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Methanol as a renewable energy carrier: An assessment of production and transportation costs for selected global locations

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ABSTRACT

The importing of renewable energy will be one part of the process of defossilizing the energy systems of countries and regions, which are currently heavily dependent on the import of fossil-based energy carriers. This study investigates the possibility of importing renewable methanol comprised of hydrogen and carbon dioxide. Based on a methanol synthesis simulation model, the net production costs of methanol are derived as a function of hydrogen and carbon dioxide expenses. These findings enable a comparison of the import costs of methanol and hydrogen. For this, the hydrogen production and distribution costs for 2030 as reported in a recent study for four different origin/destination country combinations are considered. With the predicted hydrogen production costs of 1.35–2 €/kg and additional shipping costs, methanol can be imported for 370–600 €/t if renewable or process-related carbon dioxide is available at costs of 100 €/t or below in the hydrogen-producing country. Compared to the current fossil market price of approximately 400 €/t, renewable methanol could therefore become cost-competitive. Within the range of carbon dioxide prices of 30–100 €/t, both hydrogen and methanol exhibit comparable energy-specific import costs of 18–30 €/GJ. Hence, the additional costs for upgrading hydrogen to methanol are balanced out by the lower shipping costs of methanol compared to hydrogen. Lastly, a comparison for producing methanol in the hydrogen's origin or destination country indicates that carbon dioxide in the destination country must be 181–228 €/t less expensive than that in the origin country, to balance out the more expensive shipping costs for hydrogen.

1. Introduction

In 2018, approximately 60% of European primary energy demand was met via imports [1]. Of these energy imports, 99% were derived from the fossil sources of coal, crude oil, or natural gas [1]. In 2021, against the backdrop of the drastic greenhouse gas emission reduction goals of 2050, Europe remains heavily dependent on fossil energy imports. Other energy-importing countries around the globe, such as Japan and South Korea, share this status [2]. Although the further extension of local renewable energy production and the necessary shift towards greater electrification in various sectors to increase energy efficiency will reduce this dependency, European energy autarky cannot be assured within the short timeframe set out. Thus, renewable energy imports will play a vital role in the future energy system. Apart from biomass and solar thermal systems, renewably-generated power is available in the form of electricity. As the transport of electrical energy from potential renewable energy-exporting countries is either too costly, politically undesirable due to a high degree of dependency, or simply represents an unrealistic option (i.e., Australia), electrical energy must be transformed in the country of origin into an easy-to-transport and storable energy carrier. This would enable a transition from the global fossil market towards a renewable energy-based one. The key technology for this is the splitting of water using renewable electrical energy to drive an electrolysis process for the production of hydrogen:

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2 \tag{1}$$

The hydrogen would then constitute a new base energy carrier, analogous to coal, oil, and natural gas today. Over recent decades, tremendous effort has been expended to develop the three major electrolysis technologies of alkaline, proton exchange membrane (PEM) and solid oxide [3-5]. These efforts have led to the production of commercially-available products that utilize all three technologies, with alkaline and PEM electrolysis available in the double digit MW range [6, 7]. For the

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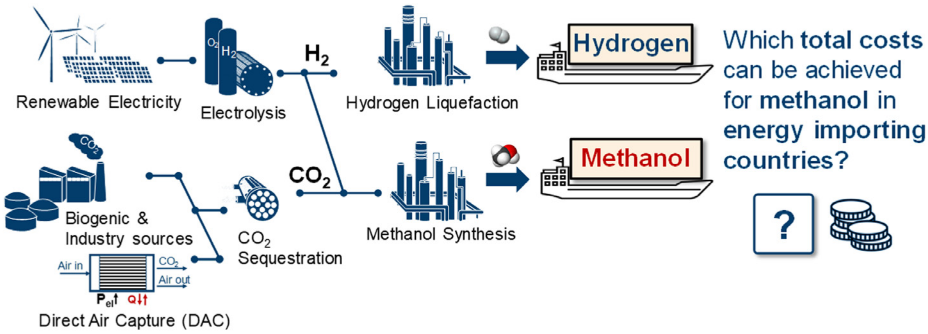


Fig. 1. General overview of the main objective of this study.

intercontinental energy trade, hydrogen derivatives are considered as complementary energy carriers to hydrogen to simplify the distribution. Due to its already existing high demand, broad applicability, and the possibility of synthesizing important follow-up products, methanol is the focus energy carrier in this study. A general overview of the main objective of this study is given in Fig. 1. In particular, the production and distribution costs of methanol are examined in detail from three different perspectives. In a first step, the key impact parameters on methanol production, namely hydrogen and carbon dioxide expenses, are highlighted and outlined. The results reveal which combinations of hydrogen net production costs and carbon dioxide prices lead to competitive methanol production costs. Then, the energy-specific total costs at the destinations of the methanol and hydrogen are compared. This assessment is performed drawing on the results of a current study by the Hydrogen Council [8] that presents the production and distribution costs of hydrogen for four different combinations of energy-exporting and -importing countries. As a degree of freedom for the methanol synthesis, the price of carbon dioxide is selected, and this has not been investigated so far. The results reveal the conditions under which additional costs of upgrading hydrogen to methanol are balanced out by the more expensive transportation of liquid hydrogen. Finally, two different scenarios of renewable methanol production are compared. Methanol is produced in either the hydrogen-producing country with carbon dioxide from direct air capture or in the destination country using imported hydrogen and carbon dioxide from a point source. The generated results show which carbon dioxide price difference would be necessary to make the production of methanol in the destination country more affordable than in the origin one. In order to support the methodology and literature data used in this contribution, a short literature review of the hydrogen production cost, hydrogen distribution, and methanol as a renewable energy carrier is presented below.

1.1. Review of the literature on hydrogen production costs

In order to reduce the production costs of hydrogen to make it competitive against current energy carriers, three main goals must be achieved, according to Saba et al. [9]. First, a further increase in efficiency will reduce operational expenditures. Second, a massive expansion of the installed capacity will reduce the specific investment costs of electrolysis units thanks to the benefits of economies of scale and learning curves. Lastly, electrolysis units must be powered using inexpensive electricity, as studies have shown that electricity costs make up a major part of hydrogen production costs [7, 10, 11]. In this domain, several studies have investigated favorable regions around the globe, in which renewable electricity can be generated at low costs and from which hydrogen can in turn be produced [7, 8, 11-14]. A key result of such studies suggests that these favorable regions are far more evenly distributed across the world than some sources of fossil energy carriers. This can be seen, for instance, in the heat map shown in Fig. 2, which was published by Fasihi and Breyer [12]. With the hourly solar irradiation and wind speed data of a spatial resolution of 0.45° x 0.45°, the levelized cost of electricity (LCOE) for solar photovoltaic (PV) (single-axis tracking) and onshore wind are presented. For the year 2030, numerous regions with LCOEs of 20 €/MWh (shown in red) can be observed, representing potential renewable energy export regions. Comparable results were presented by Perner and Bothe [14], who identified a total of 37 countries with strong renewable energy export potential. This increased the number of competitors that could be beneficial to energy-importing countries.

Stimulated by such results, a number of studies have assessed the production costs of hydrogen in favorable regions. For instance, Fasihi and Breyer [12] further analyzed the hydrogen production costs out of their LCOE for the years 2020 through 2050. With the information gathered, the baseload electricity cost and baseload hydrogen cost could be calculated, with both implementing either battery or hydrogen storage, or a combination of the two. For the year 2030, baseload hydrogen costs were determined to be 31–61 €/$MWh_{H2,HHV}$, which corresponds to 1.2–2.4 €/kg_{H2}. Furthermore, a recent study by the Hydrogen Council [8], a CEO-led organization of more than 90 hydrogen industry partners, forecast hydrogen production costs of 1.35–2.00 $/kg for three different global production sites in Chile, Saudi Arabia, and Australia. A more general study by the International Renewable Energy Agency (IRENA [7]) reported comparable hydrogen production expenses for the year 2030 of under 2 €/kg for optimal PV and wind locations, and approximately 3 €/kg for average ones. Gallardo et al. [15] calculate hydrogen production costs in Chile with different solar power technologies and electrolyzer types as 1.7–3.4 $/kg in the year 2025. Meanwhile, Heuser et al. [11] devised a detailed production and distribution network for hydrogen generation in Patagonia, based on wind power. Including compression and pipeline transport, a hydrogen cost of 2.73 €/kg was calculated. In addition, Hank et al. [13] presented efficiencies and the production and distribution costs of different renewable energy carriers. For the year 2030 and the production site “West-Sahara”, a total onsite hydrogen production cost of 90 €/MWh_{LHV} (3.0 €/kg) and 126 €/MWh_{LHV} (4.2 €/kg), with Germany as the destination country, were determined. The increase in costs compared to previous studies can be explained by reference to the high level of detail in this study [13]. In addition to the electricity and investment costs for electrolysis, the costs of sea water desalination, a hydrogen motor for electricity and heat generation, a hydrogen cavern, and a liquefaction plant, as well as product storage, were included. Still, with the presented range of expected hydrogen production costs of 1.35–3 €/kg in 2030, it can be stated that producing a renewable energy carrier is expected to become significantly less expensive within the next decade compared to the current level of approximately 4–6 €/kg [7, 8].

1.2. Review of the literature on hydrogen distribution

Following hydrogen production, the process of distributing it to energy-demanding countries must also be taken into account. Cerniauskas et al. [16] show that, for regional or continental transport, the reassignment of existing natural gas pipelines constitutes a cost-effective means of building up a hydrogen infrastructure. For the intercontinental, long-distance transport of hydrogen, however, a number of possibil-

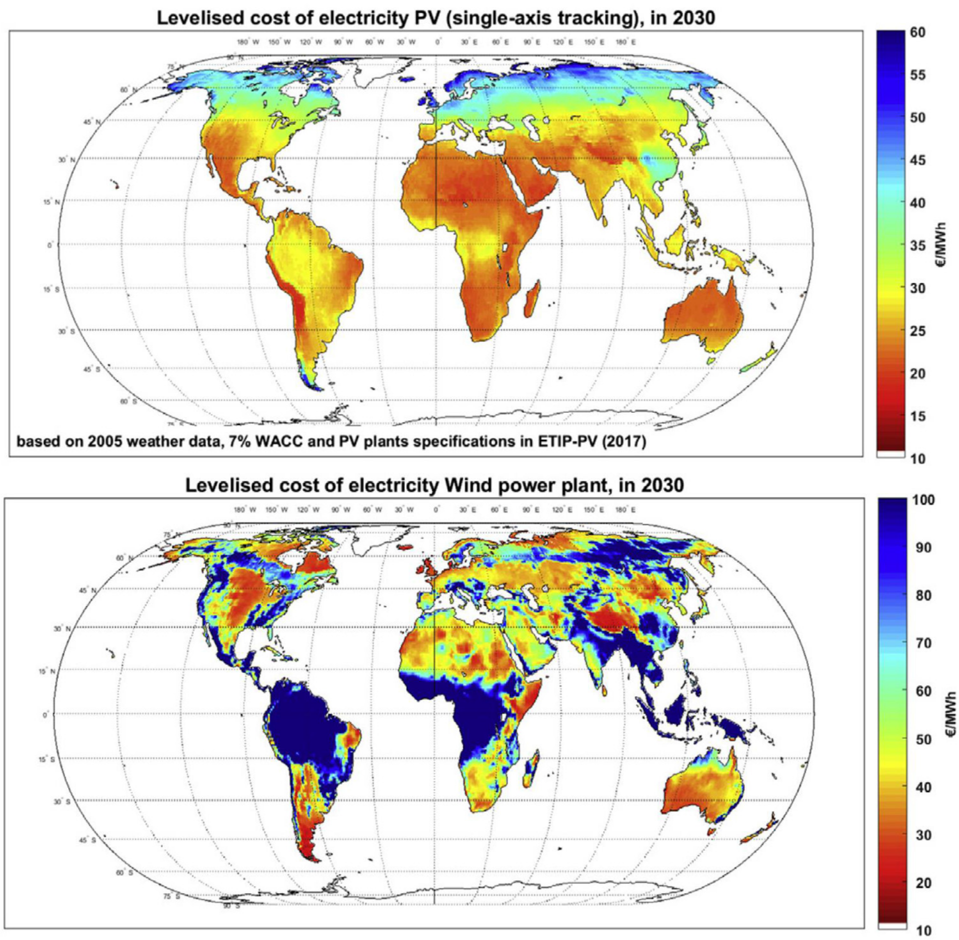


Fig. 2. Global LCOE for 2030, as presented by Fasihi and Breyer [12].

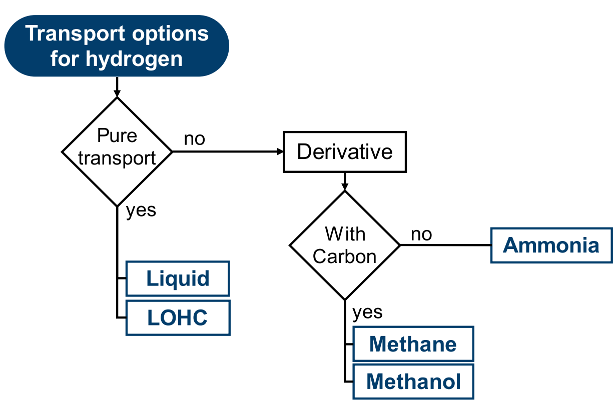


Fig. 3. Considered intercontinental transport options for hydrogen as a renewable energy carrier.

ities are discussed and these are graphically depicted in Fig. 3. At the first decision level, hydrogen can be either transported in pure form or as a derivative. The latter option can be especially relevant if the end use of the imported energy carrier is not the hydrogen itself, but the transported derivative. For direct hydrogen transportation, two different possibilities present themselves again, namely hydrogen remaining in a liquid state or being bound to a liquid organic hydrogen carrier (LOHC). For liquid transportation, hydrogen must be cooled to below 21 K under atmospheric pressure [17], which requires a theoretical minimum energy demand of 2.89 kWh/kg_{H2} [18]. However, current large-scale hydrogen liquefiers have an energy demand of 10–20 kWh/kg_{H2} [19], with the potential to decrease this down to 6 kWh/kg_{H2} [20]. Therefore, in the best case scenario, at least 18% of the energy stored in hydrogen (LHV: 33.33 kWh/kg) is required for this step.

An alternative for the transport of hydrogen are LOHCs [21]. With this technology, an organic substance is hydrogenated in the hydrogen-producing country and later dehydrogenated in the hydrogen-demanding one. The advantage of this concept is the simple handling and transportation enabled. One major disadvantage, however, is that the endothermal dehydrogenation of the LOHC in the destination country requires about 32 MJ/kg_{H2} [22], corresponding to 9 kWh/kg_{H2}; the energy demand is therefore on the same order as for liquefaction. Consequently, a significant amount of the energy transported must be used for its release at the destination point.

In order to avoid liquefaction or additional energy demand at the destination, the option of hydrogen derivatives has been frequently discussed in the relevant literature [13, 23, 24]. Some examples of carbon-free and carbon-containing options are presented in Fig. 3. A significant advantage of a carbon-free hydrogen derivative as an energy carrier is the independence of the carbon source at the production site. One example of this is ammonia [25-27]. For its synthesis, hydrogen is reacted with nitrogen via the industrial Haber-Bosch process, or is electrochemically-produced with a reduction of nitrogen [25]. The resulting gas can be liquefied by applying a pressure of 10 bar, or by cooling it to 240 K under atmospheric pressure [25], thereby making it an easy-to-transport substance. In the destination country, ammonia can be combusted in gas turbines in order to generate electricity [26]. Alternatively, Kobayashi et al. [28] and Hansson et al. [29] present ammonia as a possible future fuel for marine and automotive applications. Among its drawbacks, however, Tremel et al. [23] point out its toxicity to human and marine life, which could result in low public acceptance.

The simplest carbon-containing chemicals with potential viability as future energy carriers are methane and methanol. Carbon dioxide derived from biomass, process-related industrial activities, or separation from the air can be considered sustainable carbon sources [30-32]. Car-

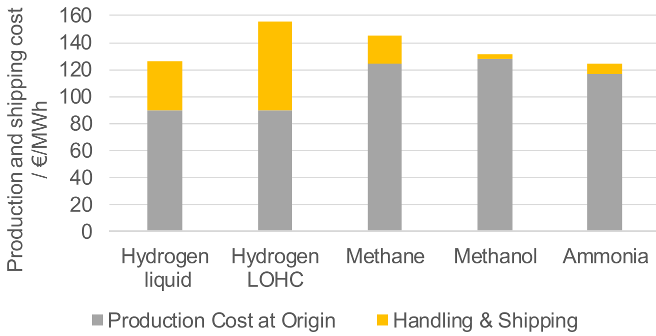


Fig. 4. Production, as well as handling and shipping costs for a distance of roughly 3000 km, of various renewable energy carriers, based on [13].

bon dioxide from fossil point sources, however, is not consistent with the overall goal of producing a renewable energy carrier.

Methane, as the main component of natural gas, can be produced via the Sabatier reaction with hydrogen and carbon dioxide [33]. The gas can then be transported as a liquid at 110 K, which is already practiced today using fossil-based natural gas [34]. Thus, an infrastructure for the handling of synthetic methane already exists. In the destination country, it can be fed into existing pipelines and used in the industrial, housing, and transportation sectors. A potential drawback of methane is the low market price of the fossil counterpart of natural gas. Peters et al. [35] determined a factor of 2–3 between renewable methane production and private consumer prices, which increases to a factor of 7–15 by comparison to natural gas prices at the German border, excluding taxes.

For the renewable energy carriers depicted in Fig. 3, Hank et al. [13] presented an integrated production and distribution system to investigate the respective production costs. The results are shown in Fig. 4. The authors note that the combined energy-specific cost of all carriers at the destination are at a comparable level to ammonia, which exhibits the lowest cost, and LOHCs, which feature the highest. However, significant differences between production costs in the origin country and the final costs in the destination one can be observed, with methanol carrying the lowest overall shipping and handling costs. Due to these favorable transportation properties and several other methanol-specific benefits, which are discussed in the next section, the focus of this study is on methanol.

1.3. Review of the literature on methanol as a renewable energy carrier

As a liquid carbon energy carrier, methanol has often been discussed in the literature [13, 36], as it is already producible from hydrogen and carbon dioxide at a high technology readiness level (TRL) [37] and is even simpler to handle than methane. Current crude oil cargo vessels could be used to transport methanol with only minor modifications. Methanol itself can be used in the transportation and chemical sectors, and receives particular attention among researchers as a viable future marine fuel [38]. Furthermore, methanol is already traded today as a base chemical and presents a wide range of possible follow-up products, spanning ethers and higher alcohols, to drop-in gasoline and even kerosene [24, 39]. Because of its vast array of possible applications, simple handling and its potential to make use of already-existing infrastructure, the idea of a “methanol economy” was already considered and proposed by Olah in 2006 [40].

Multiple synthesis routes for producing methanol are known. Conventionally, it is produced from carbon monoxide and hydrogen by means of low-pressure methanol synthesis [41]. This synthesis gas can also be obtained through different pathways. In general, fossil-based natural gas is used in steam reforming, partial oxidation, or autothermal reforming [41]. Alternative sources, apart from natural gas on the fossil side, include coal or coke oven gas [42] and, on the renewable side, synthesis gas produced via the gasification of biomass [43]. For the large-scale renewable production of methanol, electricity-based methanol produced by hydrogen from water electrolysis and carbon dioxide is the option most frequently discussed in the relevant literature [37, 44-46]. Therefore, this route is evaluated in this study. Schemme et al. [47] assessed both the synthesis of methanol from hydrogen and carbon monoxide, as well as from hydrogen and carbon dioxide, with a TRL of 9. Yet, there are significant differences between the two synthesis methods. Marlin et al. [37] outline the advantages and disadvantages of CO_2-based synthesis compared to the CO-based route. Aside from the possibility of producing methanol renewably, the higher selectivity for methanol and therefore the low amount of by-products are noted as advantages, as well as the less harsh reaction conditions caused by the lower amount of heat produced by the reactions taking place [37]. Drawbacks noted include the lower reactivity of carbon dioxide-based synthesis compared to production by carbon monoxide-containing syngas and the inherent production of water within the reactor [37]. As an example of already-existing methanol production from hydrogen and carbon dioxide, the Carbon Recycling International plant in Iceland can be mentioned. Since 2011, renewable methanol has been commercially-produced there, with a current capacity of 4000 tons per year using carbon dioxide obtained from a geothermal power plant [48].

Application areas for the produced methanol include the chemical and transportation sectors. As a globally-traded base chemical with an annual production of approximately 75 million tons [49], the anticipated future demand for renewable methanol for the chemical sector alone is substantial. Within the transport sector, methanol can generally be used as a blend or, in its pure form, in internal combustion engines [42, 45, 50]. At present, methanol can be blended in gasoline at up to the 3% level, according to DIN EN 228, and is partially used in China as M85 (a mixture of 85 vol.% methanol and 15 vol.% gasoline) or M100 (pure methanol) in the spark-ignited combustion engines of light-duty vehicles [50, 51]. Currently, methanol is widely seen as a viable future fuel for marine applications [52, 53]. For instance, seven oceangoing vessels equipped with dual fuel, two-stroke engines, which can run on methanol, fuel oil, marine diesel oil, or gas oil, have been operated since 2016 [54].

With respect to the transport sector, Fig. 5 displays the numerous promising follow-up products that can be obtained from methanol, including ethers and higher alcohols, as well as the hydrocarbons, gasoline and kerosene. The production and use of gasoline, DME, OME (polyoxymethylene dimethyl ethers) and the higher alcohols butanol and octanol based on methanol in passenger and light- and heavy-duty vehicles, is currently being investigated as part of the C^3-mobility project [55]. Additionally, Schmidt et al. [39] outline the basic steps for producing jet fuel from methanol for use in the aviation sector. Therefore, methanol is capable of yielding suitable follow-up products for all groups within the transport sector.

The literature review presented reveals three main findings. First, hydrogen production costs are expected to significantly decrease in the next decade, especially in regions with conditions favorable to renewable electricity production. Second, in order to export renewable hydrogen, the derivative methanol qualifies as a good carrier for use in intercontinental energy transport due to its ease of handling and low shipping costs. Third, the transported methanol offers broad applicability and a wide range of follow-up products. Therefore, as stated in the introduction, this study focuses on methanol and answers the question on where (in the hydrogen production or destination country) and at which cost this possible future energy carrier can be made available to energy-demanding countries in the future. Further to this, the next section outlines the methodology used in order to determine the methanol production and distribution costs.

2. Methodology and approach

In this study, the net production costs of methanol in favorable regions and its transportation to energy-demanding countries are assessed.

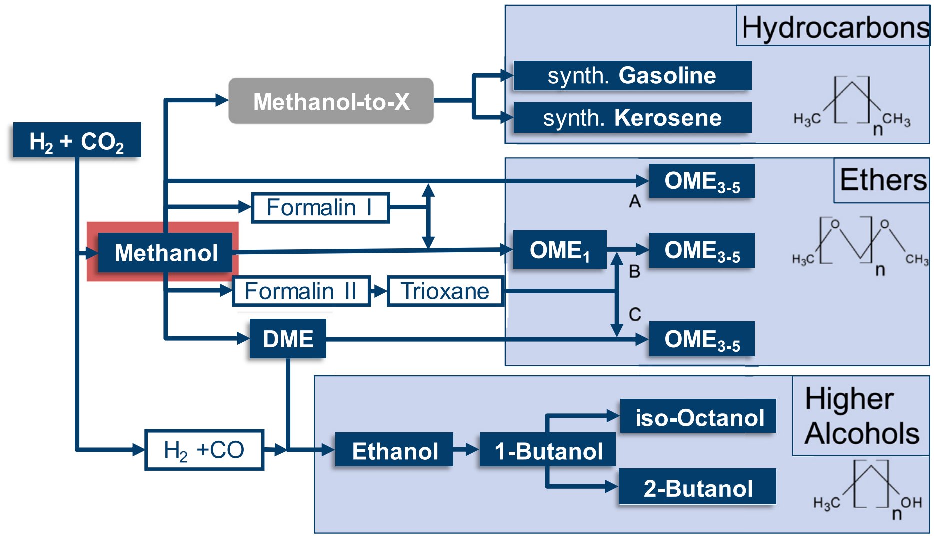


Fig. 5. Potential follow-up products of methanol; figure adapted from Schemme et al. [24].

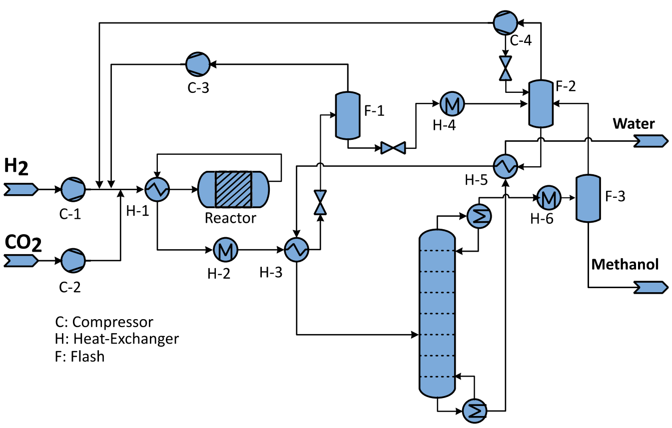


Fig. 6. Renewable methanol synthesis flowsheet presented by Schemme et al. [24].

For this, the ambitious hydrogen production and liquid transport costs will be drawn from a study by the Hydrogen Council [8] and will serve as an external input parameter. On the basis of these hydrogen production costs, the methanol production costs within the favored regions will then be determined. This will be achieved by means of a techno-economic analysis of the methanol synthesis process based on hydrogen and carbon dioxide. Therefore, the methanol synthesis modeling in the process simulation software AspenPlus, with the following component-specific cost calculation, as was already presented in Schemme et al. [24], will be outlined in this section. After deriving a methanol cost prediction model based on the hydrogen and carbon dioxide costs, the approach for estimating the transportation costs of the produced methanol will be described. The methodology presented then enables a comparison between the already-published hydrogen and newly-calculated methanol import costs.

2.1. Methanol synthesis modeling

Fig. 6 shows the developed flowsheet for methanol synthesis as presented by Schemme et al. [24], which is solely based on the two reactants of hydrogen and carbon dioxide. These reactants enter the system at a pressure of 30 bar at 25 °C and only water and methanol leave it at atmospheric pressure and approximately 60 °C. The reactor operates at a pressure of 80 bar and undergoes a maximum temperature increase of 20 K, from 230 °C to 250 °C. As a catalyst system, $CuO/ZnO/Al_2O_3$ is used. The reactions taking place in the reactor are shown in Eq. (2)–Eq. (4) [56]. A Gibbs reactor was implemented in AspenPlus to determine the product distribution based on minimizing the Gibbs free energy [24]. The chosen modeling approach neglects kinetic effects such as product inhibition, which is relevant for the hydrogenation of CO_2. The conversions calculated in the process simulations should be recognized as estimations of the upper side, as the equilibrium conversion cannot be achieved in real reactors. This estimation enables a deep process analysis constituting a feasibility analysis. Based on the overall goal of this study, further investigations into the mechanisms within the synthesis reactor are excluded. Detailed information about kinetic models can be found in Nestler et al. [57] and Slotboom et al. [58].

Hydrogenation of CO_2

$$CO_2 + 3H_2 \rightleftharpoons CH_3OH + H_2O \; \Delta H_R^{STP} = -49.5 \frac{kJ}{mol} \tag{2}$$

(Reverse) water-gas shift

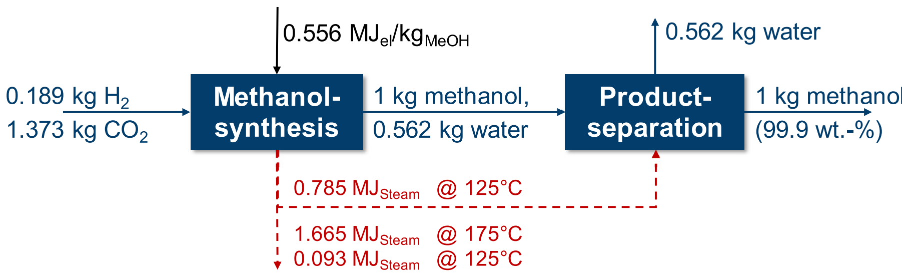
$$CO_2 + H_2 \rightleftharpoons CO + H_2O \Delta H_R^{STP} = 41.2 \frac{kJ}{mol} \tag{3}$$

Hydrogenation of CO

$$CO + 2H_2 \rightleftharpoons CH_3OH \Delta H_R^{STP} = -90.7 \frac{kJ}{mol} \tag{4}$$

The gas phases of two flash evaporators operating at 79 and 1 bar of pressure, respectively, are sent back to the reactor. They primarily consist of unreacted hydrogen and carbon dioxide. The liquid phase comprises approximately the same share of methanol and water. The water is separated in a distillation column, as depicted in Fig. 6. The resulting methanol has a purity of 99.9 wt.% and is therefore compliant with the IMPCA specification requiring at least 99.85 wt.% methanol [59]. The necessary heat for the reboiling of the column is supplied by low-pressure steam (125 °C) generated in heat exchanger H-2. Additional medium-pressure steam (175 °C) is generated to cool the reactor and can be used for other heat-demanding processes, as can be seen from the material and energy balance of the developed synthesis shown in Fig. 7. One example would be carbon dioxide sequestration.

Schemme et al. [24] determined the electrical energy demand to be 0.556 MJ per kg methanol, as shown in Fig. 7, by assuming an isentropic efficiency of the compressors of 76%. Together with an electrolysis efficiency of 70% based on the lower heating value and a CO_2 separation effort of 1.2 MJ_{el}/kg, a power-to-fuel efficiency of 57.6% was calculated. The given utility demands will serve as the input parameters for the techno-economic assessment that follows.



Educt demand		Utility demand			By-products
H_2	CO_2	Electricity	Medium pressure steam	Low pressure steam	Water
kg/kg$_{MEOH}$		MJ/kg$_{MEOH}$			kg/kg$_{MEOH}$
0.189	1.373	0.556	-1.665	-0.093	0.562

Fig. 7. Overview and evaluation of the methanol synthesis model by Schemme et al. [24].

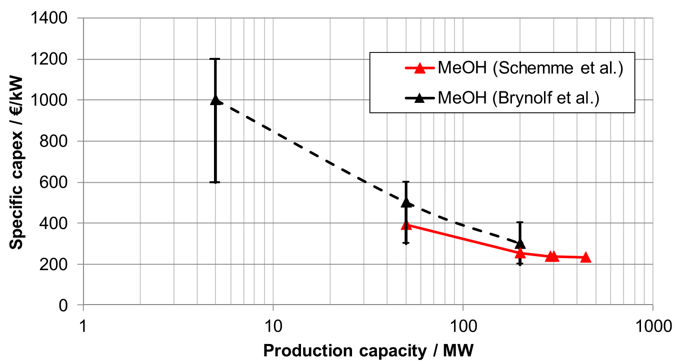


Fig. 8. Comparison of reported specific CAPEX reported by Brynolf et al. [62] and Schemme et al. [24] as a function of production capacity.

2.2. Techno-economic analysis

For the techno-economic comparison of the two proposed renewable energy carriers of hydrogen and methanol, the methanol production costs based on the presented synthesis and transportation surcharge for the produced methanol will be calculated.

The first step in the analysis is to determine the system's capital and operational expenditures. The capital expenditures (CAPEX) are calculated for a lifetime of 20 years, an interest rate of 8%, and a plant size of 300 MW of methanol, which translates into 434 kt for 8000 hours of operation per year [24]. As is depicted in Fig. 6, the developed methanol synthesis consists of four compressors, six heat exchangers, three flash evaporators, a reactor, and a distillation column. The respective costs are derived from the component-specific cost prediction model presented by Turton et al. [60]. A fixed capital investment of 60 million EUR for the outlined methanol synthesis was calculated by Schemme et al. [24]. A cost breakdown of the components is presented in Figure A-1 in the appendix. The utilized estimation method offers, as per the definition of AACE international [61], an accuracy of −30% to +50%. The specific investment costs are 235 €/kW, which correspond to the cost range of 200–400 €/kW for a 200 MW plant determined by Brynolf et al. [62], as depicted in Fig. 8. Here, the results of a comparison of multiple methanol investment cost studies for different production capacities by Brynolf et al. [62] are compared to the investment cost for different synthesis unit sizes reported in Schemme et al. [24]. A degressive trend in the specific investment costs as a function of increasing production capacity can be observed in both references in Fig. 8. However, the results of Schemme et al. [24] in Fig. 8 also indicate that the decrease in specific investment costs is significantly slowed down for production capacities above 200 MW. This effect can be explained by the components of the synthesis (i.e., compressors, towers, etc.) reaching their maximum respective capacities, as reported in Turton et al. [60]. Thereafter, economy of scale effects no longer affect the prices of the components, as they must be built in parallel instead of building larger units. Therefore, the plant size of 300 MW chosen in this work represents capital investments for industrial methanol production.

With respect to operational expenditures (OPEX), the assumption of Schemme et al. [24] is applied, whereby methanol synthesis is carried out at a chemical site in which hydrogen, carbon dioxide, process steam, and operating electricity are available and purchased at defined prices. With this assumption, the OPEX are defined to a large degree, and these are presented in Fig. 9, which shows the cost distribution for the base case of the methanol production published by Schemme et al. [24]. With a total of 93%, the expenses for hydrogen and carbon dioxide predominate the overall production costs of methanol. By comparison, the shares for the direct (labor, maintenance, repairs, etc.) and fixed (taxes, insurance, administration) OPEX, as well as the annual capital costs and operating electricity, are small. The additional operating expenditures for maintenance, repairs, insurance, and general expenses are calculated based on the cost estimation method presented by Turton et al. [60]. A breakdown of the multiplying factors used to calculate the direct and fixed OPEX is provided in Table A- 1 in the appendix.

The main outcome of Fig. 9 is the dependency of the methanol production costs on hydrogen in particular, and also the carbon dioxide price. Accordingly, these two input parameters will be varied in this study.

In order to model the shipping costs of methanol, the approach described by Pfennig et al. [63] is adopted. Here, the shipping costs of liquid synthetic fuels are given as a function of their energy content and the shipping distance is 0.00106 €/(tOE*km). The resulting costs in €/MWh and €/t of methanol are displayed in Fig. 10. For a shipping distance of 10,000 km, 5 €/t of methanol must be added to the cost of manufacturing in order to meet the methanol costs at the destination harbor. Compared to the transportation costs noted by Pfennig et al. [63], Al-Breiki and Bicer [64] determine slightly higher methanol shipping costs of 1.87 €/MWh for a distance of 12,000 km, whereas Hank et al. [13] present slightly lower shipping costs of 0.3 €/MWh for a distance of 4000 km.

2.3. Hydrogen production and transport

A recent study presented by the Hydrogen Council [8] predicts drastic cost reductions over the next five–ten years for the production of hydrogen. For three specific origin countries which have either favorable PV, wind or PV/wind conditions (i.e., Australia, Chile, and Saudi-Arabia), the prospective hydrogen production costs are predicted for 2030. Additionally, the shipping costs for the four total combinations of hydrogen-producing (origin) and hydrogen-importing (destination) countries are presented. The cost figures given in the Hydrogen Council study are then converted for this study from the US dollar to the Euro at an exchange rate of $1 = €1. Although this does not represent the current exchange rate, it will not have an impact on the findings obtained from

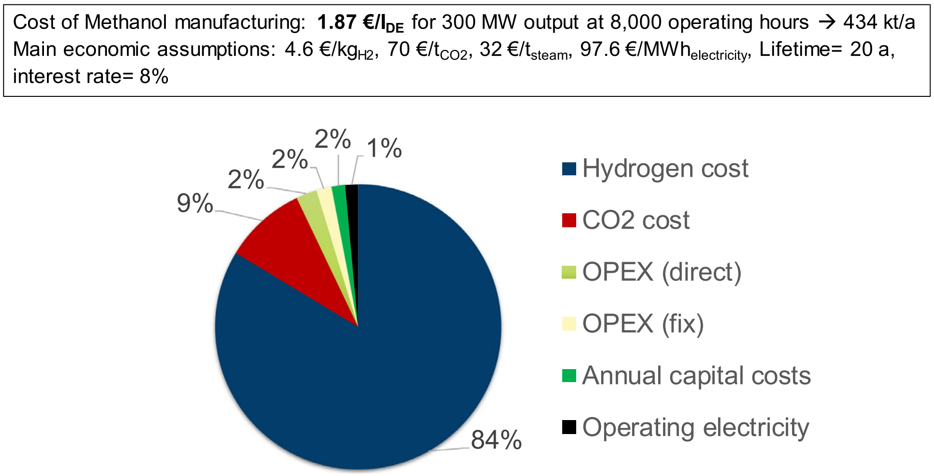


Fig. 9. Distribution of methanol production costs as presented by Schemme et al. [24].

Table 1
Origin and destination groups with their respective hydrogen production and distribution costs [8].

Origin country	Destination country	Hydrogen production costs [€/kg]	Hydrogen distribution costs [€/kg]	Total cost of hydrogen at destination [€/kg]
Chile	USA	1.35	1.35	2.70
Australia	Japan	1.88	1.42	3.30
Saudi Arabia	Japan	2.00	1.70	3.70
Saudi Arabia	Germany	2.00	1.40	3.40

Fig. 10. Methanol transportation costs based on Pfennig et al. [63] as a function of the shipping distance.

the calculated results. The main objective is a comparison of methanol and hydrogen production and distribution costs with the same boundary conditions observed. The respective differences within the pathways are therefore the key results of this study, rather than the absolute values. The results of the Hydrogen Council [8] study are presented in Table 1 and reflect the following, primary assumptions:

A decrease in PEM electrolysis investment costs by at least 60% compared to 2020 to 400 €/kW if 70 GW are installed globally. This translates to a learning curve of 13%, which is considered conservative by comparison to the learning rates achieved between 2010 and 2020 for PV (35%), onshore wind (19%), and batteries (39%).

An increase in efficiency from 64 to 69% today to 70% for PEM and alkaline electrolysis, which are common predictions discussed in the literature [62].

An average levelized cost of renewable electricity production within the four origin countries of approximately 20 €/MWh with high full load hours. This assumption is already supported by the results presented in Fig. 2 and the literature presented in the introduction [12, 14]. A general overview of the dependency of the hydrogen production cost on the cost of electricity and the full load hours of the electrolysis process is provided in Figure A-2 in the appendix.

A drastic reduction in liquid hydrogen transport costs from today's value of 15 €/kg for the shipping distance from Saudi Arabia to Japan, to 1.7 €/kg in 2030. This value is in accordance with other hydrogen transportation studies. Hank et al. [13] determine a shipping cost of 1.2 €/kg for the shipping distance between Morocco and Germany, whereas Heuser et al. [11] present costs for the liquefaction, storage, and shipping of hydrogen of 1.71 €/kg for long-distance transport between Patagonia and Japan.

The hydrogen production costs of 1.35–2.00 €/kg for 2030 are similar to those of other studies [6, 9, 12], as presented in the literature review [7, 11, 12]. With the lowest production cost and the shortest distance, hydrogen from Chile that is exported to the USA carries the lowest total cost of 2.70 €/kg. For the case of hydrogen produced in Saudi Arabia and exported to Japan, a high cost of 3.70 €/kg was noted. The values given in Table 1 are used as input costs for the economic comparison of liquid hydrogen against methanol importation in the results section.

3. Results and discussion

Drawing on the methodology presented in the previous section, the methanol production costs are discussed in detail in a first step. Then, the shipping costs are added to obtain the total methanol costs at the importing harbor for the four origin/destination combinations, which can then be compared to the liquid hydrogen production and distribution costs presented in the Hydrogen Council study. Lastly, it will be determined at which carbon dioxide price difference the import of liquid hydrogen and the use of local industry sources will be economically-beneficial compared to methanol production in the country of origin, using direct air capture.

3.1. Methanol production costs

As is discussed in Fig. 9, the expenses for hydrogen and carbon dioxide in particular determine the final methanol production costs. Given that in this study, carbon dioxide is assumed to be bought from an external supplier, carbon dioxide-purchasing expenses are defined as prices, whereas the hydrogen expenses originate from the Hydrogen Council study, in which they are defined as costs without any margins. Hence,

Table 2
Methanol production costs in €/t as a function of the CO_2 price and H_2 net production costs. The numbers given are valid for the system size of 300 MW and the presented methodology. Current (fossil, year: 2018) methanol market price: 400 €/t [65]. The timeline for the hydrogen production costs is from IRENA [7].

	NPC H_2 [€/kg]							
time	2050		2030					2020
CO_2 Price [€/t]	1	1.5	2	2.5	3	3.5	4	4.5
biomass 0	254	350	445	578	635	731	826	921
biomass 20	282	377	473	606	663	758	854	949
biomass 40	310	405	500	634	691	786	881	977
industry 60	337	433	528	661	719	814	909	1004
industry 80	365	461	556	689	746	842	937	1032
industry 100	393	488	584	717	774	869	965	1060
DAC 150	462	558	653	786	843	939	1034	1129
DAC 200	532	627	722	856	913	1008	1103	1199
DAC 300	670	766	861	994	1051	1147	1242	1337
DAC 400	809	904	1000	1133	1190	1285	1381	1476
DAC 500	948	1043	1138	1272	1329	1424	1519	1615
DAC 800	1364	1459	1554	1688	1745	1840	1936	2031

NPC range	MeOH production…
<600 €/t	**Competitive** → Max. 150% of current price level
>600 < 1200 €/t	**Possibly competitive** → Max. 300% of current price level
>1200 €/t	**Not competitive** → More than 300% of current price level

Table 2 depicts the dependence of the two expenses on the methanol production costs. For a wide range of hydrogen costs and carbon dioxide prices, the net production costs for methanol are given using the methodology and system size, which was also presented. The costs are sorted into three categories depending on their respective competitiveness to the methanol price level of 2018, of approximately 400 €/t [65]. As no carbon emissions certificates or similar discussed surcharges for fossil energy carriers are included in the current market price, it is assumed that the current fossil market prices of methanol will no longer significantly decrease, even though the development of fossil energy sources is uncertain. Therefore, renewable methanol with production costs of up to 150% of the current market price are defined as being economically-competitive. In order to achieve production costs within this category, shown in green in Table 2, renewable hydrogen would need to be accessible for 2.50 €/kg or less. As the timeline indicates, these costs are predicted for the year 2030 [7]. Therefore, competitive renewable methanol production can be achieved in the next decade. With decreasing hydrogen costs, the window for possible carbon dioxide prices and hence different sequestration technologies expands. The second category, shown in orange, represents a production price of 150–300% of the current market price. Competitiveness against current fossil methanol would require either strong legislative actions with respect to renewable energy carriers, or customer willingness to pay a surcharge for a renewable product. As can be seen in Table 2, renewable methanol production costs in this category can already be achieved at current hydrogen costs (2020) and carbon dioxide prices of up to 200 €/t. The methanol production costs, which exceed the current market price level by 300%, are marked in red in Table 2. These combinations of hydrogen and carbon dioxide expenses are considered non-competitive. The input carbon dioxide prices are qualitatively classified into the three main carbon sources discussed, namely biomass, industry, and direct air capture (DAC) [62]. The price range of carbon capture using DAC currently faces the greatest uncertainties. Values from 100 to 800 €/t_{CO2} can be found in the literature [66-68], although target prices of approximately 100 €/t_{CO2} have most recently been discussed by the DAC industry [69].

The resulting methanol prices reported in Table 2 can generally be compared with current studies on the techno-economic assessments of renewable methanol production, although differences in boundary conditions and scopes must be considered for a detailed comparison to be possible. Adnan and Kibria [70] report a two–four-fold increase in renewable versus fossil methanol production against current boundary conditions. For an optimistic scenario, which predicts input values for the year 2050, values of 400 €/t are calculated. Hence, both observations are in line with the results of this study. Furthermore, in a best case scenario, Detz et al. [71] project methanol production costs of less than 400 €/t in 2030 and a cost parity between renewable and conventional methanol in 2032. The base case scenario predicts costs of less than 800 €/t for 2030. Kourkoumpas et al. [72] report current methanol production costs of 421 €/t for electricity and carbon dioxide supplied at low cost from a lignite power plant (32 €/MWh and 31 €/t, respectively). This therefore defines a benchmark that methanol from renewable electricity and sustainable carbon dioxide must surpass. At this point, it is again highlighted that the prices for both hydrogen and carbon dioxide shown in Table 2 represent those for sustainable sources. Battaglia et al. [73] report methanol costs for a current system consisting of hydrogen production, carbon capture and methanol synthesis between 823 and 2706 €/t, depending on the cost of electricity of the various renewable sources. The highest methanol production costs result from concentrated solar power, which delivers electricity at a high cost of 162 €/MWh. Meanwhile, the lowest methanol production costs derive from the use of hydro power at 41 €/MWh of 823 €/t. This value is in good agreement with the current to near-future methanol production costs presented in Table 2. Finally, Bellotti et al. [74] report methanol production costs of 186–650 €/t for the three cases of Italy, Germany, and China. The low production prices are due to the approach of using the stock market prices for electricity in the respective countries of 54, 33, and 10 €/MWh and assuming a revenue for the produced oxygen of 150 €/t. With these assumptions, the reported methanol costs can be classified as future production costs, and are therefore also consistent with the values reported for 2030 and presented in Table 2.

3.2. Methanol compared to hydrogen costs at destination harbors

With knowledge of the influence of hydrogen and carbon dioxide expenses on methanol production costs and the shipping costs presented

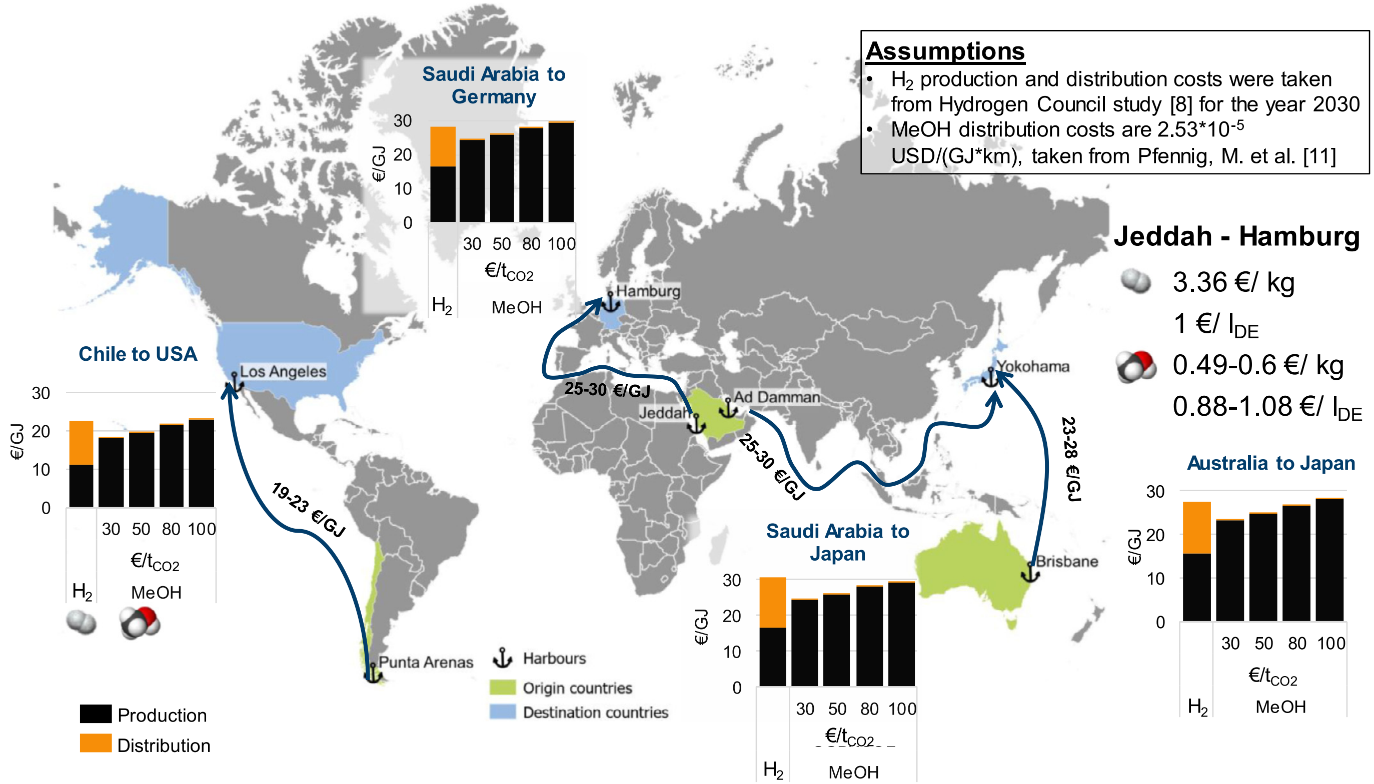


Fig. 11. Hydrogen and methanol production and distribution costs for the four investigated origin/destination combinations.

in Fig. 10, the total methanol import costs can be determined. This was achieved by taking the hydrogen production costs in the origin country given in Table 1, varying the price for carbon dioxide, and adding the shipping costs for methanol according to Fig. 10 for the four origin/destination combinations. The results are shown and compared to the Hydrogen Council's input values [8] in an overview map displayed in Fig. 11. For each origin/destination combination, an individual graph depicts the respective results. In order to compare the costs for hydrogen and methanol at the destination harbor, the energy-specific unit €/GJ based on the lower heating value is used. In each case, the first bar represents the hydrogen production and distribution costs, which are drawn from the Hydrogen Council [8] and are displayed in Table 1. The four subsequent bars represent the production costs for methanol based on the hydrogen costs at the origin for a range of CO_2 prices from 30 to 100 €/t_{CO2}, alongside the respective distribution costs presented.

As a first observation from all the graphs shown in Fig. 11, it can be stated that the distribution costs for methanol in the range of 0.20–0.34 €/GJ are almost negligible compared to the distribution of hydrogen of 11.25–14.17 €/GJ. Consequently, the share of transportation of the renewable energy carrier within the overall costs declines from 41 to 50% for hydrogen to 1–2% for methanol. In total, the methanol prices are in the range of 18.6–29.7 €/GJ, which translates to 370–591 €/t. With the categories defined in Table 2, these methanol production costs would all be marked "competitive" in the year 2030.

The second observation from the four graphs presented is that the energy-specific costs for methanol and hydrogen at the harbor are comparable for each case within the presented boundary conditions. This indicates that the additional costs for upgrading hydrogen to methanol are balanced out in some cases by the significantly less expensive shipping of liquid methanol versus liquid hydrogen. Methanol is initially less expensive for carbon dioxide prices of 30 and 50 €/t_{CO2} and becomes more expensive, depending on the origin/destination combination, beyond a specific carbon dioxide price is exceeded. Those critical prices lie within the range of 80–100 €/t_{CO2}, with the exception of Saudi Arabia to Japan, where, even at 100 €/t_{CO2}, methanol in the harbor is still slightly less expensive, at 29.7 €/GJ, compared to 30.8 €/GJ for hydrogen. For the example of exporting hydrogen or methanol from Saudi-Arabia to Germany (Jeddah – Hamburg), Fig. 11 also shows the respective production costs of 25–30 €/GJ in €/kg and EUR per liter of diesel equivalent (1 l_{DE}=35.9 MJ [75]). Both energy carriers could be imported for approximately 1 €/l_{DE} in 2030. As a comparison, in 2019, the average net price of fossil diesel in the EU was 0.59 €/l [76]. This underscores the still significant gap between liquid fossil and renewable energy carriers, even if the predicted reduction in hydrogen production by 2030 is achieved.

Comparing the different origin/destination combinations, Chile to the USA had the lowest respective costs, whereas Saudi Arabia to Japan had the highest. This is due to the predicted lowest hydrogen production costs in 2030 being in Chile (compare Table 1) and the longest transportation distance being from Saudi Arabia to Japan.

As an interim conclusion, it can be stated that if carbon dioxide is available at 100 €/t or less in the country of origin, a local upgrading of hydrogen to methanol and the shipping to energy-demanding regions around the world is comparable to, or less expensive than, the production and shipping of liquid hydrogen with respect to the energy content of the respective energy carrier. However, as carbon dioxide sequestration costs of 100 €/t or below are currently only achievable with biomass and industrial sources, the interim conclusion raises the question as to whether a sufficient amount of process-related or renewable carbon dioxide is available in the country of origin and hydrogen production site. If this is not the case, hydrogen would be the economically-beneficial choice for an energy carrier.

3.3. Marginal carbon dioxide costs for methanol production in origin vs. destination countries

Independent of the comparison of hydrogen versus methanol as an energy carrier in the previous section, the global demand for renew-

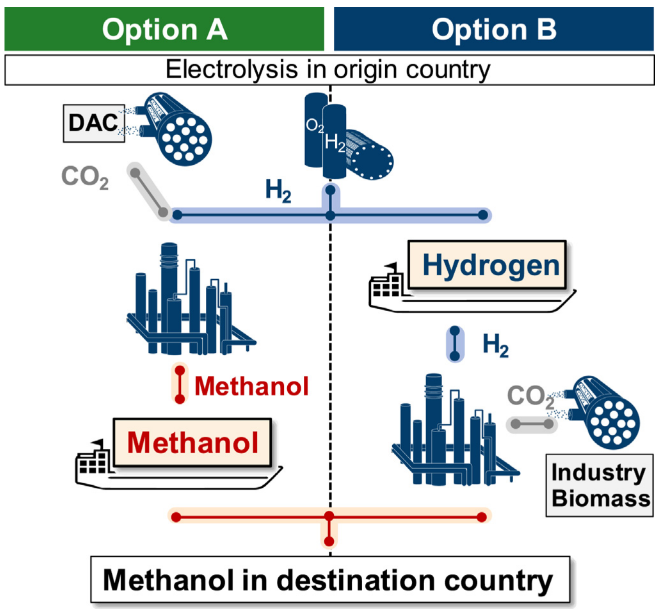


Fig. 12. Methanol production in the origin versus destination countries.

able methanol could rise significantly due to its broad applicability as a transportation fuel and within the chemical industry. If no process-related carbon dioxide from industrial processes is available, the only option for producing methanol in the country of origin would then be to extract carbon dioxide from the air at higher costs, which is shown as option A in Fig. 12. Otherwise, option B would be to import liquid hydrogen and use local carbon point sources in the destination country at lower costs. Therefore, in the last section of this paper, the point of view shifts from the comparison of methanol versus hydrogen as an energy carrier towards methanol production at the origin or destination sites.

Fig. 13 depicts the results of the aforementioned comparison of local methanol production in the countries of origin (option A) in green versus methanol production with imported hydrogen and local carbon sources (option B) in blue for the four cases. As the deviation in production costs is due to the difference in the shipping expenses of hydrogen versus methanol in each case, the surcharge for production in the destination countries is constant for the same carbon dioxide price. The respective values are given in yellow boxes and vary from 250 to 316 €/t_{MeOH}. In order to offset those cost differences, the carbon dioxide in the destination countries would need to be significantly less expensive than that used at hydrogen production sites. These marginal carbon dioxide prices are shown in the checked boxes and are in the range of 181–228 €/t_{CO2}. When comparing the four origin/destination combinations, the marginal carbon dioxide prices can also be seen to be dependent on the hydrogen destination costs presented in Table 1, with Chile to the USA displaying the lowest cost and Saudi Arabia to Japan, the highest. If the difference in carbon dioxide price in the origin country compared to the destination one exceeds the calculated values shown in Fig. 13, option B becomes economically-favorable. However, this also means that if DAC can produce carbon dioxide under 228 €/t and the transportation cost of hydrogen remains at the level proposed by the Hydrogen Council, option A will be less expensive, independent of the carbon dioxide price at the destination.

4. Conclusions

Countries and regions that are currently dependent on the import of fossil energy carriers generally have two options available for a transformation into carbon-neutral societies. The first increases the local renewable electricity production and storage capacity and substantially electrifies the industrial, household, and transportation sectors. This simultaneously reduces the total energy demand and the energy import dependency, and is therefore the obvious path that most countries already follow. Nonetheless, energy autarky can neither be assured nor is economically-viable in all energy-demanding countries, and the full electrification of every sector is unlikely. Therefore, a second option can be followed that replaces the remaining energy imports from fossil energy carriers with renewable ones. Here, the excellent potential for

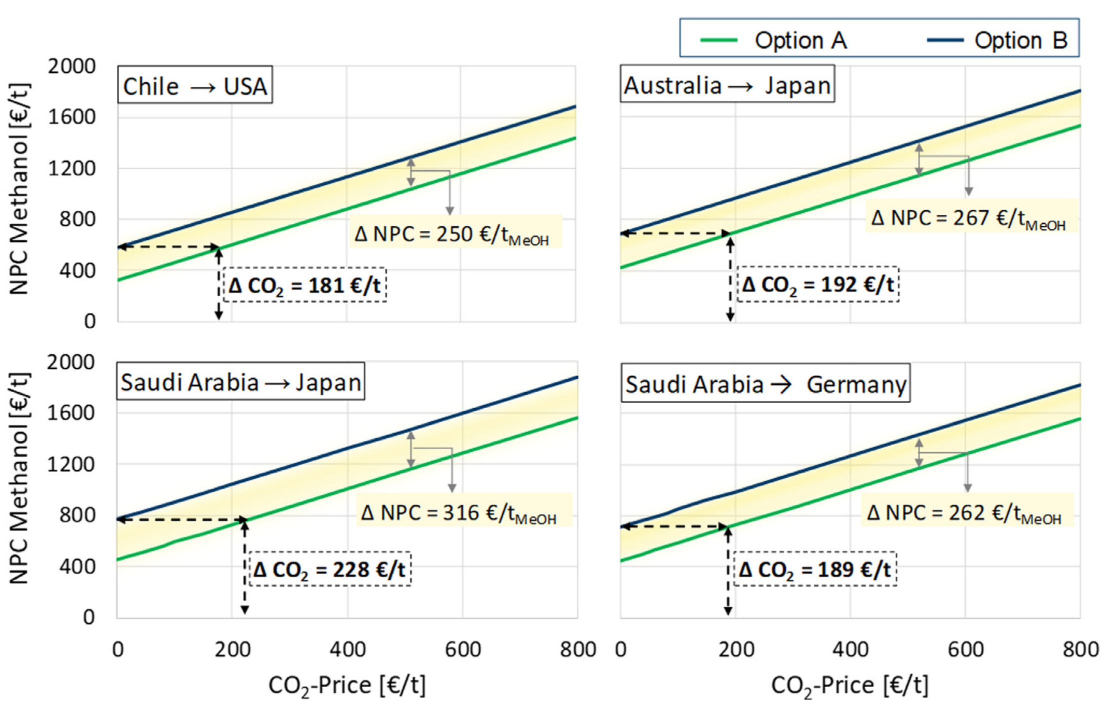


Fig. 13. Methanol net production costs (NPC) in origin versus destination countries.

producing renewable electricity in multiple global regions can be made available for energy-demanding countries via storable energy carriers. The leverage effect of the two individual strategies, and therefore the necessary amount of emphasis placed on each is thereby strongly dependent on the country in question.

This study investigates the second of these options and concentrates on hydrogen-based methanol as a potential renewable energy carrier. The identified strengths of methanol as an energy carrier include its high volumetric energy density, the mature technology for producing it from hydrogen and carbon dioxide, and its broad applicability. This offers the opportunity to partially re-use existing energy transport and distribution infrastructure and the possibility of producing carbon-neutral fuels for the existing fleet. However, the use of methanol will always result in a lower energetic efficiency compared to the direct use of electricity, as well as the direct use of hydrogen. This must be considered in use-cases in which electrification or the utilization of hydrogen offer an alternative. The dependency on a carbon source and the predicted hydrogen cost reductions, as well as the competition with fossil methanol, can be singled out as threats to the development of methanol as a renewable energy carrier.

To conclude, three main outcomes can be identified from the findings presented in this study. First, a detailed process analysis of a 300 MW methanol synthesis process with the following techno-economic assessment indicates the high level of dependency of methanol production costs on hydrogen and carbon dioxide expenses. The results demonstrate that the current production of renewable methanol would end up with production costs that would be two to three times higher than the current fossil fuel market price. In ten years, however, methanol production within the current market price range is possible if hydrogen costs of less than 2.5 €/kg can be achieved.

The second segment of the results section reveals that if carbon dioxide is available at prices below 80 €/t in the hydrogen-producing country, methanol offers lower energy-specific importing costs than hydrogen. Methanol can therefore be identified as a promising and cost-competitive renewable energy carrier. In order to obtain this result, a comparison of the import costs for four different origin/destination country combinations of methanol and hydrogen was outlined on the basis of the hydrogen production and distribution costs for 2030 drawn from a recent study. With predicted hydrogen production costs of 1.35–2 €/kg and additional shipping costs, the possible renewable energy carrier methanol can be imported for 370–600 €/t if renewable or process-related carbon dioxide is available at costs of 100 €/t or below in the hydrogen-producing country. When comparing the import costs of methanol to hydrogen, the distribution costs of both energy carriers differ significantly. The assessment showed that the additional costs for upgrading hydrogen to methanol can be balanced out by the lower shipping costs of methanol compared to those of hydrogen. However, within the range of CO_2 prices of 30–100 €/t, both hydrogen and methanol show comparable energy-specific import costs of 18–30 €/GJ. The question of whether to import hydrogen or methanol will therefore be determined on the basis of the further use of the respective energy carrier in the destination country. For the example of importing renewable energy from Saudi Arabia to Germany, both energy carriers featured import costs of 25–30 €/GJ in 2030, which translates to approximately 1 €/l_{DE}. Even though these costs are still higher than the current fossil diesel cost of 0.59 €/l_{DE}, this demonstrates that the import of renewable energy carriers can be an accompanying option for moving towards a carbon-neutral energy system. The competitiveness of carbon-neutral methanol against its fossil counterpart would be facilitated by policy measures such as a global carbon dioxide tax and a certification of the renewable origin of the produced methanol.

As a third main outcome of this study, it was found that if methanol is the desired energy carrier and no carbon dioxide is available in the hydrogen-producing country, the price of carbon dioxide in the destination country must be 181–228 €/t less expensive than direct air capture in the country of origin in order to balance out the more expensive shipping of hydrogen. With those results obtained, it can be concluded that the production of methanol in the country of origin would result in lower costs, independent of the carbon dioxide price in the destination country, if the target costs of the direct air capture industry of 100 €/t are achieved.

In the further selection process and the assessment of suitable energy carriers, multiple research fields will be important. With respect to hydrogen, both the extremely high predicted reductions in investment costs for electrolyzers and the cost of liquid hydrogen transport must be achieved. Moreover, with respect to the system analysis, models with a high spatial resolution will indicate the precise global locations at which a high level of utilization for the generation of renewable energy and electrolysis is available in the form of full load hours. In addition to the cost for hydrogen, the availability of carbon dioxide and its separation cost will also play a central role. Therefore, locally-resolved models must be used in these cases in the future as well. The promising production costs of methanol resulting from this work will therefore need to be confirmed through in-depth investigations of the assumptions made here. A final decision cannot and should not be made at this point in time. Further investigations – experimentally and theoretically – must therefore be performed in order to identify the optimal energy carrier.

Declaration of Competing Interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix

Fig. A1 depicts the cost breakdown of the investment costs of the methanol synthesis. The costs for the distillation tower and reactor already include their respective heat exchangers. The four compressors make up the largest share of the investment cost at 34%, followed by heat exchangers with 27%. This is due to a high demand on gas/gas heat exchange within the model, i.e., in heat exchangers H-1 and H-6 (compare with Fig. 6).

Table A1 shows the multiplying factors used to calculate the operational expenditures (OPEX) of the methanol synthesis. The costs for the

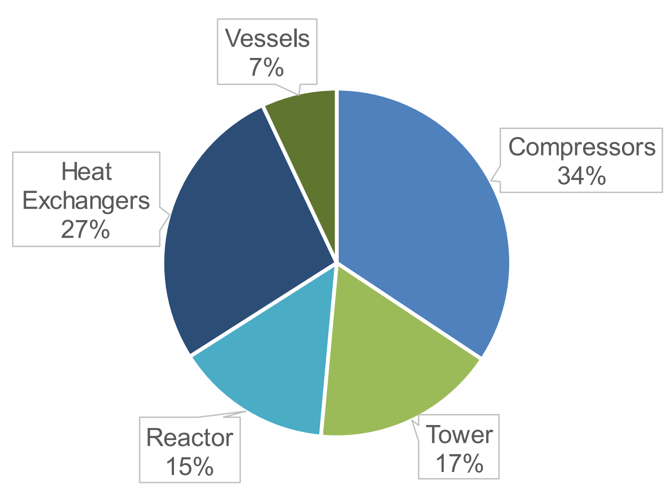

Fig. A1. Cost breakdown of the investment cost of methanol synthesis.

Table A1
Multiplying factors utilized, based on Turton et al. [60], and used in Schemme et al. [24] to calculate the OPEX of the methanol synthesis.

Cost component	Correlation / multiplying factor	
Raw materials (H_2 and CO_2)	C_{RM}	Direct OPEX
Utilities (Electricity, steam, water)	C_{UT}	
Operating labor	C_{OL}	
Direct supervision and clerical labor	0.18 C_{OL}	
Maintenance and repairs	0.06 FCI	
Operating supplies	0.009 FCI	
Laboratory charges	0.2 C_{OL}	
Patens and royalties	0.01 OPEX	
Taxes and insurance	0.032 FCI	Indirect OPEX
Plant overhead costs	0.708 C_{OL}+ 0.06 FCI	
Administration costs	0.177 C_{OL}+ 0.015 FCI	

Table A2
List of abbreviations.

AACE	Association for the Advancement of Cost Engineering
CAPEX	Capital expenditures
DAC	Direct air capture
DME	Dimethyl ether
FCI	Fixed capital investment
FLH	Full load hours
IMPCA	International Methanol Producers and Consumers Association.
IRENA	International Renewable Energy Agency
LCOE	Levelized cost of electricity
l_{DE}	Liter diesel equivalent
LHV	Lower heating value
LOHC	Liquid organic hydrogen carrier
M/O	Maintenance and operation
MeOH	Methanol
NPC	Net production cost
OME	Polyoxymethylene dimethyl ethers
OPEX	Operational expenditures
PEM	proton exchange membrane
PV	Photovoltaic
TRL	Technology readiness level

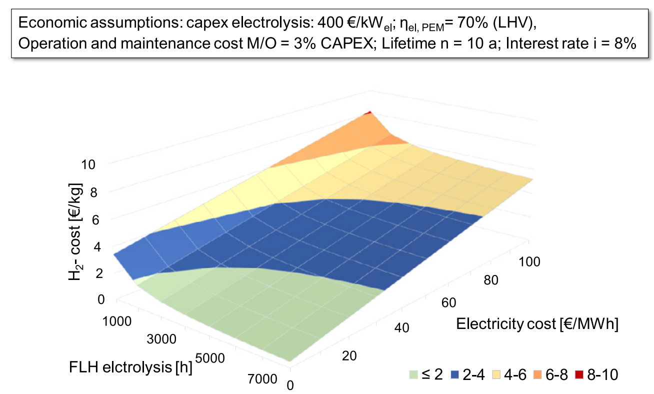

Fig. A2. Hydrogen production cost as a function of the FLH of the electrolysis and the cost of electricity for the predicted capital investment cost for PEM electrolysis by the Hydrogen Council [8].

raw materials of hydrogen and carbon dioxide make up the largest share of the manufacturing costs, as can be observed from Fig. 9. The utilities' costs are calculated with the boundary conditions presented in Schemme et al. [24] (i.e., operating electricity: 98 €/MWh; steam: 32 €/t; and cooling water: 0.1 €/t). Operating labor costs were determined with the methodology used in Turton et al. [60], which was originally presented in Alkhayat and Gerrard [77]. The remaining cost components were determined with the multiplying factors given by Turton et al. [60], which depend on either the labor costs, the fixed capital investment (FCI) or the total OPEX.

Table A2.

Fig. A2 presents the hydrogen production costs (C_{H2}) as a function of the full load hours (FLH) of the electrolysis and cost of electricity (C_E) for one set of economic parameters. The capital expenditures (CAPEX) and efficiency of the electrolysis ($\eta_{el,\ PEM}$) are derived from the cited Hydrogen Council study [8], which represent a prediction for the year 2030. The costs for operation and maintenance (M/O) and lifetime (n) of a PEM electrolysis system were obtained from Robinius et al. [78]. The respective hydrogen production costs are calculated based on the following equation:

$$C_{H2} = \frac{LHV_{H2}}{\eta_{el,\ PEM}}\left(\left(\frac{(1+i)^n \cdot i}{(1+i)^n - 1} + M/O\right) \cdot \frac{capex}{FLH} + P_E\right) \tag{A1}$$

As can be observed in Fig. A2, both the high full load hours, as well as inexpensive renewable electricity, are required for the predicted hydrogen production costs in the Hydrogen Council study [8] of less than 2 €/kg.

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