDC	High voltage direct current
HVO	Hydrotreated Vegetable Oil
ICE	Internal combustion engine
IEA	International Energy Agency
IMO	International Maritime Organization
IMO DCS	IMO Data Collection System
IPCEI	Important Project of Common European Interest
JEC	JRC-EUCAR-CONCAWE consortium
KSA	Kingdom of Saudi Arabia
kWh	Kilowatt hours (1 kWh = 1000 Wh = 3.6 MJ)
l	Liter
LCA	Life Cycle Analysis
LCH_4	Liquefied Methane
LH_2	Liquefied Hydrogen
LHV	Lower heating value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LSMGO	Low sulphur marine gas oil
LT	Low temperature
M&R	Maintenance and Replacement
MCH	Methylcyclohexane
MEA	Monoethanolamine
MENA	Middle East and North Africa
MeOH	Methanol
MS	Member State
MTG	Methanol-to-gasoline
MTGD	Methanol-to-gasoline and diesel (middle distillates)
MTK	Methanol-to-kerosene
MTOE	Million ton oil-equivalent
N_2	Nitrogen
NGPP	Natural Gas Power
NH_3	Ammonia
NH_3	Ammonia
NREL	National Renewable Energy Laboratory
O_2	Oxygen
OPEX	Operating expenditure

°C	Degree Celsius
OME$_x$	Oxymethyleneether (also called polyoxymethylene dimethyl ethers)
PEM	Proton Exchange Membrane Electrolysis
PtL	Power to liquid
PtX	Power to something
PV	Photovoltaics
RED	Renewable Energy Directive
RFNBO	Renewable Fuels of Non-Biological Origin
RWGS	Reverse Water Gas Shift (also called reverse CO shift)
SAF	Sustainable Aviation Fuel
SCR	Selective Catalytic Reduction
SMR	Steam Methane Reformer
SOEC	Solide Oxide Electrolysis Cells
toe	tons of oil-eqivalents
TWh	Terawatt-hour (1 TWh = 1000 GWh = 1,000,000 MWh)
UCO	Used Cooking Oil
WTW	Well-to-wheel

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7. TECHNICAL ANNEX

7.1. ENERGY AND MASS REQUIREMENTS TO PRODUCE 1 MJ OF THE DIFFERENT E-FUELS PATHWAYS

Figure 81: Energy and mass balance of hydrogen pathway

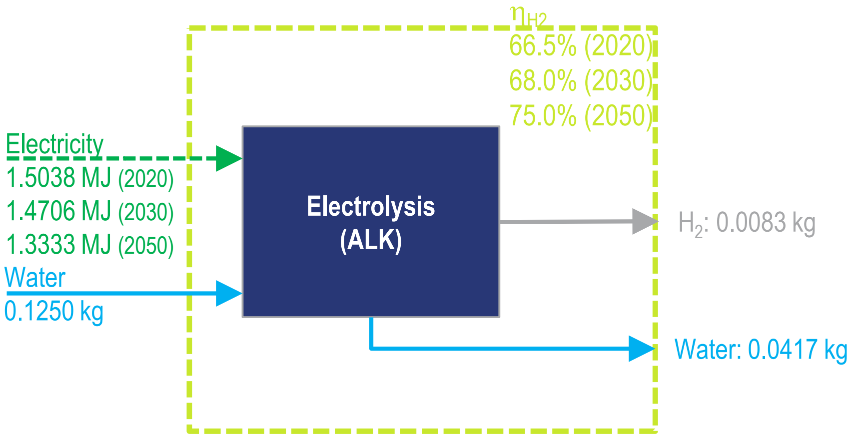


Figure 82: Energy and mass balance of e-FT Kerosene pathway (CO_2 from diluted source)

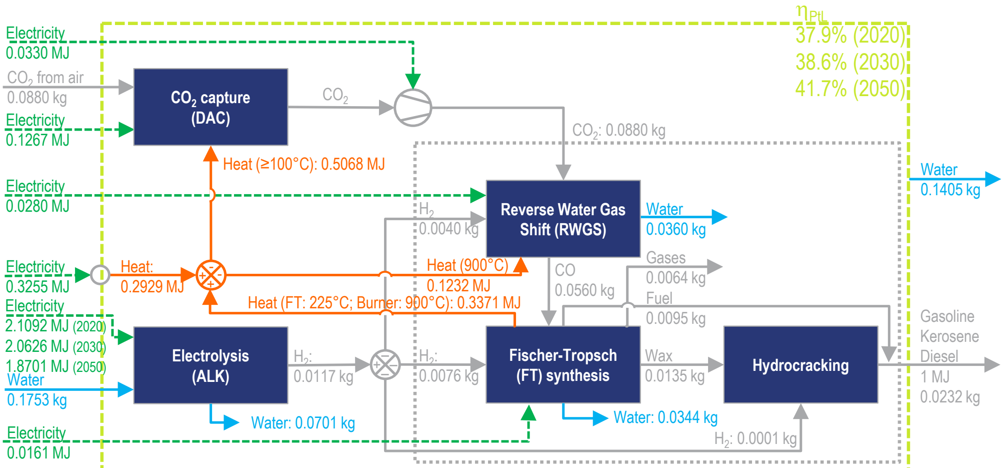


Figure 83: Energy and mass balance of e-FT Kerosene pathway (CO_2 from average concentrated source)

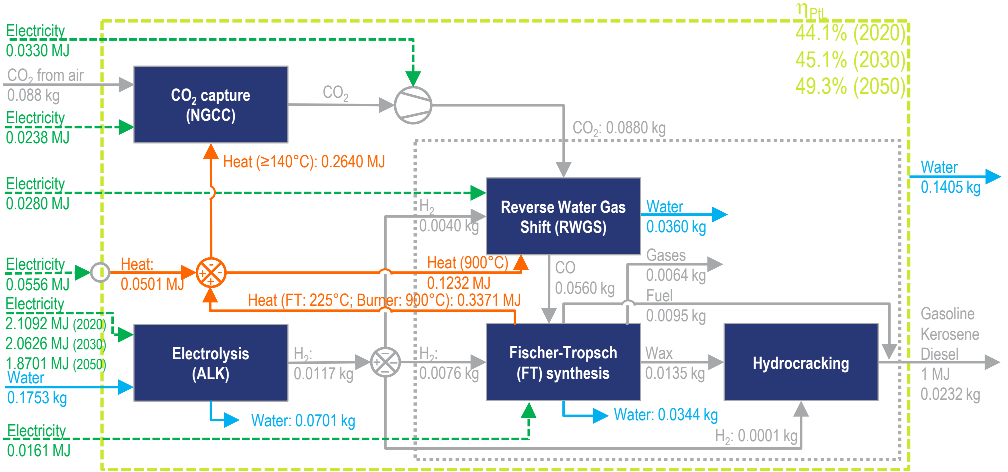


Figure 84: Energy and mass balance of e-FT Kerosene pathway (CO_2 from concentrated source)

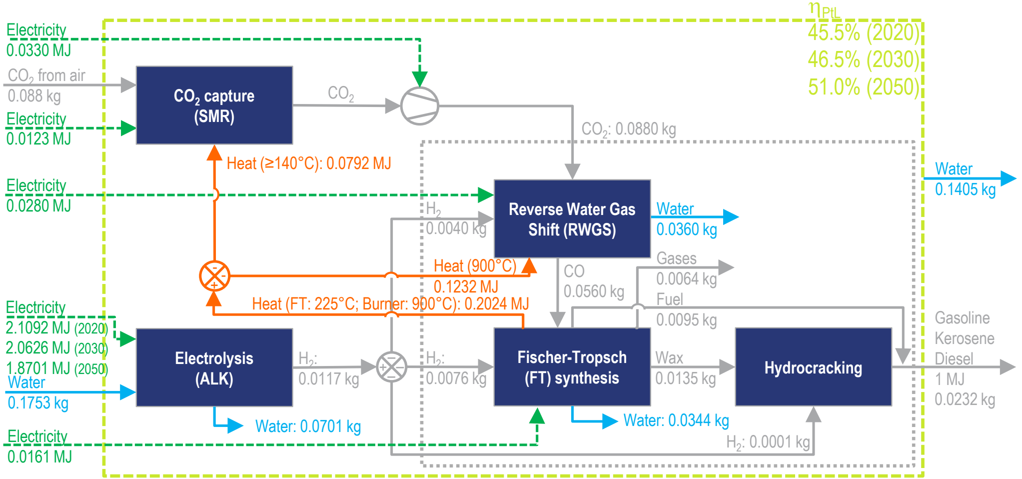


Figure 85: Energy and mass balance of e-FT Kerosene pathway (Co-electrolysis, CO_2 from diluted source)

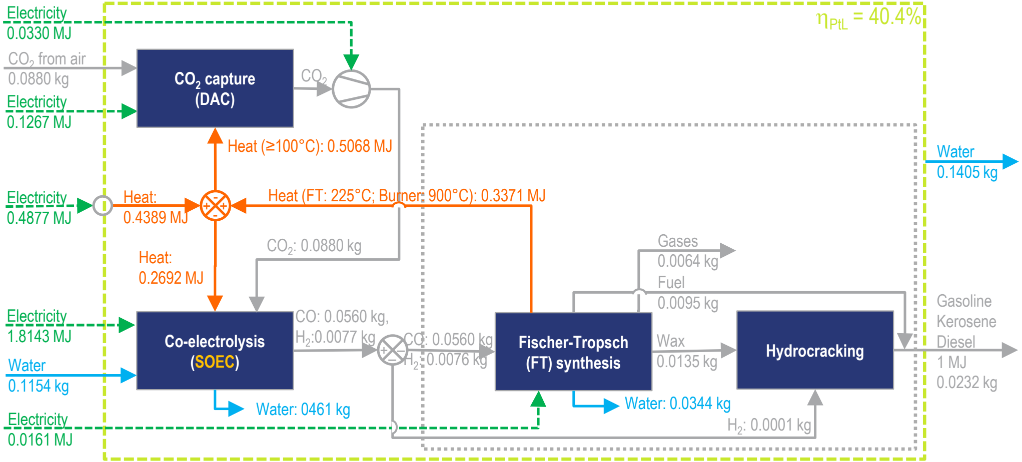


Figure 86: Energy and mass balance of e-FT Kerosene pathway (Co-electrolysis, CO_2 from concentrated source)

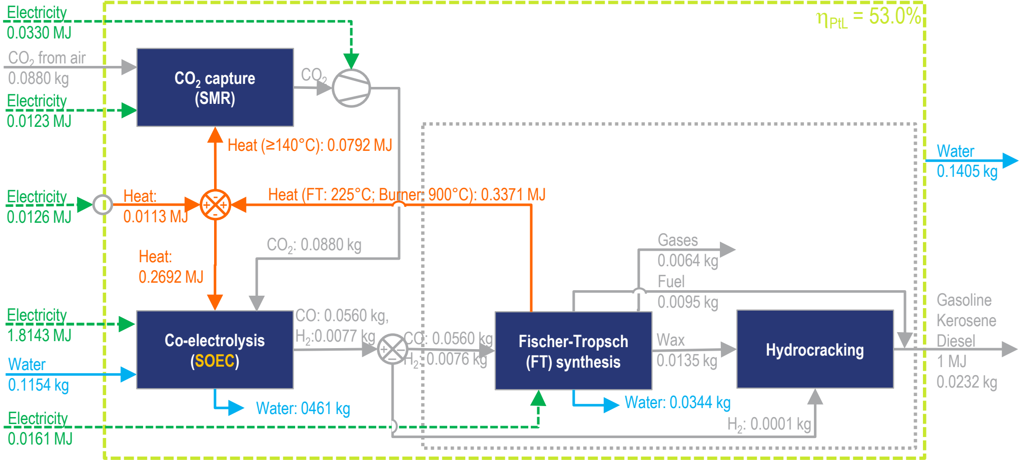


Figure 87: Energy and mass balance of e-Methane pathway (CO_2 from diluted source)

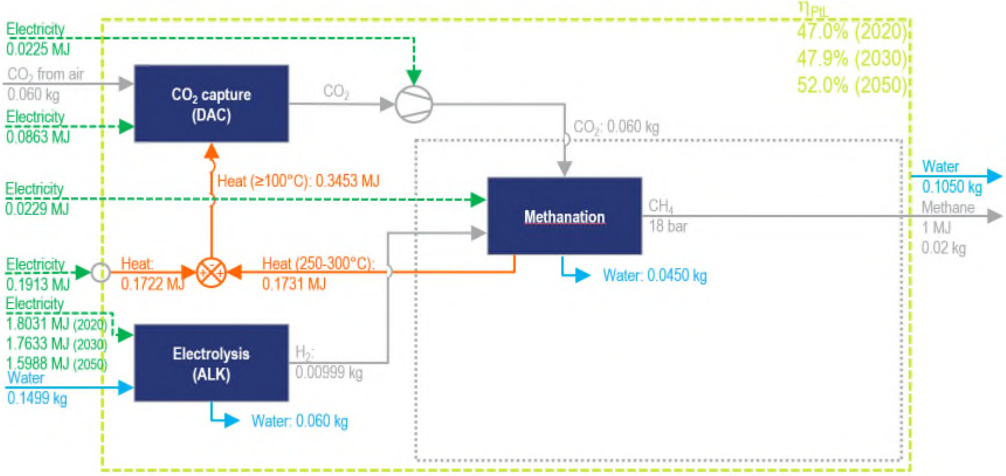


Figure 88: Energy and mass balance of e-Methane pathway (CO_2 from average concentrated source)

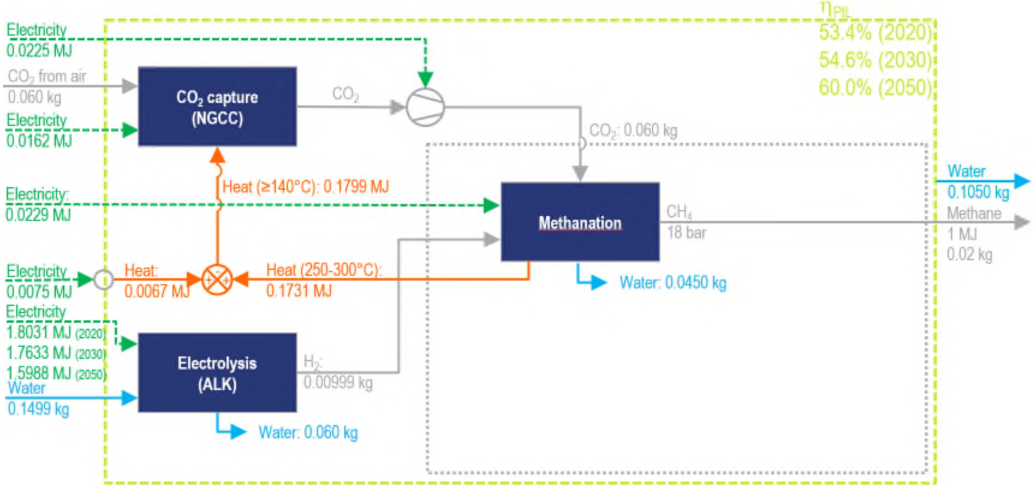


Figure 89: Energy and mass balance of e-Methane pathway (CO_2 from concentrated source)

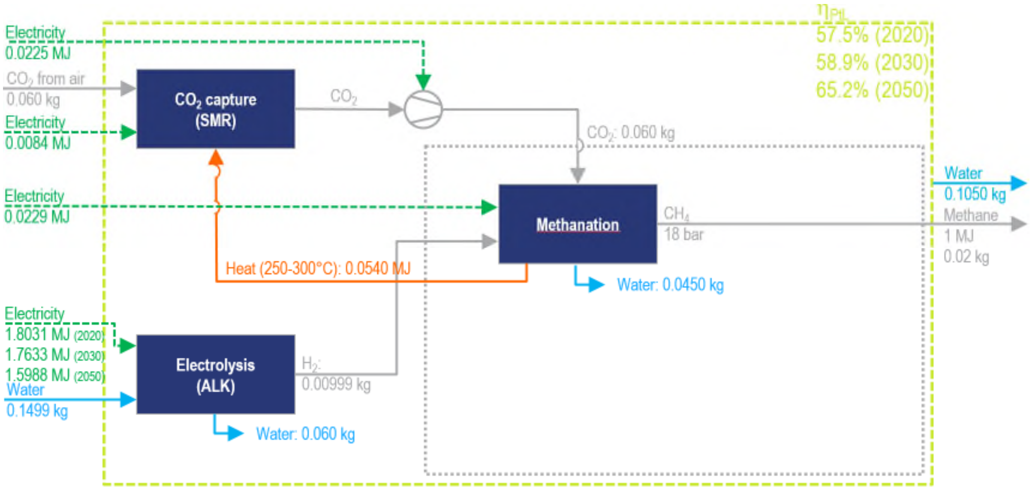


Figure 90: Energy and mass balance of e-Methanol pathway (CO_2 from diluted source)

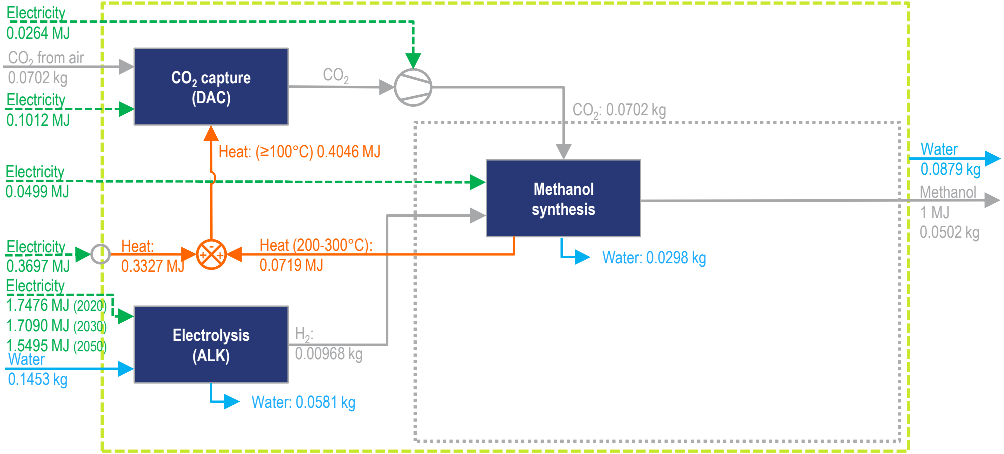


Figure 91: Energy and mass balance of e-Methanol pathway (CO_2 from average concentrated source)

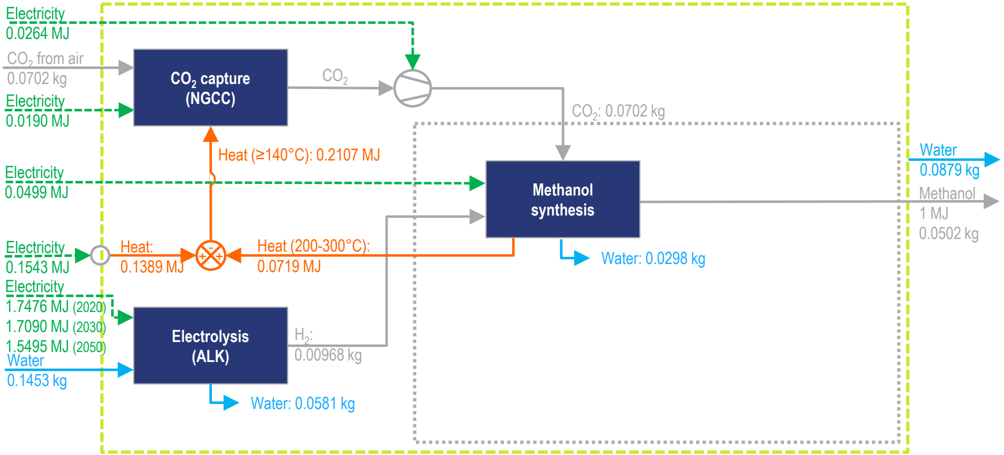


Figure 92: Energy and mass balance of e-Methanol pathway (CO_2 from concentrated source**)**

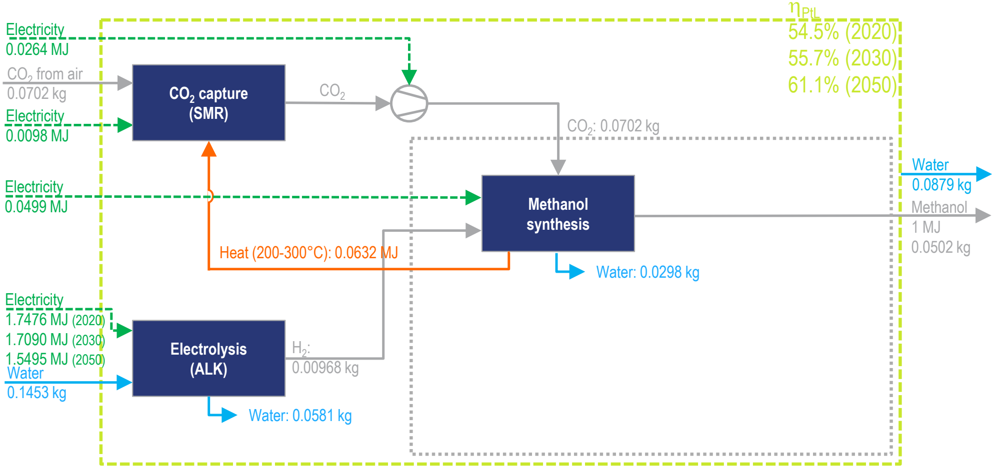


Figure 93: Energy and mass balance of e-MTG Gasoline pathway (CO_2 from diluted source)

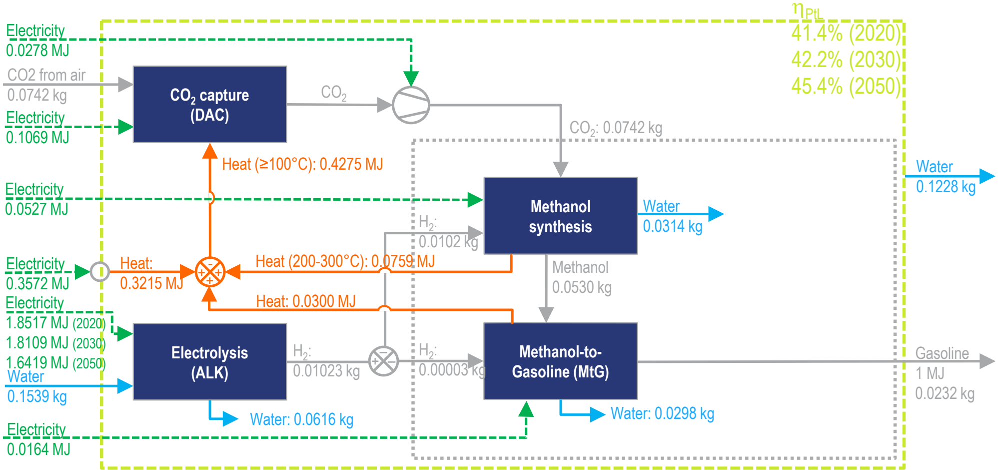


Figure 94: Energy and mass balance of e-MTG Gasoline pathway (CO_2 from average concentrated source)

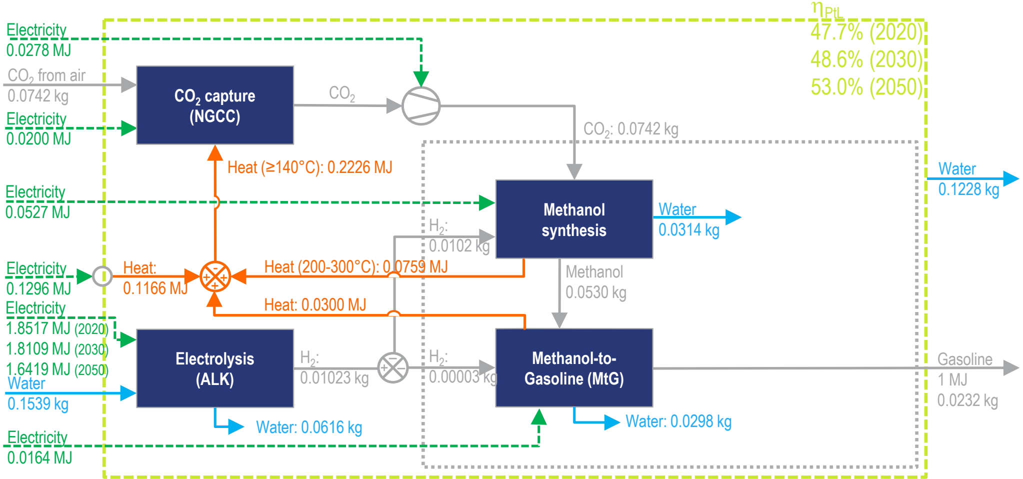


Figure 95: Energy and mass balance of e-MTG Gasoline pathway (CO_2 from concentrated source)

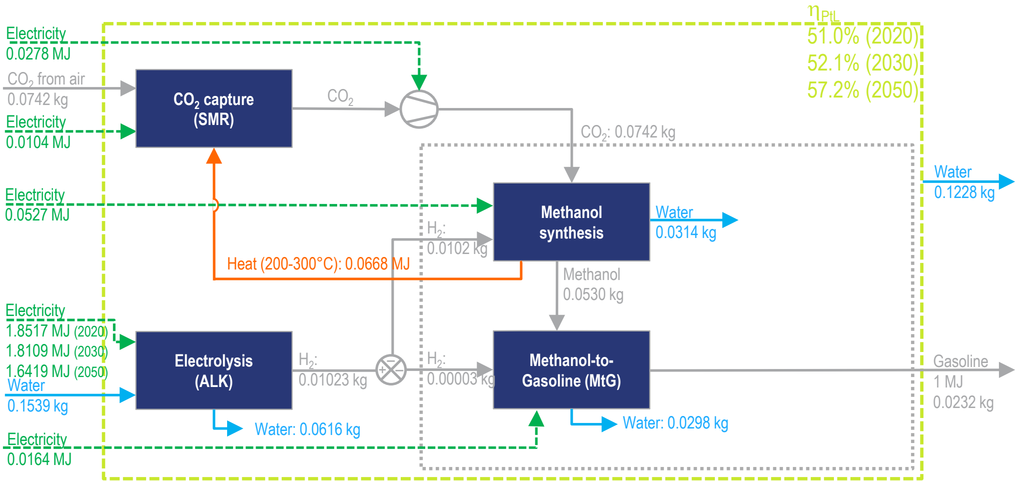


Figure 96: Energy and mass balance of e-MTK Kerosene pathway (CO_2 from diluted source)

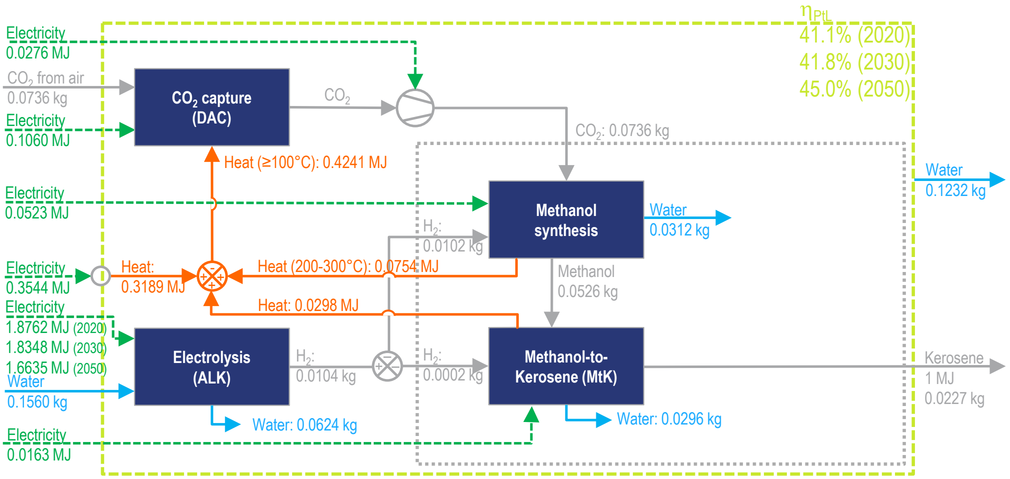


Figure 97: Energy and mass balance of e-MTK Kerosene pathway (CO_2 from average concentrated source)

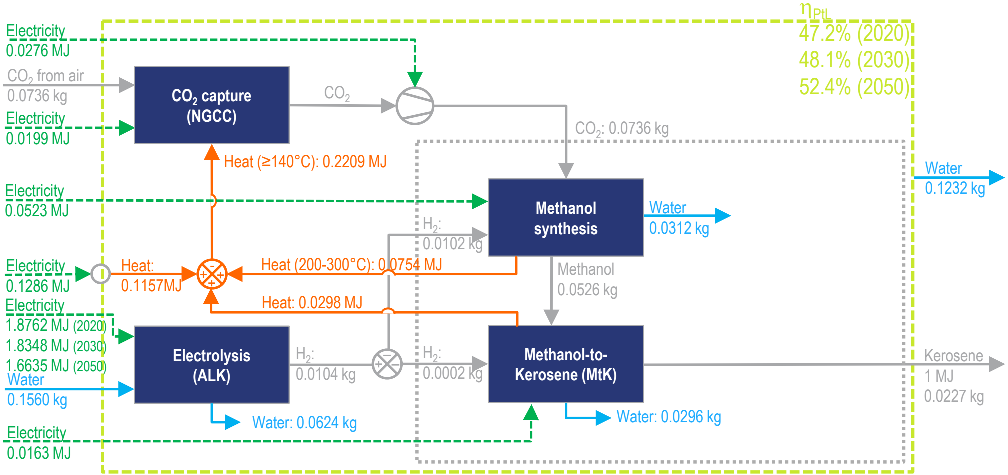


Figure 98: Energy and mass balance of e-MTK Kerosene pathway (CO_2 from concentrated source)

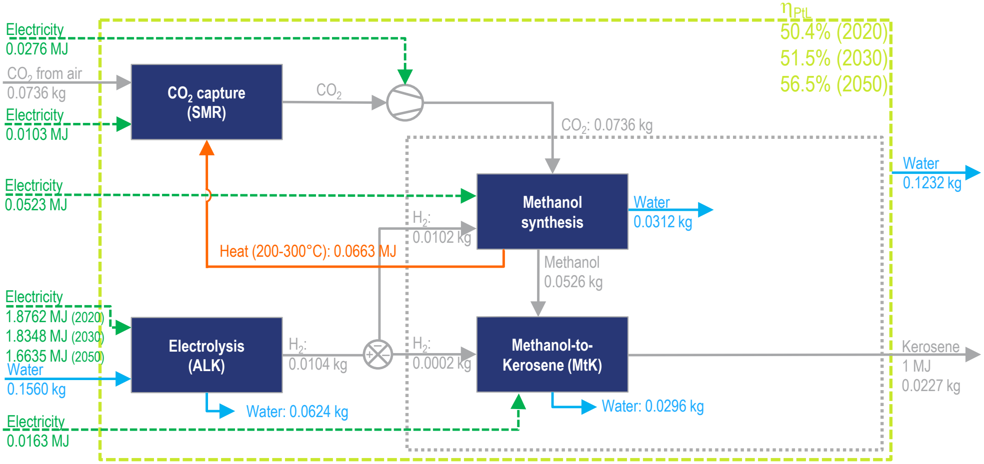


Figure 99: Energy and mass balance of e-OME_{3-5} pathway (CO_2 from diluted source)

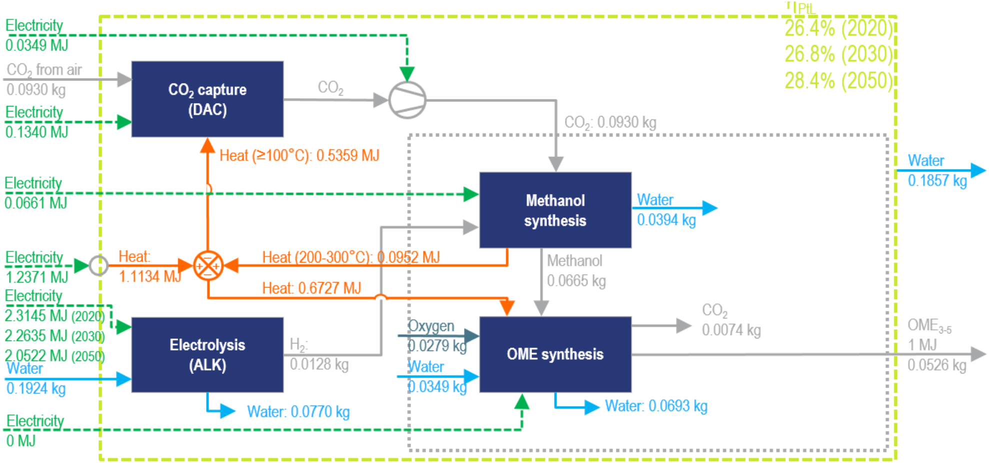


Figure 100: Energy and mass balance of e-OME_{3-5} pathway (CO_2 from average concentrated source)

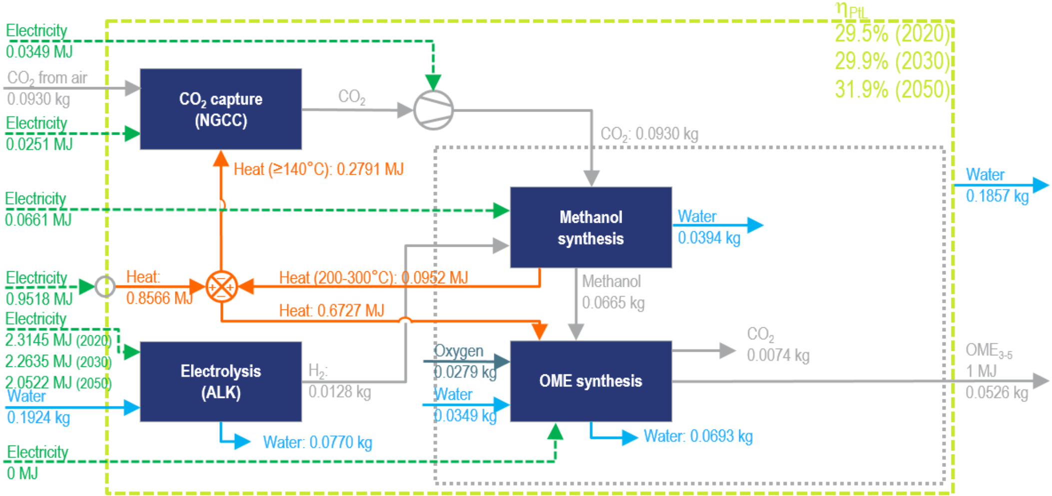


Figure 101: Energy and mass balance of e-OME_{3-5} pathway (CC from concentrated source)

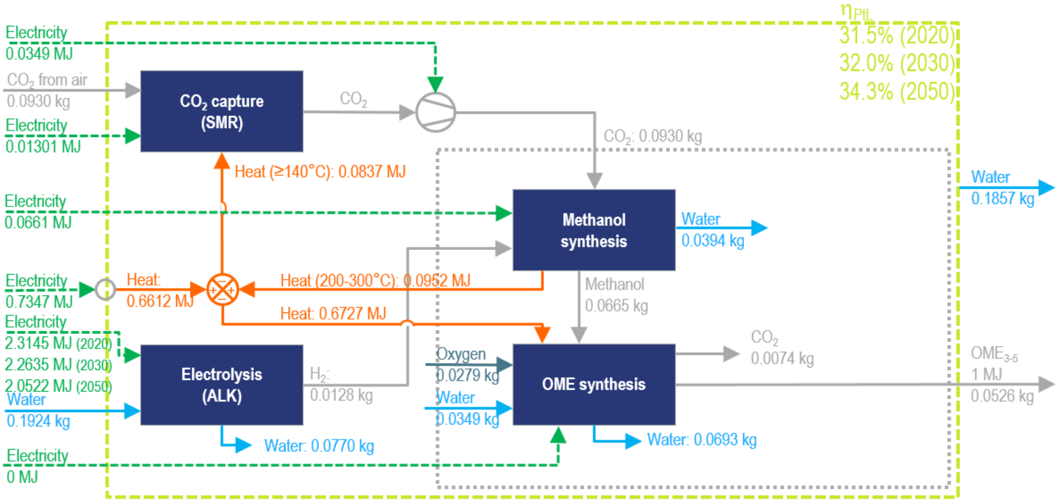
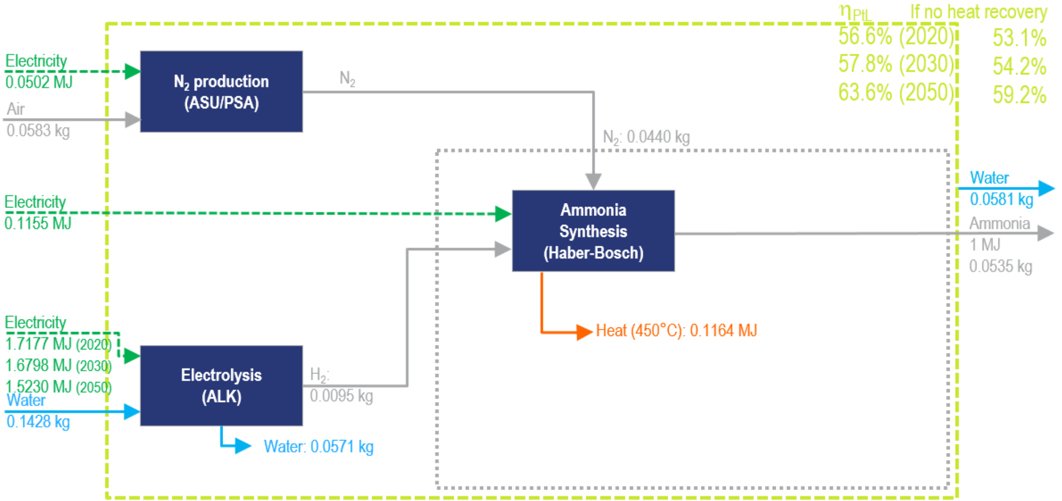


Figure 102: Energy and mass balance of e-Ammonia pathway (N_2 from air PSA)



7.2. ENERGY EFFICIENCY OF E-FUEL PATHWAYS

Figure 103: Energy consumption for producing 1 MJ of e-Methanol (CC from diluted source)

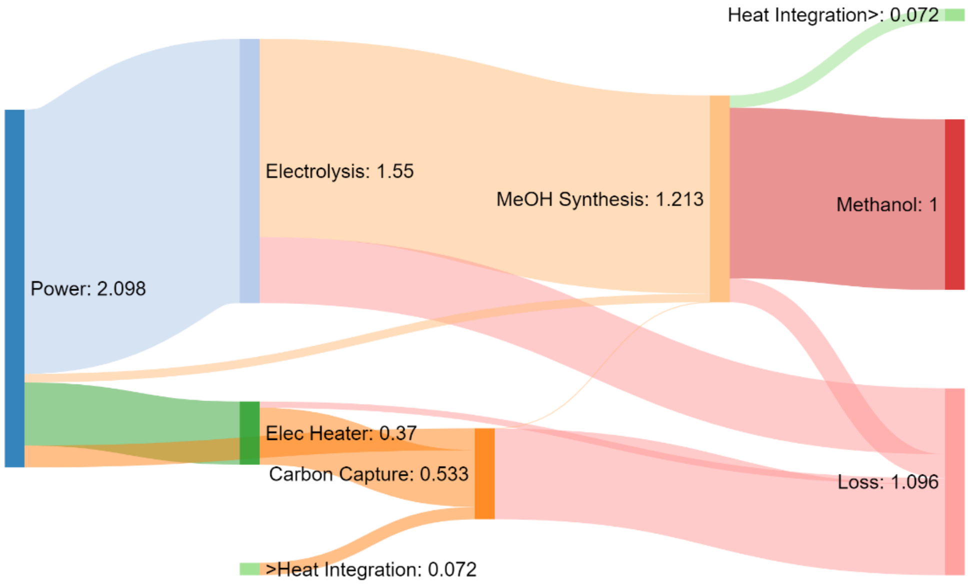


Figure 104: Energy consumption for producing 1 MJ of e-Methanol (CC from concentrated source)

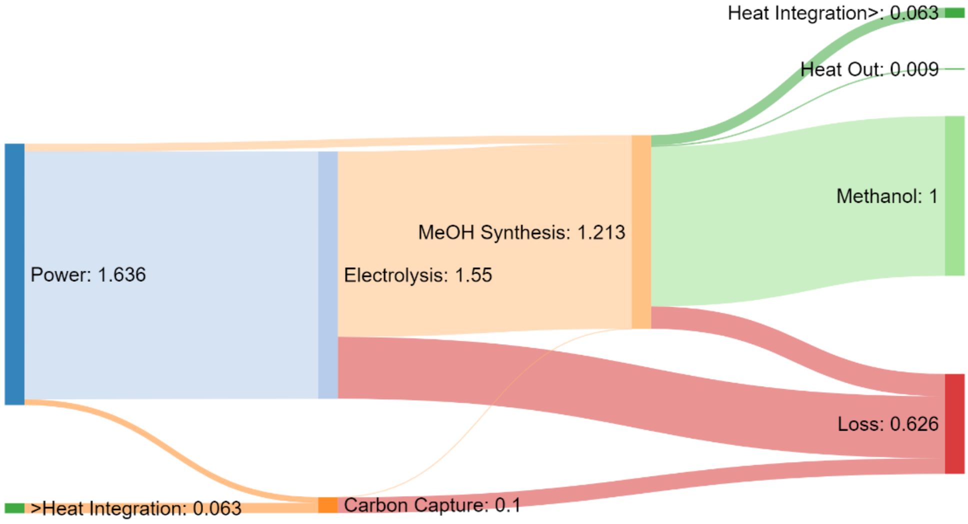


Figure 105: Energy consumption for producing 1 MJ of e-Methane (CC from diluted source)

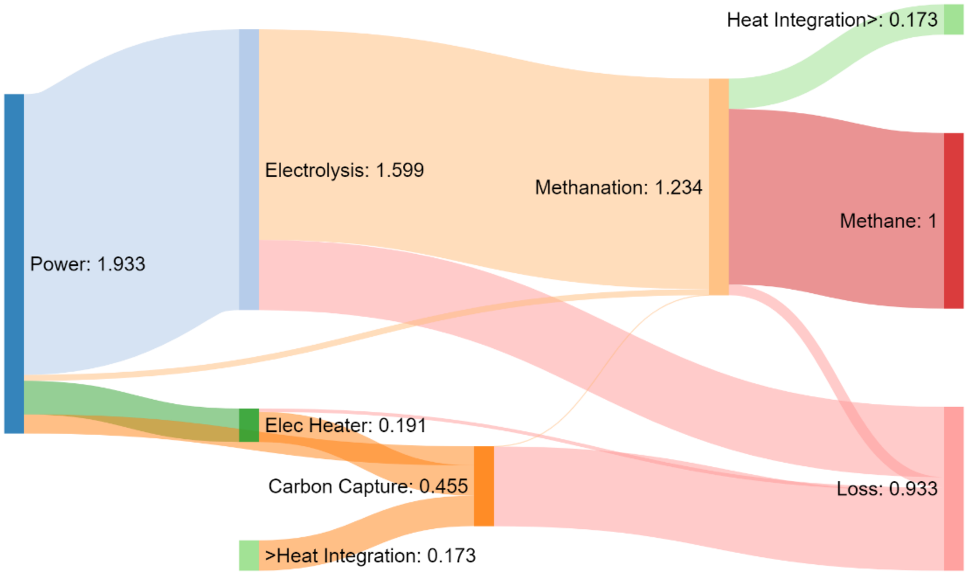


Figure 106: Energy consumption for producing 1 MJ of e-Methane (CC from concentrated source)

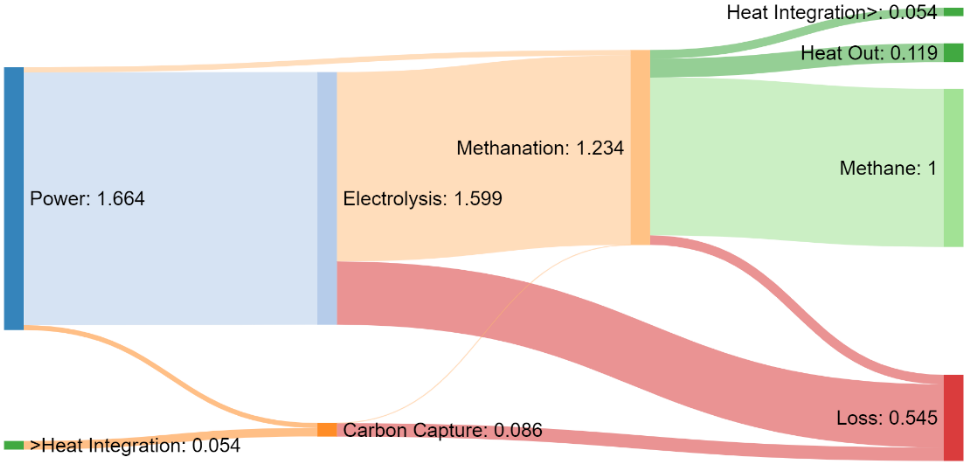


Figure 107: Energy consumption for producing 1 MJ of e-MTG Gasoline (CC from diluted source)

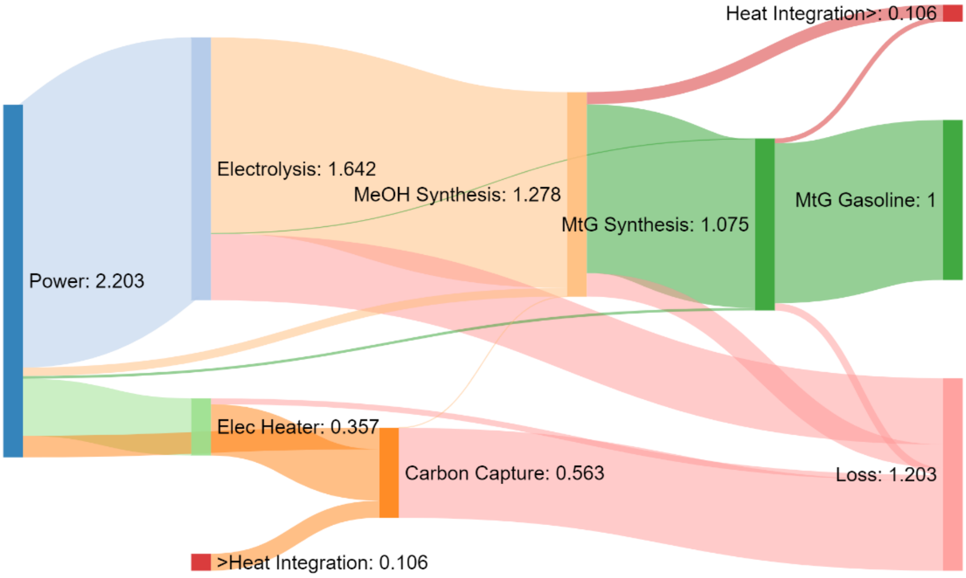


Figure 108: Energy consumption for producing 1 MJ of e-MTG Gasoline (CC from concentrated source)

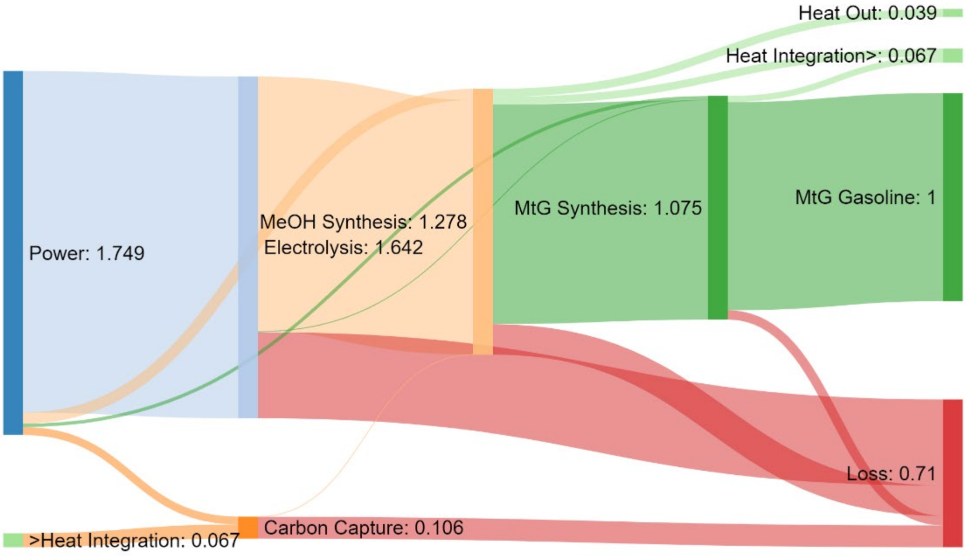


Figure 109: Energy consumption for producing 1 MJ of e-MTK Kerosene (CC from diluted source)

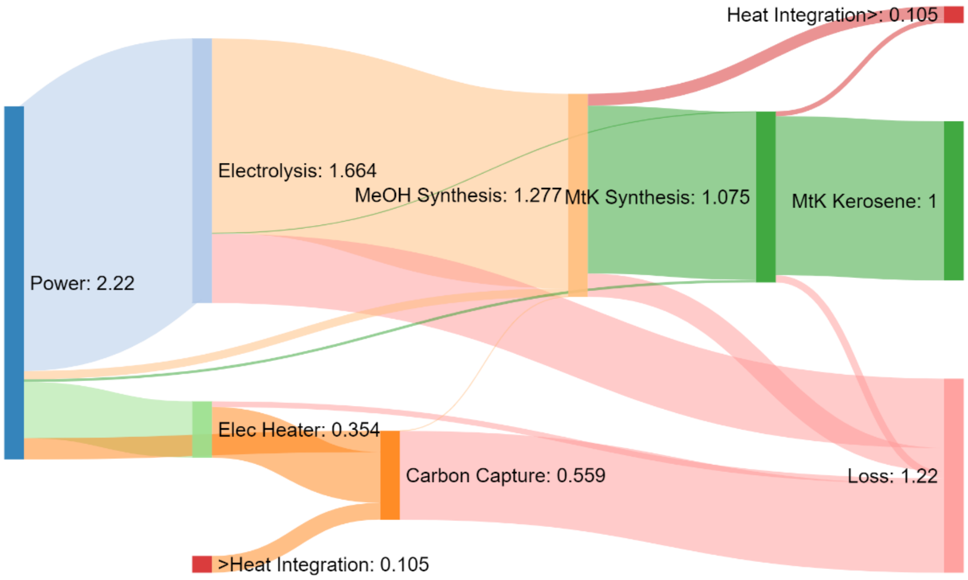


Figure 110: Energy consumption for producing 1 MJ of e-MTK Kerosene (CC from concentrated source)

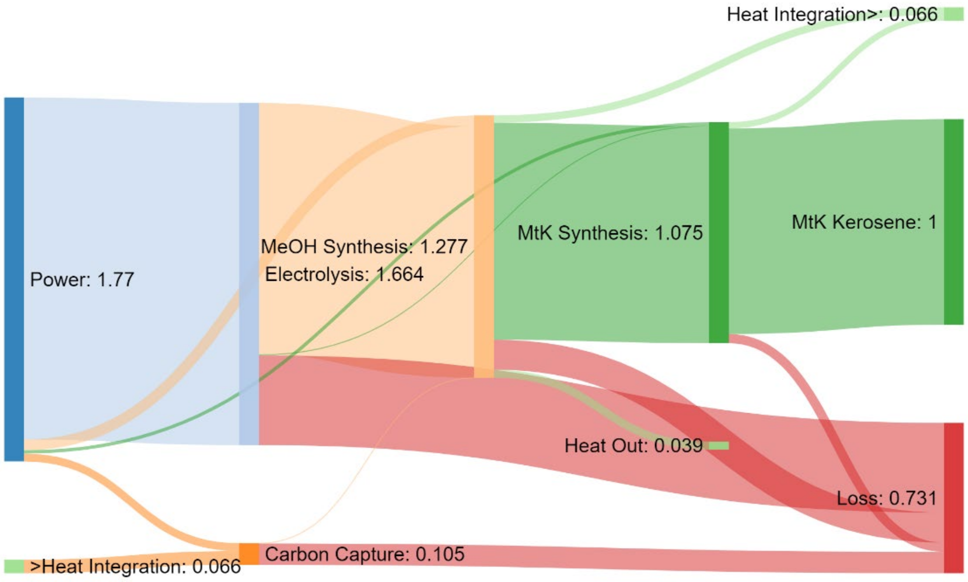


Figure 111: Energy consumption for producing 1 MJ of e-OME$_{3\text{-}5}$ (CC from diluted source)

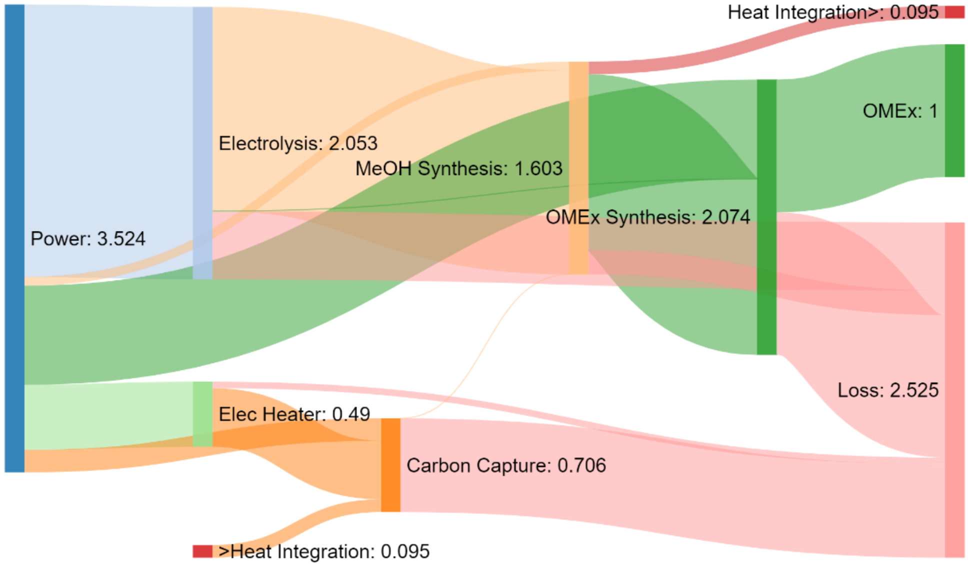


Figure 112: Energy consumption for producing 1 MJ of e-OME$_{3\text{-}5}$ (CC from concentrated source)

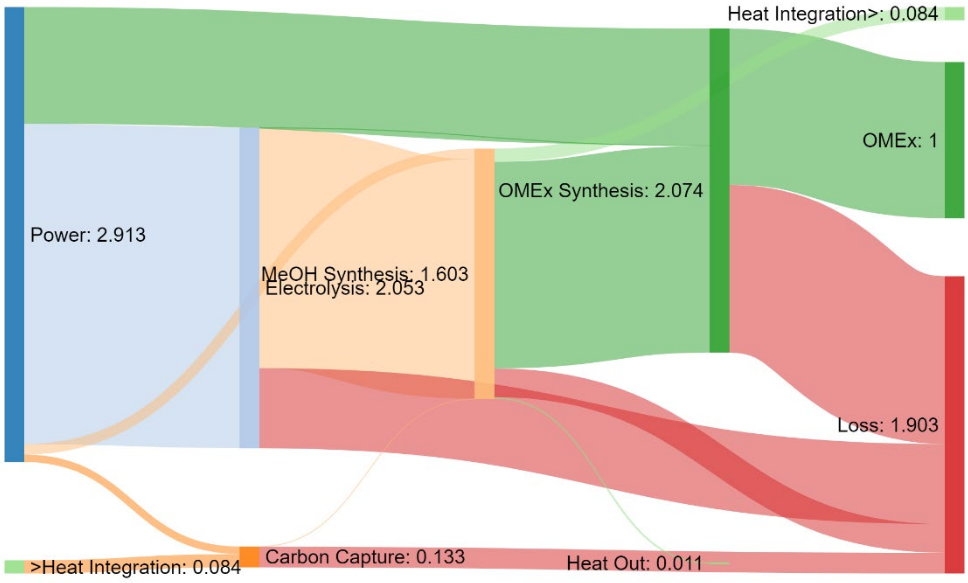
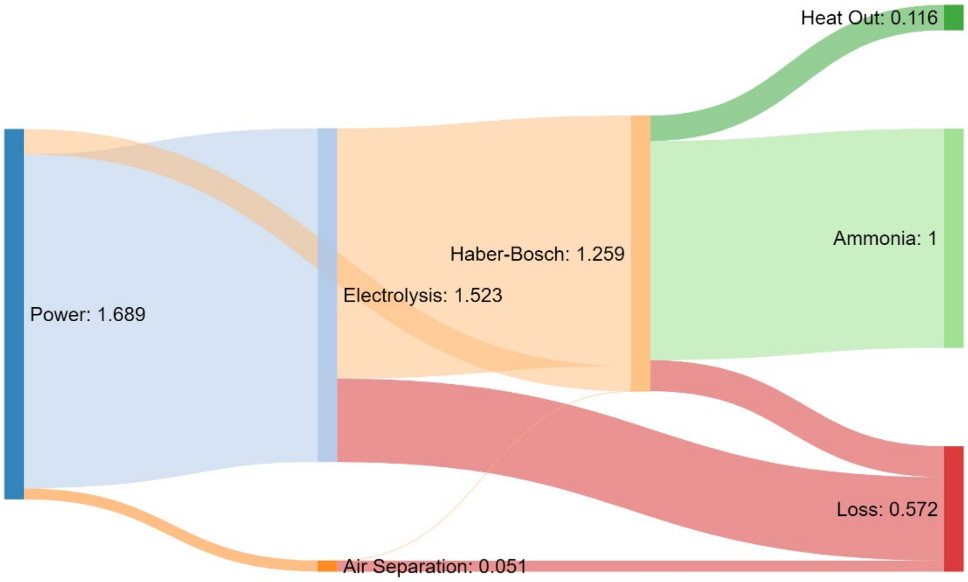


Figure 113: Energy consumption for producing 1 MJ of e-Ammonia (N_2 from air PSA)



8. ECONOMIC ANNEX

8.1. BASE CASES INVESTIGATED IN THIS STUDY

In the base case the capacity of the PtX plants is set to 1 million t of diesel equivalent of final fuel per year or 114 t of diesel equivalent[1] per hour (1368 MW of final fuel). The installed capacity of 1 million t of diesel equivalent per year must not be mixed up with the annual production of final fuel which depends on the equivalent full load period of the PtX plant.

Table 44 shows the e-fuel pathways investigated in this study.

Table 44: Overview of e-fuel pathways investigated in this study

N°	Fuel	Supply	Pathway code
1	e-Hydrogen	Europe (N)	H2EU-N
2	e-Methane	Europe (N)	CH4EU-N
3	e-Methanol	Europe (N)	MeOHEU-N
4	e-OMEx	Europe (N)	OMExEU-N
5	e-Gasoline (MTG)	Europe (N)	MTGEU-N
6	e-Kerosene (MTK)	Europe (N)	MTKEU-N
7	e-Ammonia	Europe (N)	NH3EU-N
8	e-Kerosene (FT)	Europe (N)	FTKEU-N
9	e-Diesel (FT)	Europe (N)	FTDEU-N
10	e-Hydrogen	Europe (C)	H2EU-C
11	e-Methane	Europe (C)	CH4EU-C
12	e-Methanol	Europe (C)	MeOHEU-C
13	e-OMEx	Europe (C)	OMExEU-C
14	e-Gasoline (MTG)	Europe (C)	MTGEU-C
15	e-Kerosene (MTK)	Europe (C)	MTKEU-C
16	e-Ammonia	Europe (C)	NH3EU-C
17	e-Kerosene (FT)	Europe (C)	FTKEU-C
18	e-Diesel (FT)	Europe (C)	FTDEU-C
19	e-Hydrogen	Europe (S)	H2EU-S
20	e-Methane	Europe (S)	CH4EU-S
21	e-Methanol	Europe (S)	MeOHEU-S
22	e-OMEx	Europe (S)	OMExEU-S
23	e-Gasoline (MTG)	Europe (S)	MTGEU-S
24	e-Kerosene (MTK)	Europe (S)	MTKEU-S
25	e-Ammonia	Europe (S)	NH3EU-S
26	e-Kerosene (FT)	Europe (S)	FTKEU-S
27	e-Diesel (FT)	Europe (S)	FTDEU-S
28	H2 (liquid)	MENA by ship	H2ME-Liq
29	e-Methane (LNG)	MENA by ship	NGME-Liq
30	e-Methanol	MENA by ship	MeOHME
31	e-OMEx	MENA by ship	OMExME
32	e-Gasoline (MTG)	MENA by ship	MTGME
33	e-Kerosene (MTK)	MENA by ship	MTKME

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[1] Based on conventional diesel EN 590

N°	Fuel	Supply	Pathway code
34	e-Ammonia	MENA by ship	NH3ME
35	e-Gasoline (FT)	MENA by ship	FTGME
36	e-Kerosene (FT)	MENA by ship	FTKME
37	e-Diesel (FT)	MENA by ship	FTDME
38	e-Kerosene (FT)	MENA by ship as e-crude	FTKMEe-crd
39	e-Kerosene (FT)	Europe (S) with H_2 from MENA by ship	FTKME-H2ex
40	e-Diesel (FT)	Europe (S) with H_2 from MENA by ship	FTDME-H2ex

8.2. TECHNO-ECONOMIC DATA FOR RENEWABLE ELECTRICITY GENERATION IN THE DIFFERENT REGIONS

The PtX plants are directly connected with the renewable electricity generation plants. No public electricity grid is used. In some cases, an electricity transmission cable or line is required (sea cable in case of offshore wind, overhead HVDC transmission line in case of MENA).

8.2.1. Europe

For the calculation of the cost of renewable electricity in North Europe an offshore windfarm in the North Sea has been assumed. Table 45 shows the techno-economic data for electricity from offshore wind power.

Table 45: Renewable electricity costs in EU-North (base case)

	Unit	Wind offshore 2020	Wind offshore 2030	Wind offshore 2050	Reference
Wind farm					
Rated power	MW	450	700	700	
Lifetime	yr	25	25	30	[IWES 2017]
Equivalent full load period	h/yr	4053	4053	4053	[BET et al. 2019]
Electricity generation	GWh/yr	1824	2837	2837	
CAPEX	€/kW	3219	2137	2000	[BET et al. 2019]; [IRENA 2019b]*
	million €	1449	1496	1400	
Discount rate base case		8%	8%	8%	
Cost of capital wind farm	million €/yr	136	140	124	
Operation & maintenance	€/(kW*yr)	80	62	62	[BET et al. 2019]
	million €/yr	36	43	43	
Transmission to onshore					
Lifetime	yr	25	25	30	
CAPEX	million €	518	490	490 (1)	[BET et al. 2019]
Cost of capital	million €/yr	48	46	44	
Operation & maintenance	million €/yr	10	10	10	[BET et al. 2019]
Total					
Annual costs	million €/yr	231	239	221	
Costs of electricity	€/kWh	0.126	0.084	0.078	

*IRENA 2019b: 1400-2800 €/kW in 2050; equivalent full load period of 3770-5260 h/yr

(1) No further decrease of CAPEX for sea cable has been expected after 2030

For sensitivity analysis one variant of selected pathways involving electricity from North Europe has been calculated where the electricity for the e-fuel plants is derived from 100% onshore wind or 100% PV. For time horizon 2020 the CAPEX for onshore wind in North Europe has been derived from an existing wind farm in North Europe described in [NS Energy 2018]. The construction time was from 2018 to 2020.

For time horizon 2030 and 2050, learning curves have been applied for the CAPEX based on a learning rate (LR) of 0.05 indicated for onshore wind power and 0.15 for PV in [ISE 2018] and the cumulative installed capacity worldwide in 2018 (begin of construction of the Nysäter wind farm), 2030, and 2050 indicated in [REN21 2021], [IRENA 2019a], and [IRENA 2019b].

The CAPEX for the future can be calculated by:

$$CAPEX_{year\ n} = CAPEX_{year\ 1} \cdot \left(\frac{P_{year\ n}}{P_{year\ 1}}\right)^{\frac{lg(1-LR)}{lg(2)}}$$

where:

LR: Learning rate

P: Cumulative installed capacity

n: Target year

Example: Onshore wind power in North Europe in 2050:

$$CAPEX_{2050} = 1055\,\frac{€}{kW} \cdot \left(\frac{5044\ GW}{568\ GW}\right)^{\frac{LN(1-0.05)}{LN(2)}} = 897\,\frac{€}{kW}$$

Table 46 shows the cost of renewable electricity from 100% onshore wind in North Europe.

Table 46: Renewable electricity costs in EU-North (sensitivity: 100% wind onshore)

	Unit	Wind onshore 2020	Wind onshore 2030	Wind onshore 2050	Reference/ comment
Rated power	MW	475	475	475	[Nysäter 2021]
Lifetime	yr	25	25	25	
Equivalent full load period	h/yr	3579	3579	3579	[Nysäter 2021]
Electricity generation	GWh/yr	1700	1700	1700	
CAPEX	€/kW	1055	969	897	[NS Energy 2018]*
	million €	501	460	426	
Discount rate base case		8%	8%	8%	
Cost of capital wind farm	million €/yr	47	43	40	
Operation & maintenance	€/(kW*yr)	48	48	48	[ISE 2018]
	million €/yr	23	23	23	
Annual costs	million €/yr	70	66	63	
Costs of electricity	€/kWh	0.041	0.039	0.037	

*Assumed for time horizon 2020 (2030 and 2050 calculated based on learning curves)

Table 47 shows the cost of renewable electricity from 100% PV in North Europe. Single axis sun tracking has been assumed for the PV plant. The equivalent full load period has been derived from the hourly production data from [Ninja 2021] for 2010-2019.

Table 47: Renewable electricity costs in EU-North (sensitivity: 100% PV)

	Unit	PV 2020	PV 2030	PV 2050	Reference/ comment
Rated power	MW	475	475	475	
Lifetime	yr	25	25	25	
Equivalent full load period	h/yr	1119	1119	1119	
Electricity generation	GWh/yr	532	532	532	[Cossu et al. 2021]*
CAPEX	€/kW	637	468	361	
	million €	303	222	172	
Discount rate base case		8%	8%	8%	
Cost of capital wind farm	million €/yr	28.3	20.8	16.1	
Operation & maintenance	€/(kW*yr)	18	18	18	[Cossu et al. 2021]
	million €/yr	8.6	8.6	8.6	
Annual costs	million €/yr	36.9	29.4	24.7	
Costs of electricity	€/kWh	0.070	0.055	0.037	

*Assumed for time horizon 2020 (2030 and 2050 calculated based on learning curves

For central Europe (Germany as proxy) a photovoltaic (PV)/wind hybrid power station has been assumed. PV and wind power are complementary to a large extent. High solar irradiation occurs at period with low wind speeds and vice versa. Based on [Fasihi et al. 2016] an overlap of 5% of annual electricity generation have been assumed which is curtailed. The integration costs of the last 5% of excess power typically exceed the gain in using this 'excess' electricity (economic optimisation).

Large PV/hybrid power plants can be built e. g. in regions with (former) lignite mines in Germany. An analysis of the potential of PV/wind hybrid power plants at multi-GW scale combined with e-fuel plants can be found in [IFOK et al. 2018]. As an example, Table 48 shows the potential for PV and wind power in German coal mine.

Table 48: Potential for large PV and wind power plants in German lignite mine areas [IFOK et al. 2018]

	PV (MW)	Wind (MW)
Lusatia lignite mining region	8820-11894	1966-5149
Central German mining region	4491	13-1051
Rhineland mining region	1369	1162-1303

Single axis sun tracking has been assumed for the PV plant. The equivalent full load periods of the different regions have been derived from the hourly production data from [Ninja 2021] for 2010-2019.

Table 49: Renewable electricity costs in EU-Central in 2020

	Unit	PV	Wind	PV/wind hybrid	Reference
Rated power	MW	100	100		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	1426	2688	3908	[Deutsche WindGuard 2015]
Electricity generation	GWh/yr	143	269	391*	
CAPEX	€/kW	637	1521		[Cossu et al. 2021]; [Deutsche WindGuard & ZSW 2018]
	million €	63.7	152.1	215.8	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	5.97	14.25	20.22	
Operation & maintenance	€/(kW*yr)	18	43		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	1.82	4.34	6.16	
Total	million €/yr	7.79	18.59	26.38	
	€/kWh	0.055	0.069	0.067	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

For the calculation of the CAPEX of PV and onshore wind power for 2030 and 2050 learning curves have been applied based on learning rates and assumptions for cumulative installed capacity worldwide in the future indicated in [IRENA 2019a] and [IRENA 2019b]. For PV a learning rate of 0.15 and for onshore wind power a learning rate of 0.05 has been assumed based on [ISE 2018].

Table 50: Renewable electricity costs in EU Central in 2030

	Unit	PV	Wind	PV/wind hybrid	Reference
Rated power	MW	100	100		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	1426	2688	3908	[Deutsche WindGuard 2015]
Electricity generation	GWh/yr	143	269	391*	
CAPEX	€/kW	468	1397		
	million €	46.8	139.7	186.5	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	4.38	13.09	17.47	
Operation & maintenance	€/(kW*yr)	18	43		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	1.82	4.34	6.16	
Total	million €/yr	6.20	17.43	23.63	
	€/kWh	0.043	0.065	0.060	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 51: Renewable electricity costs in EU Central in 2050

	Unit	PV	Wind	PV/wind hybrid	Reference
Rated power	MW	100	100		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	1426	2688	3908	[Deutsche WindGuard 2015]
Electricity generation	GWh/yr	143	269	391*	
CAPEX	€/kW	361	1294		
	million €	36.1	129.4	165.5	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	3.39	12.12	15.51	
Operation & maintenance	€/(kW*yr)	18	43		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	1.82	4.34	6.16	
Total	million €/yr	5.21	16.47	21.67	
	€/kWh	0.037	0.061	0.055	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Southern Spain is an arid region. Hence, we apply a similar pathway setup for EU-South as in the cases of MENA, Chile, and Australia. The electricity generated by the PV/wind hybrid power plant is transported via a high voltage direct current (HVDC) transmission line over a distance of 200 km to the PtX plant at the coast (see chapter 8.2.2 and 8.2.3).

Table 52: Renewable electricity costs in EU-South in 2020

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2073	3231		REVE 01/2020
Electricity generation	TWh/yr	10.4	16.2	25.2	
CAPEX	€/kW	637	1111		[Cossu et al. 2021]; [REVE 01/2020]
	million €	3185	5556	8741	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	298	520	819	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	231	322	
Subtotal	**million €/yr**	**389**	**751**	**1141**	
	€/kWh	**0.038**	**0.047**	**0.045**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital	million €/yr			147	
Operation & maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	**million €/yr**			**165**	
	€/kWh			**0.007**	
Total costs of electricity	**€/kWh**			**0.054**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 53: Renewable electricity costs in EU-South in 2030

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2073	3231		REVE 01/2020
Electricity generation	TWh/yr	10.4	16.2	25.2	
CAPEX	€/kW	468	1021		
	million €	2338	5104	7442	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	219	478	697	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	231	322	
Subtotal	**million €/yr**	**310**	**709**	**1019**	
	€/kWh	**0.030**	**0.047**	**0.040**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital	million €/yr			147	
Operation & maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	**million €/yr**			**165**	
	€/kWh			**0.007**	
Total costs of electricity	**€/kWh**			**0.049**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 54: Renewable electricity costs in EU-South in 2050

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2073	3231		REVE 01/2020
Electricity generation	TWh/yr	10.4	16.2	25.2	
CAPEX	€/kW	361	945		
	million €	1807	4726	6534	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	169	443	612	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	231	322	
Subtotal	**million €/yr**	**260**	**674**	**934**	
	€/kWh	**0.025**	**0.042**	**0.037**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital	million €/yr			147	
Operation & maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	**million €/yr**			**165**	
	€/kWh			**0.007**	
Total costs of electricity	**€/kWh**			**0.046**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

8.2.2. MENA (KSA)

For MENA the equivalent full load periods both for PV and wind have been derived from the hourly production data from [Ninja 2021] for 2010-2019.

Analogous to [Fasihi et al. 2016] for MENA it has been assumed that the electricity generated by the PV/wind hybrid power plant is transported via a high voltage direct current (HVDC) transmission line over a distance of 200 km to the PtX plant which is located at the coast. The capacity of the plant has also been taken from [Fasihi et al. 2016].

Table 55: Renewable electricity costs in MENA (KSA as proxy) in 2020

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2406	3193	5319*	
Electricity generation	TWh/yr	12.0	16.0	26.6	
CAPEX	€/kW	637	1125		[Cossu et al. 2021]; [REVE 10/2020]
	million €	3185	5625	8810	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	298	527	825	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	230	321	
Subtotal	**million €/yr**	**389**	**757**	**1146**	
	€/kWh	**0.032**	**0.047**	**0.043**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital	million €/yr			147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.006	
Total costs of electricity	**€/kWh**			**0.051**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 56: Renewable electricity costs in MENA (KSA as proxy) in 2030

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2406	3193	5319*	
Electricity generation	TWh/yr	12.0	16.0	26.6	
CAPEX	€/kW	468	1033		
	million €	2338	5167	7506	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	219	484	703	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	230		321
Subtotal	**million €/yr**	**310**	**714**	**1024**	
	€/kWh	**0.026**	**0.045**	**0.038**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.006	
Total costs of electricity	**€/kWh**			**0.047**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 57: Renewable electricity costs in MENA (KSA as proxy) in 2050

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2406	3193	5319*	
Electricity generation	TWh/yr	12.0	16.0	26.6	
CAPEX	€/kW	361	957		
	million €	1807	4785		
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	169	448		
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	230		321
Subtotal	**million €/yr**	**260**	**678**		
	€/kWh	**0.022**	**0.042**	**0.035**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.006	
Total costs of electricity	**€/kWh**			**0.044**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

For sensitivity analysis variants for selected e-fuel pathways have been calculated for 100% PV and 100% onshore wind (chapter 2.2.3). The costs for electricity transport via HVDC per kWh of electricity increases due to the lower equivalent full load period compared to the combined PV/wind hybrid power station (Table 58 and Table 59).

Table 58: Renewable electricity costs in MENA (KSA as proxy) for 100% PV

	Unit	PV 2020	PV 2030	PV 2050	Reference
Electricity generation					
Rated power	MW	5000	5000	5000	
Lifetime	yr	25	25	25	
Equivalent full load period	h/yr	2406	2406	2406	
Electricity generation	TWh/yr	12.0	12.0	12.0	
CAPEX	€/kW	637	468	361	[Cossu et al. 2021]
	million €	3185	2338	1807	
Discount rate base case		8%	8%	8%	
Cost of capital PV plant	million €/yr	298	219	169	
Operation & maintenance	€/(kW*yr)	18	18	18	[Cossu et al. 2021
	million €/yr	91	91	91	321
Subtotal	**million €/yr**	**389**	**310**	**260**	
	€/kWh	**0.032**	**0.026**	**0.022**	
Transmission to coast					
Capacity		5000	5000	5000	[Fasihi et al. 2016]
Lifetime	yr	50	50	50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)	0.612	0.612	0.612	[Fasihi et al. 2016]
	million €	612	612	612	
Cost of capital	million €/yr	50	50	50	
Operation & maintenance		1.2% of CAPEX/yr	1.2% of CAPEX/yr	1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr	7	7	7	
Subtotal	**million €/yr**	57	**57**	**57**	
	€/kWh	**0.005**	**0.005**	**0.005**	
Converters					
Number of converters		2	2	2	
CAPEX	€/kW	180	180	180	[Fasihi et al. 2016]
	million €	1800	1800	1800	
Cost of capital		147	147	147	
Operation & Maintenance		1.0% of CAPEX/yr	1.0% of CAPEX/yr	1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr	18	18	18	
Subtotal	million €/yr	165	165	165	
	€/kWh	0.014	0.014	0.014	
Total costs of electricity	**€/kWh**	**0.051**	**0.044**	**0.040**	

Table 59: Renewable electricity costs in MENA (KSA as proxy) for 100% Wind

	Unit	Wind 2020	Wind 2030	Wind 2050	Reference
Electricity generation					
Rated power	MW	5000	5000	5000	
Lifetime	yr	25	25	25	
Equivalent full load period	h/yr	3193	3193	3193	
Electricity generation	TWh/yr	16.0	16.0	16.0	
CAPEX	€/kW	1125	1033	957	[REVE 10/2020]*
	million €	5625	5167	4785	
Discount rate base case		8%	8%	8%	
Cost of capital PV plant	million €/yr	527	484	448	
Operation & maintenance	€/(kW*yr)	46	46	46	[ISE 2018]
	million €/yr	230	230	230	
Subtotal	**million €/yr**	757	714	678	
	€/kWh	**0.047**	**0.045**	**0.042**	
Transmission to coast					
Capacity		5000	5000	5000	[Fasihi et al. 2016]
Lifetime	yr	50	50	50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)	0.612	0.612	0.612	[Fasihi et al. 2016]
	million €	612	612	612	
Cost of capital	million €/yr	50	50	50	
Operation & maintenance		1.2% of CAPEX/yr	1.2% of CAPEX/yr	1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr	7	7	7	
Subtotal	**million €/yr**	57	**57**	**57**	
	€/kWh	**0.004**	**0.004**	**0.004**	
Converters					
Number of converters		2	2	2	
CAPEX	€/kW	180	180	180	[Fasihi et al. 2016]
	million €	1800	1800	1800	
Cost of capital		147	147	147	
Operation & Maintenance		1.0% of CAPEX/yr	1.0% of CAPEX/yr	1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr	18	18	18	
Subtotal	million €/yr	165	165	165	
	€/kWh	0.010	0.010	0.010	
Total costs of electricity	**€/kWh**	**0.061**	**0.059**	**0.056**	

*For 2020 (2030 and 2050 calculated based on learning curves)

8.2.3. Other sweet spots for renewable electricity worldwide

For sensitivity analysis long-haul potentials in other sweet spots (North Africa with Morocco as proxy, Australia, Chile) worldwide have been assessed. The equivalent full load periods of PV and wind have been derived from existing PV and wind power plants in Morocco (Table 60 and Table 61).

Table 60: Equivalent full load periods of PV plants in Morocco, Australia, and Chile

Region	PV plant	h/yr	Reference
North Africa (Morocco)	Noor Quarzazate IV, PV, 163 GWh/72MW	2263	[Masen 2019]
	Noor Laayoune, PV, 197 GWh/85MW	2318	[Masen 2019]
	Noor Boujdour, PV, 45 GWh/20 MW	2250	[Masen 2019]
	Proxy	**2300**	
Australia	Darlington Point 685 GWh/333 MW	2057	[Edify 2021a]
	Bungala Solar PV Plant, Port Augusta 570 GWh/275 MW	2072	[Power Technology 2017]
	Daydream 398 GWh/180 MW	2211	[Edify 2021b]
	Proxy	**2100**	
Chile	Lalackama I 160 GWh/60 MW	2666	[Enel 2021a]
	Lalackama II 50 GWh/18 MW	2777	[Enel 2021b]
	Amanecer Solar CAP plant up to 270 GWh/100 MW	2700	[Power Technology 2014]
	Proxy	**2700**	

Table 61: Equivalent full load periods of onshore wind power plants in Morocco, Australia, and Chile

Region	Wind farm	h/yr	Reference
North Africa (Morocco)	Tarfaya wind farm, 1000 GWh/301,3 MW	3319	[The Wind Power 2017]
	Akhfennir wind farm, 380 GWh/100 MW	3800	[NAREVA 2021a], [NAREVA 2021b]
	Amogdoul wind farm, 450 GWh/124 MW	3629	[Wind Energy - The Facts 2021]
	Average proxy	**3600**	
Australia	Hornsdale Wind Farm 1050 GWh/316 MW	3345	[NEOEN 2021]
	Sapphire Wind Farm 796.3 GWh/270 MW	2949	[CWP 2021]; [Wikipedia 8/2021]
	Collgar Wind Farm 665.8 GWh/222 MW	2999	[Collgar Wind Farm 2021] [Wikipedia 7/2021]
	Proxy	**3000**	
Chile	Statkraft 300 GWh/104 MW	2884	[REVE 04/2021]
	Taltal Wind Farm 300 GWh/99 MW	3030	[Enel 2021c]
	Atacama 2000 GWh/980 MW	2040	[Windpower Monthly 2020]
	San Martias (Biobio, North Chile) 358 GWh/107.5 MW	3330	[Renewables Now 2021]
	Proxy	**2800**	

The equivalent full load period combined with CAPEX and PPEX (maintenance, repair, labour, overhead) lead to the renewable electricity costs for the different regions shown in Table 62 to Table 70.

Table 62: Renewable electricity costs in Morocco in 2020

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2300	3600	5605*	Table 60, Table 61
Electricity generation	TWh/yr	11.5	18.0	28.0	
CAPEX	€/kW	637	1125		[Cossu et al. 2021]; [REVE 10/2020]
	million €	3185	5625	8810	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	298	527	825	
Operation & maintenance	€/(kW*yr)	18	48		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	240	331	
Subtotal	**million €/yr**	**389**	**767**	**1156**	
	€/kWh	**0.034**	**0.043**	**0.041**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.006	
Total costs of electricity	**€/kWh**			**0.049**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 63: Renewable electricity costs in Morocco in 2030

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2300	3600	5605*	Table 60, Table 61
Electricity generation	TWh/yr	11.5	18.0	28.0	
CAPEX	€/kW	468	1033		
	million €	2338	5167	7506	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	219	484	703	
Operation & maintenance	€/(kW*yr)	18	48		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	240	331	
Subtotal	**million €/yr**	**310**	**724**	**1034**	
	€/kWh	**0.027**	**0.040**	**0.037**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.006	
Total costs of electricity	**€/kWh**			**0.045**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 64: Renewable electricity costs in Morocco in 2050

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2300	3600	5605*	Table 60, Table 61
Electricity generation	TWh/yr	11.5	18.0	28.0	
CAPEX	€/kW	361	957		
	million €	1807	4785	6593	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	169	448	618	
Operation & maintenance	€/(kW*yr)	18	48		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	240	331	
Subtotal	**million €/yr**	**260**	**688**	**949**	
	€/kWh	**0.023**	**0.038**	**0.034**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.006	
Total costs of electricity	**€/kWh**			**0.042**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 65: Renewable electricity costs in Australia in 2020

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2100	3000	4845	Table 60, Table 61
Electricity generation	TWh/yr	10.5	15.0	24.2	
CAPEX	€/kW	637	1125		[Cossu et al. 2021]; [REVE 10/2020]
	million €	3185	5625	8810	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	298	527	825	
Operation & maintenance	€/(kW*yr)	18	45		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	225	331	
Subtotal	**million €/yr**	**389**	**752**	**1141**	
	€/kWh	**0.037**	**0.050**	**0.047**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.007	
Total costs of electricity	**€/kWh**			**0.056**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 66: Renewable electricity costs in Australia in 2030

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2100	3000	4845	Table 60, Table 61
Electricity generation	TWh/yr	10.5	15.0	24.2	
CAPEX	€/kW	468	1033		[Cossu et al. 2021]; [REVE 10/2020]
	million €	2338	5176	7506	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	219	484	703	
Operation & maintenance	€/(kW*yr)	18	45		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	225	331	
Subtotal	**million €/yr**	**310**	**709**	**1019**	
	€/kWh	**0.030**	**0.047**	**0.042**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.007	
Total costs of electricity	**€/kWh**			**0.051**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 67: Renewable electricity costs in Australia in 2050

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2100	3000	4845	Table 60, Table 61
Electricity generation	TWh/yr	10.5	15.0	24.2	
CAPEX	€/kW	361	957		[Cossu et al. 2021]; [REVE 10/2020]
	million €	1807	4785	6593	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	169	448	618	
Operation & maintenance	€/(kW*yr)	18	45		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	225	331	
Subtotal	**million €/yr**	**260**	**673**	**934**	
	€/kWh	**0.025**	**0.045**	**0.039**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.007	
Total costs of electricity	**€/kWh**			**0.048**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 68: Renewable electricity costs in Chile in 2020

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2700	2800	5225	Table 60, Table 61
Electricity generation	TWh/yr	13.5	14.0	26.1	
CAPEX	€/kW	637	1125		[Cossu et al. 2021]; [REVE 10/2020]
	million €	3185	5625	8810	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	298	527	825	
Operation & maintenance	€/(kW*yr)	18	44		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	220	311	
Subtotal	**million €/yr**	**389**	**747**	**1136**	
	€/kWh	**0.029**	**0.053**	**0.043**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.006	
Total costs of electricity	**€/kWh**			**0.052**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 69: Renewable electricity costs in Chile in 2030

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2700	2800	5225	Table 60, Table 61
Electricity generation	TWh/yr	13.5	14.0	26.1	
CAPEX	€/kW	468	1033		[Cossu et al. 2021]; [REVE 10/2020]
	million €	2338	5167	7506	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	219	484	703	
Operation & maintenance	€/(kW*yr)	18	44		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	220	311	
Subtotal	**million €/yr**	**310**	**704**	**1014**	
	€/kWh	**0.023**	**0.050**	**0.039**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.006	
Total costs of electricity	**€/kWh**			**0.047**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

Table 70: Renewable electricity costs in Chile in 2050

	Unit	PV	Wind	PV/wind hybrid	Reference
Electricity generation					
Rated power	MW	5000	5000		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2700	2800	5225	Table 60, Table 61
Electricity generation	TWh/yr	13.5	14.0	26.1	
CAPEX	€/kW	361	957		[Cossu et al. 2021]; [REVE 10/2020]
	million €	1807	4785	6593	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	169	448	618	
Operation & maintenance	€/(kW*yr)	18	44		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	91	220	311	
Subtotal	**million €/yr**	**260**	**668**	**929**	
	€/kWh	**0.019**	**0.048**	**0.036**	
Transmission to coast					
Capacity				5000	[Fasihi et al. 2016]
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			612	
Cost of capital	million €/yr			50	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			7	
Subtotal	**million €/yr**			**57**	
	€/kWh			**0.002**	
Converters					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			1800	
Cost of capital				147	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			18	
Subtotal	million €/yr			165	
	€/kWh			0.006	
Total costs of electricity	**€/kWh**			**0.044**	

* 5% electricity overlap curtailed based on [Fasihi et al. 2016]

8.3. TECHNO-ECONOMIC DATA FOR WATER AND CO-ELECTROLYSIS

For all pathways the same efficiency and the same cost data for the electrolysis plant have been assumed. Above 100 MWe no further cost reduction from upscaling is expected.

Table 71: CAPEX of alkaline water electrolysis plants above 100 MWe (€/kWe)

	2020	2030	2050	Reference
Stack	530	357	189	Zauner et al. 2019
Power electronics	75	47	27	
Gas conditioning	51	48	36	
Balance of plant	77	55	29	
Subtotal direct CAPEX	**734**	**507**	**281**	
Site preparation	15	10	6	H2A 2018
Engineering & design	59	41	22	
Project contingency	110	76	42	
Up-Front Permitting	110	76	42	
CAPEX total	1027	710	393	

Table 72 shows the summarized CAPEX for alkaline and co-electrolysis. The CAPEX for the co-electrolysis in has been derived from [Wolf 2020], [Zauner 2019], and [H2A 2018].

Table 72: Techno-economic data electrolysis plants

	Unit	2020	2030	2050	2050 AT
Technology	-	Alkaline	Alkaline	Alkaline	Co-electrolysis
Efficiency (LHV)	-	66.5%	68%	75%	82.1%
CAPEX total	€/kW$_e$	1027	710	393	951
	€/kW$_{H2}$	1544	1044	524	1158
Lifetime	yr	30	30	30	20

All auxiliaries such as transformer, AC/DC converter, pumps, blowers, and storage tanks are included. Costs for civil work, engineering, etc. are also included.

In [Zauner et al. 2019] the operating and maintenance costs for alkaline electrolysis are indicated with 2% of direct CAPEX per year including stack replacement. For co-electrolysis via SOEC the operating and maintenance costs are indicated with 5% of direct CAPEX per year including stack replacement [Zauner et al. 2019].

8.4. DESCRIPTION OF FUEL SUPPLY PATHWAYS

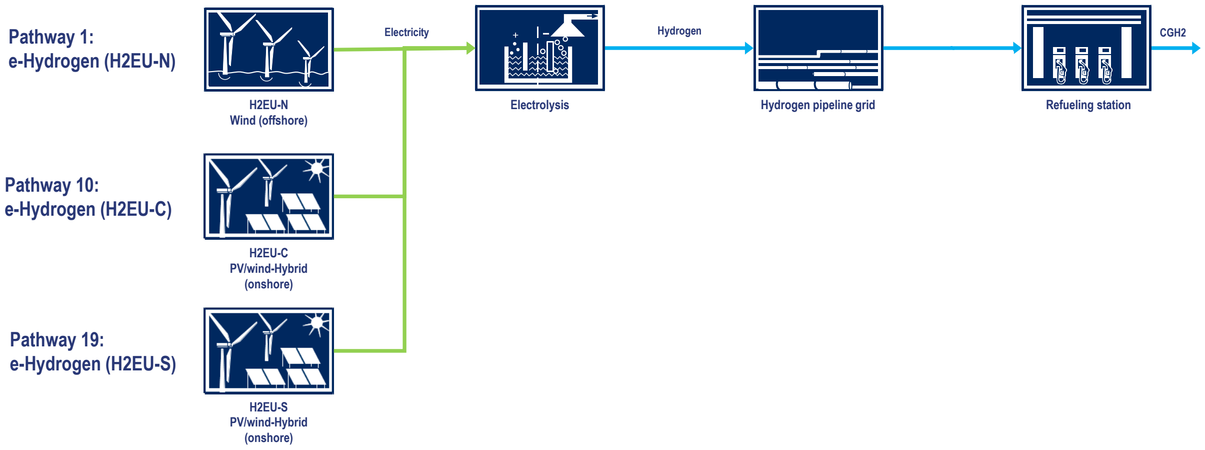
8.4.1. E-Hydrogen in the EU (H2EU-N, H2EU-C, H2EU-S)

Hydrogen is generated via water electrolysis, compressed, and stored in a stationary buffer storage at a pressure of 10 MPa to compensate fluctuations of renewable electricity supply. The hydrogen is transported and distributed to the refuelling stations via a hydrogen pipeline grid. At the refuelling station the hydrogen is compressed, pre-cooled, and dispensed to road vehicles with 70 MPa vehicle tanks.

Three variants have been taken into account:

- Electricity from offshore wind power in North Europe (e. g. in the North Sea at Norway)
- Electricity from PV-/wind-hybrid power stations in Central Europe e. g. Germany)
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain

Figure 114: e-Hydrogen



The capacity of the power-to-hydrogen plant amounts to 1368 MW of hydrogen based on the lower heating value (LHV). The electricity input into the electrolysis plant amounts to 2057 MW in 2020, 2011 in 2030, and 1824 MW in 2050.

A hydrogen buffer storage has been assumed to compensate fluctuations of the renewable electricity supply. A hydrogen storage loading compressor is required to elevate the pressure of the hydrogen leaving the electrolysis plant to 10 MPa which is the maximum pressure of the hydrogen buffer storage. The buffer storage consists of underground steel-made tubes with a diameter of 1485 mm which are typically used for natural gas storage today.

The CAPEX and costs for maintenance and repair for the compressor is based on a large hydrogen compressor with a capacity of 10,500 kg H_2/h (~117,000 Nm^3/h) described in [Planet et al. 2014]. The CAPEX for the hydrogen storage has been derived from [Jauslin Stebler 2013].

Table 73 shows the techno-economic data for the hydrogen buffer storage including hydrogen storage loading compressor.

Table 73: H_2 buffer storage with H_2 storage loading compressor for the supply of CGH_2 as transportation fuel

	Unit	Value	Reference/comment
Compressor H_2 storage loading			
Capacity	Nm^3/h	456,000	
Suction pressure	MPa	3	
Final pressure	MPa	10	
T (in)	K	313	H_2 leaving electrolyzer
T (intercooling)	K	333	
Efficiency compressor		80%	
Efficiency electric motor		90%	
Number of stages	-	2	
Electricity consumption	kWh/Nm^3	0.0649	
	$kWh/kWh_{H2, LHV}$	0.0217	
CAPEX	million €	117	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr	Planet et al. 2014
Lifetime	yr	30	
H_2 storage			
Maximum pressure	MPa	10	
Minimum pressure	MPa	2.5	
Storage capacity	h	50	of full load operation
	million Nm^3	22.8	Net storage capacity
CAPEX	million €	573	Jauslin Stebler 2013
	$€/kg_{H2}$	279	
Lifetime	yr	30	

The hydrogen is transported to the refueling stations via a pipeline grid (Table 74). The CAPEX, cost of maintenance and repair, and the length of the hydrogen pipeline grid has been derived from [Krieg 2012]. The annual hydrogen production depends on the equivalent full load period of the electrolysis plant leading to different length of the pipeline grid. The electricity consumption for hydrogen transport via pipeline has been derived from [Sphera 2021].

The 0.000864 MJ per km and kg of hydrogen indicated in [Sphera 2021] has been divided by the LHV of the hydrogen and multiplied with the average length of the transmission pipeline between the electrolysis plant and the local pipeline grid to get the electricity consumption per MJ of hydrogen. The electricity is supplied by the electricity grid at medium voltage (MV) level. It has been assumed that the transmission pipeline grid consists of three main pipelines per electrolysis plant.

Table 74: H_2 pipeline grid per electrolysis plant

	Unit	North EU	Central EU	South EU
H_2 throughput	GWh_{LHV}/yr	5543	4928	6341
Length transmission pipeline grid	km	362	321	4414
	km/refueling station	1.4	1.4	1.4
Average length of main pipeline to electrolysis plant	km	121	107	138
CAPEX transmission pipelines	€/m	526	526	526
	million	190	169	218
Lifetime	yr	30	30	30
Length local pipeline grid	km	1088	967	1244
	km/refueling station	4.1	4.1	4.1
CAPEX local pipeline grid	€/m	289	289	289
	million €	314	279	359
Lifetime	yr	30	30	30
Electricity consumption	$MJ/MJ_{H2,\ LHV}$	0.00087	0.00077	0.00099
Maintenance & repair	5% of CAPEX/yr			

Table 75 shows the techno-economic data for the hydrogen refuelling station for the dispensing of compressed gaseous hydrogen for fuel cell trucks with 70 MPa vehicle tanks. The CAPEX and the costs of maintenance and repair are based on data in [Parks et al. 2014] except the costs for approval. Learning curves have been applied to calculate the CAPEX for the different time horizons. The costs for the approval have been derived from the German safety inspection organization TÜV [Elliger 2016]. The costs for insurance have been derived from [HRSAM 2021].

Table 75: CGH_2 refueling station for CGH_2 trucks with 70 MPa vehicle tanks

	Unit	2020	2030	2050
H_2 throughput	GWh/yr	21	21	21
	kg H_2/d	2500	2500	2500
Open days per year		250	250	250
Electricity consumption	$MJ/MJ_{H2,\ LHV}$	0.1106	0.1106	0.1106
Number of dispensers	-	2	2	2
CAPEX				
H2 bulk storage	€	994,000	739,00	644,000
H2 high pressure buffer	€	1,360,000	1,010,000	880,000
H2 compressors	€	1,677,000	934,000	711,000
Pre-cooling	€	227,000	169,000	147,000
H_2 dispensers	€	189,000	141,000	122,000
Installation	€	1,334,000	897,000	751,000
Site preparation	€	289,000	194,000	163,000
Engineering & design	€	578,000	389,000	326,000
Contingency	€	289,000	194,000	163,000
Approval	€	2000	2000	2000
Total	**€**	**6,939,000**	**4,669,000**	**3,909,000**
OPEX				
Maintenance & repair		4% of compressor CAPEX/yr		
Insurance		1% of total CAPEX/yr		
Safety inspection	€/yr	1575	1575	1575
Dispenser calibration	€/yr	1432	1432	1432

The electricity for the refuelling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

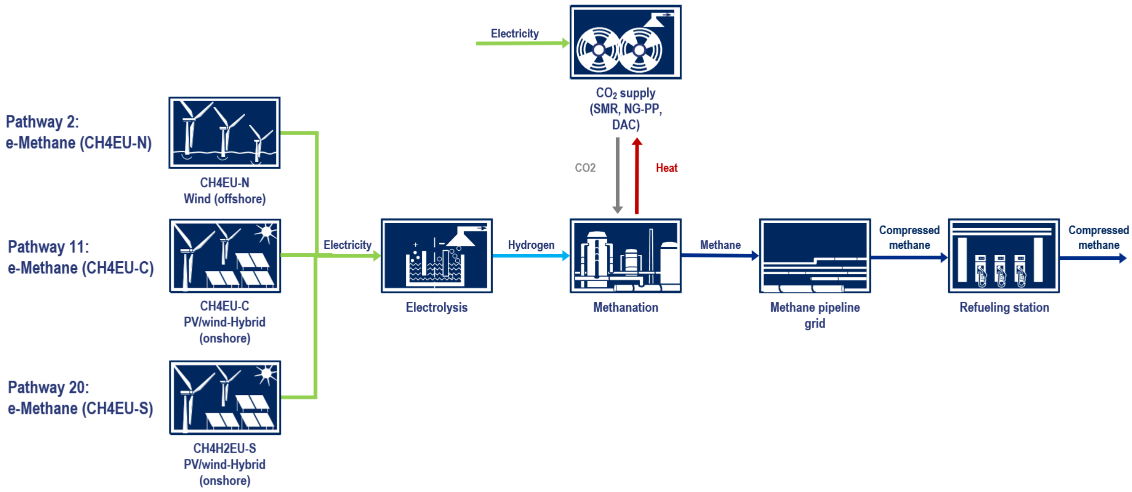
8.4.2. E-Methane in the EU (CH4EU-N, CH4EU-C, CH4EU-S)

E-methane is created through the methanation process, where a chemical reaction converts carbon dioxide and hydrogen to methane. The hydrogen needed for the process is generated via electrolysis. The carbon dioxide can be produced by several routes, for example by direct air capture (DAC), from flue gas from steam methane reforming (SMR), or from flue gas from a mix of natural gas and biomass power stations (NG-PP). After the methanation process to methane is pressurized and transported through a pipeline grid to refuelling stations where the compressed methane is dispensed to road vehicles. The three different pathways only differ in the electricity needed for the electrolysis.

The following variants have been taken into account:

- In North Europe electricity from offshore wind power is used (e. g. in the North Sea at Norway)
- In Central Europe electricity form PV-/wind-hybrid power stations are used
- In South Europe electricity from PV-/wind-hybrid power stations are used

Figure 115: e-Methane



The capacity of the power-to-methane plant amounts to 1368 MW of methane based on the lower heating value (LHV). The hydrogen demand of the downstream methanation influences the electricity input of the electrolysis plant. The electricity input into the electrolysis plant amounts to 2465 MW in 2020, 2410 in 2030, and 2185 MW in 2050.

The storage capacity of the buffer storage (Table 76) is assumed to be lower (3 h of full load operation) than that for hydrogen as fuel because the methane can be stored more easily than hydrogen due to higher energy density per m^3 of pressure vessel and the buffer storage is only used for bridging the lower flexibility of the methanation process.

Table 76: H_2 buffer storage with H_2 storage loading compressor for power-to-methane in Europe

	Unit	Value	Reference/comment
Compressor H_2 storage loading			
Capacity	Nm^3/h	546,000	
Suction pressure	MPa	3	
Final pressure	MPa	10	
T (in)	K	313	H_2 leaving electrolyzer
T (intercooling)	K	333	
Efficiency compressor		80%	
Efficiency electric motor		90%	
Number of stages	-	2	
Electricity consumption	kWh/Nm^3	0.0649	
	$kWh/kWh_{H2,\ LHV}$	0.0217	
CAPEX	million €	141	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr	Planet et al. 2014
Lifetime	yr	30	
H_2 storage			
Maximum pressure	MPa	10	
Minimum pressure	MPa	2.5	
Storage capacity	h	3	of full load operation
	million Nm^3	1.6	Net storage capacity
CAPEX	million €	41	Jauslin Stebler 2013
	$€/kg_{H2}$	279	
Lifetime	yr	30	

The hydrogen is sent together with CO_2 to a catalytic methanation process. The following reaction occur:

$$CO_4 + 4\ H_2 \rightarrow CH_4 + 2\ H_2O$$

The reaction is exothermal. The temperature is about 250 to 300°C [Etogas 2014].

For 2020 and 2030 a concentrated CO_2 source with a CO_2 concentration of 45% e. g. flue gas from steam methane reforming (SMR) plants is used for CO_2 supply. For 2050 a mix of CO_2 from SMR, flue gas from a mix of natural gas and biomass fuelled power plants, and from direct air capture of CO_2 is assumed in the base case.

For 2020 and 2030 it has been assumed that the CO_2 from a concentrated source. The CO_2 concentration of this concentrated source is assumed to be 45 % e. g. flue gas from a steam methane reforming (SMR) plant. For 2050 also a mix of concentrated, average and diluted CO_2 source has been assumed. The average CO_2 source consists of a mix of flue gas from 50% natural gas power stations (~3% CO_2) and 50% solid biomass fuelled power stations (~14% CO_2) leading to an average CO_2

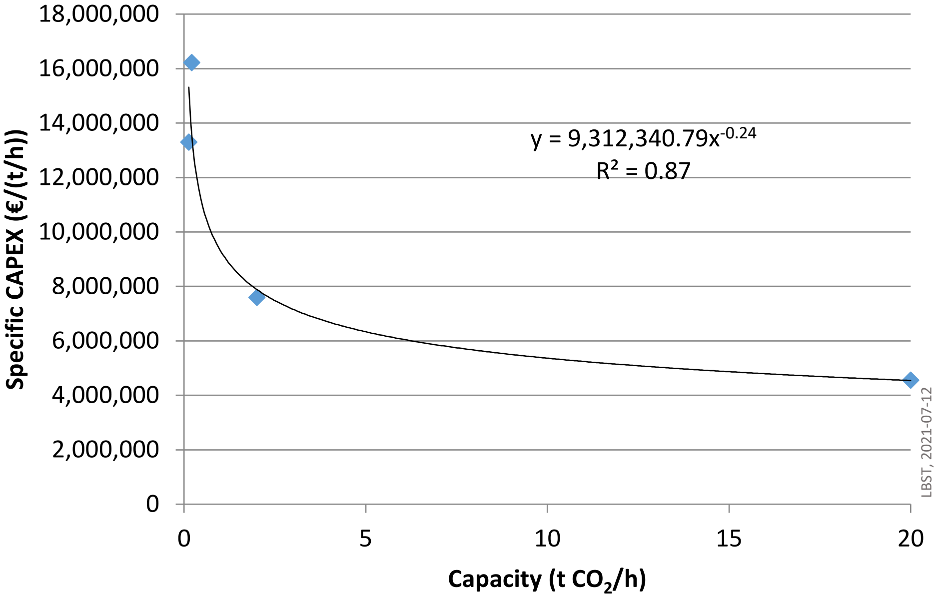
concentration of 8.5%. CO_2 via direct air capture (DAC) of CO_2 represents the diluted CO_2 source.

The electricity and heat demand for the capture of CO_2 from a concentrated source with a CO_2 concentration of 45% have been derived from [Sphera 2021]. The CO_2 concentration of biogas leaving the fermenter ranges between 40 and 50% which is similar to the 45% above, Therefore, the CAPEX has been derived from biogas upgrading plant based on scrubbing with monoethanolamine (MEA) described in [KTBL 2012]. A scaling exponent of 0.7 has been used to take into account cost reduction by scale.

The electricity and heat demand for the capture of CO_2 from natural gas and biomass fueled power stations (average source of CO_2) have been derived from [Sphera 2021]. The CAPEX and the costs of labour, maintenance, and repair has been derived from a CO_2 capture plant for natural gas power stations described [RECCS 2007] and a cement production plant described in [Gardarsdottir et al. 2019]. For the calculation of the CAPEX a scaling exponent of 0.7 has been used to take into account cost reduction by scale.

The electricity and heat demand for the DAC plant have been derived from [Beuttler et al. 2019]. The CAPEX for the DAC plant has been derived from [Climeworks 2015] and [Keufl 2019]. Figure 116 shows the specific CAPEX depending on the capacity of the DAC plant.

Figure 116: Specific CAPEX for direct air capture (DAC) of CO_2 depending on capacity



CO_2 liquefaction has been applied to provide pure CO_2 to avoid damage of methanation catalyst. Furthermore, a CO_2 buffer storage has been supplied to partly decouple CO_2 production and methanation. The techno-economic data for CO_2 liquefaction and storage is based on a capacity of 114 t CO_2/h described in [Element Energy 2018]. A scaling exponent of 0.7 has been assumed to calculate the CAPEX of the CO_2 liquefaction plant. The buffer storage has been scaled linearly.

Table 77 shows the techno-economic data for the supply of CO_2 for a methanation plant with a capacity of 1368 MW of methane based on the LHV.

Table 77: CO_2 supply for a methanation plant in Europe

	Unit	Concentrated	Average	Diluted
CO_2 source		SMR	Flue gas from power stations	DAC
Capacity	t/h	295	296	296
CO_2 capture				
Electricity	MJ/kg CO_2	0.14	0.27	1.44
Heat	MJ/kg CO_2	0.90	3.00	5.76
CAPEX	million €	120	303	702
Maintenance & repair		2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance		2% of CAPEX/yr		-
Labour	million €/yr	1.74		-
Administration		30% of labour, 40% of maintenance		-
CO_2 liquefaction & storage				
Electricity	MJ/kg CO_2	0.38*		
CAPEX	million €	44**		
Fixed OPEX CO_2 liquefier		10% of CAPEX/yr		
Fixed OPEX of CO_2 storage		5% of CAPEX/yr		

* 0.1042 kWh/kg of CO_2 at p (in) = ambient pressure; **CO_2 liquefaction: 43.3 million €; CO_2 storage: 0.5 million € (551 £ or 589 € per t of CO_2)

Table 78 shows the techno-economic data for a methanation plant with a capacity of 1368 MW based on the LHV. The equivalent full load period of the methanation plant is the same as that of the electrolysis plant.

Table 78: Techno-economic data for a methanation plant in Europe

	Unit	Value	Reference/comment
Capacity	$MW_{CH4,\ LHV}$	1368	
Inputs			
GH2	$MJ/MJ_{CH4,\ LHV}$	1.198	
CO_2	$MJ/MJ_{CH4,\ LHV}$	0.0600	
Electricity	$MJ/MJ_{CH4,\ LHV}$	0.0229	
Outputs			
CH4	MJ	1.000	
Heat (T = 250-300°C)	$MJ/MJ_{CH4,\ LHV}$	0.072	
Economic data			
CAPEX 2020/2030/ 2050	€/$kW_{CH4,\ LHV}$	792/704/541	[IEA 2019d] (880/782/601 US$/$kW_{CH4,\ LHV}$)
	million €	1083/963/740	
Lifetime	yr	30	[IEA 2019d]
Fixed O&M		3% of CAPEX/yr	[IEA 2019d]
Variable O&M	€/$GWh_{CH4,\ LHV}$	320	[IEA 2019d] (355 US$/$GWh_{CH4,\ LHV}$)

The methane is transported to the refuelling stations via a pipeline grid (Table 79). The CAPEX, cost of maintenance and repair, and the length of the pipeline grid has been derived from [Krieg 2012]. The annual methane production depends on the equivalent full load period of the methanation plant (same as electrolysis plant) leading to different length of the pipeline grid.

Table 79: CH_4 pipeline grid per methanation plant

	Unit	North EU	Central EU	South EU
CH_4 throughput	GWh_{LHV}/yr	5543	4928	6341
Length transmission pipeline grid	km	362	321	4414
	km/refueling station	1.4	1.5	1.4
Average length of main pipeline to electrolysis plant	km	121	107	138
CAPEX transmission pipelines	€/m	526	526	526
	million	190	169	218
Lifetime	yr	30	30	30
Length local pipeline grid	km	1088	967	1244
	km/refueling station	4.4	4.1	4.1
CAPEX local pipeline grid	€/m	280	280	280
	million €	305	271	348
Lifetime	yr	30	30	30
Electricity consumption	$MJ/MJ_{H2,\ LHV}$	0	0	0
Maintenance & repair	5% of CAPEX/yr			

Table 80 shows the techno-economic data for the refuelling station for the dispensing of compressed gaseous methane for CNG trucks with 20 MPa vehicle tanks (typical maximum operating pressure for CNG vehicle tanks at 15°C).

The CAPEX and the costs of maintenance and repair are based on data in [LBST 2016] except the costs for approval. Compressed gaseous methane has similar properties a compressed natural gas (CNG). CNG refuelling stations are mature. No cost reductio has been assumed for the future. The costs for the approval have been derived from the German safety inspection organization TÜV [Elliger 2016]. The costs for insurance have been derived from [HRSAM 2021].

Table 80: Compressed gaseous methane refueling station for CNG trucks

	Unit	2020/2030/2050
CH_4 throughput	GWh/yr	22.4
Open days per year	-	250
Electricity consumption	$MJ/MJ_{CH4,\ LHV}$	0.0224
Number of dispensers	-	2
CAPEX		
Gas inlet line incl. gas drier	€	120,000
Dispensers	€	100,000
Sequencing block dispenser	€	16,000
CH_4 storage (3-bank)	€	175,000
CH_4 Compressor	€	450,000
Cooling system compressors	€	30,000
Recirculation cooling cycle	€	25,000
Control unit compressors	€	80,000
Odorization	€	30,000
Equipment for data transfer	€	10,000
Concrete made building	€	100,000
Gas outlet line	€	35,000
MF-Block PF	€	10,000
Installation	€	150,000
Civil work (roof, pay system)	€	280,000
Cables, piping, material transport, calibration	€	120,000
Project management, documentation	€	80,000
Other	€	30,000
Approval	€	2000
Total	**€**	**1843,000**
OPEX		
Maintenance & repair	€/yr	4902
Safety inspection storage vessels	€/yr	2880
Dispenser calibration costs	€/yr	1432
Insurance	€/yr	18830
Total	**€/yr**	**27483**

The electricity for the refueling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

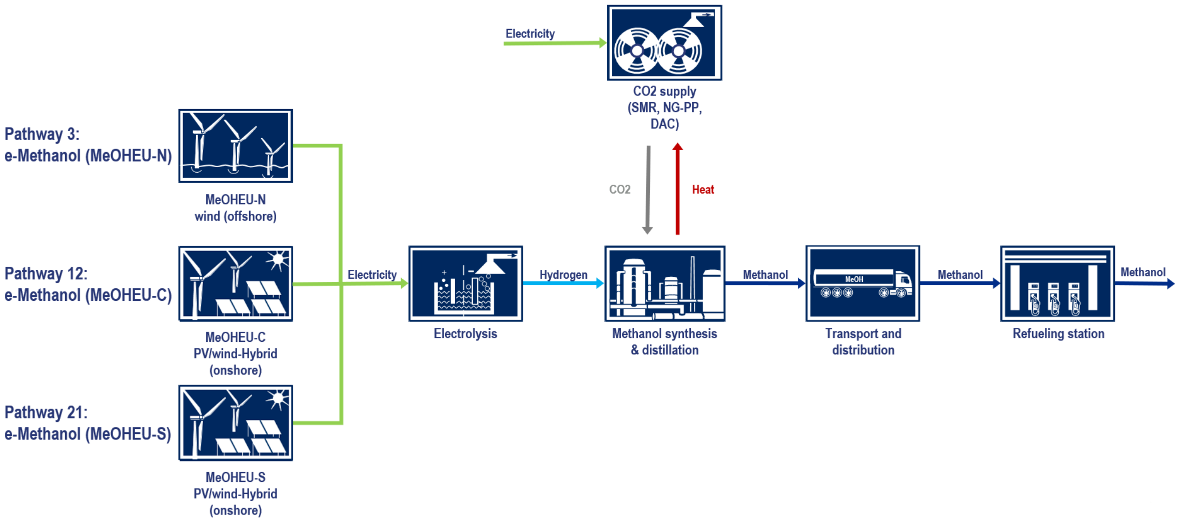
8.4.3. E-methanol in the EU (MeOHEU-N, MeOHEU-C, MeOHEU-S)

Methanol is produced by the catalytic reaction of carbon dioxide and hydrogen. The hydrogen is generated by water via electrolysis. The required carbon dioxide can be supplied either via a mix of natural gas and biomass fuelled power plants (NG-PP), direct air capture (DAC), or flue gas from steam methane reforming (SMR). The heat required by the CO_2 supply is partly originated as a by-product of the Methanol synthesis and distillation process. After the synthesis and the distillation process the methanol is transported and distributed via trucks. The trucks deliver the methanol to refuelling stations, at which the end user can access it.

(Three variants of electricity generation have been considered:

- Electricity from offshore wind power in North Europe e. g. in the North Sea at Norway
- Electricity from PV-/wind-hybrid power stations in Central Europe e. g. Germany
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain)

Figure 117: e-Methanol



The capacity of the power-to-methanol plant amounts to 1368 MW of methanol based on the lower heating value (LHV). The electricity input into the electrolysis plant amounts to 2388 MW in 2020, 2336 in 2030, and 2118 in 2050.

The methanol synthesis plant is less flexible than the methanation plant. Therefore, the capacity of the H_2 storage is assumed to be 50 h of full load operation. Table 81 shows the techno-economic data for H_2 buffer storage including H_2 storage loading compressor for power-to-methanol.

Table 81: H_2 buffer storage with H_2 storage loading compressor for power to methanol.

	Unit	**Value**	**Reference/comment**
Compressor H_2 storage loading			
Capacity	Nm^3/h	530,000	
Suction pressure	MPa	3	
Final pressure	MPa	10	
T (in)	K	313	H_2 leaving electrolyzer
T (intercooling)	K	333	
Efficiency compressor		80%	
Efficiency electric motor		90%	
Number of stages	-	2	
Electricity consumption	kWh/Nm^3	0.0649	
	$kWh/kWh_{H2, LHV}$	0.0217	
CAPEX	million €	136	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr	Planet et al. 2014
Lifetime	yr	30	
H_2 storage			
Maximum pressure	MPa	10	
Minimum pressure	MPa	2.5	
Storage capacity	h	50	of full load operation
	million Nm^3	26.5	Net storage capacity
CAPEX	million €	665	Jauslin Stebler 2013
	€/kg_{H2}	279	
Lifetime	yr	30	

For the supply of CO_2 for methanol synthesis (Table 82) the same basic data and the same references have been used as for the supply of CO_2 for methanation (chapter 8.4.2). The CO_2 storage is assumed to be 50 h of full load operation.

Table 82: CO_2 supply for a methanol synthesis plant in Europe

	Unit	**Concentrated**	**Average**	**Diluted**
CO_2 source		SMR	Flue gas from power stations	DAC
Capacity	t/h	346	346	346
CO_2 capture				
Electricity	MJ/kg CO_2	0.14	0.27	1.44
Heat	MJ/kg CO_2	0.90	3.00	5.76
CAPEX	million €	134	338	791
Maintenance & repair		2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance		2% of CAPEX/yr		-
Labour	million €/yr	1.80		-
Administration		30% of labour, 40% of maintenance		-
CO_2 liquefaction & storage				
Electricity	MJ/kg CO_2	0.38*		
CAPEX	million €	58**		
Fixed OPEX CO_2 liquefier		10% of CAPEX/yr		
Fixed OPEX of CO_2 storage		5% of CAPEX/yr		

* 0.1042 kWh/kg of CO_2 at p (in) = ambient pressure; **CO_2 liquefaction: 48.3 million €; CO_2 storage: 10.2 million € (551 £ or 589 € per t of CO_2)

Table 83 shows the techno-economic data for a methanol synthesis plant including compressors and methanol purification with a capacity of 1368 MW based on the LHV. The equivalent full load period of the methanol synthesis plant is the same as that of the electrolysis plant.

Table 83: Techno-economic data for a methanol synthesis plant in Europe

	Unit	**Value**	**Reference/comment**
Capacity	MW$_{CH3OH,\ LHV}$	1368	
Inputs			
GH_2	MJ/MJ$_{CH3OH,\ LHV}$	1.161	
CO_2	MJ/MJ$_{CH3OH,\ LHV}$	0.0702	
Electricity	MJ/MJ$_{CH3IH,\ LHV}$	0.0499	
Outputs			
Methanol	MJ	1.000	
Heat (T = 250-300°C)	MJ/MJ$_{CH3OH,\ LHV}$	0.0720	
Economic data			
CAPEX 2020/2030/2050	€/kW$_{CH3OH,\ LHV}$	768/672/500	[IEA 2019d] (854/747/555 US$/kW$_{CH3OH,\ LHV}$)
	million €	1051/920/684	
Lifetime	yr	30	[IEA 2019d]
Fixed O&M		3% of CAPEX/yr	[IEA 2019d]
Variable O&M	€/GWh$_{CH3OH,\ LHV}$	1593	[IEA 2019d] (1770 US$/GWh$_{CH3OH,\ LHV}$)

The methanol is transported to a depot over a distance of 150 km via pipeline and from there distributed to the consumers e. g. a methanol fueled ferries via truck over a distance of 150 km.

Table 84 shows the technical and economic assumptions for the transport of methanol via pipeline. A pipeline for the transport of ethanol, gasoline, kerosene, and diesel has been used as proxy.

Table 84: Techno-economic data for the transport of methanol via pipeline

	Unit	Value	Reference/comment
Throughput	GWh_{LHV}/yr	5543	
Length	km	150	
Pipeline diameter	inch	16	[Appert & Favennic 2007]
	mm	406.4	
CAPEX			
Pipes, valves, piping equipment, installation cost	€/(inch*m)	5	[Appert & Favennic 2007]
Acquisition of right-of-way, compensation, reimbursement of damage, surveys and control	€/m	15	[Appert & Favennic 2007]
Total	€/m	95	
	million €	14.3	

Table 85 shows the techno-economic data for the transport of methanol via truck.

Table 85: Techno-economic data for the transport of methanol via truck

	Unit	Value	Reference/comment
Distance	km	150	
Payload	t	27	
	GJ methanol	538	
Fuel consumption	MJ/(kg fuel*km)	0.000834	[Sphera 2021]
	l diesel/100 km	31	
Average speed	km/h	50	
Operating time	d/yr	240	
Number of roundtrips per day		1	
Loading/unloading	h/d	1.5	
Tractor truck			
CAPEX	€	102,300	lastauto omnibus 2016
Lifetime	km	1,000,000	
Fixed O&M	€/yr	16,213	lastauto omnibus 2016
Variable O&M	€/km	0.1050	LBST & Hinicio 2019
Labour costs driver	€/h	22.4	CGDD 2017
Semitrailer			
CAPEX	€	158,500	lastauto omnibus 2016
Lifetime	yr	15	
Fixed O&M	€/yr	12110	lastauto omnibus 2016
Variable O&M	€/km	0.0471	lastauto omnibus 2016
Total costs of fuel transport	**€/GJ**	**0.91**	

In case of ships bunkering can be carried out at a refuelling station (for small ships), via a bunkering ship, or directly from the truck.

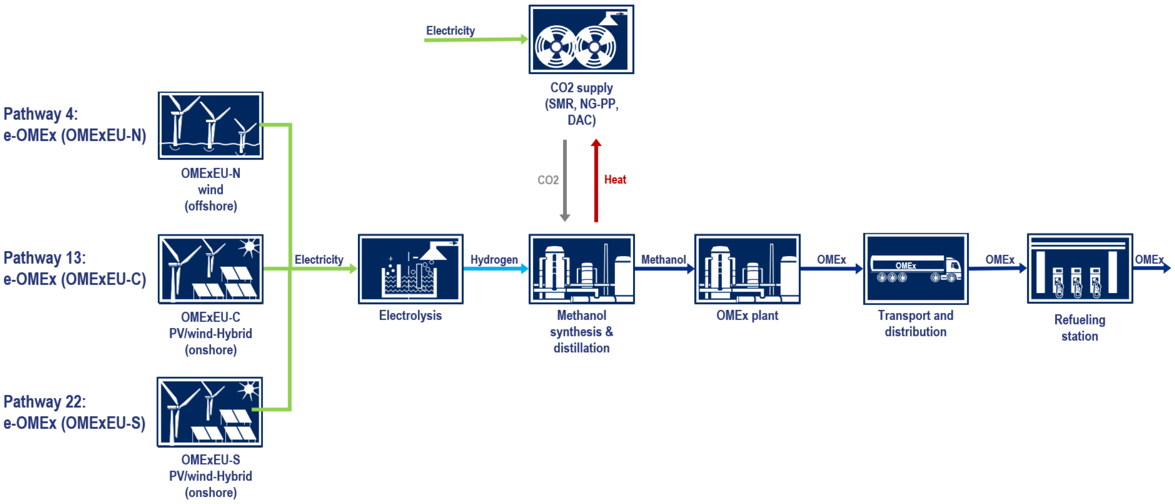
8.4.4. E-OMEx in the EU (OMExEU-N, OMExEU-C, OMExEU-S)

OMEx is produced out of Methanol. The Methanol is synthesized via CO_2 and hydrogen, generated through electrolysis. The resulting heat of the methanol synthesis and distillation process is reused by the CO_2 supply. Carbon dioxide can be supplied either via flue gas from a mix of natural gas and biomass power plants (NG-PP), direct air capture (DAC), or flue gas from steam methane reforming (SMR). After distillation, the methanol is converted to OMEx at an OMEx plant and transported via Trucks to the refuelling stations. At this point the end user can access the e-fuel.

Three variant electricity sources for the electrolysis have been considered:

- Electricity from offshore wind power in North Europe (e. g. in the North Sea at Norway)
- Electricity from PV-/wind-hybrid power stations in Central Europe e. g. Germany)
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain

Figure 118: e-OMEx



The methanol demand and as a result the hydrogen demand of the OME synthesis influences the required capacity of upstream processes and as a result the CAPEX for electrolysis, hydrogen buffer storage (Table 86), CO_2 supply (Table 87), and methanol synthesis (Table 88) compared to the pathway for the supply of methanol as transportation fuel. The equivalent full load period of the methanol and OME synthesis plant is the same as that of the electrolysis plant.

Table 86: H_2 buffer storage with H_2 storage loading compressor for power to methanol for OME production.

	Unit	Value	Reference/comment
Compressor H_2 storage loading			
Capacity	Nm^3/h	702,000	
Suction pressure	MPa	3	
Final pressure	MPa	10	
T (in)	K	313	H_2 leaving electrolyzer
T (intercooling)	K	333	
Efficiency compressor		80%	
Efficiency electric motor		90%	
Number of stages	-	2	
Electricity consumption	kWh/Nm^3	0.0649	
	$kWh/kWh_{H2,\ LHV}$	0.0217	
CAPEX	million €	180	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr	Planet et al. 2014
Lifetime	yr	30	
H_2 storage			
Maximum pressure	MPa	10	
Minimum pressure	MPa	2.5	
Storage capacity	h	50	of full load operation
	million Nm^3	35.1	Net storage capacity
CAPEX	million €	881	Jauslin Stebler 2013
	€/kg_{H2}	279	
Lifetime	yr	30	

Table 87: CO$_2$ supply for a methanol synthesis plant for downstream OME synthesis in Europe

	Unit	Concentrated	Average	Diluted
CO$_2$ source		SMR	Flue gas from power stations	DAC
Capacity	t/h	458	458	458
CO$_2$ capture				
Electricity	MJ/kg CO$_2$	0.14	0.27	1.44
Heat	MJ/kg CO$_2$	0.90	3.00	5.76
CAPEX	million €	235	412	980
Maintenance & repair		2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance		2% of CAPEX/yr		-
Labour	million €/yr	1.92		-
Administration		30% of labour, 40% of maintenance		-
CO$_2$ liquefaction & storage				
Electricity	MJ/kg CO$_2$	0.38*		
CAPEX	million €	72**		
Fixed OPEX CO$_2$ liquefier		10% of CAPEX/yr		
Fixed OPEX of CO$_2$ storage		5% of CAPEX/yr		

* 0.1042 kWh/kg of CO$_2$ at p (in) = ambient pressure; **CO$_2$ liquefaction: 58.9 million €; CO$_2$ storage: 13.5 million € (551 £ or 589 € per t of CO$_2$)

Table 88: Techno-economic data for a methanol synthesis plant for downstream OME synthesis in Europe

	Unit	Value	Reference/comment
Capacity	MW$_{\mathrm{CH3OH,\ LHV}}$	1812	
Inputs			
GH$_2$	MJ/MJ$_{\mathrm{CH3OH,\ LHV}}$	1.161	
CO$_2$	MJ/MJ$_{\mathrm{CH3OH,\ LHV}}$	0.0702	
Electricity	MJ/MJ$_{\mathrm{CH3IH,\ LHV}}$	0.0499	
Outputs			
Methanol	MJ	1.000	
Heat (T = 250-300°C)	MJ/MJ$_{\mathrm{CH3OH,\ LHV}}$	0.0720	
Economic data			
CAPEX 2020/2030/2050	€/kW$_{\mathrm{CH3OH,\ LHV}}$	769/672/500	[IEA 2019d] (854/747/555 US$/kW$_{\mathrm{CH3OH,\ LHV}}$)
	million €	1392/1219/906	
Lifetime	yr	30	[IEA 2019d]
Fixed O&M		3% of CAPEX/yr	[IEA 2019d]
Variable O&M	€/GWh$_{\mathrm{CH3OH,\ LHV}}$	1593	[IEA 2019d] (1770 US$/GWh$_{\mathrm{CH3OH,\ LHV}}$)

OMEx is produced from methanol via formaldehyde, methylal[2], and trioxane[3] as intermediate products. At first, a part of the methanol has to be converted into formaldehyde via partial oxidation. A part of formaldehyde is converted to methylal by reaction with methanol. The other part of the formaldehyde stream is converted to trioxane. Then, the methylal and the trioxane is converted to OMEx. Table 89 shows the summarized technoeconomic data for OMEx production from methanol.

Table 89: Techno-economic data for a OME synthesis plant in Europe

	Unit	**Value**	**Reference/comment**
Capacity	$MW_{OMEx,\ LHV}$	1368	
Inputs			
Methanol	$MJ/MJ_{OMEx,\ LHV}$	1.3252	
Electricity	$MJ/MJ_{OMEx,\ LHV}$	0.0000	
Heat	$MJ/MJ_{OMEx,\ LHV}$	0.6727	
Economic data			
CAPEX 2020/2030/2050	€/$kW_{OMEx,\ LHV}$	307/269/200	[IEA 2019d] (341/299/222 US$/$kW_{OMEx,\ LHV}$)
	million €	420/368/273	
Lifetime	yr	30	[IEA 2019d]
Fixed O&M		4.5% of CAPEX/yr	[IEA 2019d]
Variable O&M	€/$GWh_{OMEx,\ LHV}$	1350	[IEA 2019d] (1500 US$/$GWh_{OMEx,\ LHV}$)

The OMEx is transported to a depot over a distance of 150 km via pipeline and from there distributed to the refuelling stations.

For transport of OME the same pipeline data as for the transport of methanol (Table 84 in chapter 8.4.3) have been assumed.

For the transport via truck the different LHV of OME slightly influences the energy related transportation costs (0.95 €/GJ of OME versus 0.91 €/GJ of methanol). The payload is the same.

OME is suggested as fuel for diesel engines. Therefore, it has been assumed that OME is dispensed at refuelling stations like diesel.

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[2] also called dimethoxymethane (IUPAC name), Formal, Dimethylformal (DMFL), Formaldehyde dimethylacetal or Methylene dimethyl ether

[3] IUPAC name: 1,3,5-Trioxane

Table 90: Techno-economic data for an OME refueling station

	Unit	Value	Reference/comment
Fuel output	million l_{OME}/year	6.30*	[UBG 2020]
	GWh_{LHV}/yr	36	
Electricity consumption	$MJ/MJ_{OME,\ LHV}$	0.0034	[JEC 2020]
CAPEX	million €	1.7	[Gau-Algesheim 2020]
Lifetime	yr	15	
Discount rate		8%	Base case
Capital costs	€/yr	199,000	
O&M	€/yr	22,000*	[eFinancialModels 2021]; [HRSAM 2021]
Electricity	€/yr	30,000	
Total	€/yr	251,000	
	€/$GJ_{OME,\ LHV}$	2.0	
	€/$l_{diesel\ equivalent}$	0.070	

*3 dispensers, 2 hoses per dispenser, assumption: 6 refuellings/(hose*h), 12 h/d, 365 d/yr, 40 l/refuelling; **Maintenance: 5000 US$ for a gasoline refuelling station with a capex of 1.8 million US$ (equipment: 300,000 €; building: 1.5 million US$) [eFinancialModels 2021]; Insurance: 1% of CAPEX/yr [HRSAM 2021]

The electricity for the refuelling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

8.4.5. E-Gasoline and e-kerosene via methanol-to-gasoline in the EU (MTGEU-N, MTG-C, MTG-S, MTKEU-N, MTKEU-C, MTKEU-S)

The generation of e-gasoline or e-kerosene both start with the production of hydrogen via electrolysis. The hydrogen is together with CO_2, used to synthesis Methanol. At that process heat results as a by-product and is reused in the CO_2 supply. The carbon dioxide can be supplied through various procedures, either a mix of natural gas and biomass power plants (NG-PP), direct air capture (DAC), or flue gas from steam methane reforming (SMR) plants. After the Methanol is distilled, it can be converted into Gasoline or Kerosene via the methanol-to-gasoline (MTG) process. Transportation and distribution are executed via trucks. The Gasoline is delivered to refuelling stations where it is used to fuel road vehicles. The Kerosine is brought to storages at airports where it can be dispensed to airplanes.

For these processes three variant electricity sources for the electrolysis have been considered:

- Electricity from offshore wind power in North Europe (e. g. in the North Sea at Norway)
- Electricity from PV-/wind-hybrid power stations in Central Europe e. g. Germany)
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain

Figure 119: e-Gasoline

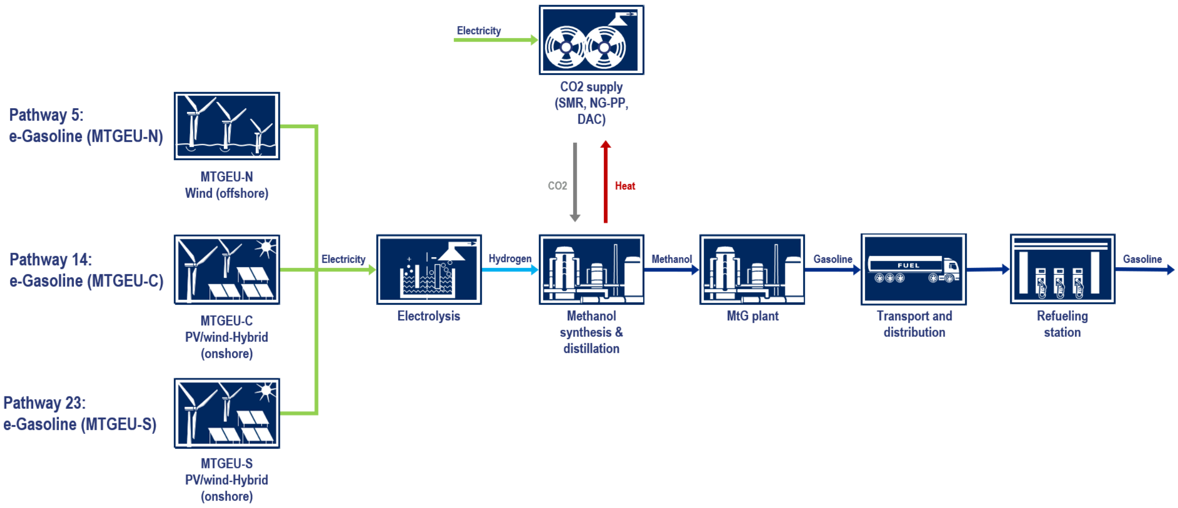
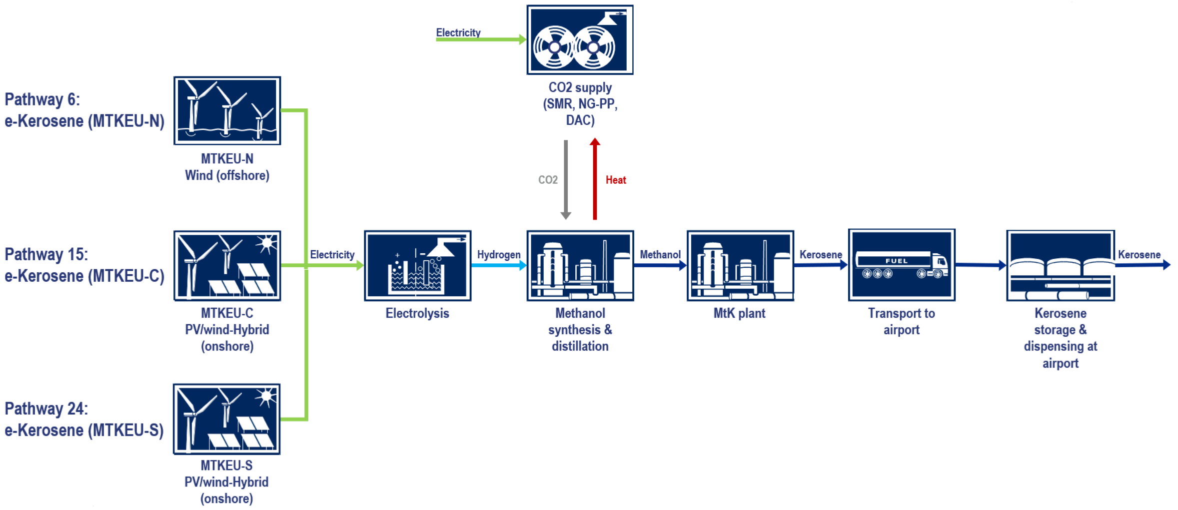


Figure 120: e-kerosene



The methanol demand of the methanol-to-gasoline process and as a result the hydrogen demand for methanol synthesis influences the required capacity of upstream processes and as a result the CAPEX for electrolysis, hydrogen buffer storage (Table 91), CO_2 supply (Table 92), and methanol synthesis (Table 93) compared to the pathway for the supply of methanol as transportation fuel. In the base case, the equivalent full load period for the methanol synthesis plant, the MTG plant, and the MTK plant is the same as that of the electrolysis plant.

Table 91: H_2 buffer storage with H_2 storage loading compressor for power to methanol for gasoline production in Europe.

	Unit	**e-gasoline**	**e-kerosene**	**Reference/ comment**
Compressor H_2 storage loading				
Capacity	Nm^3/h	561,000	566,000	
Suction pressure	MPa	3	3	
Final pressure	MPa	10	10	
T (in)	K	313	313	H_2 leaving electrolyzer
T (intercooling)	K	333	333	
Efficiency compressor		80%	80%	
Efficiency electric motor		90%	90%	
Number of stages	-	2	2	
Electricity consumption	kWh/Nm^3	0.0649	0.0649	
	$kWh/kWh_{H2,\ LHV}$	0.0217	0.0217	
CAPEX	million €	144	146	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr	3% of CAPEX/yr	Planet et al. 2014
Lifetime	yr	30	30	
H_2 storage				
Maximum pressure	MPa	10	10	
Minimum pressure	MPa	2.5	2.5	
Storage capacity	h	50	50	of full load operation
	million Nm^3	28.0	28.3	Net storage capacity
CAPEX	million €	704	711	Jauslin Stebler 2013
	€/kg_{H2}	279	279	
Lifetime	yr	30	30	

Table 92: CO_2 supply for a methanol synthesis plant for MTG and MTK in Europe

	Unit	Concentrated	Average	Diluted
CO_2 source		SMR	Flue gas from power stations	DAC
Capacity	t/h	365/362	365/362	365/362
CO_2 capture				
Electricity	MJ/kg CO_2	0.14	0.27	1.44
Heat	MJ/kg CO_2	0.90	3.00	5.76
CAPEX	million €	139/138	352/350	825/820
Maintenance & repair		2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance		2% of CAPEX/yr		-
Labour	million €/yr	1.80		-
Administration		30% of labour, 40% of maintenance		-
CO_2 liquefaction & storage				
Electricity	MJ/kg CO_2	0.38*		
CAPEX	million €	61**		
Fixed OPEX CO_2 liquefier		10% of CAPEX/yr		
Fixed OPEX of CO_2 storage		5% of CAPEX/yr		

* 0.1042 kWh/kg of CO_2 at p (in) = ambient pressure; **CO_2 liquefaction: 50.2 million €; CO_2 storage: 10.7 million € (551 £ or 589 € per t of CO_2)

Table 93: Techno-economic data for a methanol synthesis plant for downstream MTG and MTK process in Europe

	Unit	For MTG	For MTK	Reference/comment
Capacity	$MW_{CH3OH,\ LHV}$	1444	1444	
Inputs				
GH_2	$MJ/MJ_{CH3OH,\ LHV}$	1.161	1.161	
CO_2	$MJ/MJ_{CH3OH,\ LHV}$	0.0702	0.0702	
Electricity	$MJ/MJ_{CH3IH,\ LHV}$	0.0499	0.0499	
Outputs				
Methanol	MJ	1.000	1.000	
Heat (T = 250-300°C)	$MJ/MJ_{CH3OH,\ LHV}$	0.0720	0.0720	
Economic data				
CAPEX 2020/2030/ 2050	$€/kW_{CH3OH,\ LHV}$	769/672/500	769/672/500	[IEA 2019d] (854/747/555 $US\$/kW_{CH3OH,\ LHV}$)
	million €	1110/971/722	1101/964/717	
Lifetime	yr	30	30	[IEA 2019d]
Fixed O&M		3% of CAPEX/yr	3% of CAPEX/yr	[IEA 2019d]
Variable O&M	$€/GWh_{CH3OH,\ LHV}$	1593	1593	[IEA 2019d] (1770 $US\$/GWh_{CH3OH,\ LHV}$)

The methanol is converted to gasoline or kerosene via a methanol-to-gasoline (MTG) or methanol-to-kerosene (MTK) process. The MTG or MTK process consists of DME synthesis, olefin syntheses, oligomerization, and hydrotreating.

Table 94: Techno-economic data for a MTG and MTK synthesis plant in Europe

	Unit	**e-gasoline**	**e-kerosene**	**Reference/comment**
Capacity	$MW_{gasoline,\ LHV}$	1368	1368	
Inputs				
Methanol	$MJ/MJ_{gasoline,\ LHV}$	1.0562	1.0482	
Hydrogen	$MJ/MJ_{gasoline,\ LHV}$	0.0036	0.0240	
Electricity	$MJ/MJ_{gasoline,\ LHV}$	0.0164	0.0163	
Outputs				
Gasoline	MJ	1	1	
Heat	$MJ/MJ_{final\ fuel,\ LHV}$	0.0300	0.0298	
Economic data				
CAPEX 2020/2030/ 2050	$€/kW_{final\ fuel,\ LHV}$	307/269/200	307/269/200	[IEA 2019d] (341/299/222 US$/$kW_{final\ fuel,\ LHV}$)
	million €	420/368/273	420/368/273	
Lifetime	yr	30	30	[IEA 2019d]
Fixed O&M		4.5% of CAPEX/yr	4.5% of CAPEX/yr	[IEA 2019d]
Variable O&M	$€/GWh_{final\ fuel,\ LHV}$	1350	1350	[IEA 2019d] (1500 US$/$GWh_{final\ fuel,\ LHV}$)

The gasoline is transported to a depot over a distance of 150 km via pipeline and from there distributed to the refuelling stations. Table 95 shows the techno-economic data for the gasoline refuelling station.

Table 95: Techno-economic data for a gasoline refueling station

	Unit	Value	Reference/comment
Fuel output	million $\text{l}_{\text{gasoliine}}$/year	6.30*	[UBG 2020]
	GWh_{LHV}/yr	56	
Electricity consumption	$\text{MJ/MJ}_{\text{gasoline, LHV}}$	0.0034	[JEC 2020]
CAPEX	million €	1.7	[Gau-Algesheim 2020]
Lifetime	yr	15	
Discount rate		8%	Base case
Capital costs	€/yr	199,000	
O&M	€/yr	22,000*	[eFinancialModels 2021]; [HRSAM 2021]
Electricity	€/yr	30,000	
Total	€/yr	251,000	
	$\text{€/GJ}_{\text{gasoline, LHV}}$	1.3	
	$\text{€/l}_{\text{gasoline}}$	0.043	
	$\text{€/l}_{\text{diesel equivalent}}$	0.047	

*3 dispensers, 2 hoses per dispenser, assumption: 6 refuellings/(hose*h), 12 h/d, 365 d/yr, 40 l/refueling; **Maintenance: 5000 US$ for a gasoline refuelling station with a capex of 1.8 million US$ (equipment: 300,000 €; building: 1.5 million US$) [eFinancialModels 2021]; Insurance: 1% of CAPEX/yr [HRSAM 2021]

The electricity for the refuelling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

The kerosene is transported to a depot over a distance of 150 km via pipeline and from there transported to an airport.

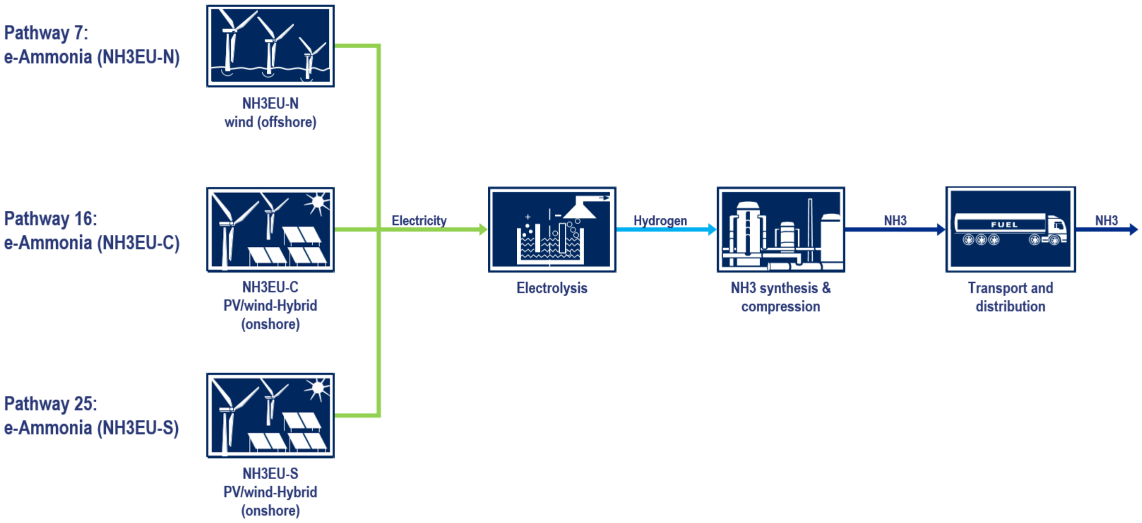
8.4.6. E-Ammonia in the EU (NH3EU-N, NH3EU-C, NH3EU-S)

To generate ammonia, as a first step hydrogen is produced via water electrolysis. It is then synthesised to ammonia, compressed, and stored until it is transported and distributed through trucks to its end use.

For this process three variant electricity sources for the electrolysis have been considered:

- Electricity from offshore wind power in North Europe (e. g. in the North Sea at Norway)
- Electricity from PV-/wind-hybrid power stations in Central Europe e.g. Germany)
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain

Figure 121: e-Ammonia



The capacity of the power-to-ammonia plant amounts to 1368 MW of methane based on the lower heating value (LHV). The hydrogen demand of the downstream ammonia synthesis influences the electricity input of the electrolysis plant. The electricity input into the electrolysis plant amounts to 2344 MW in 2020, 2292 in 2030, and 2078 MW in 2050.

The storage capacity of the buffer storage (Table 96) is assumed to be lower (3 h of full load operation) than that for hydrogen as fuel because the ammonia can be stored more easily than hydrogen and the buffer storage is only used for bridging the low flexibility of the ammonia synthesis.

Table 96: H_2 buffer storage with H_2 storage loading compressor for power-to-ammonia

	Unit	Value	Reference/comment
Compressor H_2 storage loading			
Capacity	Nm^3/h	520,000	
Suction pressure	MPa	3	
Final pressure	MPa	10	
T (in)	K	313	H_2 leaving electrolyzer
T (intercooling)	K	333	
Efficiency compressor		80%	
Efficiency electric motor		90%	
Number of stages	-	2	
Electricity consumption	kWh/Nm^3	0.0649	
	$kWh/kWh_{H2,\ LHV}$	0.0217	
CAPEX	million €	134	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr	Planet et al. 2014
Lifetime	yr	30	
H_2 storage			
Maximum pressure	MPa	10	
Minimum pressure	MPa	2.5	
Storage capacity	h	3	of full load operation
	million Nm^3	1.6	Net storage capacity
CAPEX	million €	19	Jauslin Stebler 2013
	$€/kg_{H2}$	279	
Lifetime	yr	30	

Ammonia is synthesised at a temperature of 450°C and a pressure of 10 to 25 MPa via the following reaction:

$1\ N_2 + 3\ H_2 \rightarrow 2\ NH_3$

The reaction is exothermal.

The techno-economic data of the ammonia synthesis plant in Table 97 include air separation for nitrogen supply.

Table 97: Techno-economic data for an ammonia synthesis plant in Europe

	Unit	**Value**	**Reference/comment**
Capacity	$MW_{NH3,\ LHV}$	1368	
Inputs			
GH2	$MJ/MJ_{NH3,\ LHV}$	1.140	
Electricity	$MJ/MJ_{NH3,\ LHV}$	0.1657	
Outputs			
Ammonia	MJ	1.000	
Heat	$MJ/MJ_{NH3,\ LHV}$	-	Heat not used
Economic data			
CAPEX	million €	801*	DECHEMA 2017
Lifetime	yr	30	
Fixed O&M		3% of CAPEX/yr	

*Upscaled from a 2000 t NH_3/d plant (433 MW NH_3 based on the LHV)

In the base case, the equivalent full load is assumed to be the same as that of the electrolysis plant.

Ammonia becomes liquid at ambient temperature at a pressure of about 0.9 MPa (similar to propane). The pressurized ammonia is transported to the NH_3 ship bunkering terminal via truck over a distance of 300 km. The payload amounts to 21 t.

Table 98 shows the techno-economic data for the transport of ammonia via truck.

Table 98: Techno-economic data for the transport of ammonia via truck

	Unit	Value	Reference/comment
Distance	km	300	
Payload	t	21	
	GJ NH_3	393	
Fuel consumption	MJ/(kg fuel*km)	0.001072	[Sphera 2021]
	l diesel/100 km	31	
Average speed	km/h	50	
Operating time	d/yr	240	
Number of roundtrips per day		0.5	
Loading/unloading	h/d	1.5	Loading: 1.5 h Unloading: 1.5 h
Tractor truck			
CAPEX	€	102,300	lastauto omnibus 2016
Lifetime	km	1,000,000	
Mileage	km/yr	72,000	
Fixed O&M	€/yr	16,213	lastauto omnibus 2016
Variable O&M	€/km	0.1050	LBST & Hinicio 2019
Labour costs driver	€/h	22.4	CGDD 2017
Semitrailer			
CAPEX	€	198,000	IEA G20 2019
Lifetime	yr	15	
Fixed O&M	€/yr	12110	lastauto omnibus 2016
Variable O&M	€/km	0.0471	lastauto omnibus 2016
Total costs of fuel transport	**€/GJ**	**2.16**	

According to an international shipping company, storage tanks and pumping systems for NH_3 barges for NH_3 bunkering may be lower in cost than for LNG barges. However, NH_3 safety features may add costs to bunkering and receiving vessels that most probably result in bunkering and dispensing costs somewhere between HFO and LNG.

According to [Nordic Innovation 2021] the cost of handling a toxic fuel depends on both toxicity and flammability/explosiveness, and the measures to mitigate both. In the case of NH_3, the toxicity risks are higher than for many other fuel options, but the flammability risks are lower, so that the overall costs are expected to be manageable. While liquid fuels such as methanol and marine gas oil (MGO) may be cheaper to handle, ammonia's handling costs should not differ from those of other gaseous fuels, such as liquefied natural gas (LNG), once first-of-a-kind technology deviations have been overcome.

The bunkering of ammonia is theoretically possible in parallel with cargo loading/unloading operation. But this must be authorized by the port authority. If not, this will end up in additional time in the port that is definitely a cost for the ship [Alfa Laval et al. 2020].

As a result, above quotes indicate that the cost of NH_3 bunkering/dispensing are higher than those of HFO, likely closer to that of gaseous fuels (such as LNG), possibly also higher than LNG if established safety practices in ports during loading and unloading are not eased.

In the following an estimation of the costs has been carried out. An ammonia bunkering technology company and its project partners receives public funding for an ammonia bunkering terminal of about 8.6 million € for the refuelling of NH_3 carriers [Yara 2021]. Typically, public funding amounts to about 50% of the total investment leading to a CAPEX of 17.2 million € for the ammonia bunkering terminal.

In [de Vries 2019] various concepts for NH_3 fuelled NH_3 carriers are described. The largest one has a NH_3 transport capacity of 50,184 t and a fuel tank with 3516 t of NH_3. It has been assumed that at the bunkering facility 3164 t of NH_3 is dispensed to the ship (90% of the fuel tank capacity). In [DNV 2021] 91 ship bunkering procedures have been assumed per year. As a result, 287,960 t of NH_3 are dispensed per year or 1496 GWh of NH_3 per year based on the LHV.

If the lifetime of the NH_3 bunkering facility were assumed to be 15 years, the discount rate 8%, and the OPEX were assumed to be 5% of the CAPEX per year the specific costs of NH_3 bunkering would amount to about 0.39 €/GJ of NH_3 or 0.014 € per l of diesel equivalent or about 17 € per t of LSMGO equivalent.

8.4.7. E-Kerosene and e-diesel via Fischer-Tropsch route in the EU (FTKEU-N, FTKEU-C, FTKEU-S, FTDEU-N, FTDEU-C, FTDEU-S

To generate e-kerosene and e-diesel initially there is hydrogen needed. This is produced via water electrolysis and then synthesised with carbon dioxide to e-crude through the Fischer-Tropsch process. The carbon dioxide can be supplied through various procedures, either a mix of natural gas and biomass power plants (NG-PP), direct air capture (DAC), or flue gas from steam methane reforming (SMR) plants. The heat used for these processes is the by-product of the Fischer-Tropsch synthesis. The e-crude is converted into kerosene or diesel and then transported via truck to their respective destination. For kerosene this is the airport where it is stored and dispensed. Diesel is distributed to refuelling stations where it is utilized to fuel road vehicles.

For these processes three variant electricity sources for the electrolysis have been considered:

- Electricity from offshore wind power in North Europe (e. g. in the North Sea at Norway)
- Electricity from PV-/wind-hybrid power stations in Central Europe e. g. Germany)
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain

Figure 122: e-Kerosene via Fischer-Tropsch route

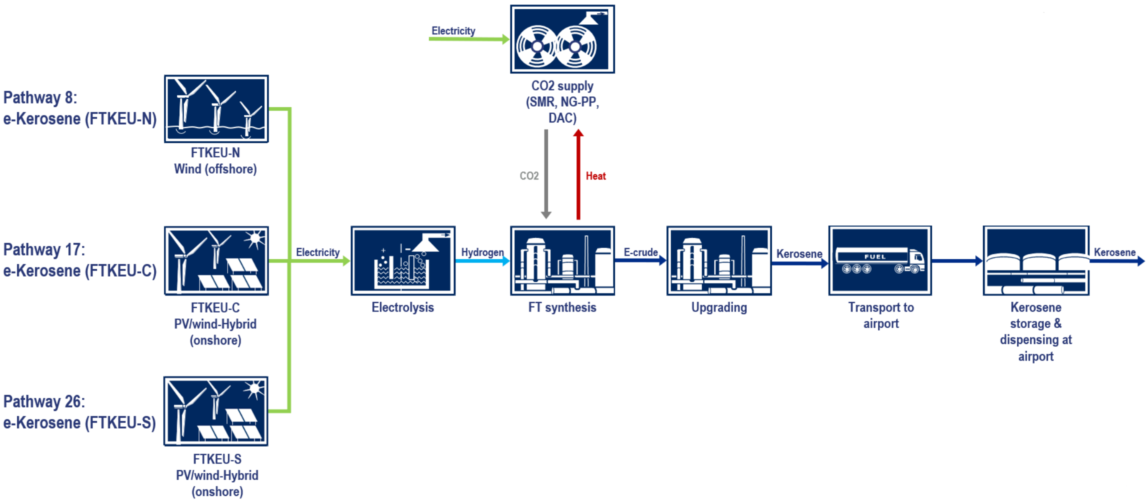
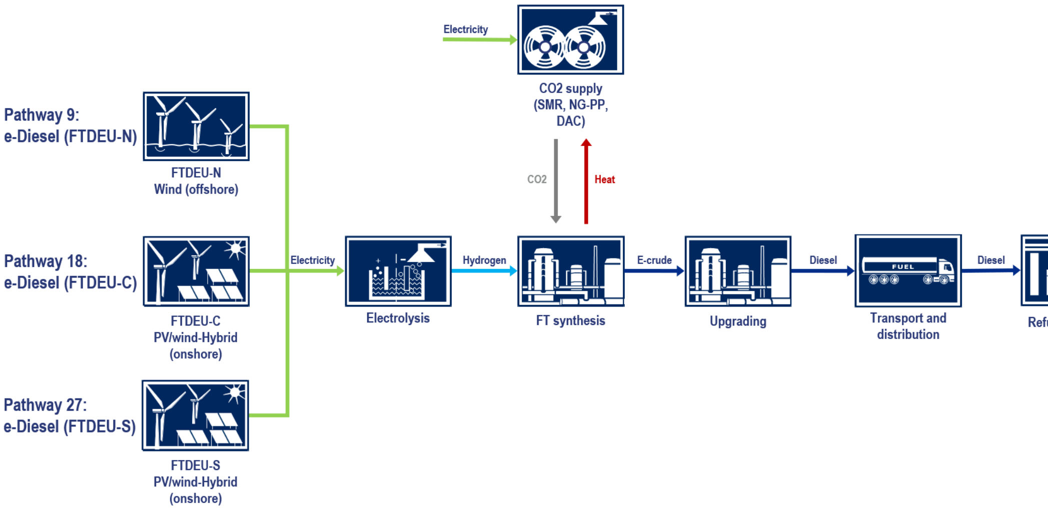


Figure 123: e-Diesel via Fischer-Tropsch route



The capacity of the power-to-liquid plant amounts to 1368 MW of diesel or kerosene based on the lower heating value (LHV). The electricity input into the electrolysis plant amounts to 2887 MW in 2020, 2823 in 2030, and 2559 in 2050.

The Fischer-Tropsch (FT) synthesis plant is less flexible than the methanation plant. Therefore, the capacity of the H_2 storage is assumed to be 50 h of full load operation. Table 99 shows the techno-economic data for H_2 buffer storage including H_2 storage loading compressor for the FT plant. The role H_2 buffer storage is to bridge rapid fluctuations of the electrolysis plant because the FT plant cannot follow the fluctuating electricity supply as fast as the electrolysis plant. In the base case, the equivalent full load period of the FT plant is assumed to be the same as that of the electrolysis plant. The equivalent full load period depends on the electricity source connected with the electrolysis plant and as a result from the region where the e-fuel plant is located.

Table 99: H_2 buffer storage with H_2 storage loading compressor for FT plant.

	Unit	Value	Reference/comment
Compressor H_2 storage loading			
Capacity	Nm^3/h	640,000	
Suction pressure	MPa	3	
Final pressure	MPa	10	
T (in)	K	313	H_2 leaving electrolyzer
T (intercooling)	K	333	
Efficiency compressor		80%	
Efficiency electric motor		90%	
Number of stages	-	2	
Electricity consumption	kWh/Nm^3	0.0649	
	$kWh/kWh_{H2,\ LHV}$	0.0217	
CAPEX	million €	165	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr	Planet et al. 2014
Lifetime	yr	30	
H_2 storage			
Maximum pressure	MPa	10	
Minimum pressure	MPa	2.5	
Storage capacity	h	50	of full load operation
	million Nm^3	32.0	Net storage capacity
CAPEX	million €	804	Jauslin Stebler 2013
	$€/kg_{H2}$	279	
Lifetime	yr	30	

Table 100 shows the techno-economic data for the CO_2 supply for a FT synthesis plant with a capacity of 1368 MW of liquid FT products.

Table 100: CO_2 supply for a FT plant in Europe

	Unit	**Concentrated**	**Average**	**Diluted**
CO_2 source		SMR	Flue gas from power stations	DAC
Capacity	t/h	433	433	433
CO_2 capture				
Electricity	MJ/kg CO_2	0.14	0.27	1.44
Heat	MJ/kg CO_2	0.90	3.00	5.76
CAPEX	million €	156	396	940
Maintenance & repair		2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance		2% of CAPEX/yr		-
Labour	million €/yr	1.92		-
Administration		30% of labour, 40% of maintenance		-
CO_2 liquefaction & storage				
Electricity	MJ/kg CO_2	0.38*		
CAPEX	million €	69**		
Fixed OPEX CO_2 liquefier		10% of CAPEX/yr		
Fixed OPEX of CO_2 storage		5% of CAPEX/yr		

* 0.1042 kWh/kg of CO_2 at p (in) = ambient pressure; **CO_2 liquefaction: 56.6 million €; CO_2 storage: 12.8 million € (551 £ or 589 € per t of CO_2)

For FT synthesis CO is required. Therefore, a reverse water gas shift (RWGS) is required if the CO is derived from CO_2. The following reactions occur:

RWGS: $n\,CO_2 + n\,H_2 \rightarrow n\,CO + n\,H_2O$

FT synthesis: $n\,CO + 2n\,H_2 \rightarrow (CH_2)_n + n\,H_2O$

The reaction proceeds exothermal.

FT synthesis can be classified into high temperature FT syntheses and low temperature FT synthesis. Low temperature FT synthesis is carried out at temperature of 225°C and a pressure of 2.5 MPa [König et al. 8/2015]. In this study low temperature FT synthesis is assumed.

To maximize the share of liquid FT products the FT synthesis is operated in a way that to get a high hydrocarbon chain growth probability (α) leading to long-chain hydrocarbons (long-chain paraffins or waxes) are formed.

Application of a low temperature FT synthesis and a cobalt-based catalyst leads to α of up to 95%. Furthermore, mainly linear alkanes are formed [König et al. 8/2015]. In case of the Shell Middle Distillate Synthesis (SMDS) process described in [Eilers et al. 1990] mainly linear heavy paraffins are formed at the FT synthesis stage. In a second step the heavy paraffins are cracked into the desired products gasoline, kerosene, and diesel. In [Eilers et al. 1990] this process is called 'heavy paraffin conversion' (HPC).

The CAPEX for the FT plant has been derived from [Becker et al. 2012], [König et al. 7/2015], and [Concawe 2021] via upscaling using different scaling exponents for different components. Furthermore, the cost data have been adjusted to 2019 values via the Chemical Engineering Plant Cost Index (CEPCI).

Table 101: CAPEX for a FT synthesis plant including RWGS with a capacity of 27.8 MW FT products (LHV) described in [Becker et al. 2012] and [König et al. 7/2015]*

	CAPEX (million US$$_{2009}$)	**CAPEX (million €$_{2019}$)**	**Scale factor**
Burner	4.99	5.19	1.00
FT reactor	3.11	3.23	1.00
RWGS	3.59	3.74	0.65
PSA	1.34	1.39	0.70
Distillation	0.47	0.49	0.70
Wax hydrocracker	4.31	4.48	0.70
Distillate hydrotreater	2.41	2.50	0.70
Naphtha hydrotreater	0.66	0.69	0.70
Catalytic reformer/platformer	3.55	3.69	0.70
C5/C6 isomerisation	0.59	0.61	0.70
Total installed cost	25.02	26.01	-
Total direct cost	**28.03**	**29.13**	**-**
Engineering & design	3.64	3.79	-
Construction	3.92	4.08	-
Legal and contractor fees	2.52	2.62	-
Project contingency	4.20	4.37	-
Total indirect costs	**14.29**	**14.86**	**-**
Total CAPEX	**42.32**	**43.99**	**-**

* Scaling factor for FT reactor and CAPEX for RWGS from [König et al. 7/2015]

In [Becker et al. 2012] the distillate and naphtha hydrotreater probably is used to remove double bonds. In this study the CAPEX for the wax hydrocracker has been replaced by a hydrocracker from [Concawe 2021] which includes fractionation and is scaled linearly. The distillation, the distillate hydrotreater, the naphtha hydrotreater, the catalytic reformer/platformer, and the C_5/C_6 isomerisation has been removed for the FT plant for kerosene and diesel production (see grey-marked rows in Table 101). Upscaling of the remaining process leads to the CAPEX shown in Table 102.

Table 102: Techno-economic data for a FT synthesis plant including RWGS in Europe (base case)

	Unit	**Value**	**Reference/comment**
Capacity	$MW_{FT\ products,\ LHV}$	1368	1 million t of diesel equivalent per year
Inputs			
GH_2	$MJ/MJ_{FT\ products,\ LHV}$	1.4036	
CO_2	$kg/MJ_{FT\ products,\ LHV}$	0.0880	
Electricity	$MJ/MJ_{CFT\ products,\ LHV}$	0.0441	
Outputs			
FT products	MJ	1	
Heat (T = 225°C)	$MJ/MJ_{CFT\ products,\ LHV}$	0.2139	
CAPEX			
Burner	million €	255	[Becker et al. 2012]
FT reactor	million €	159	[Becker et al. 2012], [König et al. 7/2015]
RWGS	million €	47	
PSA	million €	21	[Becker et al. 2012]
Hydrocracker, recycle	million €	408	[Concawe 2021]
Total installed cost	million €	891	
Total direct cost	**million €**	**997**	Total installed cost *1.12
Engineering & design	million €	130	13% of total direct cost
Construction	million €	140	14% of total direct cost
Legal and contractor fees	million €	90	9% of total direct cost
Project contingency	million €	150	15% of total direct cost
Total indirect costs	**million €**	**509**	
Total CAPEX	**million €**	**1506**	
	$€/kW_{final\ fuel}$	**1101**	
Lifetime	yr	30	
Fixed O&M	million €/yr	73.9	
Variable O&M	$€/GJ_{FT\ products,\ LHV}$	1.53	6120 US$/$GWh_{FT\ products}$

For sensitivity analysis variants with smaller (capacity: 0.2 million t of diesel equivalent per yr) and larger (capacity: 4 million t of diesel equivalent per yr) e-fuel plants have been calculated. The change of capacity influences the CAPEX of the CO_2 supply and the FT plant per unit of final fuel (e. g. $€/kW_{final\ fuel}$). The CAPEX of the electrolysis plant per unit of final fuel does not change (the CAPEX for the electrolysis plant is scaled linearly).

The diesel is transported to a depot over a distance of 150 km via pipeline and from there distributed to the refuelling stations. The kerosene is transported to a depot over a distance of 150 km via pipeline and from there transported to an airport.

Table 103 shows the techno-economic data for the diesel refuelling station.

Table 103: Techno-economic data for a diesel refueling station

	Unit	**Value**	**Reference/comment**
Fuel output	million l_{diesel}/year	6.30*	[UBG 2020]
	GWh_{LHV}/yr	63	
Electricity consumption	MJ/$MJ_{diesel, LHV}$	0.0034	[JEC 2020]
CAPEX	million €	1.7	[Gau-Algesheim 2020]
Lifetime	yr	15	
Discount rate		8%	Base case
Capital costs	€/yr	199,000	
O&M	€/yr	22,000*	[eFinancialModels 2021]; [HRSAM 2021]
Electricity	€/yr	30,000	
Total	€/yr	251,000	
	€/$GJ_{diesel, LHV}$	1.2	
	€/l_{diesel}	0.043	

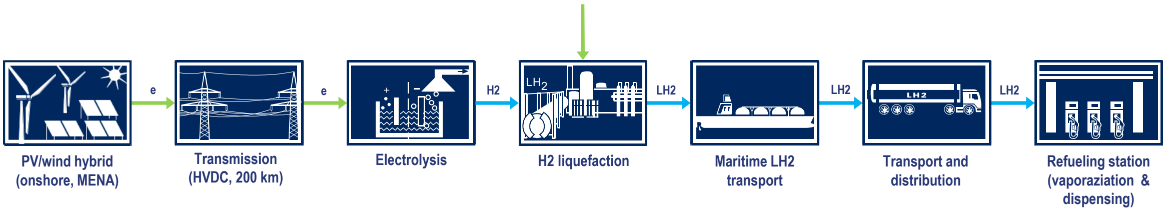
*3 dispensers, 2 hoses per dispenser, assumption: 6 refuellings/(hose*h), 12 h/d, 365 d/yr, 40 l/refuelling; **Maintenance: 5000 US$ for a gasoline refuelling station with a capex of 1.8 million US$ (equipment: 300,000 €; building: 1.5 million US$) [eFinancialModels 2021]; Insurance: 1% of CAPEX/yr [HRSAM 2021]

The electricity for the refuelling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

8.4.8. E-Hydrogen (liquid) from MENA via ship (H2ME-Liq)

Electricity from PV-/wind-hybrid power stations in MENA e. g. in the Kingdome of Saudi-Arabia (KSA). The electricity is transported via a high voltage direct current (HVDC) transmission line to the coast where the power-to-hydrogen plant is located. Hydrogen is generated through water electrolyses. It is then liquefied to be able to store larger quantities at once. The hydrogen is transported first via ship to South Europe e. g. Spain and after that further distributed to the refuelling stations via truck. At its destination, the liquid hydrogen is vaporized so it can be dispensed to road vehicles with 70 MPa vehicle tanks.

Figure 124: Liquefied e-hydrogen



At least a part of the hydrogen is required for propulsion of the LH_2 carrier. Furthermore, there is some hydrogen loss at the hydrogen liquefier. Therefore, the hydrogen production capacity and the rated power input into the electrolyser for the same output of final fuel delivered to Europe per hour (set to a capacity of 1 million t of diesel equivalent per year or 1368 MW of final fuel for all pathways[4]) is higher than for hydrogen generated in Europe. The capacity of the power-to-hydrogen plant in MENA amounts to 1474 MW of hydrogen based on the lower heating value (LHV). The electricity input into the electrolysis plant amounts to 2216 MW in 2020, 2168 in 2030, and 2029 MW in 2050. Due to the higher equivalent full load period in KSA the annual amount of final fuel is also higher than in case of hydrogen produced in Spain.

A hydrogen buffer storage has been assumed to compensate fluctuations of the renewable electricity supply and the lower capability of the hydrogen liquefaction plant to follow fluctuating hydrogen supply. A hydrogen storage loading compressor is required to elevate the pressure of the hydrogen leaving the electrolysis plant to 10 MPa which is the maximum pressure of the hydrogen buffer storage. Similar as for hydrogen generated in Europe a buffer storage consisting of underground steel-made tubes with a diameter of 1485 mm has been assumed.

In the base case, the equivalent full load period of the hydrogen liquefaction plant is assumed to be the same as that of the electrolysis plant. The equivalent full load period depends on the electricity source connected with the electrolysis plant and as a result from the region where the e-fuel plant is located.

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[4] 1 million t * 43.13/3.6 MWh/t/(8760 h) = 1368 MW of final fuel

Table 104 shows the techno-economic data for the hydrogen buffer storage including hydrogen storage loading compressor.

Table 104: H_2 buffer storage with H_2 storage loading compressor in MENA for the supply of CGH_2 as transportation fuel in the EU

	Unit	**2020/2030**	**2050**	**Reference/comment**
Compressor H_2 storage loading				
Capacity	Nm^3/h	491,000	507,000	
Suction pressure	MPa	3	3	
Final pressure	MPa	10	10	
T (in)	K	313		H_2 leaving electrolyzer
T (intercooling)	K	333	333	
Efficiency compressor		80%	80%	
Efficiency electric motor		90%	90%	
Number of stages	-	2	2	
Electricity consumption	kWh/Nm^3	0.0649	0.0649	
	$kWh/kWh_{H2,\ LHV}$	0.0217	0.0217	
CAPEX	million €	126	130	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr	3% of CAPEX/yr	Planet et al. 2014
Lifetime	yr	30	30	
H_2 storage				
Maximum pressure	MPa	10	10	
Minimum pressure	MPa	2.5	2.5	
Storage capacity	h	50	50	of full load operation
	million Nm^3	24.6	25.4	Net storage capacity
CAPEX	million €	617	637	Jauslin Stebler 2013
	€/kg_{H2}	279	279	
Lifetime	yr	30	30	

For time horizon 2050 a slightly higher capacity is required because the LH_2 carrier is fuelled with 100% H_2.

Table 105 shows the techno-economic data for the hydrogen liquefaction plant. The CAPEX of a hydrogen liquefaction plant with a capacity of 50 t per day amounts to about 105 million €. The maximum capacity of the cold box is 200 t per day [Haberstroh 2019]. For a capacity of up to 200 t per day a scaling exponent of 2/3 is applied. For a capacity above 200 t per day (which is the case here) the CAPEX is scaled linearly.

Table 105: Hydrogen liquefaction for the supply of hydrogen as transportation fuel in MENA (KSA)

	Unit	**2020/2030**	**2050**	**Reference/comment**
Capacity	**MW$_{LH2}$**	**1404**	**1449**	
	t LH$_2$/h	42.1	43.5	
	t LH$_2$/d	1011	1043	
Inputs				
Hydrogen	MJ/MJ$_{LH2}$	1.05	1.05	Haberstroh 2019
Electricity	kWh/kgLH2	8.00	8.00	Sphera 2021
	MJ/MJ$_{LH2}$	0.2401	0.2401	
	MJ/MJ$_{final\ fuel}$	0.2464	0.2464	Related to H$_2$ dispensed in the EU
CAPEX	million €	1337	1380	Haberstroh 2019
Lifetime	yr	30	30	Haberstroh 2019
Maintenance & repair		2.5% of CAPEX/yr	2.5% of CAPEX/yr	
Labour	€/(FTE*yr)	60,000	60,000	Amec Foster Wheeler 2017
		34 persons*	34 persons	NHEG 1992
	€/yr	2		

* Scaled from a liquefaction plant with a capacity of about 63 MW of LH$_2$ with a scaling exponent of 0.25 as indicated in [Hamelinck 2004]

For time horizon 2050 a slightly higher capacity is required because the LH$_2$ carrier is fuelled with 100% H$_2$.

The LH$_2$ is transported via ship from KSA to Rotterdam in the Netherlands via the Suez Canal over a distance of about 7350 km.

The maritime LH$_2$ transport includes the export terminal in KSA (Table 106), the LH$_2$ carrier (Table 107), and the import terminal in Europe.

The largest LH$_2$ tanks which are available today have a water volume of 3500 m^3 which has been assumed for 2020. For 2030 and 2050 it has been assumed that larger LH$_2$ tanks with a water volume of 11200 m^3 as planned by Kawasaki [Kawasaki 2020] are available. The uninstalled CAPEX for a LH$_2$ tank with a water volume of 3500 m^3 is indicated with 6.6 million US$ [DOE 2015]. The CAPEX for installation has been assumed to be 30% of the uninstalled CAPEX. For the larger LH$_2$ tank the CAPEX have been calculated using a scaling exponent of 0.7. The 2015 US$ have been converted to 2019 US$ by application of the Chemical Engineering Plant Cost Index and then converted to €. The CAPEX for Jetty and loading arm/equipment has been derived from [Lanphen 2019].

Table 106: Export terminal

	Unit	2020	2030/2050
Number of tanks		40	12
Water volume per tank	m^3	3500	11,200
Water volume total	m^3	140,000	134,400
Filling ratio		0.90	0.90
LH_2 storage capacity total	t	8933	8576
CAPEX			
Jetty	million €	3	3
Loading arm/equipment	million €	1	1
Tanks	million €	334	226
Total	million €	338	230
Lifetime	yr	30	30

Table 107: LH_2 carrier

	Unit	2020/2030	2050	Reference
Water volume LH2 tanks	m^3	140,000	140,000	
Filling ratio		0.85	0.85	EQHHPP 1991
Payload LH_2	t	8437	8437	
Bol-off rate		0.20 %/d	0.20 %/d	Kamiya et al. 2014
Speed	knots	18	18	Hank et al. 2020b
	km/h	33.3	33.3	
Fuel consumption	MJ/(kg H_2*km)	0.001303	0.001303	Hank et al. 2020b
Share boil-off		46%	46%	
Residual fuel		LSMGO	H_2	
CAPEX	million €	440	440	Hank et al. 2020b
Lifetime	yr	30	30	
Crew	million €/yr	0.79	0.79	Deloitte 2011
Maintenance & repair		2% of CAPEX/yr		
Suez Canal tonnage (SCNT)		105,000*	105,000*	LETH 2021
Suez Canal toll				
Laden	€/voyage	562,000	562,000	USMS 2021
Ballast	€/voyage	478,000	478,000	USMS 2021
Total	€/roundtrip	1,040,000	1,040,000	

* Based on a Moss type LNG carrier (spherical tanks), 145,000 m^3, 75,000 dwt

It has to be noted that deadweight tons (DWT) must not mixed up with LH_2 payload. The deadweight of a 133433 m^3 LH_2 carrier amounts to 72,339 t [Ahluwalia et al. 2020]. As a result, the deadweight of the LH_2 carrier in Table 107 amounts to about 76,000 t. The LH_2 payload is about 8400 t.

Suez Canal tonnage (SCNT) is a measure of the volume of the hull of the ship, not only the water volume of the LH_2 tanks. The Suez Canal toll depends on the SCNT [LETH 2021], [USMS 2021]. In [USMS 2021] the Suez Canal toll is indicated for various types of ships in SDR per SCNT (1 SDR = 1.4 US$).

For the import terminal the same assumptions have been applied as for the export terminal (Table 106). From there the LH_2 is transported via truck to the refuelling stations over a distance of 300 km (Table 108).

Table 108: Techno-economic data for the transport of LH_2 via truck

	Unit	Value	Reference/comment
Distance	km	300	
Payload	t	3.5	
	GJ LH_2	420	
Fuel consumption	MJ/(kg fuel*km)	0.006644	Sphera 2021
	l diesel/100 km	32	
Average speed	km/h	50	
Operating time	d/yr	240	
Number of roundtrips per day		0.5	
Loading/unloading	h/d	0.75	
Tractor truck			
CAPEX	€	102,300	lastauto omnibus 2016
Lifetime	km	1,000,000	
Mileage	km/yr	72,000	
Fixed O&M	€/yr	16,213	lastauto omnibus 2016
Variable O&M	€/km	0.1050	LBST & Hinicio 2019
Labour costs driver	€/h	22.4	CGDD 2017
Semitrailer			
CAPEX	€	780,000	[Gardener Cryogenics 1994]; [Schmitz 1998]
Lifetime	yr	15	
Fixed O&M	€/yr	12110	lastauto omnibus 2016
Variable O&M	€/km	0.0471	lastauto omnibus 2016
Total costs of fuel transport	**€/GJ**	**9.27**	

The CAPEX of the semi-trailer has been derived from [Gardener Cryogencs 1994] (LH_2 tank and equipment) and [Schmitz 1998] (chassis). The cost data from 1994 and 1998 have been converted to today's values via the Chemical Engineering Plant Cost Index (CEPCI).

At the refuelling station (Table 127) the LH_2 is compressed via a cryogenic compressor, vaporized, and subsequently dispensed as CGH_2. A CGH_2 buffer storage with a maximum pressure of 100 MPa is also installed. A description of this concept can be found in [Decker 2019].

The CAPEX has been derived from [HRSAM 2021] except dispensers. According to [Parks et al. 2014] the CAPEX for dispenser used in the HRSAM model is too low. On the other hand, two instead of four dispensers are installed is assumed because the refuelling of fuel cell truck is assumed for this study. It has to be noted that the CAPEX indicated for the components of the refuelling station already the installation factors are already included.

Learning curves have been are applied for various components of the refuelling station leading to a decrease of overall costs.

Table 109: LCGH$_2$ refuelling station for CGH_2 dispensing

	Unit	2020	2030	2050
H_2 throughput	GWh/yr	15.7	15.7	15.7
	kg H_2/d	1013	1013	1013
Open days per year		250	250	250
Electricity consumption	MJ/MJ$_{H2, LHV}$	0.0005	0.0005	0.0005
Number of dispensers	-	2	2	2
CAPEX	€			
LH_2 tank	€	286,000	286,000	286,000
Dispensers	€	246,000	194,000	169,000
Electrical supply	€	76,000	76,000	76,000
CGH_2 storage	€	344,000	271,000	237,000
Evaporator	€	116,000	91,000	79,000
High pressure cryogenic pump	€	462,000	363,000	317,000
Balance of plant	€	100,000	100,000	100,000
Initial capital costs	**€**	**1,630,000**	**1,381,000**	**1,264,000**
Site preparation	€	81,000	69,000	63,000
Engineering & design	€	163,000	138,000	126,000
Project contingency	€	81,000	69,000	63,000
Up-front permitting costs	€	49,000	41,000	38,000
Total	€	2,004,000	1,698,000	1,554,000
Operating & maintenance				
Labour	€/yr	80,600*		
Insurance		1% of total CAEX/yr		
Maintenance & repair for high pressure cryogenic pump		4% of total CAPEX/yr		
Maintenance & repair for other components		1% of total CAEX/yr		
Overhead		20% of labour		

*Based on 25 €/h instead of 11 US$/h indicated in [HRSAM 2021]

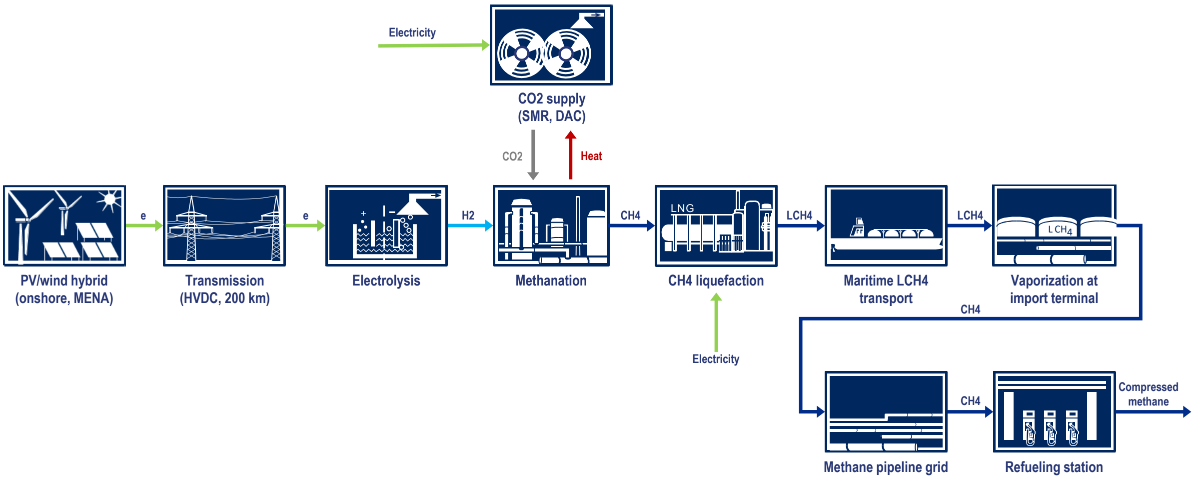
The electricity for the refuelling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

8.4.9. E-Methane from MENA via ship (NGME-Liq)

E-methane is generated via the methanation process, where a chemical reaction converts carbon dioxide and hydrogen to methane. The hydrogen needed for the process is generated via electrolysis. The electricity required in this process is produced through PV-/wind-hybrid power stations. The electricity is transported via a high voltage direct current (HVDC) transmission line to the coast where the power-to-hydrogen plant is located.

The carbon dioxide can be produced by several routes, for example by direct air capture (DAC) or from flue gas from steam methane reforming (SMR). The heat required for these processes is the reused by-product of the methanation. After the methanation process the methane is liquefied so that larger quantities can be stored at once. The liquid methane is then transported via ships. At the import terminal the methane is vaporized again, pressurized and transported through a pipeline grid to refuelling stations. Here compressed methane is dispensed to road vehicles.

Figure 125: e-Methane from MENA via ship



The hydrogen demand of downstream processes such as the methanation step and the boil-off loss during maritime transport of liquefied methane influences the hydrogen production capacity and the rated power input into the electrolyser for the same output of final fuel delivered to Europe per hour (set to a capacity of 1 million t of diesel equivalent per year or 1368 MW of final fuel for all pathways in the base case) is higher than for methane generated in Europe. The electricity input into the electrolysis plant amounts to 2494 MW in 2020, 2410 MW in 2030, and 2228 MW in 2050. Due to the higher equivalent full load period in KSA the annual amount of final fuel is also higher than in case of methane produced in Spain.

The storage capacity of the buffer storage (Table 110) is assumed to be lower (3 h of full load operation) than that for hydrogen as fuel because the methane can be stored more easily than hydrogen due to higher energy density per m^3 of pressure vessel and the buffer storage is only used for bridging the lower flexibility of the methanation process.

In the base case, the equivalent full load period of the methanation plant and the methane liquefaction plant is assumed to be the same as that of the electrolysis plant. The equivalent full load period depends on the electricity source connected with the electrolysis plant and as a result from the region where the e-fuel plant is located.

Table 110: H_2 buffer storage with H_2 storage loading compressor for power-to-methane in MENA and liquefied methane export to Europe

	Unit	2020/2030	2050	Reference/ comment
Compressor H_2 storage loading				
Capacity	Nm^3/h	553,000	557,000	
Suction pressure	MPa	3	3	
Final pressure	MPa	10	10	
T (in)	K	313	313	H_2 leaving electrolyzer
T (intercooling)	K	333	333	
Efficiency compressor		80%	80%	
Efficiency electric motor		90%	90%	
Number of stages	-	2	2	
Electricity consumption	kWh/Nm^3	0.0649	0.0649	
	$kWh/kWh_{H2,\ LHV}$	0.0217	0.0217	
CAPEX	million €	142	143	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr	3% of CAPEX/yr	Planet et al. 2014
Lifetime	yr	30	30	
H_2 storage				
Maximum pressure	MPa	10	10	
Minimum pressure	MPa	2.5	2.5	
Storage capacity	h	3	3	of full load operation
	million Nm^3	1.66	1.67	Net storage capacity
CAPEX	million €	42	42	Jauslin Stebler 2013
	€/kg_{H2}	279	279	
Lifetime	yr	30	30	

For time horizon 2050 the capacity is slightly higher because the LCH_4 carrier is fueled with 100% methane.

Table 111: CO_2 supply for a methanation plant in MENA for 2020/2030/2050

	Unit	**Concentrated**	**Average**	**Diluted**
CO_2 source		SMR	Flue gas from power stations	DAC
Capacity	t/h	299/299/301		
CO_2 capture				
Electricity	MJ/kg CO_2	0.14	0.27	1.44
Heat	MJ/kg CO_2	0.90	3.00	5.76
CAPEX	million €	121	306/306/307	709/709/713
Maintenance & repair		2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance		2% of CAPEX/yr		-
Labour	million €/yr	1.74		-
Administration		30% of labour, 40% of maintenance		-
CO_2 liquefaction & storage				
Electricity	MJ/kg CO_2	0.38*		
CAPEX	million €	44**		
Fixed OPEX CO_2 liquefier		10% of CAPEX/yr		
Fixed OPEX of CO_2 storage		5% of CAPEX/yr		

* 0.1042 kWh/kg of CO_2 at p (in) = ambient pressure; **CO_2 liquefaction: 43.7 million €, 43.9 in 2050; CO_2 storage: 0.5 million € (551 £ or 589 € per t of CO_2)

Table 112: Techno-economic data for a methanation plant in Mena (KSA)

	Unit	**2020/2030**	**2050**	**Reference/comment**
Capacity	$MW_{CH4, LHV}$	1384	1394	
Inputs				
GH2	$MJ/MJ_{CH4, LHV}$	1.198	1.198	
CO_2	$MJ/MJ_{CH4, LHV}$	0.0600	0.0600	
Electricity	$MJ/MJ_{CH4, LHV}$	0.0229	0.0229	
Outputs				
CH4	MJ	1.000	1.000	
Heat (T = 250-300°C)	$MJ/MJ_{CH4, LHV}$	0.072	0.072	
Economic data				
CAPEX	$€/kW_{CH4, LHV}$	792/704	541	[IEA 2019d] (880/782/601 $US\$/kW_{CH4, LHV}$)
	million €	1096/974	755	
Lifetime	yr	30	30	[IEA 2019d]
Fixed O&M		3% of CAPEX/yr	3% of CAPEX/yr	[IEA 2019d]
Variable O&M	$€/GWh_{CH4, LHV}$	320	320	[IEA 2019d] (355 $US\$/GWh_{CH4, LHV}$)

Table 113: CH₄ liquefaction in MENA (KSA)

	Unit	2020/2030	2050	Reference/comment
Capacity	MW_{LCH4}	1384	1394	
	t LCH_4/h	99.6	99.6	
	t LCH_4/d	2390	2390	at full load operation
Inputs				
Methane	MJ/MJ_{LCH4}	1.00	1.00	
Electricity	kWh/kg_{LCH4}	0.342	0.342	Ott et al. 2015
	MJ/MJ_{LCH42}	0.0246	0.0246	
	$MJ/MJ_{final\ fuel}$	0.0249	0.0249	Related to CH_4 dispensed in the EU
CAPEX	million €	527	531	Hank et al. 2020b
Lifetime	yr	30	30	
Maintenance & repair, labour		2.0% of CAPEX/yr	2.0% of CAPEX/yr	Hank et al. 2020b

According to [Eurasian Ventures 2020] the CAPEX for LNG terminals with a 263,000 m^3 LNG storage including re-gasification ranges 200 and 400 million US$. For the export terminal which has no re-gasification unit the lower value (200 million US$) and for the import terminal the average value (300 million US$) has been assumed. The lifetime has been assumed to be 30 years. For the transport of liquefied methane, a Moss type LNG carrier has been assumed (Table 114).

Table 114: LCH$_4$ carrier

	Unit	2020/2030	2050	Reference
Water volume LCH$_4$ tanks	m^3	140,000	140,000	
Filling ratio		0.98	0.98	
Payload LCH$_4$	t	57,624	57,624	
Bol-off rate		0.10 %/d	0.10 %/d	Hank et al. 2020b
Speed	knots	20	20	Hank et al. 2020b
	km/h	37.0	37.0	
Fuel consumption	MJ/(kg CH$_4$*km)	0.0001872	0.0001872	Hank et al. 2020b
Share boil-off		60%	60%	
Residual fuel		LSMGO	CH$_4$	
CAPEX	million €	152	152	Hank et al. 2020b
Lifetime	yr	30	30	
Crew	million €/yr	0.79	0.79	[Deloitte 2011]
Maintenance & repair		3.5% of CAPEX/yr		Hank et al. 2020b
Suez Canal tonnage (SCNT)		105,000*	105,000*	LETH 2021
Suez Canal toll				
Laden	€/voyage	562,000	562,000	USMS 2021
Ballast	€/voyage	478,000	478,000	USMS 2021
Total	€/roundtrip	1,040,000	1,040,000	

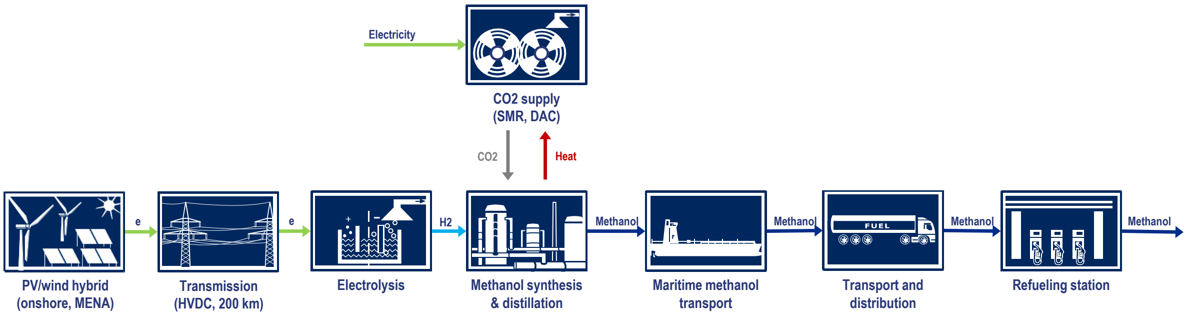
* Based on a Moss type LNG carrier (spherical tanks), 145,000 m^3, 75,000 dwt

At the import terminal the liquefied methane is re-gasified and injected into the natural gas grid. The pipeline grid and the same refuelling stations have been assumed as for e-methane generated in the EU (chapter 8.4.2).

8.4.10. E-Methanol from MENA via ship (MeOHME)

Methanol is produced by the catalytic reaction of carbon dioxide and hydrogen. The hydrogen is generated by water via electrolysis. The electricity required in this process is produced through PV-/wind-hybrid power stations. The required carbon dioxide can be supplied either via direct air capture (DAC) or flue gas from steam methane reforming (SMR). The heat required by the CO$_2$ supply is partly originated as a by-product of the Methanol synthesis and distillation process. After the synthesis and the distillation process the methanol is transported first through ships and then distributed via trucks. The trucks deliver the methanol to refuelling stations, at which the end user can retrieve it.

Figure 126: e-Methanol from MENA via ship



The ship for methanol transport to Europe consumes LSMGO (2020 and 2030) or e-diesel (2050). No methanol loss occurs along the fuel supply chain. Therefore, the same assumptions concerning required capacity can be applied for the hydrogen buffer storage, the CO_2 supply, and the methanol synthesis in MENA as for methanol produced in Europe (chapter 8.4.3).

The techno-economic data for the export terminal in Table 115 haves been derived from [Lanphen 2019]. The number of tanks has been adjusted to the transport capacity of the methanol carrier. A filling ratio of 0.95 has been assumed as indicated for petroleum tanks in [Perdue 2009].

Table 115: Export terminal for methanol transport

	Unit	**2020/2030/2050**
Number of tanks		3
Water volume per tank	m^3	50,000
Water volume total	m^3	150,000
Filling ratio		0.95
Methanol storage capacity total	t	118,950
CAPEX		
Jetty	million €	3
Loading arm/equipment	million €	1
Tanks	million €	105
Total	million €	109
Lifetime	yr	50

Dedicated ships are built for the transport of methanol because the tanks and equipment have to be adapted to methanol (resistant against corrosion). Table 116 shows the techno-economic data of the methanol carrier. The payload for the methanol carrier has been derived Millennium Explorer which is one of the largest methanol carriers been built until now.

Table 116: Methanol carrier

	Unit	2020/2030/2050	Reference
Water volume methanol tanks	m^3	120,000	Wärtsiläe 2021a
Filling ratio		0.95	Perdue 2009
Payload methanol	t	90,402	
Speed	knots	15	Hank et al. 2020b; Wärtsiläe 2021a
	km/h	27.8	
Fuel consumption	MJ/(kg CH_3OH *km)	0.0000605	Sphera 2021
CAPEX	million €	54	Hank et al. 2020b
Lifetime	yr	30	
Crew	million €/yr	0.79	[Deloitte 2011]
Maintenance & repair		3.5% of CAPEX/yr	Hank et al. 2020b
Deadweight tons (DWT)	t	105,715	
Suez Canal tonnage (SCNT)		52,900*	LETH 2021
Suez Canal toll			
Laden	€/voyage	307,000	USMS 2021
Ballast	€/voyage	261,000	USMS 2021
Total	€/roundtrip	568,000	

*For liquid fuel tankers the SCNT is about the half of the deadweight

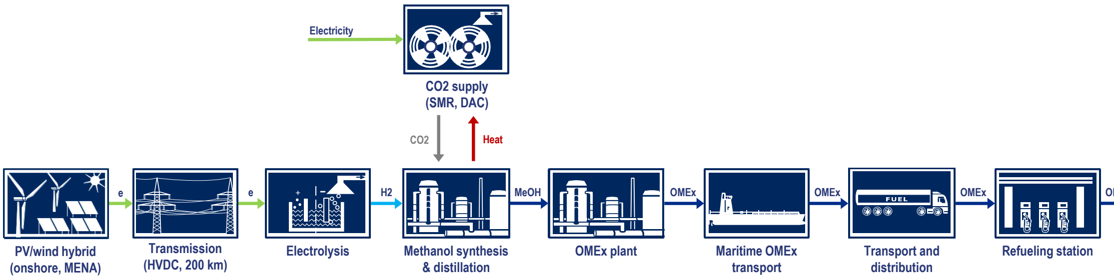
For the import terminal the same techno-economic assumptions have been applied as for the export terminal.

Inside the EU the methanol is distributed to the consumers e. g. ships in the same way as for methanol produced in Europe (chapter 8.4.3).

8.4.11. E-OMEx from MENA via ship (OMExME)

OMEx is produced out of Methanol. The Methanol is synthesized from the products carbon dioxide and hydrogen. The hydrogen is generated by water electrolysis, where the required electricity is produced through PV-/wind-hybrid power stations. The resulting heat of the methanol synthesis and distillation process is reused by the carbon dioxide supply. CO_2 is retrieved either via flue gas from direct air capture (DAC) or flue gas from steam methane reforming (SMR). After distillation, the methanol is converted to OMEx at an OMEx plant and transported firstly via ships and then distributed through trucks to the refuelling stations. At this point the end user can access the e-fuel.

Figure 127: e-OMEx from MENA via ship



The ship for OMEx transport to Europe consumes LSMGO (2020 and 2030) or e-diesel (2050). No OMEx loss occurs along the fuel supply chain. Therefore, the same assumptions concerning required capacity can be applied for the hydrogen buffer storage, the CO_2 supply, the methanol synthesis, and the OMEx synthesis in MENA as for methanol produced in Europe (chapter 8.4.4).

Table 117: Export terminal for OMEx transport

	Unit	**2020/2030/2050**
Number of tanks		3
Water volume per tank	m^3	50,000
Water volume total	m^3	150,000
Filling ratio		0.95
OMEx storage capacity total	t	159,986
CAPEX		
Jetty	million €	3
Loading arm/equipment	million €	1
Tanks	million €	105
Total	million €	109
Lifetime	yr	50

For the transport of OMEx the same ship as for methanol transport has been assumed. Table 118 shows the techno-economic data of the OMEx carrier. The density of OMEx significantly higher than that of methanol. Therefore, a lower filling ratio has been assumed than for methanol to avoid overloading of the ship.

Table 118: OMEx carrier

	Unit	2020/2030/2050	Reference/comment
Water volume OMEx tanks	m^3	120,000	Wärtsiläe 2021a
Filling ratio		0.71	To avoid overloading
Payload methanol	t	90,872	
Speed	knots	15	Hank et al. 2020b; Wärtsiläe 2021a
	km/h	27.8	
Fuel consumption	MJ/(kg OMEx *km)	0.0000604	Sphera 2021
CAPEX	million €	54	Hank et al. 2020
Lifetime	yr	30	
Crew	million €/yr	0.79	[Deloitte 2011]
Maintenance & repair		3.5% of CAPEX/yr	Hank et al. 2020
Deadweight tons (DWT)		105,715	
Suez Canal tonnage (SCNT)		52,900*	LETH 2021
Suez Canal toll			
Laden	€/voyage	307,000	USMS 2021
Ballast	€/voyage	261,000	USMS 2021
Total	€/roundtrip	568,000	

*For liquid fuel tankers the SCNT is about the half of the deadweight

For the import terminal the same techno-economic assumptions have been applied as for the export terminal.

Inside the EU the OMEx is distributed to refuelling stations in the same way as for OMEx produced in Europe (chapter 8.4.4).

8.4.12. E-Gasoline and e-kerosene from MENA via METHANOL-TO-GASOLINE and via ship (MTGME, MTKME)

The generation of e-gasoline or e-kerosene both start with the production of hydrogen via electrolysis. The electricity required in this process is produced through PV-/wind-hybrid power stations. The hydrogen is together with CO_2, used to synthesis Methanol. At that process heat results as a by-product and is reused in the carbon dioxide supply. The carbon dioxide can be supplied through various procedures, either direct air capture (DAC) or flue gas from steam methane reforming (SMR) plants. After the Methanol is distilled, it can be converted into Gasoline or Kerosene via the methanol-to-gasoline (MTG) process. Transportation is executed firstly via ships and then distributed via trucks. The Gasoline is delivered to refuelling stations where it is used to fuel road vehicles. The Kerosine is brought to storages at airports where it can be dispensed to airplanes.

Figure 128: e-Gasoline from MENA via ship

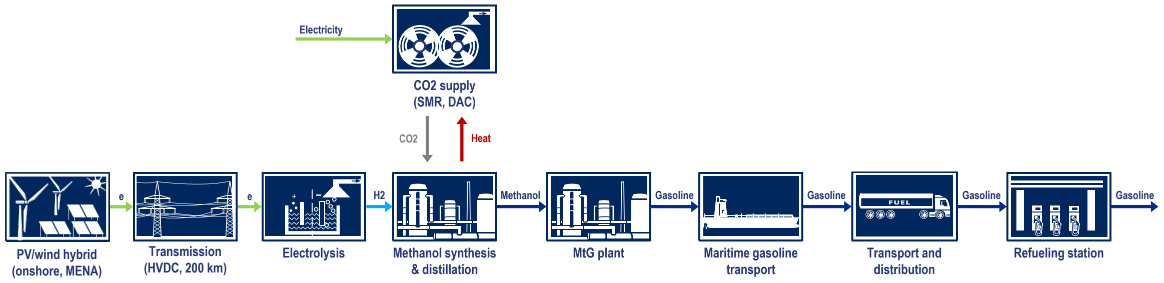
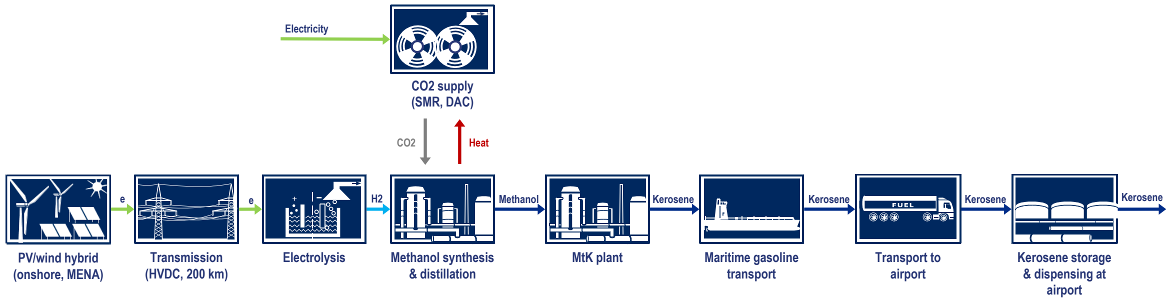


Figure 129: e-Kerosene from MENA via ship



The ship for gasoline and kerosene transport to Europe consumes LSMGO (2020 and 2030) or e-diesel (2050). No gasoline or kerosene loss occurs along the fuel supply chain. Therefore, the same assumptions concerning required capacity can be applied for the hydrogen buffer storage, the CO_2 supply, the methanol synthesis, and the MTG or MTK process in MENA as for gasoline and kerosene produced in Europe (chapter 8.4.5).

Table 119: Export terminal for gasoline and kerosene transport

	Unit	Gasoline	Kerosene
Number of tanks		3	3
Water volume per tank	m^3	50,000	50,000
Water volume total	m^3	150,000	150,000
Filling ratio		0.95	0.95
OMEx storage capacity total	t	111,750	120,000
CAPEX			
Jetty	million €	3	3
Loading arm/equipment	million €	1	1
Tanks	million €	105	105
Total	million €	109	109
Lifetime	yr	50	50

The techno-economic data for the ship for the marine transport of gasoline and kerosene have been derived from [Hank et al. 2020b]. For the transport of crude oil base products like gasoline, kerosene, and diesel product tankers are used. The physical and chemical properties of the e-gasoline and e-kerosene are similar as those for crude oil-based gasoline and kerosene. Therefore, a product tanker can also be used for the transport of e-gasoline and e-diesel. Table 120 shows the techno-economic data of the product tanker for the transport of gasoline and kerosene.

Table 120: Product tanker for the transport of gasoline and diesel

	Unit	**2020/2030/2050**	**Reference/comment**
Water volume gasoline or kerosene tanks	m^3	140,000	Hank et al. 2020b
Filling ratio		0.95	Perdue 2009
Payload gasoline/kerosene	t	90,872/99,085	
Speed	knots	15	Hank et al. 2020b
	km/h	27.8	
Fuel consumption	MJ/(kg gasoline or kerosene *km)	0.0000604	Sphera 2021
CAPEX	million €	54	Hank et al. 2020b
Lifetime	yr	30	
Crew	million €/yr	0.79	[Deloitte 2011]
Maintenance & repair		3 % of CAPEX/yr	Hank et al. 2020b
Deadweight tons (DWT)		110,000	
Suez Canal tonnage (SCNT)		55,000*	LETH 2021
Suez Canal toll			
Laden	€/voyage	265,000	USMS 2021
Ballast	€/voyage	195,000	USMS 2021
Total	€/roundtrip	460,000	

*For liquid fuel tankers the SCNT is about the half of the deadweight

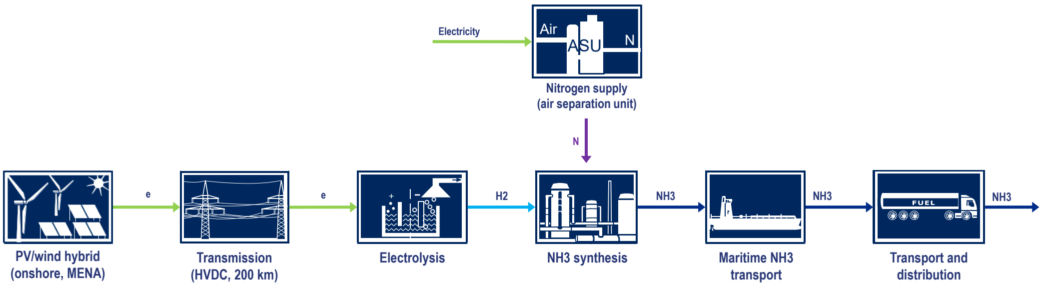
For the import terminal the same techno-economic assumptions have been applied as for the export terminal.

Inside the EU the gasoline and kerosene are distributed to refuelling stations or an airport in the same way as for gasoline and kerosene produced in Europe (chapter 8.4.5).

8.4.13. E-Ammonia from MENA via ship (NH3ME)

To generate ammonia, as a first step hydrogen is produced via water electrolysis. The electricity required in this process is produced through PV-/wind-hybrid power stations. It is than synthesised to ammonia, compressed, and stored until it is transported firstly via ship and then distributed through trucks to its final use.

Figure 130: e-Ammonia from MENA via ship



The transport of ammonia (NH3) involves a boil-off which is used for ship propulsion. Therefore, the capacities of the H_2 buffer storage (Table 121) and NH_3 synthesis plant (Table 122) upstream the NH_3 transport have to be higher to supply the same amount of final fuel per hour to Europe. For time horizon 2050 the capacity is slightly higher than for 2020 and 2030 because the NH_3 carrier is fueled with 100% ammonia.

Table 121: H_2 buffer storage with H_2 storage loading compressor for power-to-ammonia in MENA and export to Europe

	Unit	2020/2030	2050	Reference/comment
Compressor H_2 storage loading				
Capacity	Nm^3/h	523,000	530,000	
Suction pressure	MPa	3	3	
Final pressure	MPa	10	10	
T (in)	K	313	313	H_2 leaving electrolyzer
T (intercooling)	K	333	333	
Efficiency compressor		80%	80%	
Efficiency electric motor		90%	90%	
Number of stages	-	2	2	
Electricity consumption	kWh/Nm^3	0.0649	0.0649	
	$kWh/kWh_{H2,\ LHV}$	0.0217	0.0217	
CAPEX	million €	134	136	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr	3% of CAPEX/yr	Planet et al. 2014
Lifetime	yr	30	30	
H_2 storage				
Maximum pressure	MPa	10	10	
Minimum pressure	MPa	2.5	2.5	
Storage capacity	h	3	3	of full load operation
	million Nm^3	1.57	1.59	Net storage capacity
CAPEX	million €	39	40	Jauslin Stebler 2013
	$€/kg_{H2}$	279	279	
Lifetime	yr	30	30	

Table 122: Techno-economic data for an ammonia synthesis plant in MENA (KSA)

	Unit	2020/2030	2050	Reference/ comment
Capacity	$MW_{NH3,\ LHV}$	1375	1394	
Inputs				
GH2	$MJ/MJ_{NH3,\ LHV}$	1.140	1.140	
Electricity	$MJ/MJ_{NH3,\ LHV}$	0.1657	0.1657	
Outputs				
Ammonia	MJ	1.000	1.000	
Heat	$MJ/MJ_{NH3,\ LHV}$	-	-	Heat not used
Economic data				
CAPEX	million €	804*	812*	DECHEMA 2017
Lifetime	yr	30	30	
Fixed O&M		3% of CAPEX/yr	3% of CAPEX/yr	

*Upscaled from a 2000 t NH_3/d plant (433 MW NH_3 based on the LHV) assuming a scaling exponent of 0.7

For large-scale storage at the export terminal and maritime transport the NH_3 is cooled down to a temperature of -33°C [Hank et al. 2020a]. The techno-economic data for the export terminal in Table 115 haves been derived from [Lanphen 2019]. The number of tanks has been adjusted to the transport capacity of the methanol carrier. A filling ratio of 0.98 has been assumed.

Table 123: Export terminal for NH_3 transport

	Unit	2020/2030/2050
Number of tanks		2
Water volume per tank	m^3	50,000
Water volume total	m^3	100,000
Filling ratio		0.98
NH_3 storage capacity total	t	66,836
CAPEX		
Jetty	million €	3
Loading arm/equipment	million €	1
Tanks	million €	100
Total	million €	104
Lifetime	yr	30

Practically all LPG carriers also can be used for the transport of NH_3. Fully-refrigerated LPG or NH_3 carriers have a cargo space of up to about 100,000 m^3 [Wärtsilä 2021b]. The water volume of the NH_3 tanks have been derived from the Crystal Marine built by Kawasaki. NH_3 has a higher density than LPG. Therefore, the filling ratio have been set to 0.75 to avoid overloading of the ship.

Table 124: NH_3 carrier

	Unit	2020/2030	2050	Reference
Water volume NH_3 tanks	m^3	80,138	80,138	Wärtsilä 2021b
Filling ratio		0.75	0.75	
Payload NH_3	t	40,991	40,991	
Bol-off rate		0.04%	0.04%	Hank et al. 2020b
Speed	knots	17	17	Wärtsilä 2021b
	km/h	31.5	31.5	
Fuel consumption	MJ/(kg NH_3*km)	0.0000687	0.0000687	Sphera 2021
Share boil-off		29%	29%	
Residual fuel		LSMGO	NH_3	
CAPEX	million €	64	64	Lanphen 2019
Lifetime	yr	30	30	
Crew	million €/yr	0.79	0.79	[Deloitte 2011]
Maintenance & repair		4% of CAPEX/yr		Lanphen 2019
Deadweight tons /DWT)	t	53,395	53,395	
Suez Canal tonnage (SCNT)		45,801*	45801*	LETH 2021
Suez Canal toll				
Laden	€/voyage	253,000	253,000	USMS 2021
Ballast	€/voyage	215,000	215,000	USMS 2021
Total	€/roundtrip	468,000	468,000	

*The SCNT is close to the vessels International Gross Tonnage which is indicated with 45801 for the LPG carrier Crystal Marine

For the import terminal the same techno-economic assumptions have been applied as for the export terminal.

Inside Europe the NH_3 is transported to the ship bunkering terminal in the same way as for NH_3 produced in Europe.

8.4.14. E-Gasoline, -kerosene, and -diesel from MENA via FT route and via ship (FTGME, FTKME, FTDME)

To generate e-kerosene, e-gasoline and e-diesel initially there is hydrogen needed. This is produced via water electrolysis. The electricity required in this process is produced by PV-/wind-hybrid power stations. The hydrogen is then synthesised with carbon dioxide to e-crude through the Fischer-Tropsch process. The carbon dioxide can be supplied by various procedures, either direct air capture (DAC) or flue gas from steam methane reforming (SMR) plants. The heat used for these processes is a by-product of the Fischer-Tropsch synthesis. The e-crude is converted into kerosene, gasoline or diesel and afterwards transported firstly via ships and then through trucks to their respective destination. For kerosene this is the airport where it is stored and dispensed. Diesel and gasoline are distributed to refuelling stations where they are utilized to fuel road vehicles.

Figure 131: e-Gasoline from MENA via FT route and via ship

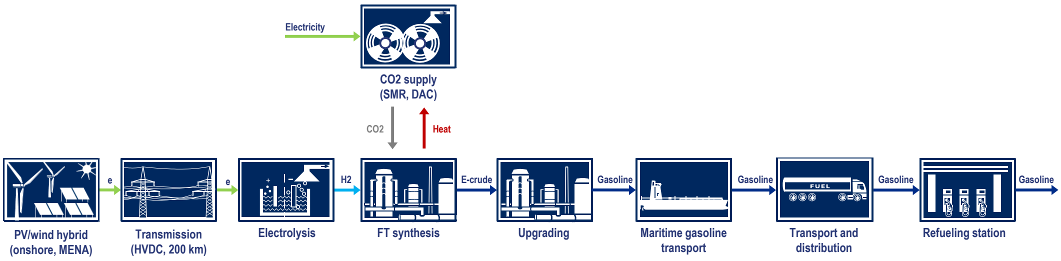


Figure 132: e-Kerosene from MENA via FT route and via ship

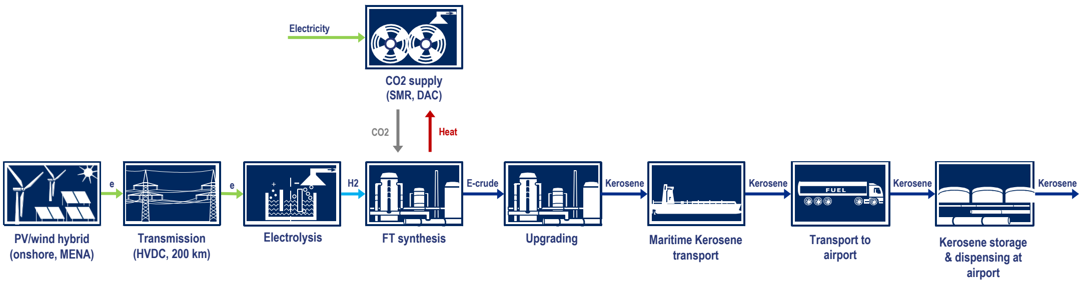
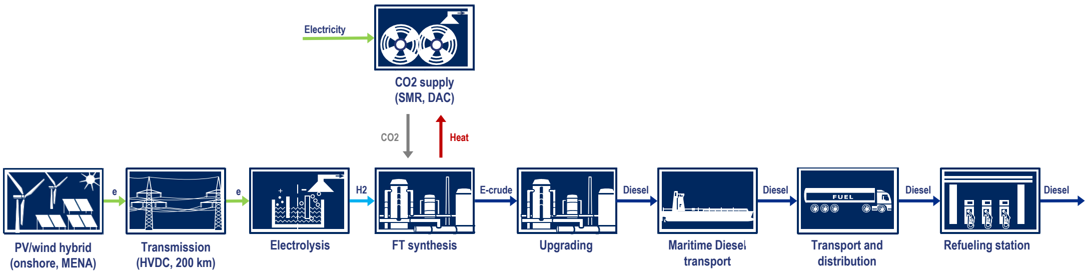


Figure 133: e-Diesel from MENA via FT route and via ship



The ship for the transport of gasoline, kerosene, and diesel to Europe consumes LSMGO (2020 and 2030) or e-diesel (2050). No gasoline, kerosene, or diesel loss occurs along the fuel supply chain except in case of 2050 for diesel where the ship is fuelled with e-diesel. For kerosene the same assumptions concerning required capacity can be applied for the hydrogen buffer storage, the CO_2 supply, and the FT plant as for kerosene produced in Europe. In case of diesel some of the FT diesel is used in 2050 for ship propulsion leading to a slightly higher capacity and as a result to a slightly higher CAPEX for the upstream processes.

For gasoline there are some differences in the CAPEX of the FT plant because it is optimized to the production of gasoline meeting the fuel specifications for Otto engines.

Table 125: Techno-economic data for a FT synthesis plant for gasoline production including RWGS in MENA (KSA)

	Unit	Value	Reference/comment
Capacity	$MW_{\text{FT products, LHV}}$	1368	
Inputs			
GH_2	$MJ/MJ_{\text{FT products, LHV}}$	1.4036	
CO_2	$kg/MJ_{\text{FT products, LHV}}$	0.0880	
Electricity	$MJ/MJ_{\text{CFT products, LHV}}$	0.0441	
Outputs			
FT products	MJ	1	
Heat (T = 225°C)	$MJ/MJ_{\text{CFT products, LHV}}$	0.2139	
CAPEX			
Burner	million €	255	Becker et al. 2012
FT reactor	million €	159	Becker et al. 2012; [König et al. 7/2015
RWGS	million €	47	
PSA	million €	21	Becker et al. 2012
Distillation	million e	7	Becker et al. 2012
Wax hydrocracker	million €	69	Becker et al. 2012
Distillate hydrotreater	million €	38	Becker et al. 2012
Naphtha hydrotreater	million €	10	Becker et al. 2012
Catalytic reformer/platformer	million €	56	Becker et al. 2012
C5/C6 isomerization	million €	9	Becker et al. 2012
Total installed cost	million €	671	Becker et al. 2012
Total direct cost	**million €**	**751**	Total installed cost *1.12
Engineering & design	million €	98	13% of total direct cost
Construction	million €	105	14% of total direct cost
Legal and contractor fees	million €	68	9% of total direct cost
Project contingency	million €	113	15% of total direct cost
Total indirect costs	**million €**	**383**	
Total CAPEX	**million €**	**1135**	
Lifetime	yr	30	
Fixed O&M	€/yr	40.1	
Variable O&M	$€/GJ_{\text{FT products, LHV}}$	1.53	6120 $US\$/GWh_{\text{FT products, LHV}}$

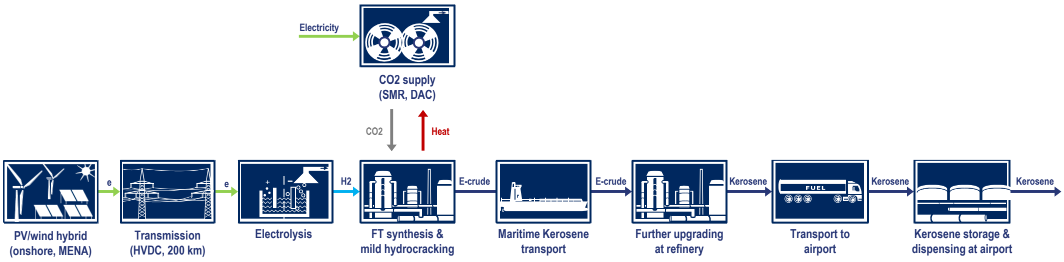
The gasoline, kerosine, and diesel is transported from KSA to Europe over a distance of 5143 km. For the port facilities and the product carrier the same assumptions have been applied as for gasoline and kerosene via the methanol-to-gasoline and methanol to-kerosene process (chapter 8.4.12). The differences between kerosene and diesel due to different density are small.

For the transport and distribution inside Europe the same assumptions have been applied as for e-gasoline, e-kerosene, and e-diesel produced inside Europe (chapter 8.4.5 and 8.4.7).

8.4.15. E-Kerosene from MENA via FT route and via ship as e-crude (FTKME-e-crd)

To generate e-kerosene, hydrogen is needed. It is created via water electrolysis, where the electricity required for this procedure is produced by PV-/wind-hybrid power stations. The hydrogen is then synthesised with carbon dioxide to e-crude through the Fischer-Tropsch process. Also, a mild hydrocracking process is applied to the fuel. The carbon dioxide needed for the synthesis can be supplied through various procedures, either direct air capture (DAC) or flue gas from steam methane reforming (SMR) plants. The heat used for these processes is a by-product of the Fischer-Tropsch synthesis. The e-crude is then shipped to a refinery where it is further upgraded and converted to kerosene. From there the kerosene is transported via trucks to airports where it is stored and dispensed.

Figure 134: e-Kerosene from MENA via FT route and via ship



The techno-economic data for the electrolysis plant, the hydrogen buffer storage and the CO_2 supply are the same as for the fully-integrated stand-alone FT plant. The differences are at the FT synthesis stage and the further processing to final fuel. At the e-crude plant in KSA a mild hydrocracker is required to make the e-crude transportable.

Table 126 shows the CAPEX for a FT plant for e-crude production with a capacity of 1370 MW_{LHV} of FT products (1 million t/yr[5]). The CAPEX for the burner, FT reactor, PSA has been derived from [Becker et al. 2012]. The CAPEX for the RWGS has been derived from [König et al 7/205]. The CAPEX for the mild hydrocracker has been derived from [Concawe 2021]. The CAPEX for the burner and FT reactor has been scaled linearly as indicated in [Becker et al. 2012] and [König et al. 7/2015]. For the calculation of the CAPEX of the RWGS a scaling exponent of 0.65 has been applied, and for PSA a scaling exponent of 0.70.

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[5] Capacity 1 million t/yr based on 8760 h/yr. The real plant produces less FT products due to lower equivalent full load period depending on the electricity source

Table 126: CAPEX FT plant for e-crude production with a capacity of 1370 MW FT products (1 million t/yr)

Component	CAPEX (Million €)	SE	Comment
Burner	255	1.00	
FT reactor	159	1-00	
RWGS	47	0.65	
PSA	21	0.70	
Mild hydrocracker	179	n. d. a.	179 €/(t feed/yr)
Total installed cost	**662**		
Total direct costs	**741**		**Total installed cost *1.12**
Engineering & design	96		13% of total direct costs
Construction	104		14% of total direct costs
Legal and contractor fees	67		9% of total direct costs
Project contingency	111		15% of total direct costs
Total indirect costs	**378**		
CAPEX total	**1119**		

SE: scaling exponent

The e-crude is transported to South EU via ship. At the import terminal the e-crude is converted to the final fuel.

No cost of capital has been applied for the refinery because existing refineries has been assumed. The CAPEX for the refinery is only used for the calculation of the OPEX. Table 126 shows the CAPEX for the refinery components. The equivalent full load period of the refinery in the EU is higher (8000 h/yr) than that of the FT plant in MENA (5320 h/yr) leading to a lower capacity to get the same amount of final fuel per year (0.61 million t diesel equivalent/yr).

Table 127: CAPEX of refinery components (hydrocracker, recycle) including fractionator

Component	CAPEX (Million €)	Comment
Total installed costs	408	408 €/(t hydrocracker feed/yr); capacity: 1 million t feed/yr
Total direct cots	**457**	**Total installed cost *1.12**
Engineering & design	59	13% of total direct costs
Construction	**64**	14% of total direct costs
Legal and contractor fees	41	9% of total direct costs
Project contingency	69	15% of total direct costs
Total indirect costs	233	
CAPEX total	**690**	

Table 128 shows the assumptions for the operating and maintenance costs of the refinery.

Table 128: Operating and maintenance costs of the refinery

Component	Operating a maintenance cost	Reference
Labour	0.7% of CAPEX total/yr	Hedden & Jess 1994
Insurance	0.5% of CAPEX total/yr	
Maintenance & repair	1.9% of CAPEX total/yr	
Overhead	1.8% of CAPEX total/yr	
Total	**4.9% of CAPEX total/yr**	
	34 million €/yr per FT plant in MENA	
Production of final fuel	**26 PJ/yr**	
	0.61 million t/yr	

The operating and maintenance costs of the refinery only contributes to about 1.3 € per GJ of final fuel (or 0.045 € per l of diesel equivalent to the overall costs of fuel supply.

The final fuel is transported to a depot via pipeline over a distance of 150 km and from there ´via truck to the airport over a distance of 150 km.

8.4.16. E-Kerosene and diesel via FT route with H_2 from MENA via ship (FTKME-H2ex, FTDME-H2ex)

To generate e-kerosene and e-diesel, hydrogen is needed. It is created via water electrolysis, where the electricity required for this procedure is produced by PV-/wind-hybrid power stations. The hydrogen is liquefied to be able to store larger quantities at once. It is afterwards shipped to a facility where the liquid hydrogen is vaporised and then synthesized via the Fischer Tropsch process to e-crude or diesel. The carbon dioxide needed for the synthesis can be retrieved through various procedures, either direct air capture (DAC) or flue gas from steam methane reforming (SMR) plants. The heat used for these processes is a by-product of the Fischer-Tropsch synthesis. The e-crude is then converted to kerosene. Kerosene and diesel are both transported via trucks. The destination of the kerosine are airports where it is stored and dispensed to airplanes, while the diesel is distributed to refuelling stations where it is utilized to fuel road vehicles.

Figure 135: e-Kerosene with H_2 from MENA via ship

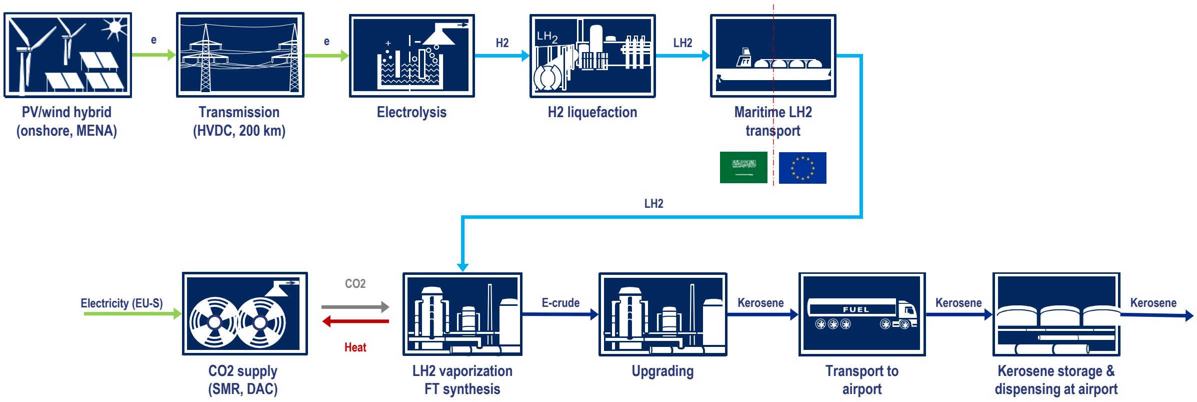
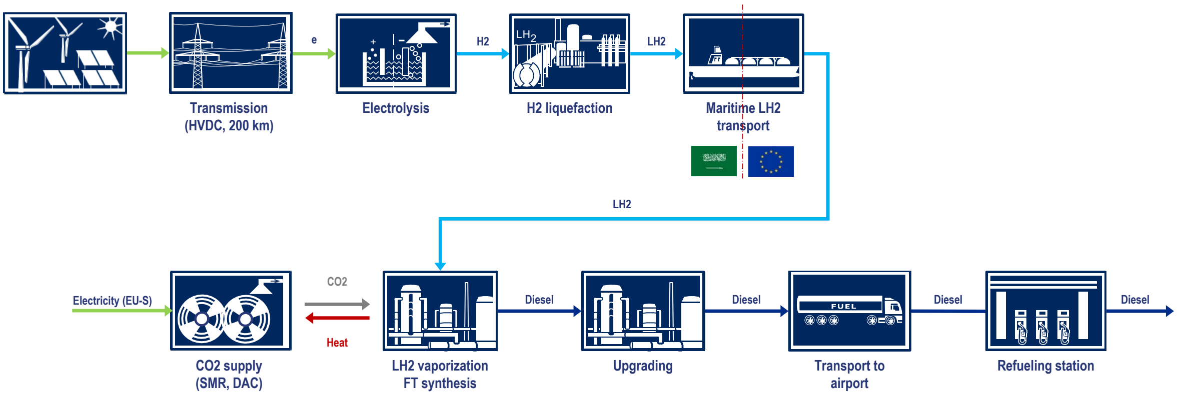


Figure 136: e-Diesel with H_2 from MENA via ship



Due to the various process steps including hydrogen generation, hydrogen liquefaction, maritime LH2 transport, FT syntheses and upgrading of the FT products to final fuel the capacity of the electrolysis plant is significantly higher for the same capacity of final fuel than for fully-integrated stand-alone power-to-fuel-plants in KSA described in chapter 8.4.14.

For 2020 the electricity input of the electrolysis plant amounts to 3111 MW compared to 2887 MW for the fully-integrated stand-alone power-to-fuel plants in KSA.

On the other hand, the capacity of the FT plant including upgrading to final fuel located in the EU is lower because the equivalent full load period is assumed to be 8000 h/yr. The reason is that the FT plant is fully decoupled from the electrolysis plant in MENA.

8.4.17. Pathways involving decentralised e-crude plants and fully integrated FT plants into existing refinery

The stand-alone FT plant for Central Europe is described in Table 102 in chapter 8.4.7. For South Europe a larger FT plant has been assumed.

For the distributed e-crude plants and the fully integrated FT plant a location in Central Europe and MENA has been assumed. Table 129 shows the techno-economic data for the distributed e-crude plants and Table 130 for the fully integrated FT plant.

Table 129: Techno-economic data for a distributed e-crude plant based on FT synthesis including RWGS in Central Europe

	Unit	Value	Reference/comment
Capacity	$MW_{FT\ products,\ LHV}$	1368	1 million t/yr
Inputs			
GH_2	$MJ/MJ_{FT\ products,\ LHV}$	1.4036	
CO_2	$kg/MJ_{FT\ products,\ LHV}$	0.0880	
Electricity	$MJ/MJ_{CFT\ products,\ LHV}$	0.0441	
Outputs			
FT products	MJ	1	
Heat (T = 225°C)	$MJ/MJ_{CFT\ products,\ LHV}$	0.2139	
CAPEX			
Burner	million €	255	[Becker et al. 2012]
FT reactor	million €	159	[Becker et al. 2012], [König et al. 7/2015]
RWGS	million €	47	
PSA	million €	21	[Becker et al. 2012]
Mild hydrocracker	million €	179	[Concawe 2021]
Total installed cost	million €	662	
Total direct cost	**million €**	**741**	Total installed cost *1.12
Engineering & design	million €	96	13% of total direct cost
Construction	million €	104	14% of total direct cost
Legal and contractor fees	million €	67	9% of total direct cost
Project contingency	million €	111	15% of total direct cost
Total indirect costs	**million €**	**378**	
Total CAPEX	**million €**	**1119**	
Lifetime	yr	30	
Fixed O&M	million €/yr	33.6	3% of CAPEX/yr
Variable O&M	$€/GJ_{FT\ products,\ LHV}$	1.53	6120 $US\$/GWh_{FT\ products}$

For an equivalent full load period of 3910 hours per year for e-fuel plants located in Central Europe (same as electrolysis plant) the fixed O&M amounts to 33.6 million € per year and the variable O&M amounts to 29.4 million € per year. The OPEX share of the existing refinery amounts to about 33.8 million € per year. As a result, the total OPEX amounts to about 97 million € per year for the distributed FT plant combined with further processing of the e-crude in an existing refinery.

Table 130: Techno-economic data for an e-crude plant based on FT synthesis including RWGS in Central Europe for fully integration into existing refinery

	Unit	**Value**	**Reference/comment**
Capacity	$MW_{FT\ products,\ LHV}$	1368	1 million t/yr
Inputs			
GH_2	$MJ/MJ_{FT\ products,\ LHV}$	1.4036	
CO_2	$kg/MJ_{FT\ products,\ LHV}$	0.0880	
Electricity	$MJ/MJ_{CFT\ products,\ LHV}$	0.0441	
Outputs			
FT products	MJ	1	
Heat (T = 225°C)	$MJ/MJ_{CFT\ products,\ LHV}$	0.2139	
CAPEX			
Burner	million €	255	[Becker et al. 2012]
FT reactor	million €	159	[Becker et al. 2012], [König et al. 7/2015]
RWGS	million €	47	
PSA	million €	21	[Becker et al. 2012]
Total installed cost	million €	483	
Total direct cost	**million €**	**541**	Total installed cost *1.12
Engineering & design	million €	70	13% of total direct cost
Construction	million €	76	14% of total direct cost
Legal and contractor fees	million €	49	9% of total direct cost
Project contingency	million €	81	15% of total direct cost
Total indirect costs	**million €**	**276**	
Total CAPEX	**million €**	**816**	
Lifetime	yr	30	
Fixed O&M	million €/yr	24.5	3% of CAPEX/yr
Variable O&M	$€/GJ_{FT\ products,\ LHV}$	1.53	6120 $US\$/GWh_{FT\ products}$

For an equivalent full load period of 3910 hours per year for e-fuel plants located in Central Europe (same as electrolysis plant) the fixed O&M amounts to 24.5 million € per year and the variable O&M amounts to 29.4 million € per year. The OPEX share of the existing refinery amounts to about 33.8 million € per year. As a result, the total OPEX amounts to about 88 million € per year for the FT plant fully integrated into an existing refinery.

8.4.18. Fossil fuels involving CCS

For fossil fuels involving CCS natural gas is assumed as feedstock. The assumptions for the costs of natural gas, CO_2 emissions, and auxiliary electricity are shown in Table 16 and Table 17.

The methanol plant consists of autothermal reforming and downstream methanol synthesis and purification. This is the typical plant design applied for natural gas-to-methanol plants today. For FT kerosene and diesel partial oxidation with downstream FT synthesis is applied as typical for GTL plants.

For NH_3 syntheses the same natural gas via steam reforming plant is used as for the supply of H_2 as final fuel.

Table 131: H_2, Methanol, and FTK/FTD from natural gas involving CCS

	Unit	H_2	Methanol	FTK/FTD
Capacity	Nm^3/h	100,000		
	MW_{LHV}	300	1153	645
	t/h		208	
Natural gas consumption	MJ_{LHV}/MJ_{LHV}	1.446	1.641	1.789
Electricity consumption	MJ_{LHV}/MJ_{LHV}	-0.0014*	0.0315	0.0115
Water consumption	kg/MJ_{LHV}	0.0372		
CO_2 capture rate		90%	90%	89%
CO_2 emissions at plant site	g/MJ_{LHV}	8.2	2.5	3.3
CO_2 bound in the final fuel	g/MJ_{LHV}	0	68.9	73.6/73.2
CAPEX	million €	398	386	614
Lifetime	yr	25	25	25
Equivalent full load period	h/yr	8000	8000	8000
OPEX				
Maintenance	million €/yr	4.6		
Labour costs	million €/yr	2.6		
Admin/general overhead	million €/yr	1.3		
Insurance	million €/yr	3.1		
Chemicals, catalysts, adsorbents	million €/yr	0.4		
OPEX total	million €/yr	12.0	11.6	20.9
References		AFW 2017	Collodi et al. 2016	IEA 2000

* (-): credit for excess electricity

8.4.19. Nuclear electricity

The techno-economic data for nuclear power are based on the so-called ‘European Pressurized Reactor’ (EPR) because all nuclear reactors which are under construction or recently started commercial operation in Europe are EPR (Flamanville in France, Hinkley Point in the United Kingdom. Olkiluoto in Finland). The EPR is a third-generation concept for a pressurerized water reactor. It has been developed by Areva, Électricité de France, and Siemens. Table 132 shows the techno-economic data for a nuclear power station based on the European Pressurized Reactor (EPR). No distinct decrease of CAPEX for newly built nuclear power plants has been detected in the last decades [Lovering et al. 2016]. For all time horizons the same CAPEX has been assumed for nuclear power.

Table 132: New nuclear power station

	Unit	Value	References
Capacity	MW$_e$	1650	Areva 2014
CAPEX	billion €	10.9	WNN 2018
	€/kWe	6606	
Equivalent full laod period	h/yr	8059	Areva 2014
Electricity generation	TWh/yr	13.3	
Lifetime	yr	60	Areva 2014
Costs of capital	million €/yr	880.7	
Burn-up rate	MWd/t$_{UO2}$	45,000	
	kWh/kg$_{UO2}$	1,080,000	
Efficieny		37%	Areva 2014
Costs of nuclear fuel	€/kg$_{UO2}$	1211	WNA 2018
	€/kWh$_e$	0.00303	
	million €/yr	40.3	
Financial charges of the inventory	million €/yr	14.9	[LBST & Hinicio 2019] based on [CourDeComptes 2012]
Nuclear waste disposal	million €/yr	31.3	
Last core	million €/yr	2.5	
Labor	million €/yr	56.8	
Pension reform & LT employee benefits	million €/yr	14.4	
Agent rate	million €/yr	3.2	
Overhead, central and support services	million €/yr	24.3	
Maintenance	million €/yr	102.0	
External consumption s (spare parts)	million €/yr	58.3	
Other costs and revenues	million €/yr	1.7	
Decommissioning	million €/yr	16.7	WNA 2018
Total costs	**million €/yr**	**1247.0**	
	€/kWhe	**0.094**	

In [IEA 2021] the levelized costs of of nuclear electricity in the EU are indicated with 150 US$ per MWh (134 € per MWh) in 2020, 120 US$ per MWh (107 € per MWh) in 2030, and 115 US$ per MWh (102 € per MWh) in 2050. [IEA 2021] indicated a decrease of CAPEX over time although the levelized costs of electricity are higher than assumed in this study for 2050 (94 €/MWh). The CAPEX is indicated with 6600 US$/kWe ub 2020, 5100 US$ per kW in 2030, and 4500 US$/kWe in 2050.

In [IEA 2020] the costs of nuclear electricity from exististing nuclear power plants including CAPEX for long-term operation (LTO) with a lifetime extension of 20 years and a discount rate of 7% are indicated with 28.6 to 37.9 US$ per MWh (0.025 to 0.034 €/kWh) depending on CAPEX and capacity factor [IEA 2020b].

8.5. SENSITIVITY ANALYSES

8.5.1. Sensitivity to different renewable electricity costs

Figure 137: Sensitivity to different renewable electricity costs by region for 2020 (CO_2 from concentrated source)

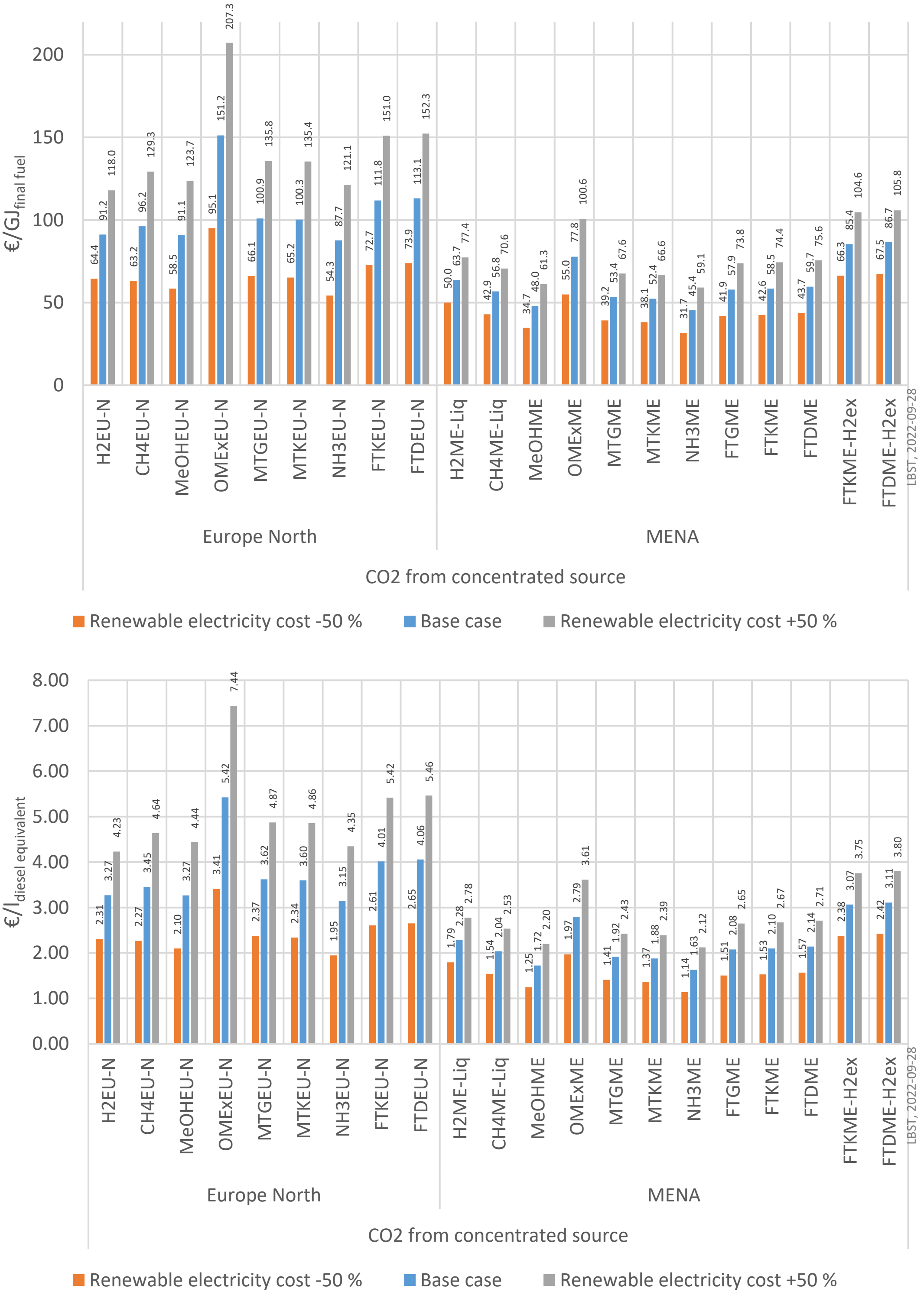
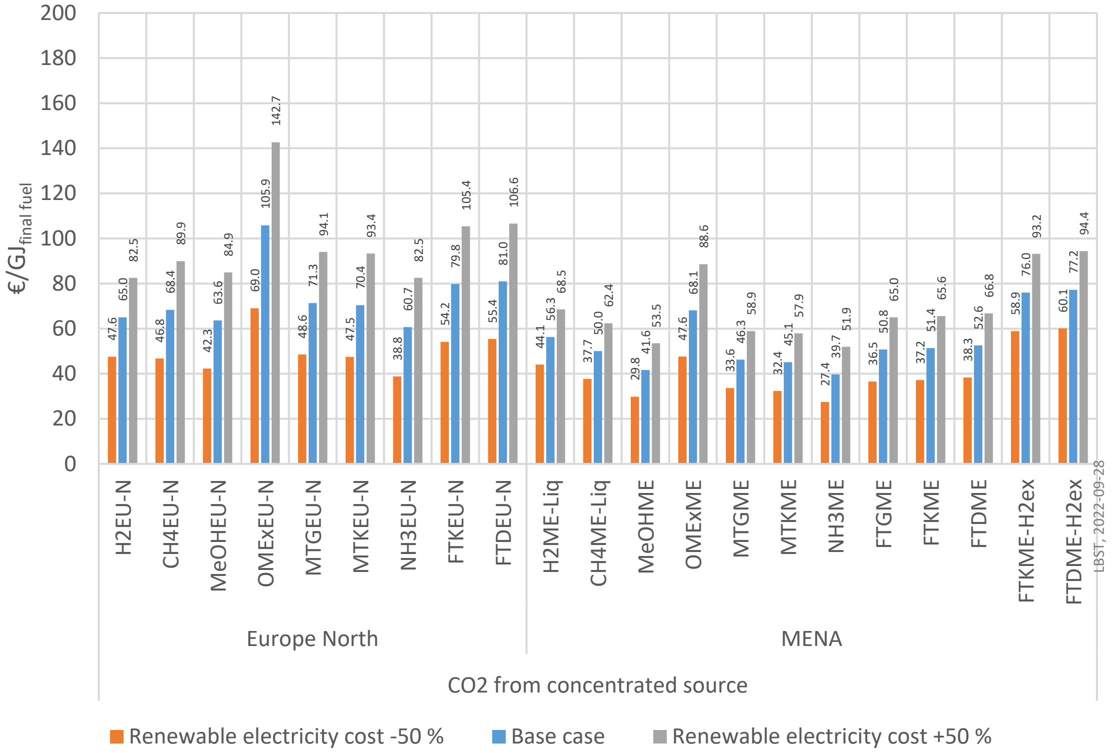


Figure 138: Sensitivity to different renewable electricity costs by region for 2030 (CO_2 from concentrated source)



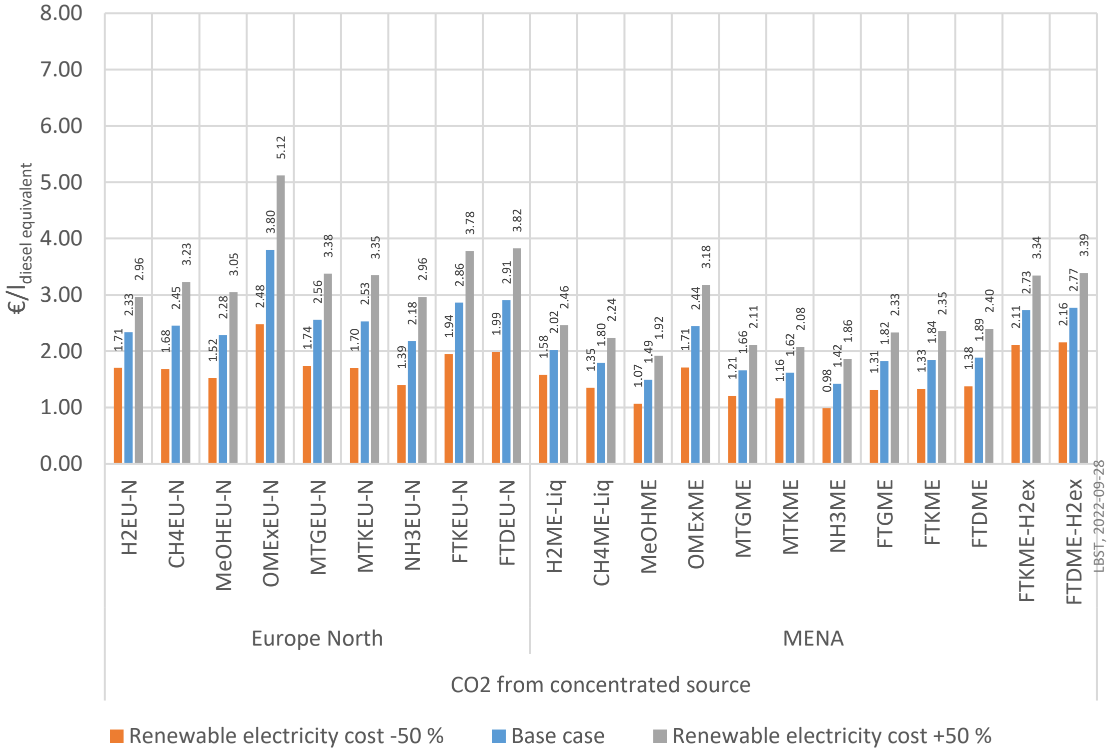
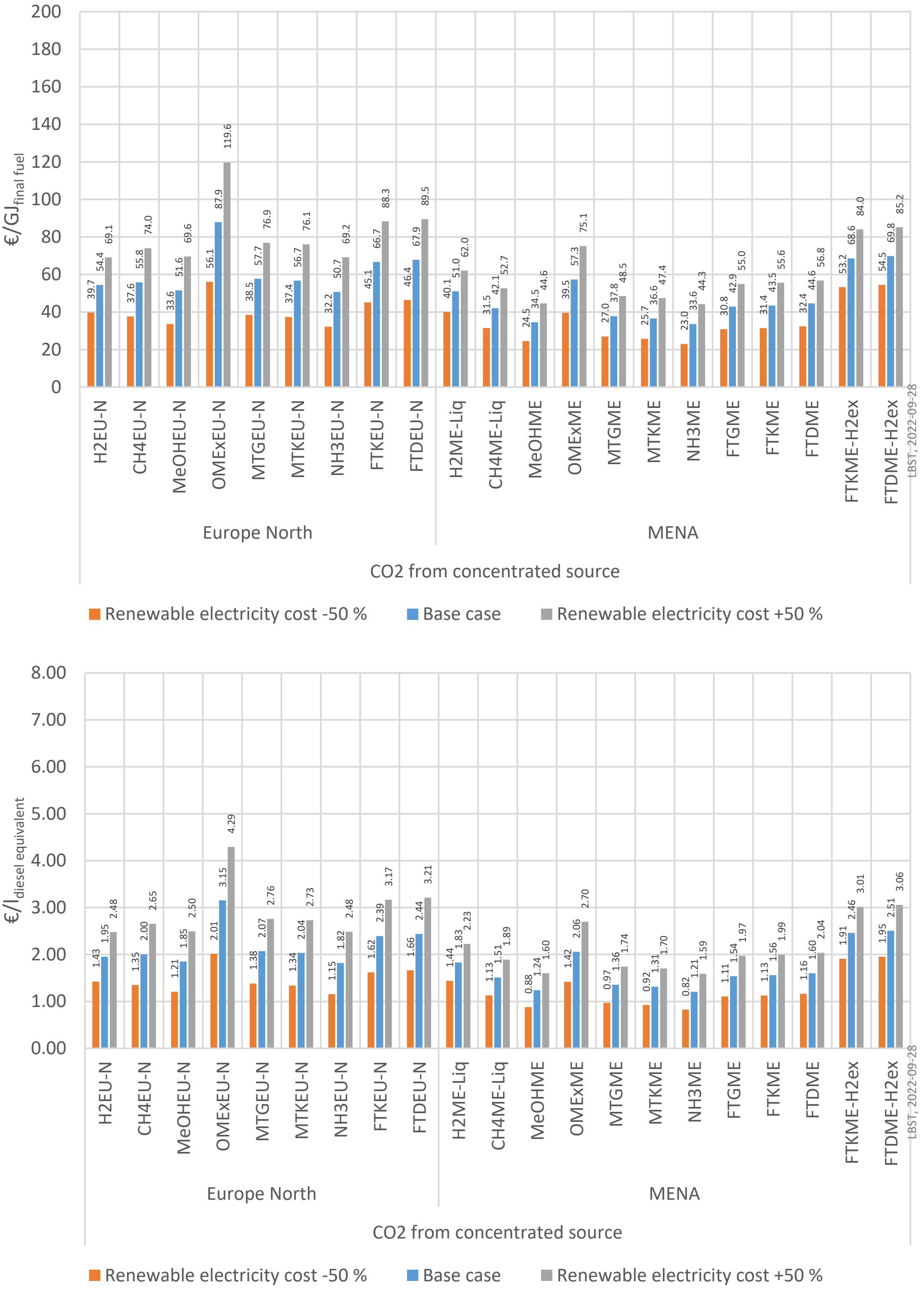


Figure 139: Sensitivity by different renewable electricity costs by region for 2050 (CO_2 from concentrated source)



8.5.2. Sensitivity to different discount rates

Figure 140: Sensitivity to different discount rates by region for 2020 (CO_2 from concentrated source)

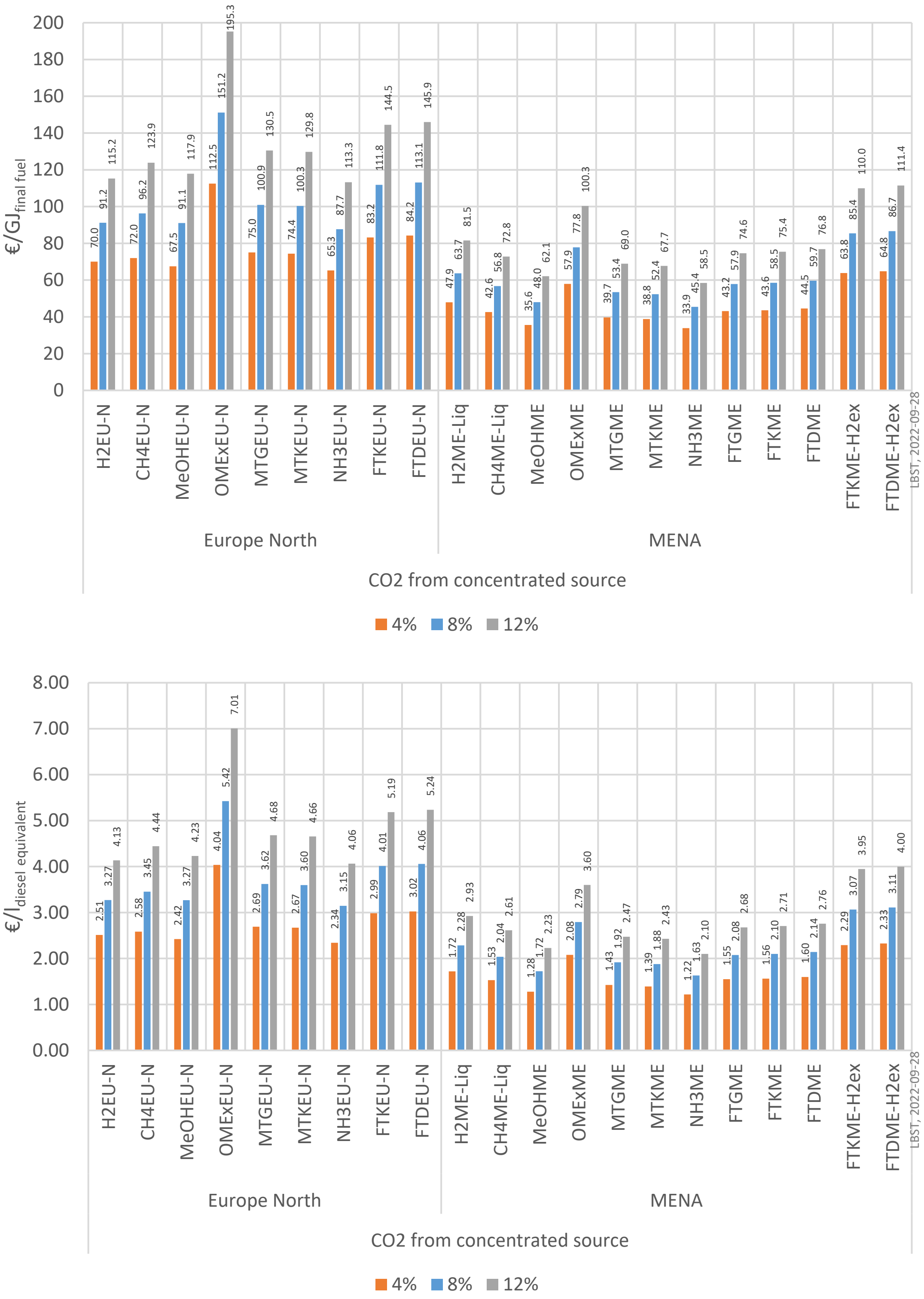
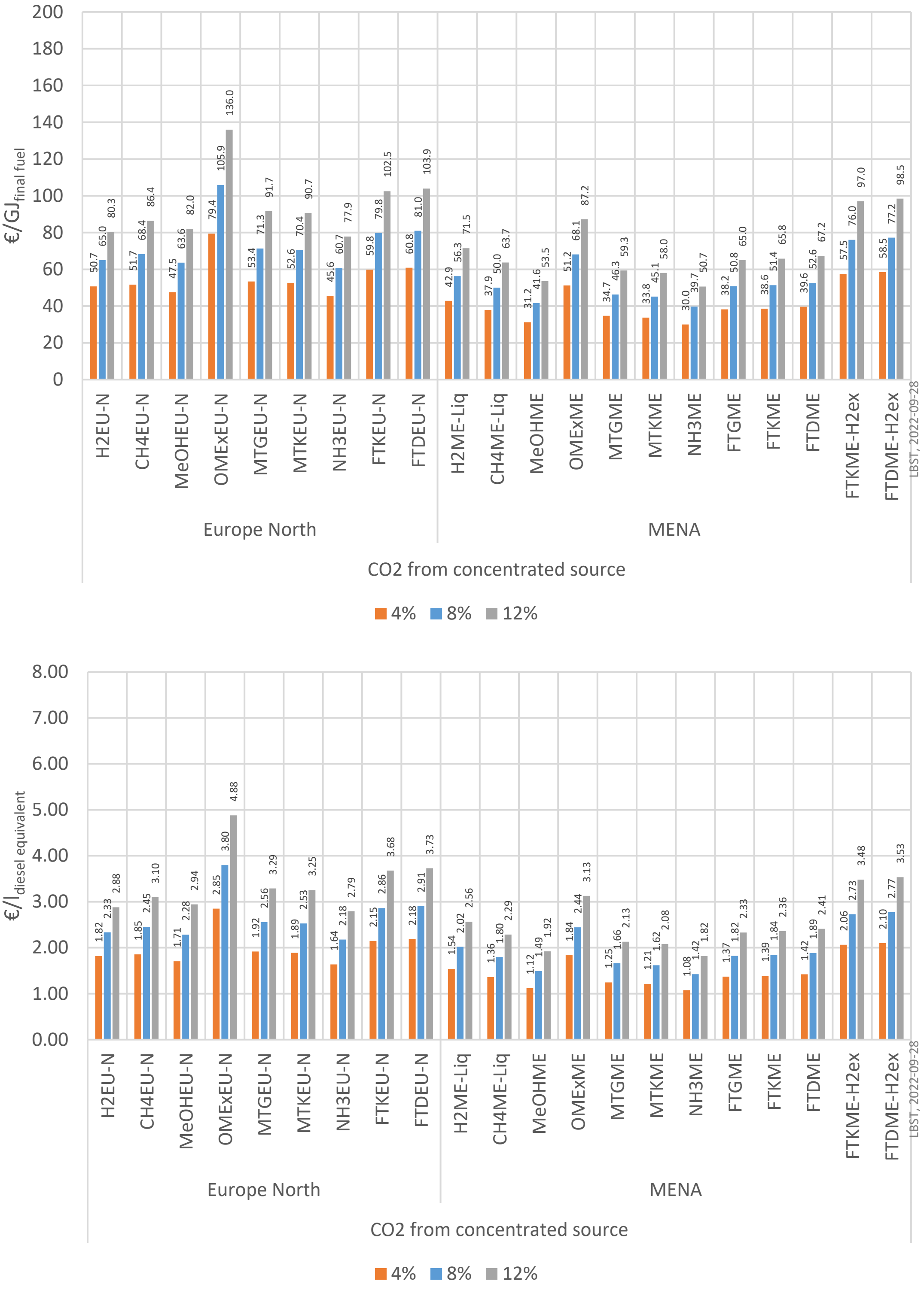


Figure 141: Sensitivity to different discount rates by region for 2030 (CO_2 from concentrated source)

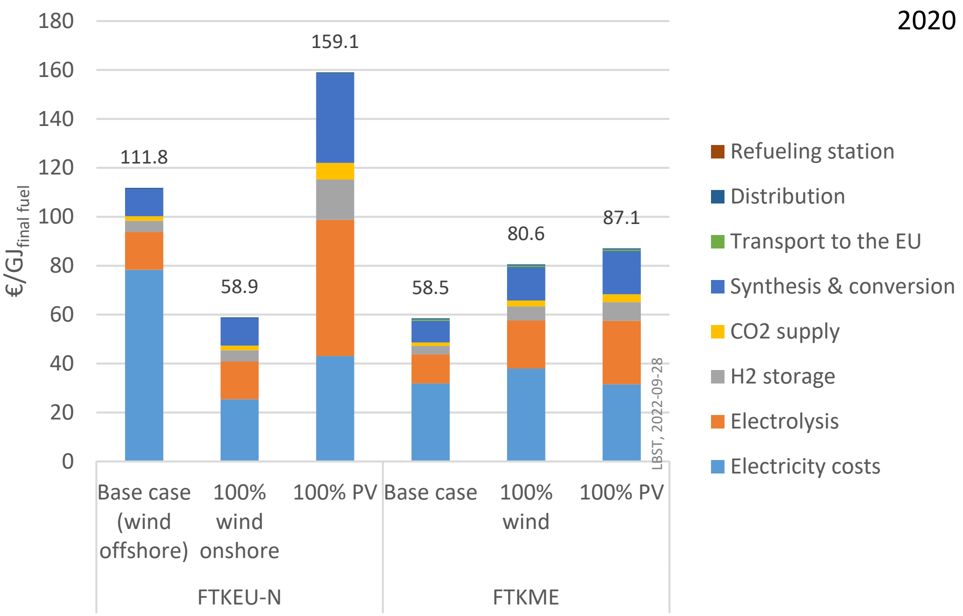


8.5.3. Sensitivity to electricity source

Table 133: E-fuel costs in 2020 depending on electricity source

	FTKEU-N			FTKME		
	Base case (wind offshore)	**100% wind (onshore)**	**100% PV**	**Base case (PV/wind hybrid)**	**100% wind**	**100% PV**
€/GJ$_{\text{final fuel}}$						
Electricity costs	78.3	25.4	43.1	31.9	38.0	31.5
Electrolysis	15.5	15.5	55.6	11.8	19.6	26.0
H_2 storage	4.6	4.6	16.5	3.5	5.8	7.7
CO_2 supply	1.9	1.9	6.8	1.4	2.4	3.2
Synthesis & upgrading	11.2	11.2	36.4	8.9	13.7	17.7
Transport to the EU	0.0	0.0	0.0	0.6	0.6	0.6
Distribution	0.5	0.5	0.6	0.5	0.5	0.5
Refuelling station	0.0	0.0	0.0	0.0	0.0	0.0
Total	**111.8**	**58.9**	**159.1**	**58.5**	**80.6**	**87.1**
€/l$_{\text{diesel equivalent}}$ (based on conventional diesel EN 590)						
Electricity costs	2.81	0.91	1.55	1.14	1.36	1.13
Electrolysis	0.56	0.56	2.00	0.42	0.70	0.93
H_2 storage	0.16	0.16	0.59	0.12	0.21	0.28
CO_2 supply	0.07	0.07	0.24	0.05	0.09	0.11
Synthesis & upgrading	0.40	0.40	1.31	0.32	0.49	0.64
Transport to the EU	0.00	0.00	0.00	0.02	0.02	0.02
Distribution	0.02	0.02	0.02	0.02	0.02	0.02
Refuelling station	0.00	0.00	0.00	0.00	0.00	0.00
Total	**4.01**	**2.11**	**5.71**	**2.10**	**2.89**	**3.13**

Figure 142: E-fuel costs in 2020 depending on electricity source for FT Kerosene produced in North Europe and MENA



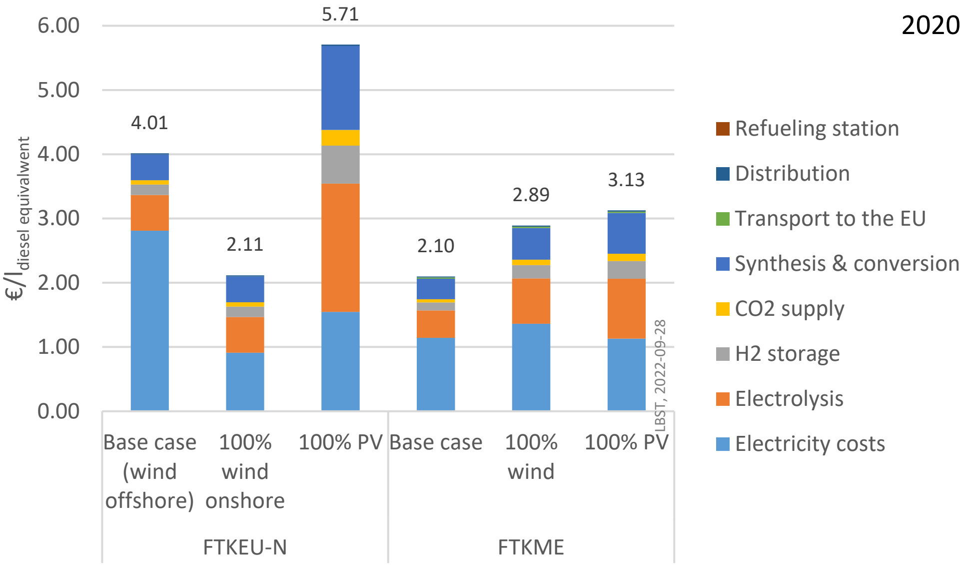
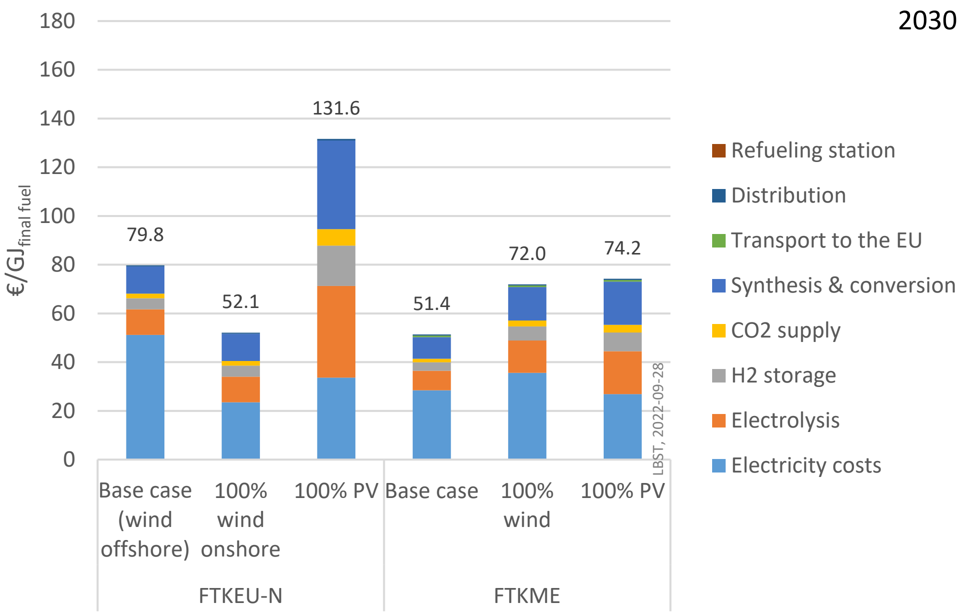
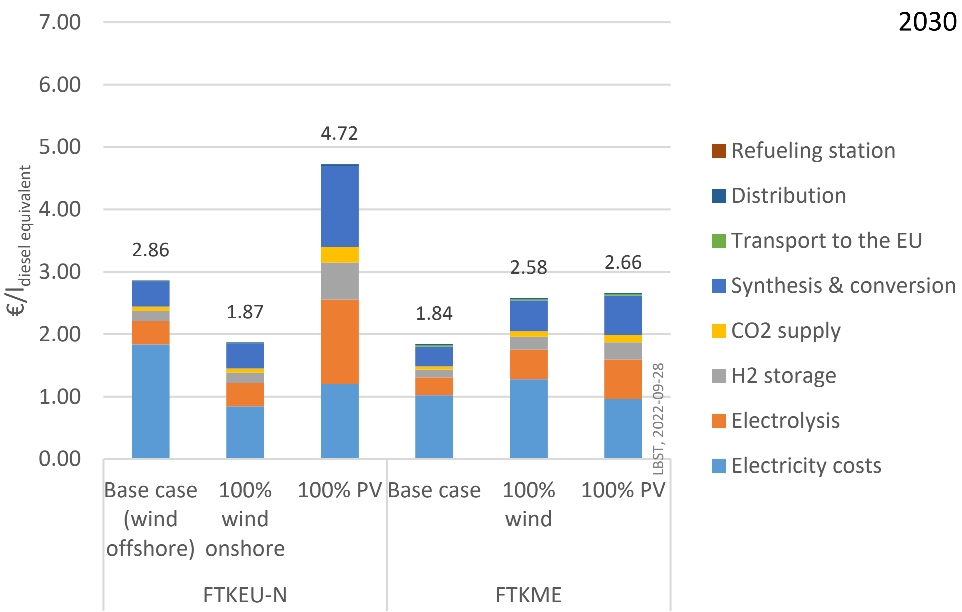


Table 134: E-fuel costs in 2030 depending on electricity source

	FTKEU-N			FTKME		
	Base case (wind offshore)	100% wind (onshore)	100% PV	Base case (PV/wind hybrid)	100% wind	100% PV
€/GJ$_{\text{final fuel}}$						
Electricity costs	51.2	23.5	33.6	28.4	35.6	26.9
Electrolysis	10.5	10.5	37.7	8.1	13.3	17.6
H$_2$ storage	4.6	4.6	16.5	3.5	5.8	7.7
CO$_2$ supply	1.9	1.9	6.8	1.4	2.4	3.2
Synthesis & upgrading	11.2	11.2	36.4	8.9	13.7	17.7
Transport to the EU	0.0	0.0	0.0	0.6	0.6	0.6
Distribution	0.5	0.5	0.7	0.5	0.5	0.5
Refuelling station	0.0	0.0	0.0	0.0	0.0	0.0
Total	**79.8**	**52.1**	**131.6**	**51.4**	**72.0**	**74.2**
€/l$_{\text{diesel equivalent}}$ (based on conventional diesel EN 590)						
Electricity costs	1.84	0.84	1.21	1.02	1.28	0.96
Electrolysis	0.38	0.38	1.35	0.29	0.48	0.63
H$_2$ storage	0.16	0.16	0.59	0.12	0.21	0.28
CO$_2$ supply	0.07	0.07	0.24	0.05	0.09	0.11
Synthesis & upgrading	0.40	0.40	1.31	0.32	0.49	0.64
Transport to the EU	0.00	0.00	0.00	0.02	0.02	0.02
Distribution	0.02	0.02	0.02	0.02	0.02	0.02
Refuelling station	0.00	0.00	0.00	0.00	0.00	0.00
Total	**2.86**	**1.87**	**4.72**	**1.84**	**2.58**	**2.66**

Figure 143: E-fuel costs in 2030 depending on electricity source for FT Kerosene produced in North Europe and MENA





8.5.4. Sensitivity to CO_2 source

Figure 144: E-fuel costs in 2020 depending on CO_2 source for FT kerosene produced in North Europe and MENA

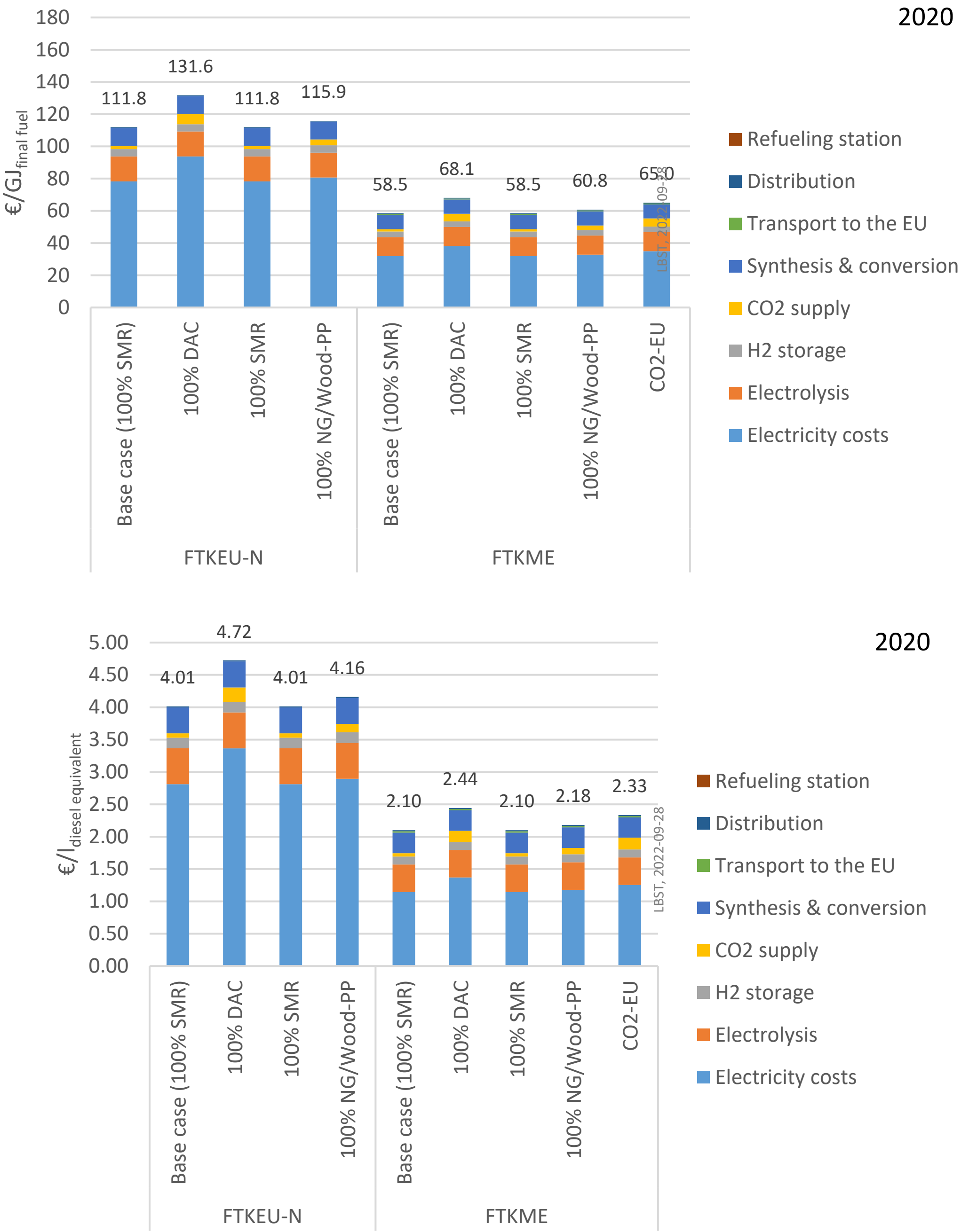
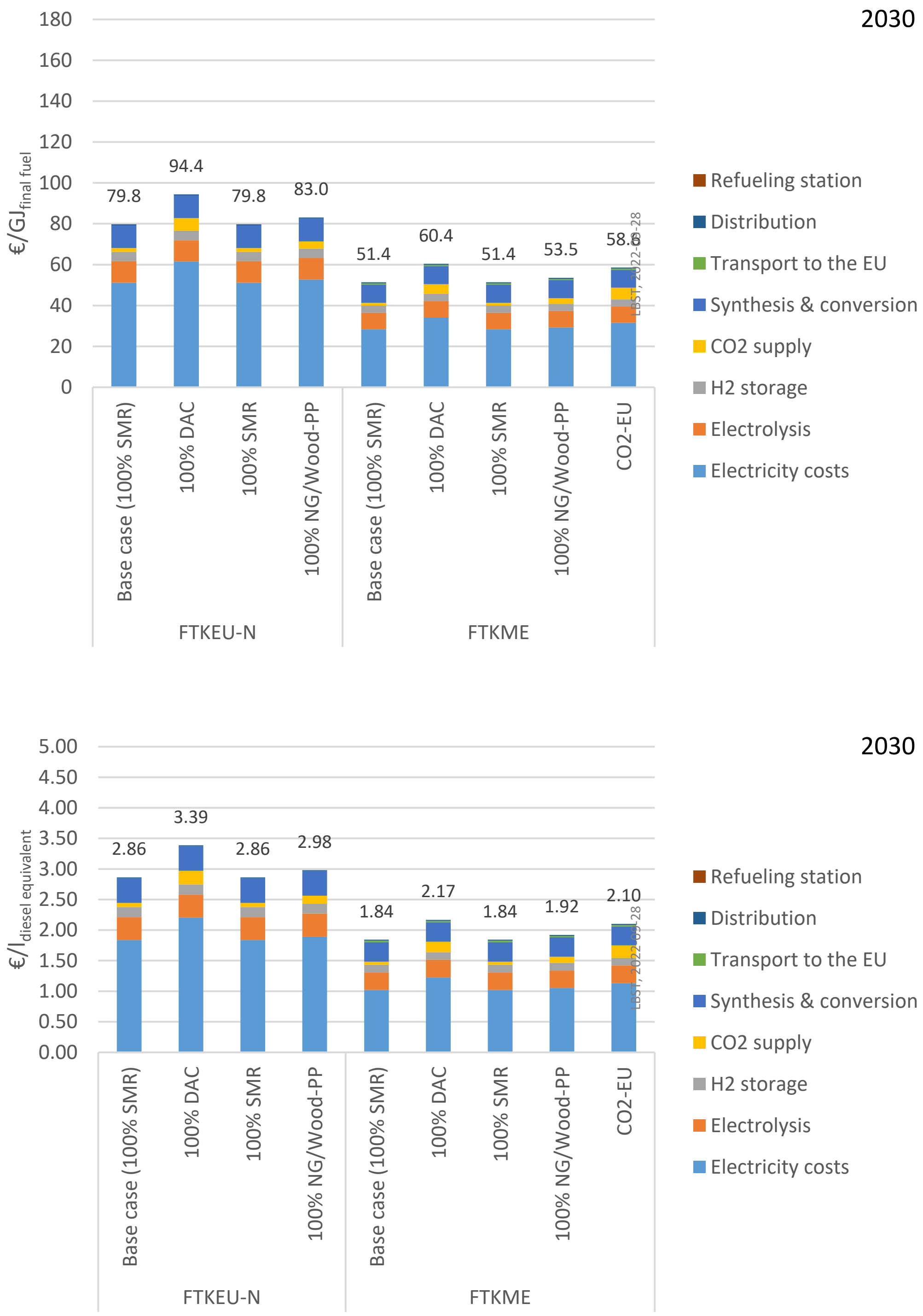


Figure 145: E-fuel costs in 2030 depending on CO_2 source for FT kerosene produced in North Europe and MENA



8.5.5. Variation of transportation inside Europe

Figure 146: Influence of longer transport distance inside Europe on the e-fuel costs in 2020

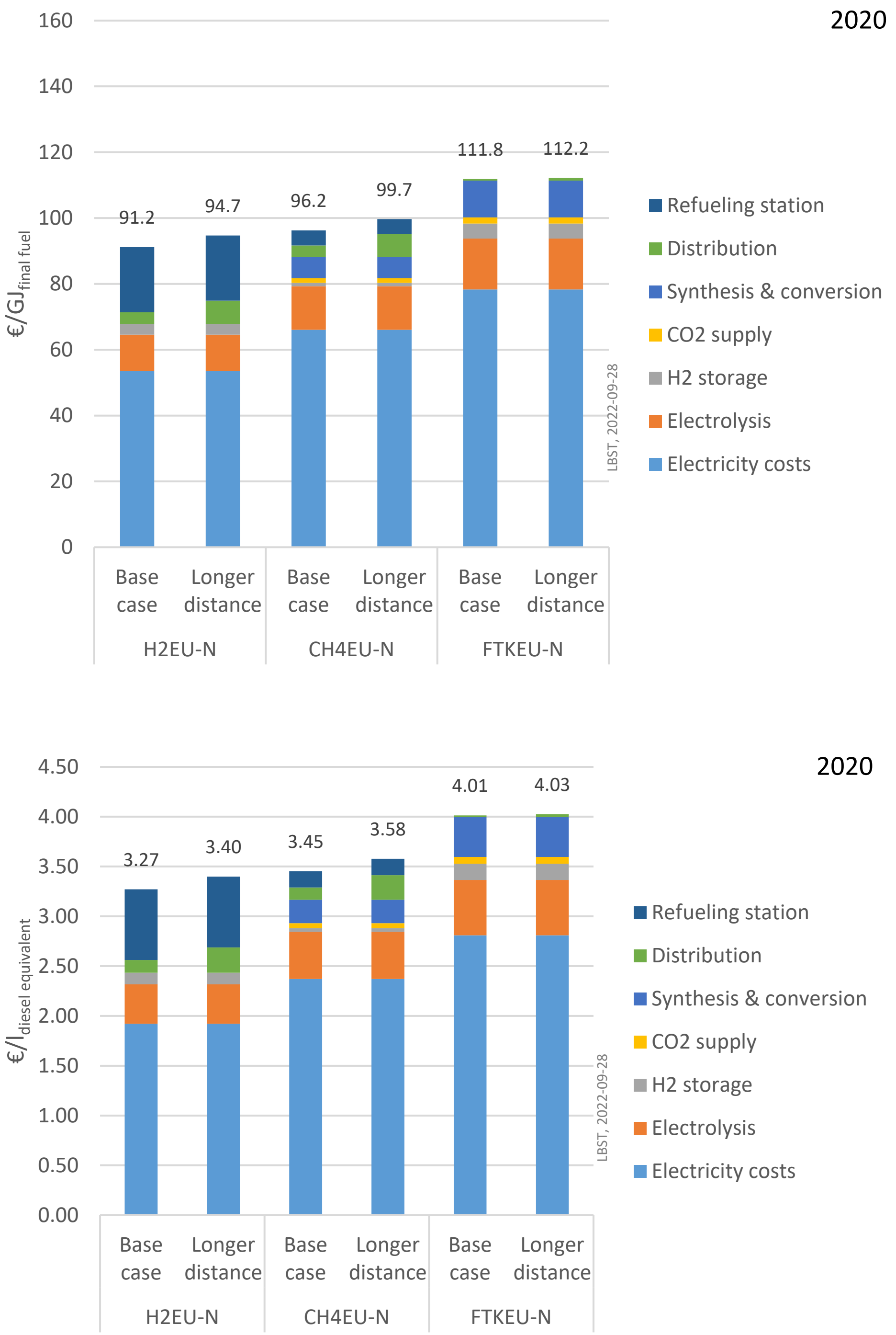
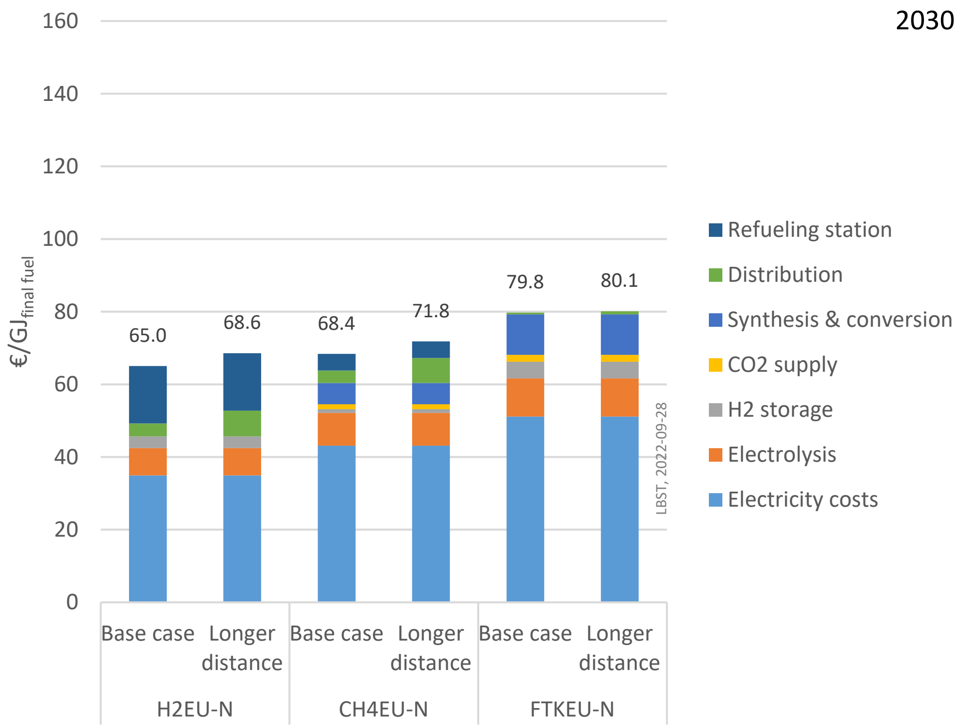


Figure 147: Influence of longer transport distance inside Europe on the fuel costs in 2030



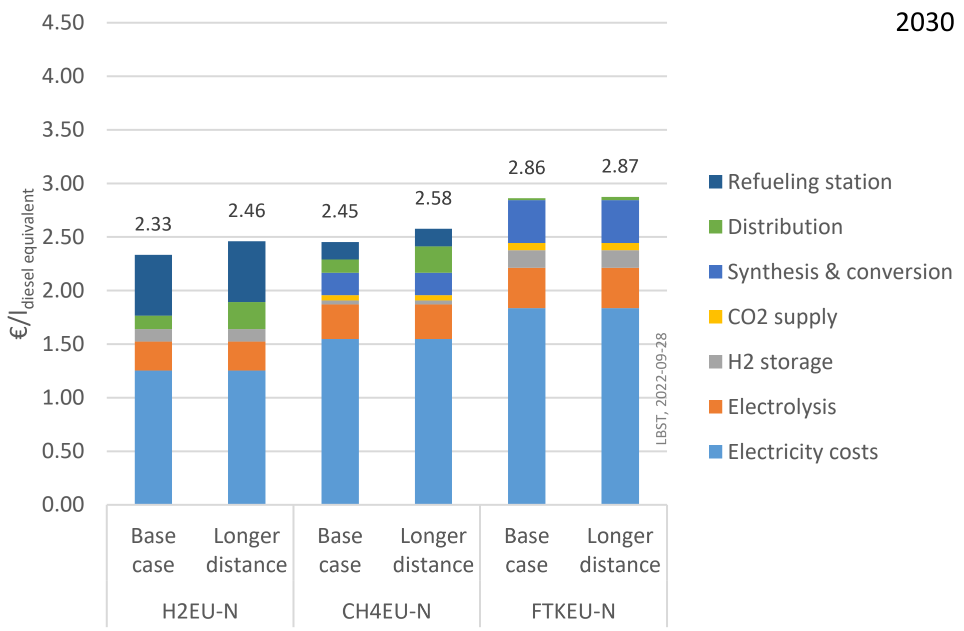


Figure 148: Influence of other transport types inside Europe on the e-fuel costs in 2020

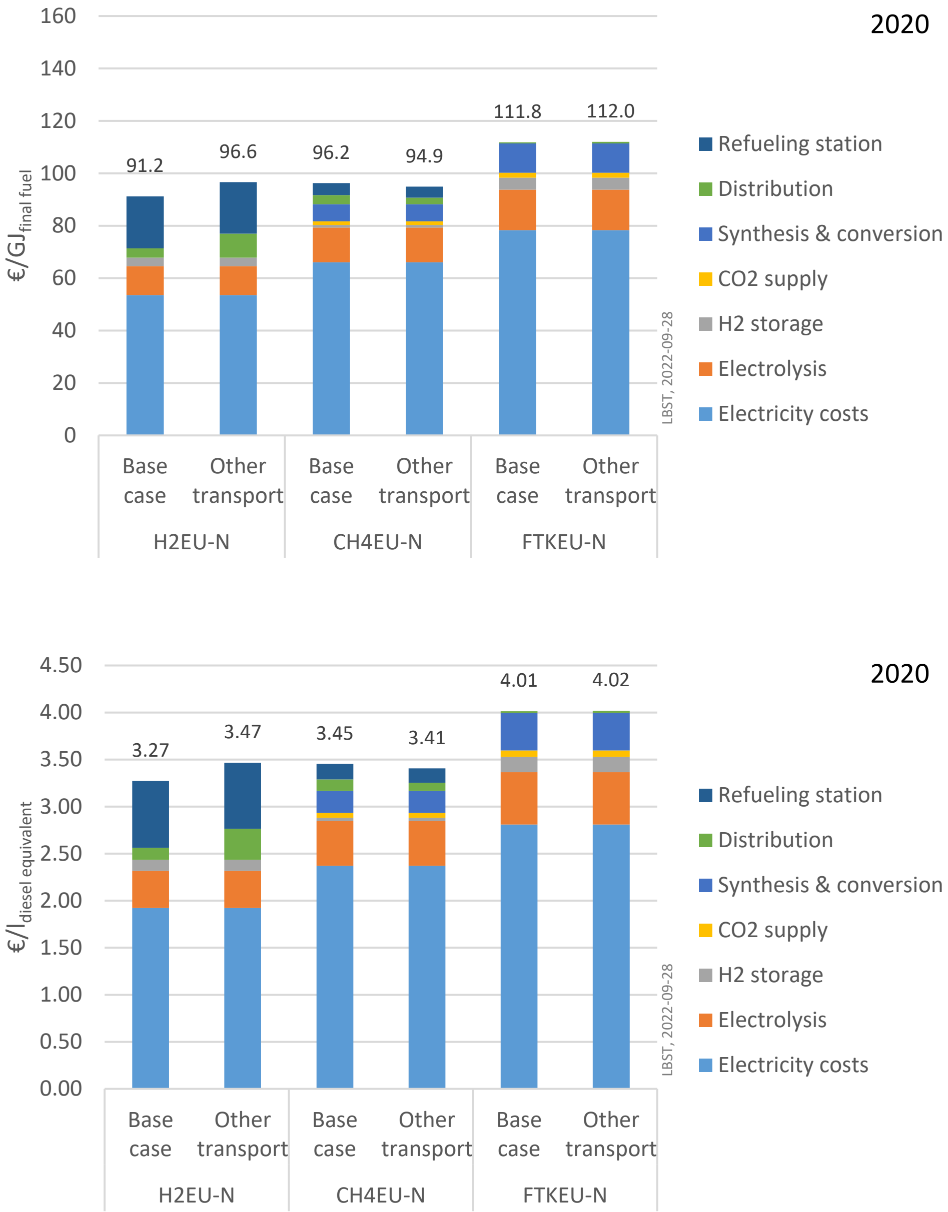
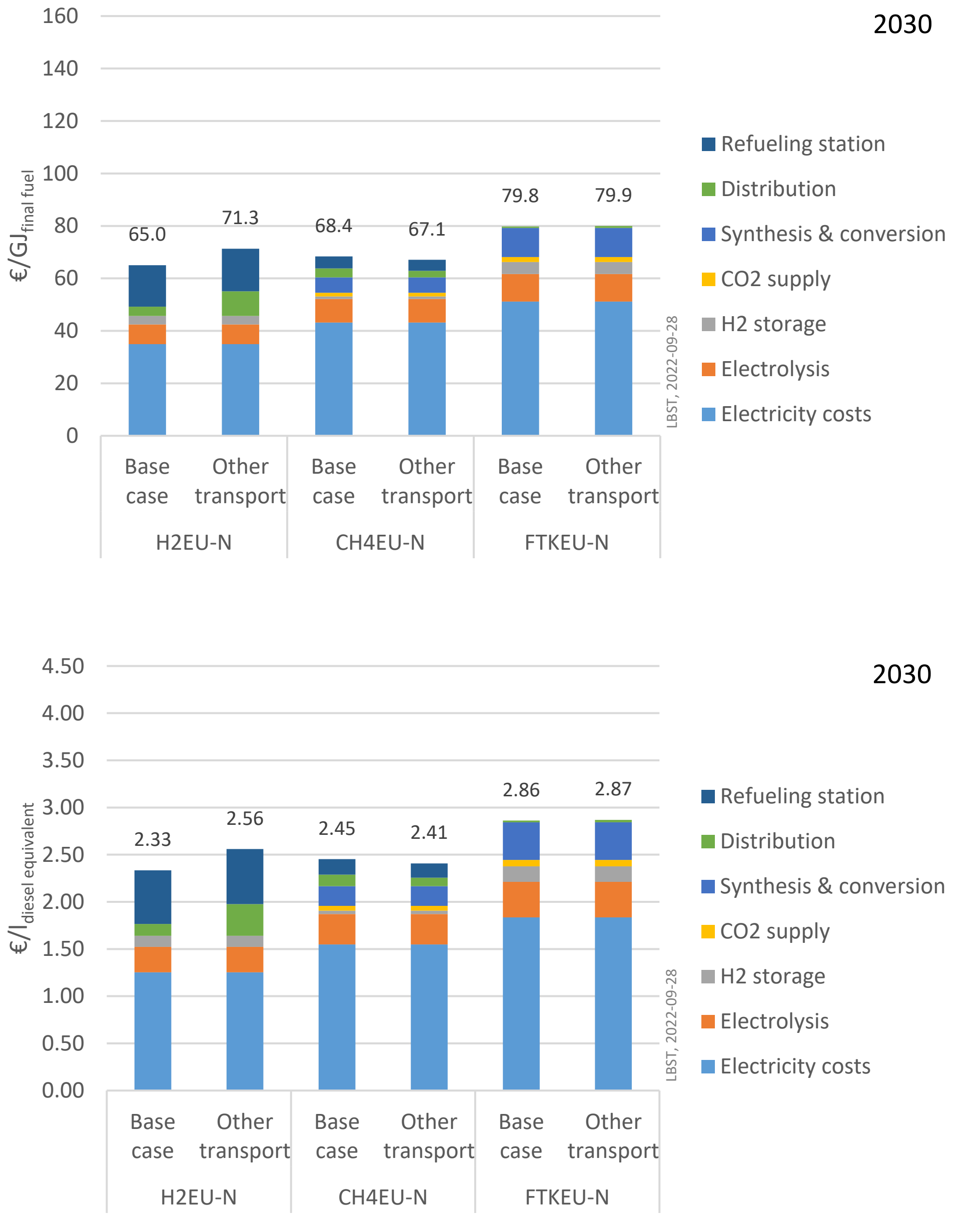
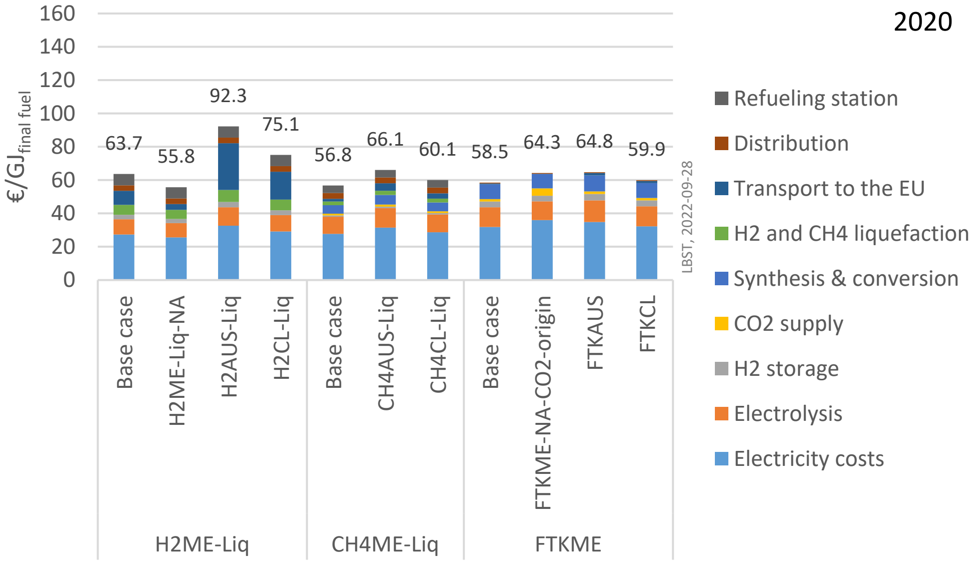


Figure 149: Influence of other transport types inside Europe on the e-fuel costs in 2030



8.5.6. Long-haul from other other potential sweet spots worldwide

Figure 150: Influence of long-haul marine transport from potential other sweet spots worldwide on the e-fuel cost in 2020



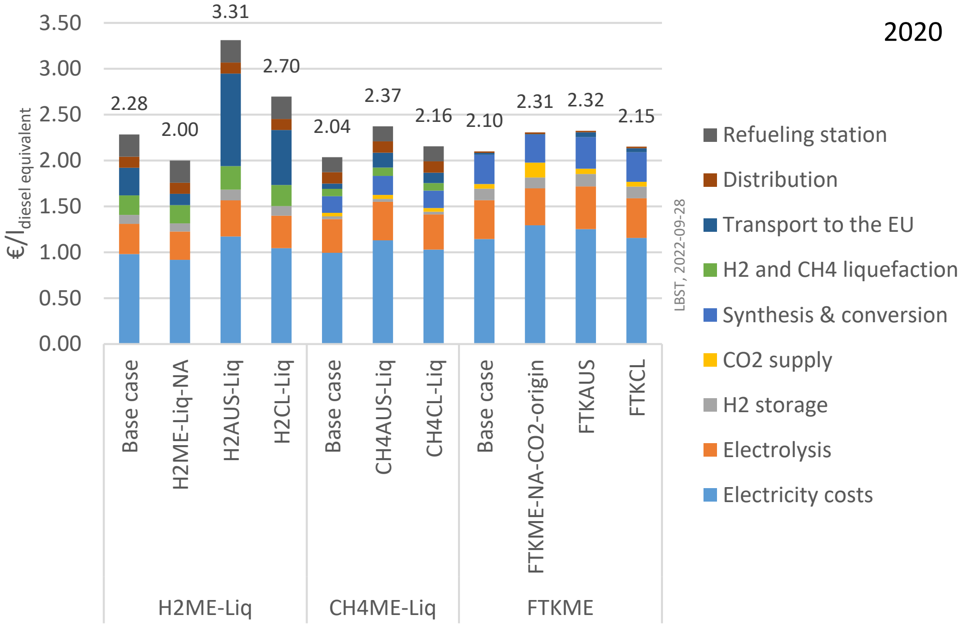
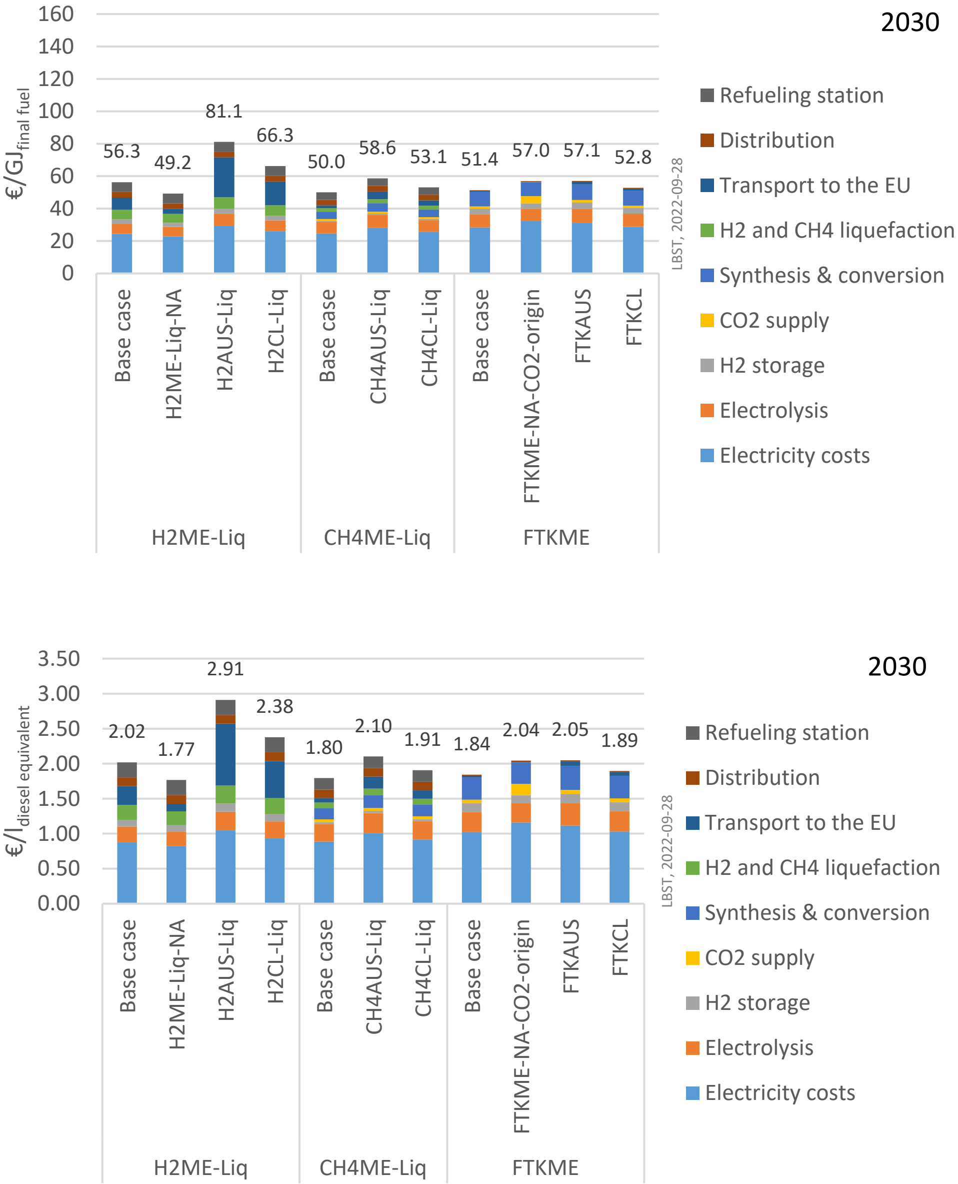
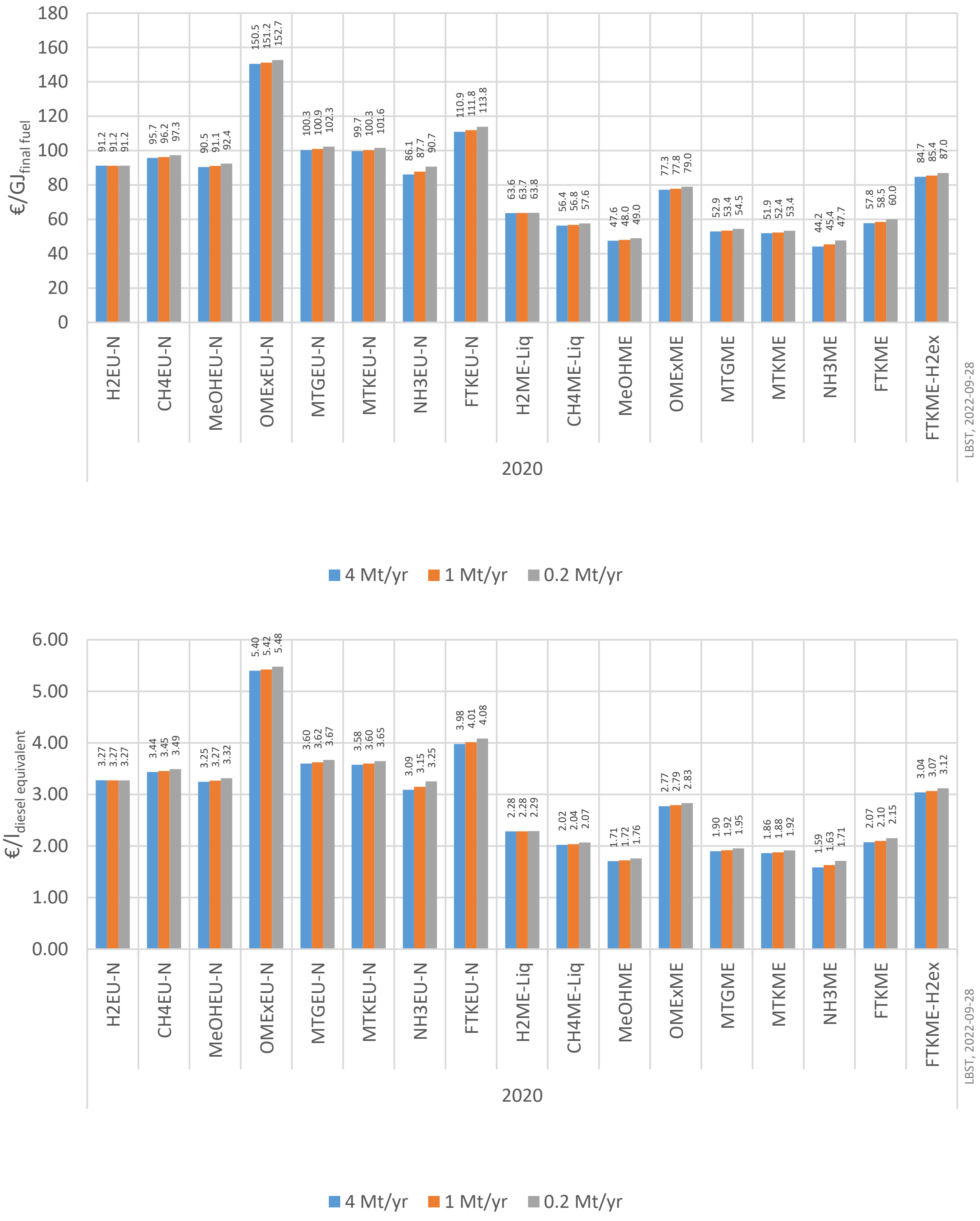


Figure 151: Influence of long-haul marine transport from potential other sweet spots worldwide on the fuel cost in 2030



8.5.7. Larger/smaller e-fuels plant size

Figure 152: Influence of larger/smaller e-fuels plant capacity in 2020



8.6. RESULTS FROM FOSSIL (WITH CCS) VERSUS E-FUEL PRODUCTION COSTS

The costs of e-fuels using renewable electricity are compared with fuels derived from natural gas with CCS. The carbon capture rate at the fuel production plant site amounts to about 90% except in case of the supply of natural gas as final fuel where all carbon from the natural gas is bound in the final fuel. In the case of hydrogen as final fuel, 90% of the carbon bound in the natural gas is captured and 10% is released at the steam reforming plant site.

In case of carbon containing synthetic fuels, a high fraction of the carbon bound in the natural gas is transferred into the final fuel and will be emitted during the use of the fuel (e.g. combustion in a vehicle).

For natural gas-based methanol, an autothermal reforming (ATR) process is used for synthesis gas production. Downstream the ATR a conventional methanol synthesis process is applied to generate methanol from CO and H_2 (in contrast to e-methanol where CO_2 and H_2 is fed into the methanol synthesis step).

For natural gas-based FT kerosene and diesel, a partial oxidation process is applied for synthesis gas production like at the GTL plant in Qatar to get the required H_2 to CO ratio for FT synthesis.

For OME synthesis, MTG process, MTK process and NH_3 synthesis, the same processes as for the e-fuels have been used.

The Emissions Trading System (ETS) price for CO_2 is applied for large industry, while non-ETS CO_2 prices are applied for CO_2 from combustion of the final fuel in the vehicle. A stronger inclusion of the transport sector into the ETS has been proposed in the European Comission’s ‘Fit-for-55’ policy package mid 2021 [EC 2021].

To compare non-carbon containing fuels (like hydrogen) with carbon containing fuels like FT diesel, the combustion of the final fuel is taken into account for the CO_2 costs (Table 16 in chapter 2.1.2) besides the CO_2 emissions at the plant site (part which is not captured).

For 2050, a CO_2 price of 250 € per t is assumed as indicated in [IEA 2021]. As a sensitivity, a CO_2 price of 60 € per t is also assumed (Table 16 in chapter 2.1.2).

Figure 153: Fuel costs of fossil low-carbon fuel production pathways involving CCS compared to fuel costs for e-fuel pathways in 2050 (CO_2 price: 250 €/t) - per GJ of final fuel

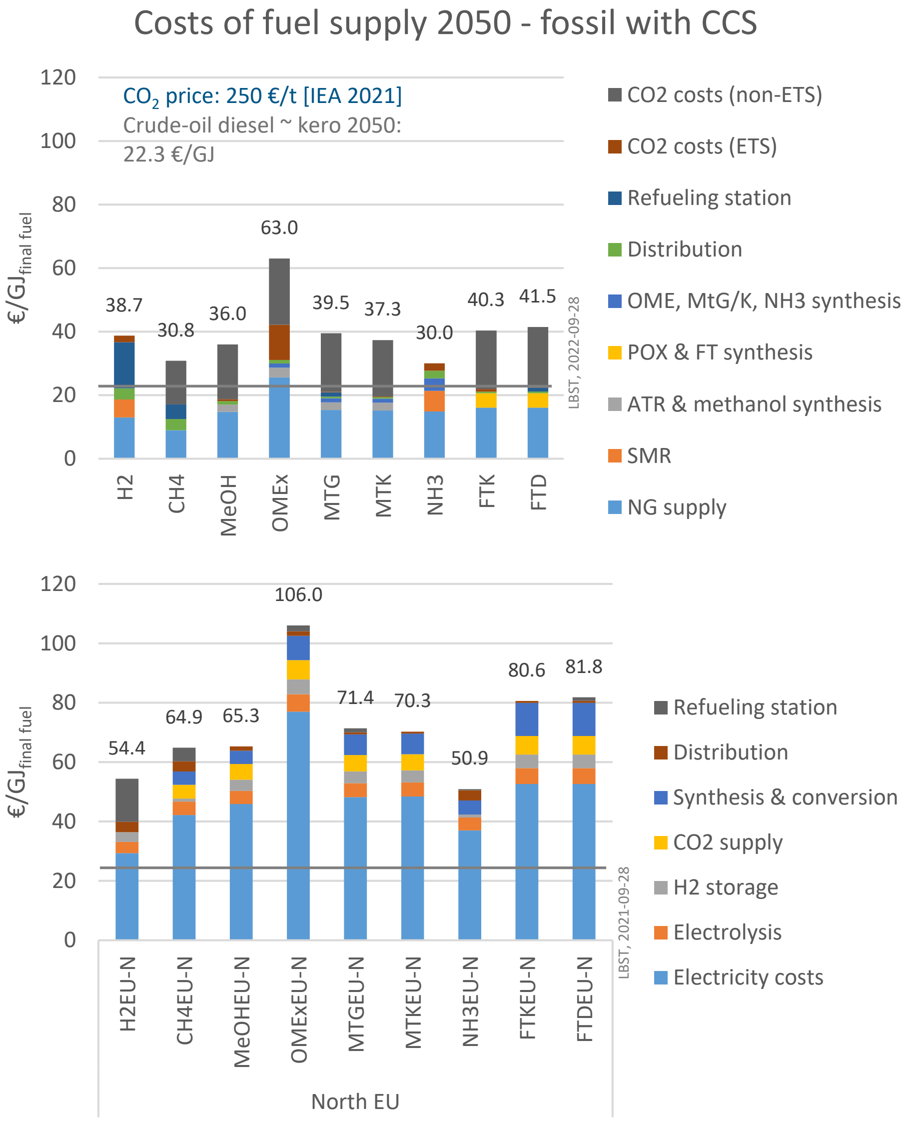


Figure 154: Fuel costs of fossil low-carbon fuel production pathways involving CCS compared to fuel costs for e-fuel pathways in 2050 (CO_2 price: 250 €/t) - per l of diesel equivalent

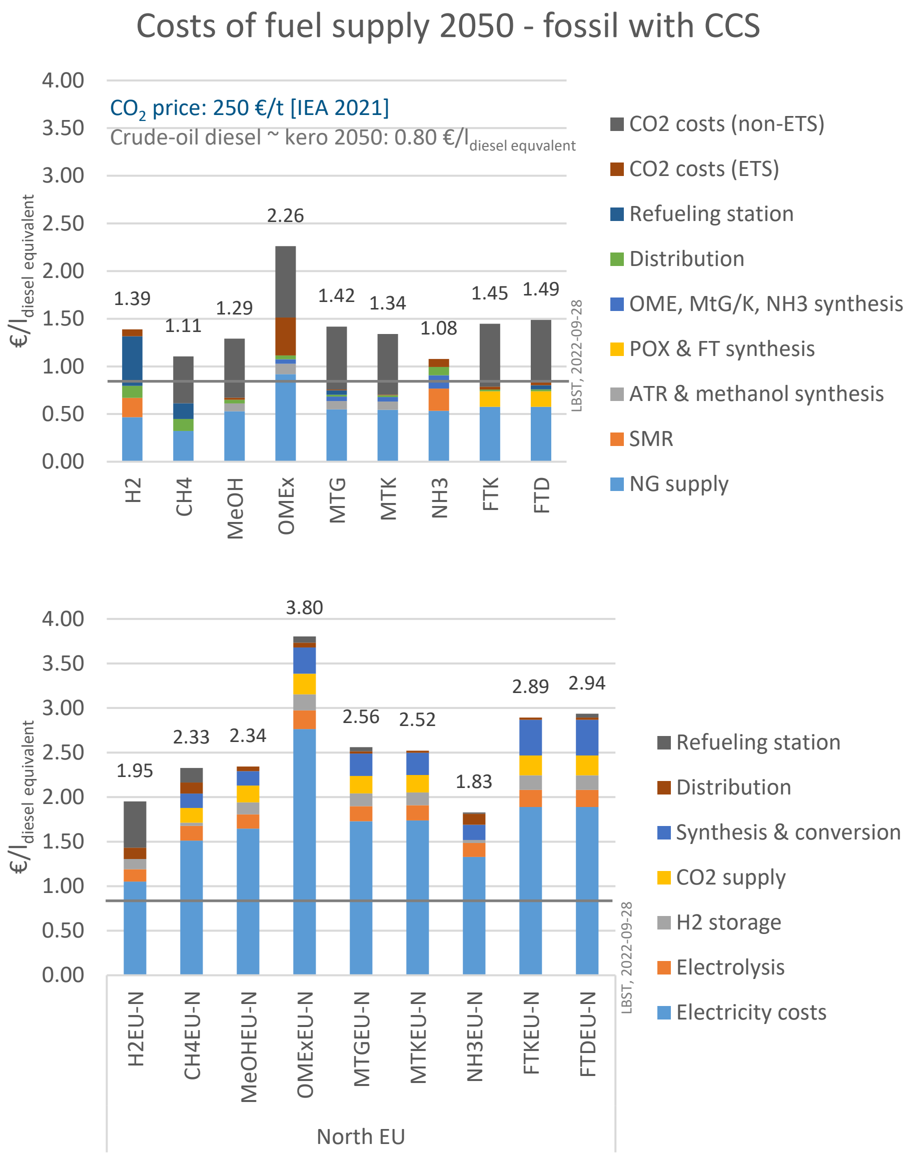


Figure 155: Fuel costs of fossil low-carbon fuel production pathways involving CCS compared to fuel costs for e-fuel pathways in 2050 (CO_2 price: 60 €/t) - per GJ of final fuel

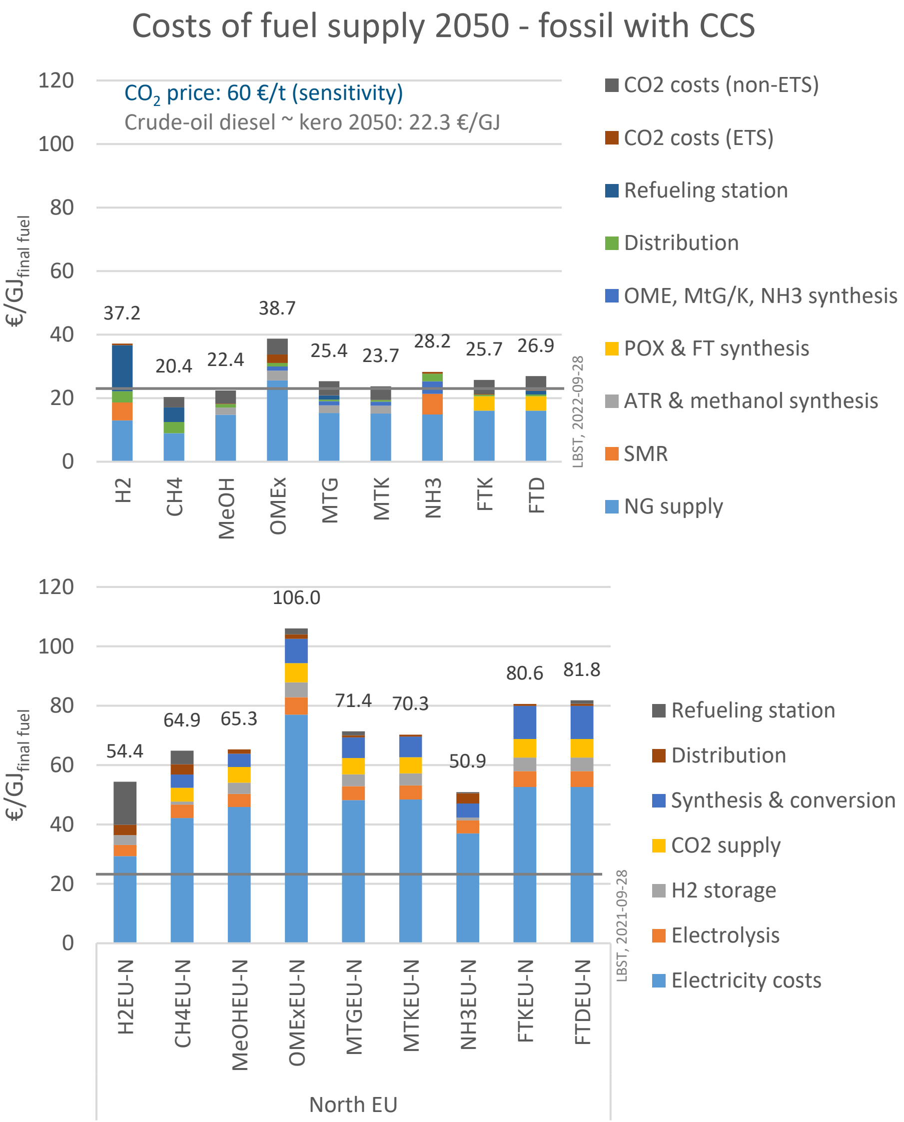
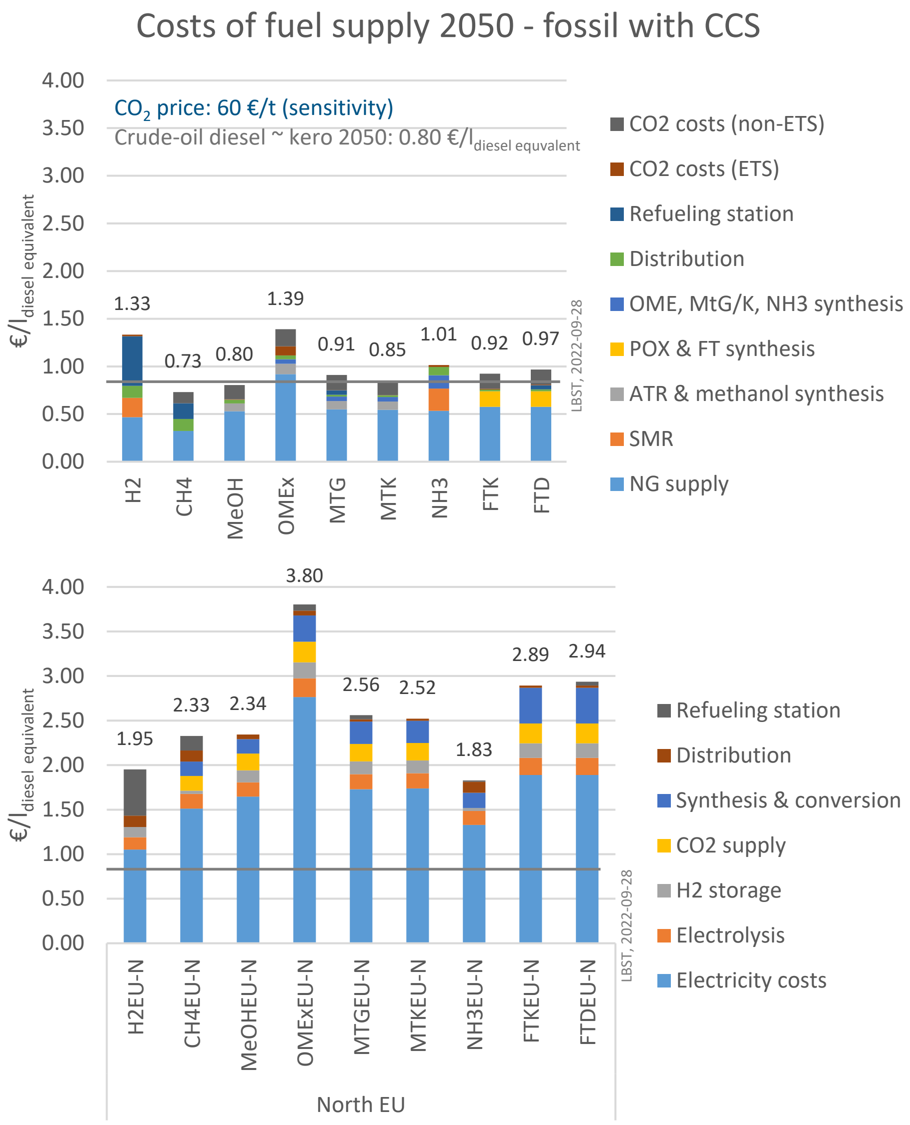


Figure 156: Fuel costs of fossil low-carbon fuel production pathways involving CCS compared to fuel costs for e-fuel pathways in 2050 (CO_2 price: 60 €/t) - per l of diesel equivalent



It has to be noted that above costs refer to fuel supply (including embedded carbon), i.e. without use efficiencies. Fuel cell electric vehicles (FCEV) have a higher efficiency than vehicles with internal combustion engines (ICE), leading to lower fuel costs per km. However, the powertrain evaluation (TTW) is out of the scope of this project.

8.7. RISKS AND BARRIERS TO E-FUELS DEPLOYMENT

Table 135: Risks and barriers to e-fuels deployment – workshop results

Category	Risk / Barrier Description	Impact	Likelihood	Mitigating actions
Political	No, or weak political support for e-fuels	H	H for road, L for aviation	Encourage appropriate level of support, consistency of support
	Lack of stable policies to support e-fuels			
	Lack of robust instruments to bolster e-fuels introduction**			
	Inconsistent approach to subsidies etc. across different countries	M	L	None. Policies likely to align anyway
	Lack of support to policies not aligned with the current green trend (ICE ban, push for EVs, etc.)	M	H for road, L for aviation	Encourage support for e-fuels in appropriate sectors - i.e. those that are hard to abate - which could include heavy duty road
	ICE ban			
	Political willingness for full electrification in road			
	Preference towards 'efficiency-first' principle, resulting in higher appraisal of battery and hydrogen fuel cell-electric powertrains*			
	Priority in fostering zero-emission powertrains, such as battery and hydrogen fuel cell-electric powertrains*			
	Risk that policies are too specific and exclude e-fuels (either intentionally or by omission), e.g. limiting transport tailpipe emissions would favour specifically electric vehicles.	M		
	Risk that policies are not sufficiently specific and therefore become too complex to implement in a way that provides a level playing field.	M		
	Prioritization of renewable power capacities for other sectors	M	H	Make argument that all sectors need to decarbonise and some (e.g. aviation) have few alternatives to e-fuels
	Avoidance of EU energy dependence on other countries with high level of renewable energy resources	L	L	None
	Insufficient renewables capacity made available for e-fuels production because policy supports it's use for electricity first (note: separate issue from technical generation potential, technical deployment rate of generation capacity, and social acceptance issues)	H	H	Encourage support for e-fuels in appropriate sectors - i.e. those that are hard to abate - which could include heavy duty road
Economic	Failure to achieve cost reductions	H	L	Support projects and R&D as appropriate to ensure cost reductions are realised
	Technology learning for renewable power and PtX conversion plants does not materialise into cost reductions estimated in the e-fuels study, e.g. because of increasing resource prices**			
	Availability of cheap CO2 sources			
	Related to the previous, production cost could be a barrier			
	Lower purchasing power if power costs surge (Spain, Portugal)			
	Cost of research, especially if increasing because of lack of consensus between stakeholders			
	High CAPEX			
	Refiners fail to make the investments involved in integrating e-fuel plants with crude/biorefineries, thereby limiting the opportunities for e-fuels plants	L	L	None required
	Lack of suitable sites to locate e-fuels plants	M	L	Identify appropriate brown fields sites and prepare groundwork
	Much cheaper to locate e-fuels plants overseas	L	L	None. Shouldn't hinder general e-fuels development
	Deployment of renewable electricity capacity as well as limitation in electrical network connection (could limit the scale of the assets)	M	M	Start discussions with renewables suppliers and T&D operators to investigate potential constraints on electricity capacity and on ways to mitigate these
	Efuels higher production cost versus biofuels or fossil fuels	H	H for road, L for aviation	Need to combine efforts on lobbying for support policies and investments to reduce costs (see above). Could focus efforts in those sectors where benefits are likely to be greatest, e.g. aviation, and take advantage of possible "trickle down" into other sectors, e.g. HD road
	alternatives become much more competitive			
	Low profitability business case			
	High commercial risk			
Social	No / low acceptance of carbonaceous fuels	M	M	Provide transparent information on the potential benefits of e-fuels in the sectors where they are anticipated for use, e.g. through independent studies and programme of "education"
	Preference for alternative power trains			
	Efuels seen as greenwashing			
	Negative perception of thermal engine technologies (bad publicity, lack of knowledge about technological progress)			
	Reluctance of the population to have wind turbines, carbon capture units "in their yards"	M	H for renewables, low for industrial site, H for power transmission	Provide transparent information on the potential benefits of e-fuels in the sectors where they are anticipated for use, e.g. through independent studies and programme of "education"
	Lack of social acceptance for further massive deployment of renewable power plants in Europe**	L	L	Not required
	Lack of social/fiscal participation from local population in e-fuel deployment**	L	L	
	Risk of uneven distribution of economic benefits from local e-fuel deployments**	L	L	
	Poor social impact assessments (EIA), e.g. leading to unintended consequences in the local-economic or social domain**	L	L	
	Acceptability of high-risk technologies at stake ex-ante/ex-post unintended or intended incidents, such as: ammonia for energy use at scale, nuclear power for e-fuels production, CO2 storage risk	L	L	
	Society not willing/not capable of paying for an e-fuel	L	L	

Category	Risk / Barrier Description	Impact	Likelihood	Mitigating actions
Technological	Unable to optimise processes	H	L	Support projects and R&D as appropriate to ensure technology issues are overcome
	Incompatibility of engines and fuels			
	Low process efficiency			
	High energy consumption of some units like RWGS, still on low TRL	M	L	Support projects and R&D as appropriate to ensure technology issues are overcome
	Low TRL in some parts of the process			
	Immature technology			
	First-of-a-kind risks			
	Inability to get high enough CO2 capture rates	H	H for CO2 based fuels, L for non-CO2 based	Support projects and R&D as appropriate to ensure technology issues are overcome
	Unknown ramp-up potential for electrolysis, carbon capture, fuel synthesis	H	M	Support projects and R&D as appropriate to ensure technology issues are overcome
	Required development of electrolyser assembly line production			
	Scale-up and deployment challenges			
	Up-scaling and commercialisation of RWGS and/or co-electrolysis (key elements in Fischer-Tropsch pathways)			
	Direct air capture proves too challenging to achieve at reasonable costs	M	M	Support projects and R&D as appropriate to ensure technology issues are overcome
	Unable to design system to cope with intermittency	M	L	Support projects and R&D as appropriate to ensure technology issues are overcome
Legal	Planning processes too complicated / time consuming	H	H for road, L for aviation	Work with regulators / policymakers to ensure regulations are fit for purpose recognising the benefits of e-fuels
	Lack of appropriate regulatory arrangements			
	Lack of regulatory predictability			
	Regulatory uncertainty			
	(Nationally-determined) sustainability certification systems are too heterogenic or incompatible	M	L	Policies likely to align anyway
	City or regional regs			
	Delegated Acts in RED II pending	L	L	Will resolve soon
	Ineffective chain of custody for inputs	M	L	No required
	Tail pipe regulation in CO2 standards regulation	M	L	Not required
	Crediting system not in place			
	If imported, risk of non-recognition of CO2 captured from outside EU			
	If local, risk of non-recognition of point source C as circular			
	Lack of initiative for ASTM-approval of methanol route for PtL jet fuel	H	L	Work closely with ASTM and other relevant stakeholders (e.g. engine makers) from an early stage to get routes into the approval process
	fuel accreditation and blend wall agreements			
Environmental	Ongoing CO2 impact	L	L	Policies likely to align anyway
	Ongoing air quality impact			
	Local pollution problems associated to thermal engines (particles, NOx, HCs, etc.)			
	Acceptability of CO2 sources	M	L	Work with regulators / policymakers to ensure regulations are fit for purpose recognising the benefits of e-fuels
	Risk of using avoidable CO2 emissions as feedstock to produce fuels			
	Lack of specification of carbon source eligible specifically			
	Plot plan requirement for PV, wind mills, DAC plants	M	L	Work with regulators / policymakers / civil society to ensure regulations are fit for purpose and that the benefits of e-fuels are clearly articulated
	Poor environmental impact assessments (EIA), e.g. resulting in excessive local water consumption**	M	L	Developments in desalination should ensure this issue is minimised
	Water accessibility in desert areas			
	Gap/lack of consistency in GHG accounting systems, resulting in under reporting of GHG emissions (risk applicable to any energy activity, not just e-fuels)	L	L	Not required
	Sustainability criteria for e-fuels too weak to drive the uptake needed for cost reduction (versus alternatives like fossil+CCS pathways)	L	L	Not required

* Risk/barrier for fuels used in combustion engines

** Risks/barriers that are not necessarily specific to e-fuels projects, but rather common with major investment ventures

H = High, M = Medium; L = Low

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