International Journal of Hydrogen Energy 148 (2025) 149938

Contents lists available at ScienceDirect

International Journal of Hydrogen Energy

journal homepage: www.elsevier.com/locate/he

Renewable energy supply via carbon-based molecules – A techno-economic assessment of various import pathways

Fabian Carels [*], Stefan Bube, Martin Kaltschmitt

Institute of Environmental Technology and Energy Economics, Hamburg University of Technology, Eißendorfer Straße 40, 21073, Hamburg, Germany

ARTICLE INFO

Keywords:
Energy import
Hydrogen supply
Hydrogen derivatives
Supply chain assessment
CO_2 cycle
Techno-economic analysis

ABSTRACT

The EU's transition to net-zero greenhouse gas emissions (GHG) likely necessitates renewable energy imports. This paper assesses various import pathways for energy-rich "green" molecules into the EU, focusing on carbon-based molecules like "green" methanol and synthetic natural gas (SNG). These energy carriers, produced using hydrogen derived from renewable electricity and non-fossil CO_2, are compared with alternative import pathways, including liquid hydrogen, ammonia, and liquid organic hydrogen carriers (LOHCs). Different forms of final energy supply are analyzed, including pure hydrogen and hydrogen derivatives. Results show, that among the examined pathways relying on carbon-based molecules, energy imports via methanol with largely closed carbon cycles are particularly promising. A closed carbon cycle reduces the cost of energy supply with methanol by around 15 % compared to CO_2 provision via Direct Air Capture (DAC). For methanol, SNG and ammonia, direct use is more economical than reconversion into hydrogen. For pure hydrogen supply, importing gaseous hydrogen by pipeline or liquid hydrogen by ship results in the lowest hydrogen supply cost (~0.15 €/$kWh_{H2, LHV}$). If hydrogen is imported via carriers, methanol or ammonia should be preferred, while SNG and LOHCs are less competitive.

1. Introduction

The European Union's (EU) energy supply is highly reliant on imports, with a significant share of the consumed fossil fuel energy coming from non-EU countries. Over the last 15 years, imports of fossil fuel energy have consistently accounted for 50–60 % of the EU's overall energy consumption [1,2]. Even the steadily increasing use of domestic sources of renewable energy in recent years has not yet significantly reduced this dependency. Currently, almost all of these energy imports into the EU are in the form of fossil, carbon-based carriers – and here mainly natural gas and crude oil (products) [3].

To achieve the EU's target of net-zero greenhouse gas (GHG) emissions by 2050, these fossil fuel imports must be phased out within the next 25 years [4]. However, the potential for low-cost energy generation from renewable sources within the EU is limited. One option to overcome this challenge is to import renewable energy (carrier) from non-EU regions throughout the world characterized by promising potential, especially for electricity generation from wind power (e.g., Patagonia) and solar energy (e.g., the Sahara Desert). Thus, imports of renewable energy carrier are likely to become a key component of a diversified and resilient energy supply within a GHG-neutral energy system in the EU [5,6].

For the intercontinental long-distance transportation of this basically GHG-neutral energy, chemical compounds, so-called "green" molecules, can be produced as secondary energy carriers using electricity from renewable sources. Such "green" molecules are better suited for an energy import, as they can be transported and stored on a large scale much easier and more flexible compared to electricity. Additionally, appropriate energy-rich "green" molecules can be used, e.g., to defossilize hard-to-abate sectors difficult or impossible to electrify [7].

In recent years, various options for the import of "green" molecules into the EU have been discussed. Many of the proposed pathways involve a shift away from carbon-based energy carriers, leading to a transition from established markets and existing transportation and storage infrastructures to new regimes. The import of "green" hydrogen (H_2) – either in gaseous form via pipelines or as liquefied hydrogen by ship – and ammonia (NH_3) derived from "green" hydrogen are generally regarded as particularly promising. However, an alternative strategy for importing "green" energy could emphasize carbon-based molecules produced from "green" hydrogen and carbon/carbon containing

---

[*] Corresponding author.
E-mail address: fabian.carels@tuhh.de (F. Carels).

https://doi.org/10.1016/j.ijhydene.2025.06.128
Received 19 March 2025; Received in revised form 20 May 2025; Accepted 7 June 2025

molecules of non-fossil origin. This approach could leverage existing infrastructures and established markets, facilitating a smoother transition towards defossilized energy systems needed to fulfill the EU's target for net-zero GHG emissions.

Synthetic natural gas (SNG) and methanol are two possible options for such carbon-based energy carriers to be produced from "green" hydrogen and carbon dioxide (CO_2). The processes required for the production of these molecules (catalytic methanation, methanol synthesis) are considered well-researched and, based on current knowledge, could be, from a technical perspective, implemented in the near future at a scale sufficient for energy import volumes relevant to the existing EU-energy system. Consequently, possible import pathways for renewable energy relying on such carbon-based molecules are characterized by short implementation horizons and all over lower technical barriers compared to other options [8,9]. Furthermore, in contrast to ammonia, for example, SNG and methanol offer high flexibility in (existing) end-use applications, enabling direct substitution of fossil fuels in various sectors.

A major challenge for scaling up "green" SNG and methanol supply lies in the favorable availability of sufficient quantities of CO_2 of non-fossil origin. Within the envisaged climate-neutral energy system, CO_2 from fossil fuels is not allowed to be emitted into the atmosphere any longer and is therefore only available within a short transition phase, if at all. Therefore, Direct Air Capture (DAC) technology is often emphasized as the primary approach for CO_2 provision in the context of producing "green" carbon-based energy carriers. However, DAC systems are not yet fully technically mature; additionally, these systems have so far been characterized by high energy and land requirements, alongside with significant investment costs. Even with a successful further technological development and a progressing plant scaling, DAC-based CO_2 supply is likely to remain expensive due to the high thermodynamically capture effort resulting from the low CO_2 concentration within ambient air [10,11]. These high expenses associated with CO_2 provision significantly raise the production costs of "green" methanol and SNG. As a result, their supply is often considered economically unfeasible or too expensive compared to energy import pathways based on carbon-free "green" molecules, such as ammonia produced from renewable electricity [12–15].

To avoid costly DAC-based provision, the utilization of CO_2 from biomass/organic waste streams and the implementation of technically largely closed carbon cycles can be alternatives for the supply of non-fossil CO_2. Within a closed-cycle approach, CO_2 released during the use of the carbon-based energy carrier is captured and returned to the energy-exporting country to be reused within the respective fuel synthesis [16,17]. Achieving high CO_2 recycling rates would likely require to use the "green" SNG or methanol in central, large-scale applications, such as power plants, industrial processes, or centralized hydrogen reforming facilities, where efficient CO_2 capture is most likely feasible.

Within recent years, a lot of different publications assessed various pathways for the import of renewable electricity-based energy in the form of "green" molecules. However, significant differences exist in the scope, level of detail, and evaluation criteria (e.g., energy supply cost, energy efficiency, GHG emissions). Furthermore, the range of analyzed import options varies widely regarding the transported molecule, transportation mode (e.g., ship or pipeline) and the form of energy supplied within the importing country (e.g., elemental hydrogen or hydrogen derivatives). Despite the breadth of the existing studies, energy import pathways using "green" carbon-based molecules remain insufficiently explored, particularly concerning the diversity of possible CO_2 supply options. For example, several studies exclude carbon-based energy carriers entirely from their assessments [12,18–20]. Others investigations consider carbon-based molecules for the intercontinental transportation of "green" energy but leave the approach for CO_2 provision unspecific [21–23] or assume CO_2 provision exclusively through DAC [14,15,24–27]. Further research assesses the import of carbon-based energy carriers in detail, but does not carry out a comprehensive comparison of these options with other "green" energy import pathways [28,29].

Against this background, this paper aims to expand on the existing literature by providing a holistic, comparative techno-economic assessment of renewable electricity-based energy imports into the EU using "green" carbon-based molecules – specifically methanol, and SNG – produced in regions with favorable wind and solar energy supply. To this end, the cost of energy supply with these import pathways and their contribution to meet the energy demands of import-dependent countries are quantified, based on a detailed technical supply chain modeling. To provide a comprehensive assessment, "green" methanol and SNG are then compared with other options for importing "green" energy in form of energy-rich molecules, including liquid hydrogen, ammonia, hydrogen bound to a liquid organic hydrogen carrier (LOHC), and pipeline-based gaseous hydrogen transportation. Diverse supply chain designs that deliver either elemental hydrogen or derivatives (SNG, methanol, ammonia) are considered. For carbon-based import molecules, a key focus is placed on the examination of various CO_2 supply concepts, including the innovative and hitherto little-regarded approach of a closed carbon cycle. In addition, for supply chains delivering hydrogen, different reconditioning methods for recovering pure hydrogen from the respective carrier are evaluated.

2. Technical background

For the conversion of renewable electricity into energy-rich import molecules suitable for an intercontinental long-distance transport, water electrolysis is always an inevitable first step. In this electrolysis process, electricity is used to split water into "green" hydrogen and oxygen. The hydrogen can then be further converted into "green" carbon-based molecules, additionally requiring a continuous CO_2 supply. For this reason, Section 2.1 first discusses suitable options for such a CO_2 supply, before Section 2.2 describes the technical fundamentals of producing, transporting, storing, and utilizing "green" carbon-based energy carriers.

Additional explanations on the technical background of alternative renewable energy supply options – later compared to carbon-based molecules – can be found in the Supplementary Information (Section I); i.e., importing "green" energy using liquid hydrogen, ammonia, LOHC, and hydrogen pipelines.

2.1. CO_2 supply

In an energy system aligned with the overarching objectives of the Paris Agreement (i.e., no emissions of additional GHG), the CO_2 used for the production of "green" carbon-based molecules must be necessarily of non-fossil origin. This is particularly true if the CO_2 is not captured but released into the atmosphere during the later use of the respective molecules. In the following, suitable CO_2 supply options are discussed.

Biogenic CO_2. Particularly suitable for obtaining biogenic CO_2 are processes in which some or all of the carbon bound within the organic matter is released while the biomass is energetically utilized or converted. Examples of such processes are bioethanol production (pure CO_2 is produced as a by-product and typically released unused into the atmosphere), upgrading biogas to biomethane (usually 40 to 50 vol-% CO_2 in the biogas) and combustion of solid biofuels (8–15 vol-% CO_2 in the emitted exhaust gas) [30–32]. The (energetic and economic) efforts of making such biogenic CO_2 sources available for the production of carbon-based "green" import molecules is typically relatively low, especially when biomass conversion processes are accessible where CO_2 is already available in a highly concentrated stream [33]. Next to capturing, any necessary transportation, intermediate storage and compression may add to the energy expenses, the costs and GHG emissions associated with the CO_2 provision. Despite the existing and, so far, largely untapped potential for low-effort exploitation of biogenic CO_2, the availability of sufficient quantities in the future is highly uncertain.

The potential of sustainably useable biomass – and thus also of the resulting biogenic CO_2 – is limited by the natural production capacities of the biosphere, the given market competition especially with the food and fodder markets as well as other constraints such as land use limitations or existing infrastructure deficits.

CO_2 from ambient air. If biogenic CO_2 is not available in sufficient quantities, the DAC process allowing atmospheric CO_2 to be extracted as a pure stream, may be an alternative. Various DAC technologies, mainly based on different adsorption and absorption processes, are currently under investigation; some of them are already implemented as small-scale demonstration plants [34,35]. For the time being, the most promising DAC technology for CO_2 supply in the production of "green" carbon-based molecules is the low-temperature DAC processes, where usually amine-based sorbents are used for removing the CO_2 from the air and the subsequent release of the CO_2 from the sorbent takes place at around 100 °C [36]. This temperature level allows for the integration of waste heat, e.g., from exothermal synthesis reactions to (partially) cover this thermal energy demand [37]. Additionally, high temperature heat pumps might be used to meet the remaining heat demand efficiently and solely through renewable electricity [10,11,38]. Table 1 shows exemplarily the energy demand of CO_2 supply with low-temperature DAC after the integration of synthesis waste heat and heat pumps, whereby the thermal energy demand after heat integration differs as a significantly larger amount of reactor heat is available in from methanation (SNG pathway) than from methanol synthesis (Methanol pathway). Accordingly, the total electricity demand for CO_2 supply via DAC, which includes covering the remaining thermal energy demand with high temperature heat pumps, is also lower in the SNG pathway.

Closed carbon cycles. An alternative to the complete supply of CO_2 from a biogenic source or from the ambient air is the implementation of a system for the technical recirculation of CO_2. In such a largely closed carbon cycle approach, the CO_2 released during the use of carbon-based molecules would be captured and transported back to the energy-exporting country, where it could be reused for molecule synthesis [17,39]. Only small amounts of CO_2 would need to be sourced from biomass or ambient air to compensate for inevitable carbon losses occurring within this cycle. From today's perspective, minimizing carbon losses to such low levels is only feasible at acceptable technical and economic cost if the carbon-based import molecule is used in large-scale facilities, for example in industry or in large power plants.

The intercontinental, transnational transportation of large quantities of CO_2 is not yet state-of-the-art. Nevertheless, small-scale CO_2 carriers with maximum capacities of around 1,800 t_{CO2} per ship are already under operation, primarily for the food and beverage industry [40]. To enable closed CO_2 cycles on a relevant scale, significantly larger ships would be required. These carriers will most likely transport CO_2 in a liquid form near its triple point (5.18 bar, −56.6 °C) to achieve a maximum storage density on the transport vessel [41,42]. For this purpose, semi-refrigerated tanks, which combine moderate cooling with pressurization, would be used. This technology is already successfully employed for transporting gases like liquefied petroleum gas (LPG) or ethylene. Recently, two liquid CO_2 tankers with a capacity of around 8, 500 t_{CO2} each were constructed to transport captured CO_2 for underground storage (CCS) in Norwegian offshore reservoirs [43]. Beyond that, even larger CO_2 carriers (~25,000 t_{CO2}/vessel) are announced to be delivered by 2026 latest [44]. The largest proposed concept for CO_2 carriers to date envisions a capacity of approximately 105,000 t_{CO2} [45].

Table 1
Energy demand of CO_2 supply with low-temperature DAC.

Parameter	Unit	SNG pathway		Methanol pathway	
Electricity demand (without heat pumps)	kWh_{el}/kg_{CO2}	0.48 [25,35,37,38]			
Thermal energy demand (before heat integration)	kWh_{th}/kg_{CO2}	1.66 [25,35,37,38]			
Thermal energy demand (after heat integration)	kWh_{th}/kg_{CO2}	0.82	a	1.59	a
Total electricity demand (after heat integration and with heat pumps)	kWh_{el}/kg_{CO2}	0.89	b	1.28	b

[a] Own calculation, based on the available waste heat from synthesis (see Supplementary Information (Section III)).

[b] Coefficient of performance of the heat pumps: 2.0 [10,11].

2.2. "Green" carbon-based energy carriers

For the conversion of "green" hydrogen into carbon-based "green" energy carriers (here: considered as import molecules), SNG and methanol are the primary options due to their relatively simple synthesis and their versatile applications within the existing overall economy.

- SNG is chemically almost identical to conventional natural gas, consisting of methane, the simplest alkane [46,47]. By liquefying SNG, a very high volumetric energy density of over 6,000 kWh_{LHV}/m^3 can be realized [48].
- Methanol, the simplest/shortest alcohol, has a volumetric energy density of approximately 4,500 kWh_{LHV}/m^3. While its energy density is lower than that of liquified SNG (LSNG), methanol offers practical advantages in terms of storage and handling, as it is liquid under ambient conditions and does not require high-pressure or cryogenic storage [49,50].

2.2.1. Synthetic natural gas (SNG)

Catalytic methanation is a fully industrially established synthesis process. While existing plants primarily methanize fossil fuel-based synthesis gases rich in carbon monoxide (CO) – for example, from coal gasification – it will most likely be necessary to shift this synthesis process from CO to CO_2 for the prospective production of SNG based on renewable electricity [51]. The methanation reaction, also known as the Sabatier process (Equation (1)), takes place at temperatures between 250 and 550 °C and is highly exothermic [52,53]. At full stochiometric conversion of the reactants, the (thermodynamic) maximum achievable energy conversion efficiency is 83.2 $\%_{LHV}$ (without taking into account the auxiliary electricity demand) [25,54]. According to the enthalpy of reaction, the released heat is around 2.85 kWh per kg of methane produced. This heat can be (partially) made available for heating other processes (if there is a heat demand at the respective location; otherwise this heat needs to be assessed as a loss) [37,52].

$$CO_2 + 4\,H_2 \rightleftharpoons CH_4 + 2\,H_2O \qquad \Delta H_{R(298\ K)} = -165.0\ kJ/mol \tag{1}$$

SNG can be transported and stored using the existing natural gas infrastructure without any technical restrictions. Intercontinental overseas transportation can be realized using liquefied natural gas tankers (LNG tankers). The methane liquefaction necessary for the corresponding conditioning requires between 0.25 and 1.4 kWh_{el}/kg_{CH4} [12,55,56]. The methane slip during liquefaction can be relevant for the GHG balance of an SNG-based energy supply; these losses can make up to 1.5 % of the liquefied methane [56], but they are usually significantly lower [57,58]. Modern LNG tankers typically use insulated membrane tanks for the cryogenic ship-based storage of LNG, with capacities reaching up to 266,000 m^3 [12,25]. However, the average size of the global fleet is significantly lower (~180,000 m^3), e.g., due to constraints resulting from the limitations of certain waterways (e.g., Panama Canal) [12].

Despite advanced and costly insulation systems installed on board these SNG tankers, some heat input into the storage tank is unavoidable, causing a portion of the LNG to evaporate during the transport. To protect the tank systems from any damage, the evaporated gas, also known as boil-off gas, must be vented. For modern tankers, these boil-off losses summing up to typically around 0.1 % per day and might be used to power the respective ship [12,59].

SNG can be utilized within the existing natural gas markets without the need for technical adjustments by the respective end users. Assuming sufficient availability of "green" SNG, this provides the opportunity to gradually phase out fossil natural gas and replace it with "green" SNG in application fields such as power generation, industrial processes, and heating of buildings. Furthermore, defossilization of sectors such as mobility or steel production currently using other fossil fuels (e.g., hard coal or crude oil products) is also technically possible with the help of SNG [48,55]. Besides such a direct utilization, the use of SNG as a hydrogen carrier can be an option. To do so, methane is split into pure hydrogen and CO_2 at a temperature level of over 800 °C within an endothermic catalytic reforming reaction. Several technologies can be considered for this reforming process. Nowadays, steam methane reforming (SMR) is the most common option, primarily used (so far) to produce hydrogen from fossil natural gas. In conventional SMR, the required heat is supplied by external reactor firing, typically involving the burning of a share of the overall used natural gas. Accordingly, CO_2 is released both within the reforming reactor and during external firing (diluted within the flue gas), making the efficient capture of large proportions of CO_2 challenging [60,61]. An alternative process in which CO_2 is produced exclusively in the reactor is autothermal reforming (ATR). Here, endothermic SMR is combined with exothermic partial oxidation (POX) so that the overall reaction is adiabatic and no external heat is required. For the POX to take place pure oxygen (O_2), e.g., supplied by an air separation unit, is needed. The CO generated during SMR and POX can be converted into CO_2 together with steam in a water-gas shift reactor, thereby increasing the hydrogen yield [62,63].

Downstream process steps are required to capture the CO_2 as well as to purify the produced hydrogen. This can be realized by, for example, amine wash and pressure swing adsorption (PSA) units [60]. The methane demand of the ATR is between 3.0 and 3.2 kg_{CH4}/kg_{H2}, resulting in a chemical conversion efficiency of 75–80 $\%_{LHV}$ [60,64–66]. ATR is currently used on an industrial scale to produce synthesis gases rich in CO and hydrogen [63]. However, new plants are being planned to supply pure hydrogen while capturing the CO_2 produced in the process [64,67]. A potential alternative to ATR, which also allows for high CO_2 capture rates, is the modification of the conventional SMR and here especially the external heat supply to the reactor. One promising concept envisages supplying the required heat by electrical resistance heating instead of fuel gas combustion (electrified steam reforming – eSR) [68,69]. The eSR of methane is not commercially used today. However, large-scale reactor concepts are currently under development and related reforming concepts have already been successfully demonstrated with electric heating [70,71]. The electricity demand of such a reactor is expected to be in the range between 8.6 and 9.2 kWh_{el}/kg_{H2}. This extensive use of external energy allows for a particularly high hydrogen yield relative to the amount of methane consumed (2.4–2.6 kg_{CH4}/kg_{H2}) [61,65].

2.2.2. Methanol

Catalytic methanol synthesis is an exothermic process usually operated in a temperature range of 200–300 °C. CO_2-based methanol formation is described by Equation (2) [50,72]. In the practical implementation, hydrogen and CO_2 are almost completely converted into the desired product, enabled by the recycling of unconverted synthesis gas within the overall process [25,73]. Consequently, the chemical conversion efficiency is 87.9 $\%_{LHV}$, while, according to the reaction's enthalpy, 0.43 kWh_{th}/kg_{CH3OH} are released as (waste) heat [12]. To obtain pure methanol, a subsequent separation from the released methanol-water mixture via distillation is required, resulting in a respective heat demand. Depending on the realized heat integration approach, the resulting demand for thermal energy can be met by the heat released during the exothermal methanol generation. If at all, only a small part of the reactor (waste) heat can be decoupled and used for other processes (if available at the specific location) [37,74].

A respective plant located in Iceland with a capacity of 4,000 t/a of methanol demonstrates renewable methanol production from hydrogen and CO_2 on a (semi) commercial scale since 2011 [49,75]. Recently, two much larger plants for CO_2-based methanol synthesis have been realized in China, although the hydrogen and CO_2 are not obtained from renewable sources, but from exhaust gases from fossil fuel-based processes [76].

$$CO_2 + 3\,H_2 \rightleftharpoons CH_3OH + H_2O \qquad \Delta H_{R(298\ K)} = -49.2\ kJ/mol \tag{2}$$

Given its liquid state under standard conditions, methanol is relatively straightforward to transport and store [49]. Already today, methanol is transported intercontinentally by ship. Dedicated methanol tankers achieve cargo capacities of up to 120,000 m^3 [77]. If the importance of ("green") methanol continues to grow, it is conceivable that methanol tankers with larger capacities, as are common in crude oil transportation today, could be realized in the future on the basis of existing know-how and the given experiences.

In the recent past, the global demand for methanol has surged significantly, nearly doubling over the last 15 years. Methanol produced from fossil fuels, primarily coal and natural gas, is widely used as a feedstock/important component for the production of various chemical products such as paints, solvents, and plastics. Additionally, methanol is increasingly employed as a fuel-blending component within the mobility sector, particularly in China. In the future, "green" methanol is anticipated to play a key role, particularly in the defossilization of the chemical industry, where it can serve as a feedstock for a wide range of downstream products [49,78]. Current developments also suggest that international shipping will increasingly adopt "green" methanol as a potentially CO_2-neutral fuel [79,80].

Furthermore, methanol may be employed as a hydrogen carrier. Similar to methane, the molecule can be split into hydrogen and CO_2 through an endothermic reforming process. The necessary temperatures required for the methanol reforming reaction to take place are in the range between 200 and 400 °C [72,81]. However, methanol reforming has not yet been implemented on an industrial scale, nor have any plants for methanol-based hydrogen production been announced. Therefore, existing (literature) data on conversion efficiencies and energy requirements are uncertain. For autothermal reforming (heat is provided internally by utilizing part of the supplied methanol), the methanol demand is expected to be in the range of 6.7–7.1 kg_{CH3OH}/kg_{H2}, corresponding to a chemical conversion efficiency of 85–90 $\%_{LHV}$ [82,83]. Hydrogen purification losses may result in a higher methanol demand but are not expected to be significant due to the technological less demanding separation of hydrogen and CO_2. To combine methanol-based pure hydrogen provision with a high CO_2 capture rate, electrically heated methanol steam reforming is also conceivable. If implemented at scale, this process could potentially achieve a methanol consumption of less than 6 kg_{CH3OH}/kg_{H2} [84–86]. Considering the thermal energy demand of methanol steam reforming, including the energy required to evaporate both, methanol and water, the total electricity demand of such a reactor is estimated to range between 7 and 10 kWh_{el}/kg_{H2} [81,83,86].

Table 2 summarizes the most important characteristics of the use of green SNG and green methanol as energy carriers and outlines key differences.

Table 2
Comparison of green SNG and green methanol.

Aspect	SNG	Methanol
Volumetric energy density	~6,000 kWh_{LHV}/m^3 (liquefied)	~4,500 kWh_{LHV}/m^3
Storage requirements	Pressurized (when gaseous) or cryogenic (when liquid)	At ambient temperature and atmospheric pressure
Infrastructure compatibility	Fully compatible with (liquified) natural gas infrastructure	Partly compatible with liquid fuel and chemical infrastructure
Boil-off losses	~0.1 %/day (modern tanks/tankers)	Negligible
Market adaptability	Power and heat generation, industry	Feedstock for chemical industry, (marine) fuel
Climate risk (leakage)	High (methane = potent GHG)	Low (methanol degrades fast in air/water)

3. Assessment approach

Following the overall objective of this paper – to evaluate renewable energy imports based on "green" SNG and methanol and compare them with alternative import molecules – the general assessment approach illustrated in Fig. 1 is employed.

3.1. Framework definition

Method. As a first step, a suitable and consistent framework is set up allowing a systematic and fair assessment of energy import options based on different import molecules. This framework serves as the basis for the subsequent system definition and modeling, as it defines the scope, central assumptions and boundaries.

Data. The most important framework assumptions set for this study are listed below.

- Scope and type of energy supply: Large-scale, point-to-point energy import with full technological maturity of all supply chain components
- Reference year for all technology-specific parameters: 2035
- Transportation distance for "green" molecule import: 5,000 km
- Requirements of energy supply at the point-of-import: H_2 derivative or pure H_2 ($\geq$99.95 %) at a pressure of 100 bar
- Financial and economic framework: Depreciation of the investment costs of all system components over their technical lifetime at a weighted average cost of capital (WACC) of 6 %
- Plant availability: 8,000 h/a
- Energy availability and cost
  - Continuous provision of "green" H_2 within the export country (as energy to be exported): 0.1 $€_{2024}/kWh_{H2,LHV}$ (based on [87,88])
  - Baseload electricity supply in the export country (as auxiliary energy for conditioning): 0.07 $€_{2024}/kWh_{el}$ (based on [89,90])
  - Baseload electricity supply in the import country (as auxiliary energy for reconditioning): 0.1 $€_{2024}/kWh_{el}$ (based on [89,90])
  - Baseload heat supply in the import country (>300 °C, as auxiliary energy for reconditioning): 0.1 $€_{2024}/kWh_{H2,LHV}$ (based on [89, 90])
  - Renewable marine fuel (for the propulsion of ships that cannot be powered by the molecule they transport): 0.11 $€_{2024}/kWh_{fuel,LHV}$ (based on [13])

3.2. System definition

Method. The definition of the system to be assessed involves, in particular, the specification of the import molecules and resulting energy supply chains, as well as the selection of the technical components of the respective supply chains. Furthermore, the interfaces between the supply chain components are defined.

Data. Renewable energy imports via electricity-based "green" SNG and methanol can be realized with a wide range of possible supply chain configurations. These specific configurations are determined by the available technological options (as described in Chapter 2) applied for the key components, and their combination. Fig. 2 illustrates the energy supply chains assessed in this paper utilizing SNG and methanol as carbon-based import molecules.

Initially, the "green" hydrogen provided in the exporting country is converted into methane or methanol through the respective catalytic synthesis process. These carbon-based molecules are then shipped from the export country to the import country. In the case of SNG, liquefaction is required after the synthesis process to enable an efficient shipping with conventional LNG tankers.

For the utilization of carbon-based molecules in the importing country, two principal routes are being considered: either (i) directly as derivatives or (ii) as carriers for the supply of pure hydrogen. When used as hydrogen carrier, SNG and methanol undergo reforming via ATR, which utilizes a portion of the carrier for supplying the heat internally, or eSR, where external electrical heating is employed. After reforming, the produced hydrogen is compressed to meet the requirements of energy supply specified in the framework conditions (Fig. 1).

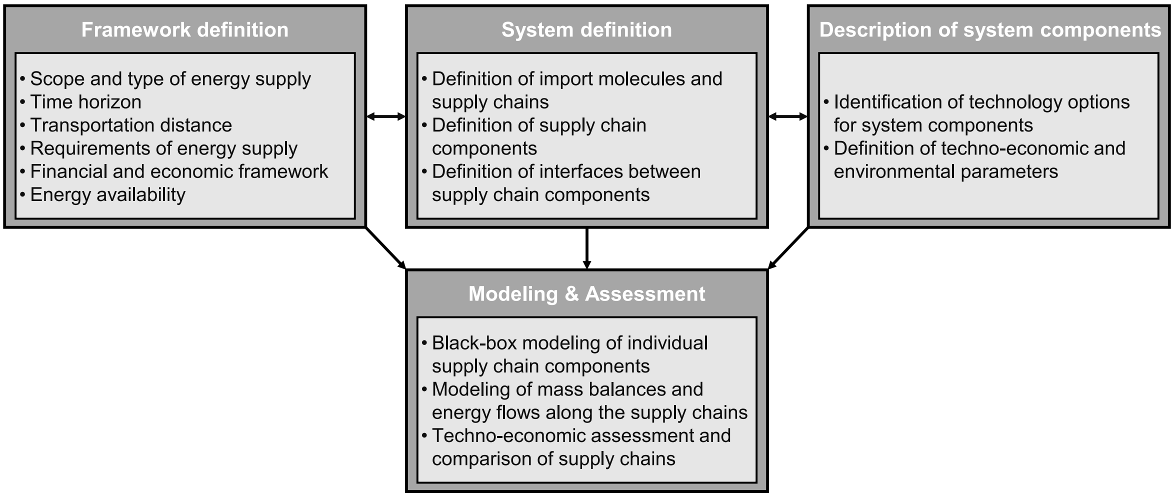
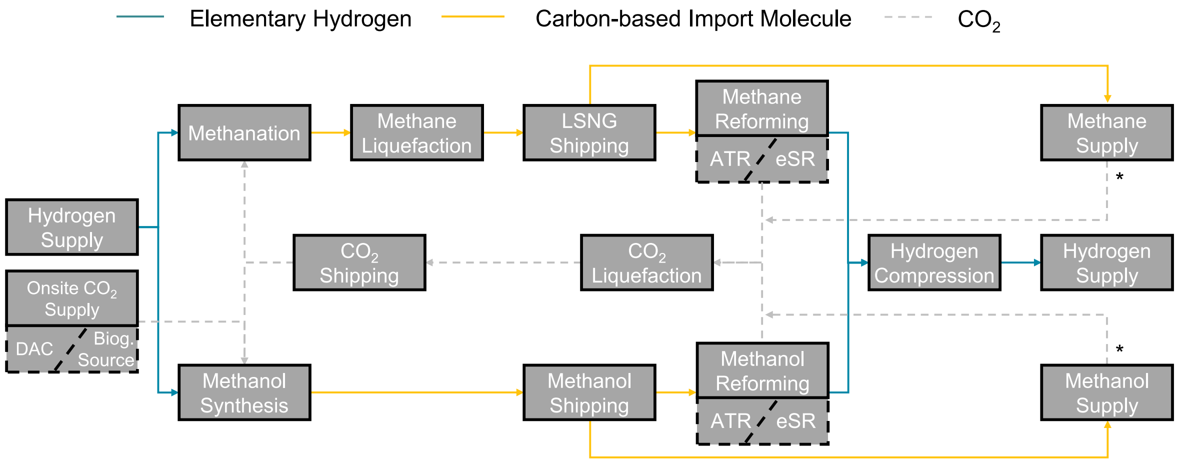


Fig. 1. General approach for system definition, modeling, and assessment.



* CO_2 capture can take place at the site of centralized energy use of the carbon-based import molecule or, if the import molecule is converted into a material product, at the end of the product's life cycle (e.g., waste incineration)

Fig. 2. Assessed energy supply chains and their components for energy imports using "green" carbon-based molecules (ATR = Autothermal reforming; Biog. = Biogenic; CO_2 = Carbon dioxide; DAC = Direct air capture; eSR = electrified steam reforming; LHV = Lower heating value; LSNG = Liquefied synthetic natural gas).

Further differentiation within the supply chain configurations is made concerning the concept of CO_2 provision. Configurations with and without a CO_2 cycle are analyzed. For supply chains incorporating a CO_2 cycle including capture at the reforming plant, liquefaction and shipping of CO_2 as core components, the CO_2 obtained from an onsite source at the point-of-export is used exclusively to offset carbon losses. In contrast, supply chains without a CO_2 cycle rely entirely on such an onsite source for the provision of the required CO_2. Regarding this onsite source, two options are considered: (i) a biogenic CO_2 source and (ii) the DAC process, which extracts CO_2 from ambient air.

In addition to the components outlined in Fig. 2, intermediate storage of SNG, methanol, and CO_2 is included both before and after shipping to align continuous synthesis/reforming processes with the intermittent character of shipping.

Based on the outlined differentiation, a total of 16 distinct supply chain configurations for energy supply using carbon-based import molecules are considered. To provide a comprehensive analysis, these supply chains are compared among each other and with the following alternative energy import pathways:

- **Liquid hydrogen (LH_2)**: Import of liquified H_2 by ship, with subsequent regasification for supply of gaseous hydrogen.
- Hydrogen bound to a **liquid organic hydrogen carriers (LOHC):** Import by ship, with subsequent H_2 recovery via LOHC dehydrogenation. As with carbon-based import molecules, both internal heat supply (using a portion of the dehydrogenated H_2 for gas-fired reactor heating) and external heat supply (electrical reactor heating) are considered.
- **Ammonia (NH_3):** Import of "green" ammonia by ship, for either direct ammonia utilization or pure H_2 supply. For ammonia-based H_2 supply, ammonia cracking is evaluated, considering both internal and external heat supply, similar to the approach used for H_2 supply with carbon-based molecules and LOHCs.
- **Gaseous hydrogen (GH_2):** Import of gaseous H_2 via pipeline for direct supply.

All energy supply chains assessed are modeled according to the approach outlined in Section 3.4 on the same level of detail and within the same system framework. The definitions of all analyzed supply chains are listed in detail in the Supplementary Information (Section II).

3.3. *Description of system components*

Method. The system definition is accompanied by a description of the various required system components, aiming to select suitable technologies for all components and to specify them with techno-economic parameters. In accordance with the specification of the framework definition, this has to be realized according to the defined time horizon (here: 2035).

Data. The technology-specific parameters were determined based on a comprehensive meta-study (for all techno-economic data see Supplementary Information (Section III)).

3.4. *Modeling and assessment*

Modeling method. The modeling of the predefined energy supply chains aims to assess mass balances and energy flows, first at the level of the individual components and subsequently across the various energy supply chains. While a black-box approach is used to describe the input and output streams of the individual components, the modeling of the entire supply chain takes into account the interfaces between the components. This modeling enables the conclusive assessment and comparison of the energy supply chains defined in terms of their techno-economic performance. The mathematical principles of this assessment are described below.

Assessment method. The primary parameter for the techno-economic assessment of the various supply chains is the total cost of the final energy supply at the point-of-import (c_{FES}). Thus, c_{FES} includes all costs associated with the energy supply and is calculated according to Equation (3). The sum of the annual costs associated with each individual supply chain component is divided by the total amount of energy supplied via the system at the point-of-import over one year (E_{FES}).

$$c_{FES} = \frac{C_{H2} + C_{conv} + C_{carrier} + C_{import} + C_{store} + C_{reconv}}{E_{FES}} \tag{3}$$

The various costs of the supply chain components are defined as follows.

- C_{H2}: Annual cost of H_2 provision at the point-of-export (includes, besides H_2 production cost, also storage cost to enable continuous supply to conversion unit).

- **C_{conv}**: Annual cost of converting H_2 into the respective import molecule.
- **$C_{carrier}$**: Annual cost of carrier provision $c_{carrier}$ (e.g., CO_2, N_2, LOHC molecule).
- **C_{import}**: Annual cost of transporting the import molecule from the point-of-export to the point-of-import.
- **C_{store}**: Annual cost of storing the import molecule.
- **C_{reconv}**: Annual cost of reconverting the import molecule into pure H_2 and compress the H_2 to the desired supply pressure.

Not all of the listed costs are relevant for every supply chain under investigation. For example, when hydrogen is transported in elemental form, either as compressed gas or liquid hydrogen, there is no need for a carrier ($C_{carrier} = 0$). Similarly, if SNG, methanol, or ammonia are supplied directly, reconversion into pure hydrogen is not required ($C_{reconv} = 0$).

C_{H2} is calculated as the product of the specific cost of hydrogen supply at the point-of-export ($c_{H2,specific}$) and the total amount of hydrogen required annually (Equation (4)). The total hydrogen energy required at the point-of-export can be divided into the energy effectively delivered at the point-of-import (E_{FES}) and the energy lost along the supply chain (E_{loss}). E_{loss} accounts for all processes resulting in a reduction of the energy contained in the molecule, such as conversion and reconversion losses or boil-off during transportation and storage. However, additional energy inputs provided externally, such as electricity or heat supplied for re-/conversion processes, are not included in E_{loss}.

$$C_{H2} = c_{H2,specific}(E_{FES} + E_{loss}) \tag{4}$$

The energy required to generate the tankers' propulsion can either be provided by a dedicated marine fuel, or, if technically possible, by using part of the transported "green" molecule (i.e., in SNG, methanol, liquid hydrogen, and ammonia shipping). If the transported molecule is used, the energy demand of ship transportation ($E_{shipping}$) has to be covered by additional hydrogen production and is therefore part of E_{loss}; if a dedicated marine fuel is used, the costs incurred for its provision are part of $c_{transport}$ (Equation (6)).

In the case of energy supply using "green" carbon-based molecules, $C_{carrier}$ includes all costs associated with the provision of CO_2 (Equation (5)). Here, supply chains with and without a closed carbon cycle for CO_2 provision are analyzed. When calculating the costs of the carbon cycle, liquefaction ($C_{CO2,liq}$), ship transportation ($C_{CO2,transport}$) and intermediate storage ($C_{CO2,store}$) are taken into account. Furthermore, the costs associated with the provision of CO_2 directly at the site of synthesis ($C_{CO2,supply,onsite}$) are considered, either to compensate for carbon losses during the CO_2 cycle or – in scenarios where no CO_2 cycle is used – for CO_2 provision exclusively from an onsite source.

$$C_{carrier,CO2} = C_{CO2,liq} + C_{CO2,transport} + C_{CO2,store} + C_{CO2,supply,onsite} \tag{5}$$

The annual costs for the individual supply chain components except c_{H2} are calculated using Equation (6). Here, $ACAPEX_i$ represents the annualized, discounted investment costs, while $OPEX_i$ summarized energy-related operational costs (i.e., provision of electricity, thermal energy, marine fuel) as well as expenses for maintenance and repair and other operating costs (e.g., harbor fees).

$$C_{component,i} = ACAPEX_i + OPEX_i \tag{6}$$

$$ACAPEX_i = CAPEX_i \frac{WACC(1 + WACC)^{DP_i}}{(1 + WACC)^{DP_i} - 1} \tag{7}$$

The annualized investment costs $ACAPEX_i$ (of the component i) are determined using the annuity method. This involves multiplying the initial investment for the respective component ($CAPEX_i$) – including costs for equipment, plant design, and installation (based on literature data) – by the annuity factor. The annuity factor is calculated based on the weighted average cost of capital ($WACC$) and the depreciation period (DP_i).

The calculation of each cost component – and thus of the total cost of the final energy supply – is based on technology-specific capital and operating expenditures, energy demands, and system utilization factors as specified in the Supplementary Information (Section III). For each supply chain component, the respective costs are annualized and attributed to the final energy output according to Equations (3)–(7).

In addition to the cost of the final energy supply at the point-of-import c_{FES}, the supply chains are assessed regarding their contribution to meet the energy demands of import-dependent countries. To this end, the net energy import (NEI), realized by each supply chain, is evaluated. The NEI is defined as the share of the imported energy that is actually provided for the energy system of the importing country. It is calculated by subtracting the energy required within the importing country for processing the supply chain ($E_{In,PoI}$) from the total energy supplied at the point-of-import (E_{FES}) (Equation (8)):

$$NEI = \frac{E_{FES} - E_{In,PoI}}{E_{FES}} \tag{8}$$

Various components of the supply chain can cause energy demands in the importing country and thus contribute to $E_{In,PoI}$. These may include the external energy required for reconversion of the import molecule into hydrogen and subsequent hydrogen compression to the desired supply pressure (E_{reconv}), as well as the energy required for ship- or pipeline-based transport of the import molecule (E_{import}). The energy demand of ship-based transport is only relevant to the NEI if not the import molecule itself but a dedicated marine fuel is used. In the case of supply chains relying on carbon-based import molecules and utilizing closed CO_2 cycles, CO_2 liquefaction ($E_{CO2,liq}$) and the return transport of CO_2 ($E_{CO2,transport}$) from the importing country to the exporting country cause an additional energy demand in the import country. For the transport of both the import molecule and CO_2, it is assumed that the energy demand is partially incurred in the exporting country and partially in the importing country (Equation (9)):

$$E_{In,PoI} = E_{reconv} + \frac{E_{import}}{2} + E_{CO2,liq} + \frac{E_{CO2,transport}}{2} \tag{9}$$

The NEI allows the cost of final energy supply (c_{FES}) to be related to the actual amount of additional energy provided in the importing country. Accordingly, the cost of net energy import (c_{NEI}), calculated using Equation (10), reflect the true cost of fulfilling the supply objective – delivering additional energy to the importing country.

$$c_{NEI} = \frac{c_{FES}}{NEI} \tag{10}$$

4. Results and discussion

This chapter discusses the results of the supply cost (Sections 4.1 to 4.4) and net energy import (Section 4.5) assessment of the pathways for renewable electricity-based energy import. To present the results, the costs are allocated to distinct contributor categories along the supply chains, with detailed definitions of these categories provided in the Supplementary Information (Section 2).

In accordance with the framework definition (Section 3.1) the results presented in this chapter are based on techno-economic parameters projected for 2035 to represent a mid-term future in which all key technologies are expected to be commercially mature. The selected parameter values (see Supplementary Information (Section III)) were derived from a broad literature base reflecting industry roadmaps, academic scenario analyses, and expert forecasts. While the absolute values may change as markets and technologies evolve, the comparative nature of this study ensures that the relative assessment of the analyzed import pathways remains robust.

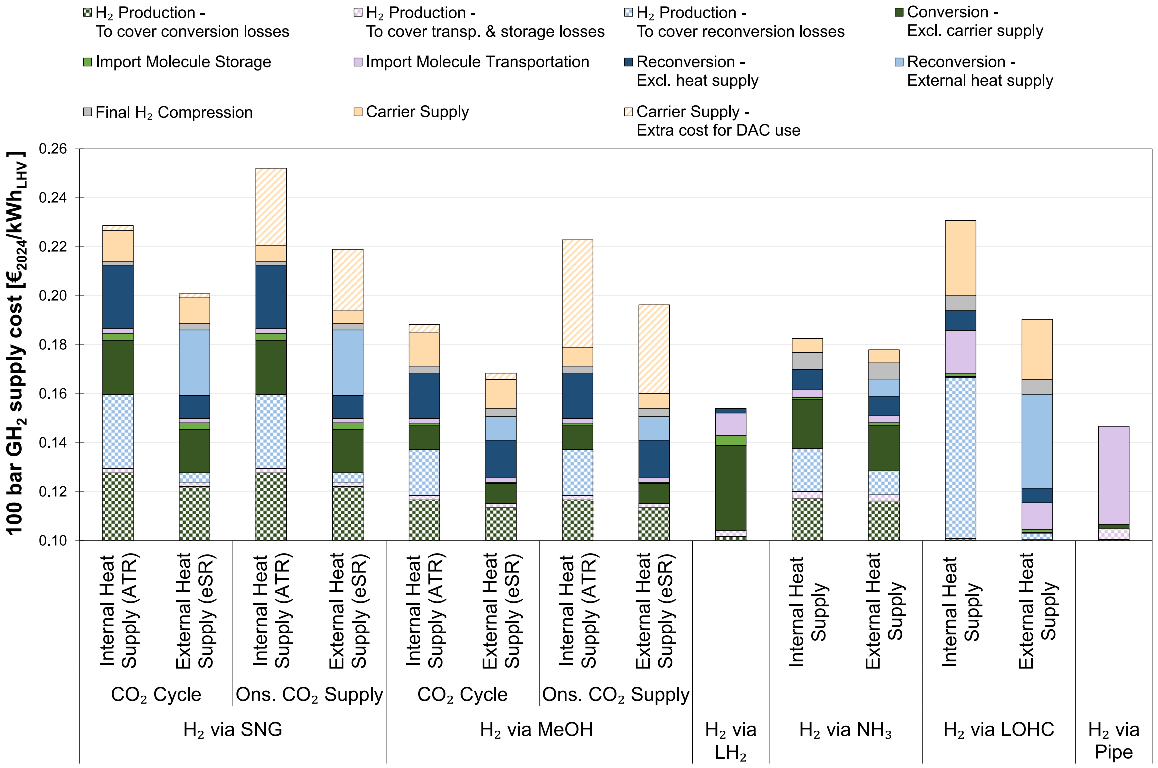


Fig. 3. Cost in 2035 for a supply of gaseous hydrogen at 100 bar
(The cost of providing one kWh of hydrogen at the point-of-export is the same for all pathways (0.1 €$_{2024}$/kWh$_{H2,LHV}$) and is therefore not shown here but part of the overall supply cost.) (ATR = Autothermal reforming; CO_2 = Carbon dioxide; DAC = Direct air capture; eSR = electrified steam reforming; GH_2 = Gaseous hydrogen; LH_2 = Liquid hydrogen; LHV = Lower heating value; LOHC = Liquid organic hydrogen carrier; MeOH = Methanol; NH_3 = Ammonia; Ons. = onsite; SNG = Synthetic natural gas).

4.1. Cost of hydrogen supply using carbon-based import molecules

The specific costs of supplying gaseous hydrogen at 100 bar in the import country are illustrated in Fig. 3. The production cost for one kWh of hydrogen at the point-of-export – representing the energy ultimately delivered at the point-of-import – is assumed to be 0.10 €/kWh$_{H2,LHV}$ according to Section 3.1 and, as being identical across all pathways, is not shown in Fig. 3 but included in the stated total supply cost.

Supply cost composition. The analyzed supply chains using "green" SNG or methanol as carriers to import hydrogen incur supply cost ranging between 0.165 and 0.252 €/kWh$_{H2,LHV}$. For these supply chains, hydrogen production in the exporting country accounts for clearly more than half (in all cases >58 %) of the total hydrogen supply cost. This significant contribution of the hydrogen production in the export country to the total supply cost emphasizes the critical importance of a cost-effective hydrogen production and the identification of optimal production sites for economically viable hydrogen imports.

A further significant share of the hydrogen production costs results from additional hydrogen production required to compensate for energy losses caused by the respective conversion and reconversion processes (*H_2 Production - To cover conversion losses* and *H_2 Production - To cover reconversion losses*). Besides this, for the two hydrogen import options, SNG and methanol, transportation and terminal storage costs are minor, confirming the infrastructural advantages often attributed to carbon-based import molecules [9,25,37]. This is true for the costs associated with acquiring and operating vessels (*Import Molecule Transportation*) and storage tanks (*Import Molecule Storage*), as well as the indirect costs arising from losses, e.g., due to using part of the loaded import molecule as fuel for the ship's propulsion (*H_2 Production - To cover transp. & storage losses*). Additionally, the cost of compressing hydrogen to 100 bar after reconversion is negligible (*Final H_2 Compression*).

Fig. 3 illustrates that the cost of hydrogen supply via carbon-based import molecules is strongly influenced by the respective configuration of the supply chain, including the reforming technology, the CO_2 supply concept, and the availability of onsite CO_2 sources.

SNG vs. Methanol. There are clear differences between methanol and SNG-based hydrogen supply pathways; Fig. 3 shows cost advantages of methanol-based over SNG-based hydrogen supply. These advantages are largely attributable to the lower cost associated with compensating for re-/conversion losses through additional hydrogen production (*H_2 Production – To cover re-/conversion losses*) and providing external heat for reconversion (*Reconversion – External heat supply*). Overall, the cost advantage of methanol-based hydrogen supply compared to SNG-based supply ranges between 10 and 20 % in the scenario under consideration, assuming identical configurations of the supply chain with regard to reformer technology and CO_2 supply concepts. This is mainly attributable to the lower reaction enthalpy of methanol synthesis and methanol decomposition. A higher share of the energy stored within the hydrogen is transferred to the methanol molecule during methanol synthesis, while methanation converts less of the hydrogen's energy into methane to the expense of the production of more waste heat. Consequently, the thermal energy required to recover hydrogen from methanol during reforming is also lower than for SNG. Another clear advantage of methanol over SNG as a hydrogen carrier is the lower energy and equipment requirements for conditioning. Unlike SNG, which must undergo an energy-intensive liquefaction process, methanol is already in a liquid form when leaving the synthesis process. This results in lower costs for the conditioning of the transported hydrogen derivative within methanol-based supply chains (here assigned to the cost category *Conversion - Excl. carrier supply*). However, methanol-based hydrogen supply incurs higher specific costs for CO_2 provision compared to SNG (*Carrier Supply*) (see below, paragraph carbon supply).

Internal vs. external heat supply. According to Fig. 3, supply chains applying eSR and thus utilizing external energy to meet the heat demand of the reconversion process are generally more cost-efficient than those relying on ATR (internal heat supply). Under the given assumptions, the use of eSR leads to cost savings of ca. 13 % for SNG-based and ca. 12 % for methanol-based hydrogen supply. This cost advantage results mainly from the higher chemical reconversion efficiency of eSR compared to ATR reducing the need for additional hydrogen production to offset reconversion losses (*H_2 Production – To cover reconversion losses*). Moreover, as less SNG or methanol needs to be transported along the supply chain to deliver the same hydrogen quantity in the import country, infrastructure components such as re-/conversion plants and tankers can be scaled down, leading to further cost savings in eSR-based supply chains. Although eSR requires additional electricity input for external reactor heating in the import country, this approach is significantly more efficient (electricity → heat) than the provision of heating energy along the supply chain in ATR-based concepts involving multiple energy conversions (electricity → hydrogen → methane/methanol → heat). In the case analyzed here, this increased energy efficiency translates into lower costs for reconversion heat supply.

Carbon supply. In the context of the analyzed CO_2 supply concepts, the assessment reveals that utilization of low-cost biogenic CO_2 offers clear cost advantages over CO_2 sourcing with DAC. Under the framework conditions considered here, the lowest hydrogen supply costs using carbon-based import molecules are achieved with a CO_2 supply solely using a biogenic onsite source. If such a biogenic source is not available and CO_2 needs to be supplied entirely via the DAC technology, the hydrogen supply cost increases significantly. The additional costs due to DAC usage are considerably higher for methanol (+25 % for reforming via ATR) than for SNG (+15 % for reforming via ATR). This disparity can be attributed to these two key factors.

- Compared to methane, the methanol molecule requires a greater amount of CO_2 per kWh of energy delivered, making methanol-based hydrogen supply more sensitive to the cost of CO_2 supply.
- Due to methane's higher reaction enthalpy (see above) methanation generates more waste heat compared to the methanol synthesis. Furthermore, the waste heat released during the methanol synthesis is largely required internally for the separation and purification purposes (i.e., distillation of methanol), whereas there are no such constraints during the methanation process. This methanation waste heat can be integrated into the DAC process, reducing the heat demand of DAC plants by ca. 50 % (Table 1) within a SNG-based hydrogen supply. This integration lowers the specific CO_2 supply cost from 173 to 144 €/t_{CO2} (Table 3). In contrast, the heat integration potential for methanol synthesis is significantly lower, resulting in only minimal reductions in the specific cost of CO_2 supply with DAC. However, effective utilization of waste heat for DAC always requires spatial proximity between the synthesis and DAC systems, as heat transport is limited by both technical and economic constraints.

An alternative CO_2 supply concept analyzed here involves implementing a closed CO_2 cycle. Within such a concept, CO_2 released during the reforming process is captured, liquefied and transported back to the energy-exporting country. In the examined case, the specific costs of such an CO_2 cycling are about 50 €/t_{CO2}. These costs are distributed across shipping (~20 €/t_{CO2} for a 5,000 km transportation distance), liquefaction (~15 €/t_{CO}), and intermediate storage at the terminals. The specific costs associated with the CO_2 cycle are slightly lower in the case of methanol than for SNG-based hydrogen supply (Table 3) as a larger total amount of CO_2 is transported here, and therefore the investment costs of the storage tanks, which are dimensioned according to the capacity of the CO_2 tankers, can be depreciated over a larger total amount of CO_2.

Compared to relying solely on onsite CO_2 supply via DAC, the implementation of a CO_2 cycle leads to cost savings. In the case of methanol-based hydrogen supply, these savings are close to ca. 15 %, while for SNG-based hydrogen supply, the cost reductions are ca. 8 %. The higher cost reduction for methanol-based hydrogen supply results from the greater sensitivity to CO_2 supply cost and the lower potential for heat integration to reduce DAC cost (see above). Considering the assumed CO_2 capture rate at the reforming plants and additional carbon losses (e.g., losses during transportation of CO_2 or methane/methanol), around 92 % of the CO_2 needed for the synthesis can be supplied through the cycle. Consequently, the availability of a biogenic CO_2 source has little influence on the overall hydrogen supply cost, as it is only used for compensating carbon losses.

4.2. *Cost of hydrogen supply with carbon-based import molecules compared to hydrogen supply with other import molecules*

Given the assumptions and framework conditions made here, the import of gaseous hydrogen via pipeline, at 0.147 €/$kWh_{H2,LHV}$, exhibits the lowest energy supply cost among all assessed import pathways. While the pipeline's high material and capital requirements lead to substantial transportation costs (*Derivative Transportation*), these are offset by the absence of any effort to supply a carrier, as well as the lack of energy-intensive conversion and reconversion steps. Additionally, compression and pipeline transportation only incur small hydrogen losses, allowing nearly the entire amount of the hydrogen produced in the energy-exporting country to be delivered to the importing country. Thus, the costs for the production of additional hydrogen to compensate for losses are low.

Similarly, the import of hydrogen in liquid form via specialized tankers results in lower supply cost (0.153 €/kWh_{H2}) compared to all assessed supply chains using carbon-based import molecules as hydrogen carriers. For example, the cost difference between methanol-based hydrogen supply, using a CO_2 cycle and eSR (as the most promising configuration), and liquid hydrogen import is about 10 %. Liquid hydrogen imports are particularly distinguished by their low hydrogen losses, which are lower than those of all other assessed ship-based supply pathways. This also includes boil-off losses during shipping, which, under large-scale implementation and expected boil-off rates (0.15 % per day; see Supplementary Information (Section III)), are unlikely to have a significant impact on the overall costs in import scenarios with short to medium transportation distances (here: 5,000 km). Moreover, regasification of liquid hydrogen (*Reconversion - Excl. heat supply*) hardly causes notable costs and can also take place at higher pressures, eliminating the need for additional compression to

Table 3
Specific CO_2 supply cost.

		SNG-based hydrogen supply	Methanol-based hydrogen supply
		Values in €/t_{CO2}	
DAC	Without heat integration	173	173
	With heat integration – Onsite CO_2 supply	144	171
	With heat integration – CO_2 cycle	115	147
CO_2 cycle		53	51

achieve the targeted pressure level of hydrogen supply. Hydrogen liquefaction, however, is a significant contributor to overall supply costs, adding about 0.35 €/$kWh_{H2,LHV}$ (*Conversion - Excl. carrier supply*). These liquefaction costs are roughly evenly split between electricity costs and plant investment, maintenance, and operational expenses. As shown in Fig. 3, transportation costs (*Import Molecules Transportation*) are considerably higher than for carbon-based hydrogen carriers, primarily due to the elevated capital investment required for novel liquid hydrogen tankers. Notably, neither hydrogen liquefaction nor liquid hydrogen tankers have been implemented on a large industrial scale, resulting in particularly high cost uncertainties for the supply pathway based on liquid hydrogen.

In the analyzed scenario, hydrogen imports using ammonia as a carrier have supply cost of around 0.18 €/$kWh_{H2,LHV}$. Thus, it is in the same cost range as methanol-based hydrogen supply with autothermal reforming (ATR) when low-cost biogenic CO_2 is available or a CO_2 cycle is employed. Compared to a combination of methanol import and electrified steam reforming (eSR) for hydrogen supply, the ammonia-based hydrogen import causes slight additional costs. Unlike the carbon-based hydrogen supply chains analyzed, the type of heat supply for hydrogen recovery from ammonia does not have a major influence on the overall costs. This is because hydrogen purification losses associated with ammonia cracking are significant and assumed to be largely available to cover the heat demand of the ammonia cracking, minimizing the thermal energy to be supplied additionally to the cracking process (*internally* via the combustion of additional hydrogen/ammonia or via an *external* source). Fig. 3 also illustrates, that the ammonia-based hydrogen supply benefits from a low-cost provision of the required nitrogen (*Carrier Supply*) compared to the provision of other carriers (i.e., CO_2 and LOHC material). Air separation is an established process that has been used for decades and, in contrast to CO_2 provision using DAC systems, can be easily realized at scale.

Under the framework conditions considered, hydrogen import using LOHCs is only cost-competitive with other carrier-based pathways (especially methanol and ammonia) if the required dehydrogenation heat can be covered by an external source at moderate cost (here: 0.10 $€_{2024}$/kWh_{th}; see Section 3.1). With about 40 % of the energy contained in the released hydrogen, this external energy demand would be substantial, clearly exceeding the external energy required for eSR of carbon-based hydrogen carriers. This raises concerns about the feasibility and sustainability of deploying such large energy quantities in countries actually aiming to import “green” energy. If the required thermal energy is provided internally by burning part of the released hydrogen, the total costs add up to more than 0.23 €/$kWh_{H2,LHV}$ and are thus well above the costs of ammonia-based and most promising configurations of methanol-based pathways. The high costs of reconversion are compounded by the significant expenses associated with providing the LOHC molecule (here: benzyl-toluene). This is primarily due to the system ties up a large amount of LOHC material and the corresponding capital required to purchase it.

Overall, the economic analysis of all hydrogen supply chains indicates that, if pure hydrogen is required within the importing country, it should, when technically feasible, also be transported in its pure form – either as gaseous hydrogen via pipeline (preferable option, if possible) or as liquid hydrogen via ship. If direct hydrogen import is not technically or logistically viable, methanol emerges as the most cost-effective carrier, provided that a low-cost, non-fossil CO_2 source is available. Alternatively, ammonia-based imports may also be considered. In contrast, hydrogen imports via LOHCs and SNG, as well as methanol-based supply chains relying solely on DAC for CO_2 provision, appear economically unviable under the assessed conditions.

4.3. Cost of hydrogen derivative supply

Today’s global energy supply relies heavily on carbon-based energy carriers. Consequently, an alternative to using “green” SNG and methanol as hydrogen carriers is their direct utilization in various end applications. Although ammonia is less versatile as an energy carrier than methanol and SNG, the existing ammonia markets in fertilizer production and chemical industry offer opportunities for the direct use of

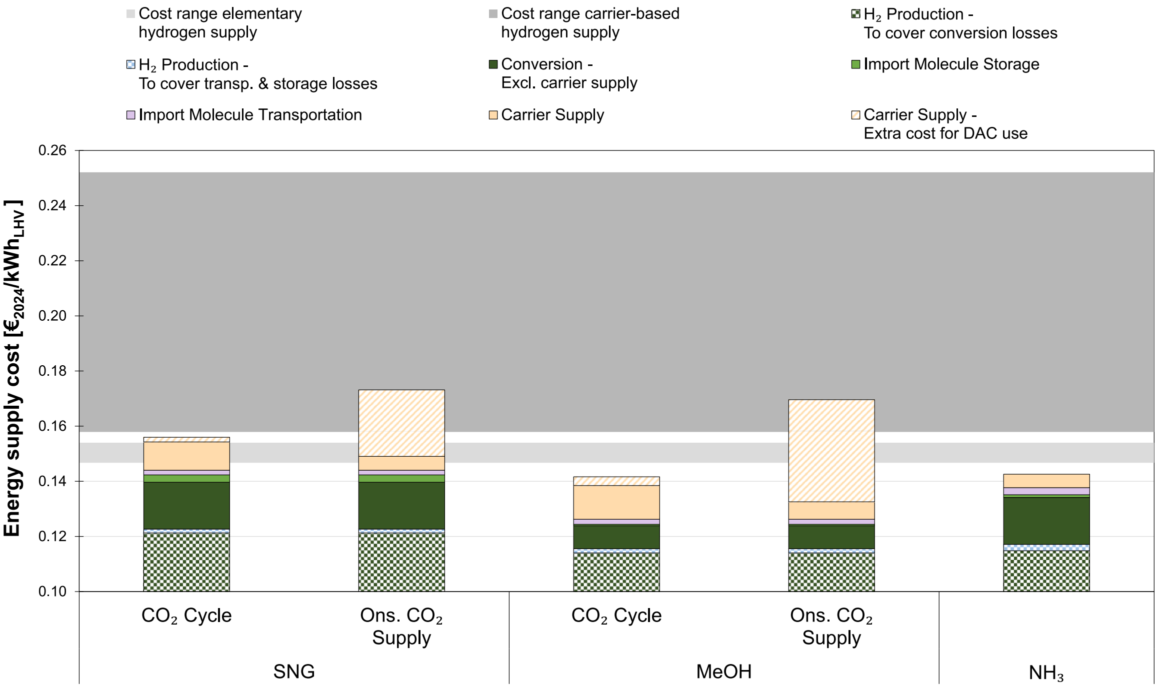


Fig. 4. Cost in 2035 for a supply of hydrogen derivatives compared to cost of hydrogen supply
(The cost of providing one kWh of hydrogen at the point-of-export is the same for all pathways and is therefore not shown here but part of the overall supply cost.)
(CO2 = Carbon dioxide; DAC = Direct air capture; H_2 = Hydrogen; LHV = Lower heating value; MeOH = Methanol; NH_3 = Ammonia; SNG = Synthetic natural gas).

"green" ammonia.

According to Fig. 4, the direct use of these derivatives consistently results in lower specific energy supply cost compared to supplying hydrogen derived from the respective derivatives. This cost reduction is caused by several factors. Firstly, costs can be saved as there is no need to build and operate reconversion plants. Secondly, less hydrogen has to be produced in the exporting country to supply the same amount of energy in the import country, as there are no reconversion losses to be compensated for. Thirdly, the improved efficiency of energy utilization in the import country reduces the required capacity of key supply chain components, such as conversion units, storage and transportation infrastructure, thereby further lowering the overall costs.

The cost for direct supply of carbon-based "green" import molecules is in the range calculated for importing hydrogen in its elemental form (gaseous hydrogen via pipelines or liquid hydrogen via ship) – provided that the required CO_2 does not have to be sourced entirely through DAC systems. Similar to the assessment as hydrogen carriers, methanol has a cost advantage over SNG, mainly due to lower energy losses during conversion (*H_2 Production - To cover conversion losses*), simpler intermediate storage (*Import Molecule Storage*) and the absence of a liquefaction requirement (part of *Conversion – Excl. carrier supply*). As Fig. 4 shows, methanol and SNG supply only have similar cost if the CO_2 is provided exclusively through DAC. This further highlights the greater sensitivity of methanol's competitiveness to CO_2 provision costs (Section 4.1). If a low-cost biogenic CO_2 source is available, the direct supply of methanol could even achieve slightly lower specific costs than hydrogen import via pipeline for the transportation distance considered here (5,000 km). The import of "green" ammonia for direct use is also promising from an economic point of view, as the energy supply cost of around 0.14 €/kWh$_{H2,LHV}$ is slightly below the cost of importing gaseous hydrogen via pipeline.

4.4. Impact of transportation distance on energy supply cost

A parameter variation is conducted for all defined import pathways to assess the impact of transportation distance on the overall energy supply cost. For clarity of presentation, only the cost trends for selected pathways are shown in Fig. 5.

Compared to other options considered, the costs of importing SNG and methanol are only slightly dependent on the transportation distance. This is mainly due to two reasons.

1. The infrastructure for storing and shipping these molecules is well-established and cost-efficient, because it has been in place for decades.
2. The high volumetric energy density of methanol and methane, compared to other import molecules, lowers the number of ships and storage facilities required.

However, the cost sensitivity on transportation distance is much higher for methanol and SNG when using closed CO_2 cycles instead of onsite CO_2 supply; e.g., in the case of methanol-based hydrogen supply, an increase of the transportation distance from 5,000 to 20,000 km raises energy supply cost only by around 6 % with onsite CO_2 provision but by 15 % with a closed CO_2 cycle. This is mainly due to additional distance-related costs arising when a CO_2 cycle is implemented (purchase and operation of CO_2 tankers). Furthermore, the share of recycled CO_2 also decreases with increasing transportation distances. At greater distances, more SNG or methanol is consumed as fuel during transportation of the derivative, reducing the amount of CO_2 available for capture during reforming and thus necessitating a higher share of expensive DAC-based CO_2 provision. Nevertheless, under the framework

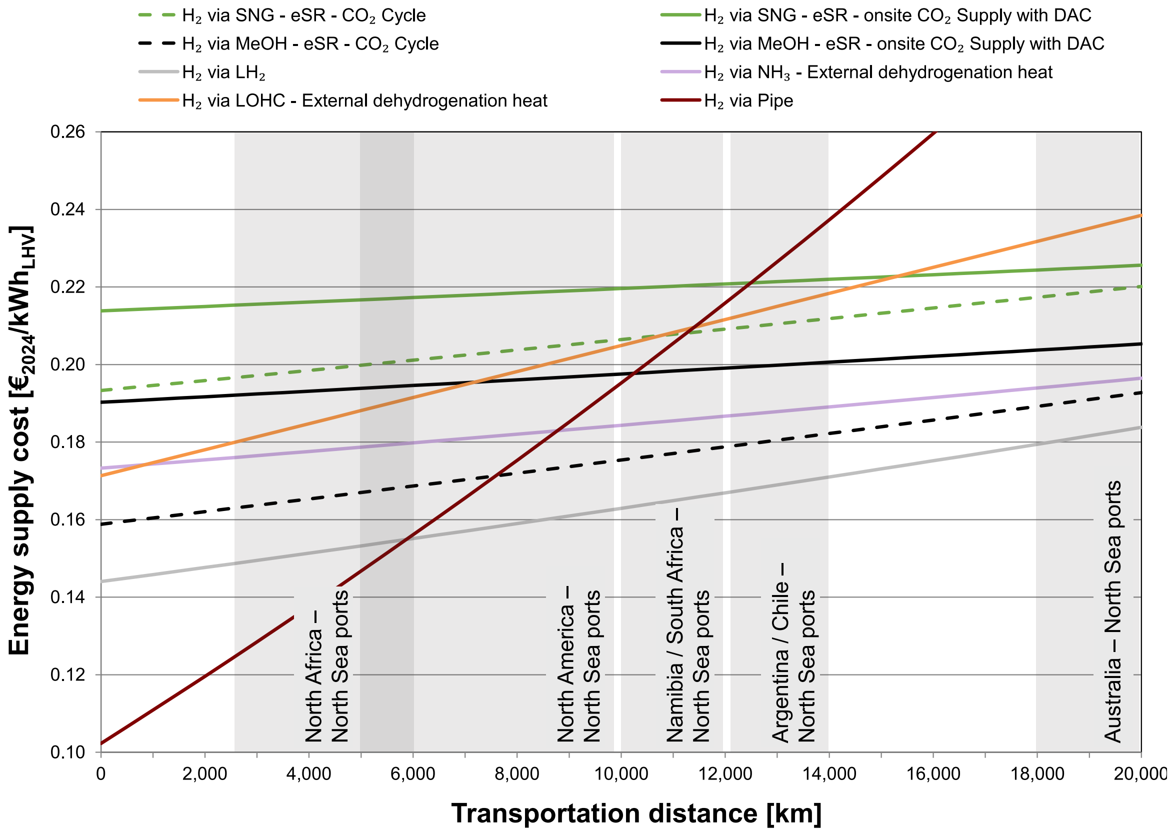


Fig. 5. Impact of transportation distance on cost for a supply of gaseous hydrogen at 100 bar in 2035
(CO_2 = Carbon dioxide; DAC = Direct air capture; eSR = electrified steam reforming; LH_2 = Liquid hydrogen; LHV = Lower heating value; LOHC = Liquid organic hydrogen carrier; MeOH = Methanol; NH_3 = Ammonia; SNG = Synthetic natural gas).

assumptions and technology parameters considered, implementing a CO_2 cycle remains more cost-efficient than a sole onsite CO_2 supply via DAC, even for very long transportation distances (Fig. 5).

Hydrogen imports via pipeline demonstrate the highest sensitivity to transportation distance among all options analyzed. The high contribution of transportation costs to the overall cost (Fig. 3), along with the proportional scaling of the pipeline's material and capital requirements with distance, explains this strong dependency. However, within transportation distances that are realistic under the given topographical (e.g., mountain ranges, shelf edge) and political limitations, hydrogen imports via pipelines are still the most cost-efficient option for a "green" energy supply. Hydrogen imports using LOHCs also show a strong correlation between energy supply cost and transportation distance. This is primarily because the amount of LOHC material required in the system scales directly with transportation duration. However, even at very short distances, LOHC-based imports are more costly than particularly promising options, such as pipeline transportation, liquid hydrogen, or methanol-based imports (Fig. 3). Energy imports based on ammonia and liquid hydrogen, in contrast, display a weak correlation between costs and transportation distance, similar to methanol and SNG. While the boil-off of liquid hydrogen is inherently time-dependent and could potentially increase cost sensitivity to transportation distance, this effect is minimal under the assumptions made here. The low boil-off rate of 0.18 % assumed here (as indicated by the literature, e.g., [12,66,91]) ensures that nearly all vaporized hydrogen can be utilized for ship propulsion, preventing excessive losses. Therefore, the boil-off does not result in any significant disadvantages for liquid hydrogen imports compared to the other ship-based options.

4.5. Net energy import

The primary purpose of importing renewable electricity-based energy carriers is to provide additional energy when domestic production in the importing country is insufficient or too expensive. However, the previous supply chain analysis reveals that some import pathways require considerable energy inputs within the importing country. As a result, the net energy import (*NEI*) (see Equation (8)) may be significantly reduced, meaning that a larger overall energy volume must be imported to provide the same additional energy to the importing country.

As Fig. 6 shows, the *NEI*, like the energy supply cost, is influenced by various factors of supply chain design, including whether the import molecule is used as a hydrogen carrier or directly, the approach of CO_2 provision, and – if used as hydrogen carrier – the choice of the reforming technology.

Within the system boundaries considered here (supply of energy directly at the point-of-import without consideration of any inland transport) and under the given assumptions (e.g., neglecting energy required to pump the derivative from ship to land, and to re-gasify in the case of SNG and ammonia), no energy is required in the importing country when SNG, methanol, and ammonia are used directly. Accordingly, the imported energy is entirely available to the energy system of the importing country without requiring domestic energy (*NEI* = 1). Only if a closed CO_2 cycle is implemented, the *NEI* for carbon-based import molecules decreases slightly to 0.97 % for SNG and 0.96 % for methanol due to the energy required for CO_2 liquefaction and transport.

If carbon-based import molecules are used as a hydrogen carrier, the net energy import decreases due to additional domestic energy requirements related to the reconversion. The *NEI* of supply chains using "green" SNG and methanol as hydrogen carriers ranges from 0.66–0.90 %. Here, supply chains that use ATR for hydrogen recovery (0.79–0.90 %) achieve better results in the energy effectively provided in the importing country than supply chains using eSR (0.66–0.74 %), since most of the reforming energy is generated in the exporting country. Using eSR, the electricity required for reactor heating reduces the net energy import by around a quarter (29 % in the case of SNG and 23 % in the case of methanol). The implementation of a CO_2 cycle further reduces the amount of energy available in the importing country, albeit by

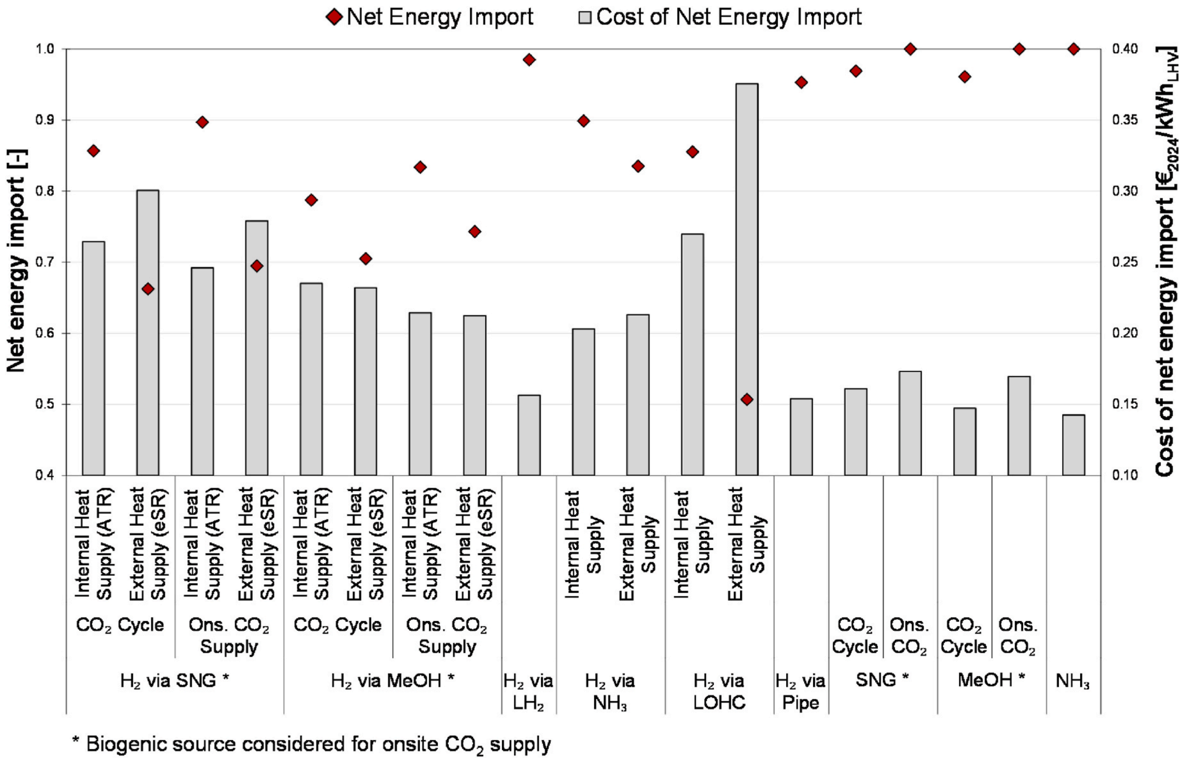


Fig. 6. Net energy import of different energy import pathways in 2035
(ATR = Autothermal reforming; CO_2 = Carbon dioxide; eSR = electrified steam reforming; H_2 = Hydrogen; LH_2 = Liquid hydrogen; LHV = Lower heating value; LOHC = Liquid organic hydrogen carrier; MeOH = Methanol; NH_3 = Ammonia; Ons. = onsite; SNG = Synthetic natural gas).

only 3–5 %.

Similar correlations as for SNG- and methanol-based hydrogen import apply to imports based on other carriers. In the case of LOHCs, the origin of the dehydrogenation heat is a key factor the for net energy import. If an external heat source (domestic energy) is used, only around 50 % of the energy contained in the hydrogen provided is actually added to the importing country's energy system. If, in contrast, part of the hydrogen bound to the LOHC is used for internal heat supply, the *NEI* increases to over 85 %. However, the internal supply of dehydrogenation heat is generally a much less cost-effective option (Section 4.2). In the case of hydrogen import with ammonia, more than 80 % of the energy supplied is available for the energy system of the importing country, even if an external heat source is used for ammonia cracking. One reason for this is that the thermal energy demand for ammonia cracking is already largely covered by occurring hydrogen losses, and thus, the additional thermal energy to be provided is comparatively low (Section 4.2).

The import of liquid hydrogen via ship and gaseous hydrogen via pipelines have a higher *NEI* than importing hydrogen using carrier molecules. In this respect, liquid hydrogen imports in particular show energy system related advantages over other ship-based hydrogen import options. The regasification of liquid hydrogen requires hardly any energy, while simultaneously allowing for the direct production of gaseous hydrogen at high pressure. Furthermore, it is potentially possible to utilize the high temperature difference between the liquid hydrogen and the environment during regasification to provide additional energy (e.g., through a cryogenic power generation cycle). It is therefore conceivable that, with an optimal design of the regasification terminal and through efficient utilization of cold energy, a *NEI* above 1 could be achieved for liquid hydrogen supply chains (not shown in Fig. 6).

As Fig. 6 shows, considering the amount of additional energy provided in the importing country as a cost reference value can significantly influence the economic assessment of the examined energy supply pathways. Generally, relating the costs to the amount of energy actually provided favors supply pathways where the transported molecule is used directly (i.e., does not have to be converted using energy in the importing country), further expanding their already existing advantage (see Section 4.1 to Section 4.3). This is true for hydrogen supply, where the cost of net energy import the c_{NEI} illustrates the systemic advantages of importing hydrogen by pipeline and as liquid hydrogen – almost all of the imported energy is provided to the importing country – compared to all carrier-based options. And this is also true for the direct application of "green" SNG, methanol and ammonia compared to their use as hydrogen carrier. For hydrogen supply using carbon-based import molecules the analysis of the cost of final energy supply (c_{FES}) has revealed an economic advantage of supply pathways with external heat supply for methanol/SNG reforming (see Section 4.1). This advantage is put into perspective when considering the cost of net energy import (c_{NEI}). For hydrogen supply using SNG as a carrier, the c_{NEI} is even higher with external heat supply for reforming (eSR) than with internal heat supply (ATR). For hydrogen supply based on methanol, the c_{NEI} are almost the same for reforming via ATR and eSR. Furthermore, the economic viability of different reforming approaches also depends on the energy cost difference between the importing and exporting country. Scenarios where this cost difference is very high (cheap hydrogen in the export country and expensive baseload energy in the import country), generally work in favor of hydrogen supply pathways with internal heat provision.

5. Summary and conclusion

This section concludes by summarizing the most important results of the assessment carried out and drawing conclusions for the use of carbon-based import molecules.

5.1. Summary

This paper provides a comprehensive assessment of supply cost and the net energy import (*NEI*) of renewable electricity-based energy imports using carbon-based molecules, specifically "green" methanol and synthetic natural gas (SNG). The primary objective is to evaluate various supply chain configurations that deliver either hydrogen or hydrogen derivatives, including an examination of different CO_2 supply concepts. Additionally, if hydrogen is to be supplied in the importing country, different technical approaches for methanol resp. SNG reforming are assessed. These carbon-based molecules are compared concerning hydrogen/energy supply cost and *NEI* to other options for the import of "green" electricity-based energy, including shipborne transportation of liquid hydrogen, ammonia (as carrier for supply of hydrogen or for direct use as a derivative) or liquid organic hydrogen carrier (LOHC) and pipeline transportation of gaseous hydrogen. The comparison of all considered supply pathways leads to the following overall conclusions.

- Under the assumptions of this assessment hydrogen supply cost using "green" methanol and SNG as carriers ranges between 0.16 and 0.25 €/kWh$_{H2,LHV}$, depending on the specific supply chain design. The choice of the respective reforming technology significantly impacts these hydrogen supply cost. Reconversion to hydrogen by means of electrified steam reforming (eSR) offers a more efficient utilization of the carrier than autothermal reforming (ATR); this means that less SNG or methanol needs to be imported to provide the same amount of hydrogen. This more energy efficient use of the molecule also results in a cost advantage for eSR. However, eSR requires considerable energy inputs within the importing country, resulting in less additional energy effectively being provided in the importing country. Furthermore, scenarios with high energy cost differences between export and import countries – i.e., cheap hydrogen production in the export country and/or expensive electricity in the import country – can favor reconversion via ATR, as it minimizes energy consumption within the import country.
- The direct use of imported "green" SNG and methanol leads to lower specific energy supply costs compared to the provision of elemental hydrogen via reconversion of these carbon-based molecules. The cost reductions are in the order of 20–30 % for SNG and 15–25 % for methanol, primarily due to the elimination of the reconversion to hydrogen and the associated losses.
- Among the examined "green" carbon-based import molecules, methanol generally offers advantages over SNG. These benefits are largely attributed to the lower chemical binding enthalpy of the methanol molecule, resulting in more energy-efficient synthesis (i.e., less heat losses) and, if used as hydrogen carriers, reconversion. As a result, methanol-based "green" energy supply is featured by lower energy losses that have to be compensated for by costly production of additional hydrogen in the energy-exporting country. Further advantages over SNG stem from methanol being available as a liquid directly after synthesis, thus eliminating the need for energy-intensive liquefaction and enabling an easy storage at ambient conditions. The cost advantages of "green" methanol over SNG determined are between 10 % and 20 % for hydrogen supply and between 2 and 10 % for direct utilization.
- The cost of providing non-fossil CO_2 significantly impacts the competitiveness of energy supply using SNG and "green" methanol, with biogenic sources likely to be the most cost-effective option in the near future. For export countries in which such biogenic CO_2 sources are not or not sufficiently available, sourcing CO_2 from ambient air with Direct Air Capture (DAC) systems is an (more expensive) alternative. CO_2 provision with DAC increases the cost of SNG-based hydrogen supply by about 15 % and methanol-based hydrogen supply by about 25 % compared to the use of low-cost biogenic CO_2. The additional costs incurred by DAC are lower for SNG than for "green" methanol, as (i) the potential for reducing DAC

costs through the integration of synthesis waste heat is greater in the case of SNG, and (ii) methanol requires more CO_2 per kWh of energy provided.

- The implementation of closed CO_2 cycles is an option to overcome the potentially limited availability of biogenic CO_2 and/or the high cost of supply via DAC. Capturing the CO_2 released during the use of SNG or methanol at a high percentage appears to be feasible in both the eSR as well as the ATR, and would most likely enable the supply of over 90 % of the CO_2 required for synthesis via such a largely closed cycle. The specific cost of CO_2 cycling calculated here is ca. 50 €/t_{CO2}, including expenses for liquefaction, intermediate storage, and shipping over a 5,000 km distance. Compared to relying solely on onsite DAC-based CO_2 supply, closed CO_2 cycles reduce hydrogen supply cost using carbon-based carriers by about 15 % for methanol and 8 % for SNG, under the assumptions made here.
- For a supply of pure hydrogen, import by pipeline over short to medium transportation distances has the lowest cost among all pathways, but it also exhibits the highest dependency on transportation distance. The import of liquid hydrogen by ship is also very promising and likely to be less expensive than hydrogen import based on the various carriers; provided the necessary technologies (e.g., liquefaction and liquid hydrogen tankers) are successfully scaled up. Taking into account current estimates of boil-off rates for large-scale liquid hydrogen tankers, it is likely that hydrogen losses during ship transportation and storage will not have a decisive influence on the supply costs – this is true even for long transportation distances. The cost of the ammonia-based hydrogen supply falls within the range calculated for a methanol-based import using a low-cost option for CO_2 provision (CO_2 cycle or biogenic CO_2 source). Similar to SNG and methanol, the direct use of “green” ammonia enables significantly lower specific energy supply cost – in the analyzed scenario even below the cost of pipeline-based hydrogen import. Importing hydrogen with LOHCs, in contrast, does not appear to be particularly promising. Thus, the high energy demand for hydrogen recovery from LOHC molecules currently under discussion, such as benzyl-toluene, is significantly higher than that of the other carrier-based options, causing correspondingly high costs.

5.2. Conclusion

The following recommendations for a renewable energy supply using import molecules can be derived from the results of this paper:

- If SNG, methanol or ammonia is required by the final energy consumer in the importing country, the energy should always be imported in the corresponding form (i.e., as the respective derivative). Importing elemental hydrogen in order to produce the required derivatives in the importing country is economically unviable. In addition, the import of derivatives offers greater flexibility with regard to the selection of suitable export countries due to the low influence of transportation distance on costs.
- If the final energy consumer is flexible in choosing a “green” molecular energy carrier, hydrogen imported in elemental form (gaseous via pipeline or liquid by ship), methanol, or ammonia should be used. Supplying a flexible end energy consumer with pure hydrogen recovered from an imported hydrogen derivative does not make economic sense.
- The reconversion of hydrogen derivatives (SNG, methanol, ammonia) into elemental hydrogen is, from an economic point of view, only justified if (i) substantial amounts of pure hydrogen are genuinely needed by end consumers in the importing country (which must be carefully assessed) and (ii) hydrogen transport via pipelines or liquid hydrogen tankers is not viable due to technical or political constraints. If carrier-based hydrogen import is necessary, methanol (with electrically heated reforming and low-cost CO_2 provision) or ammonia should be prioritized. Energy imports based on SNG or LOHCs do not appear to be competitive from today’s perspective.
- For the import of “green” energy via carbon-based molecules, methanol is preferable to SNG, regardless of whether for direct use as a derivative or as a hydrogen carrier. Methanol can be synthesized more energy-efficiently than SNG, can be transported and stored safely under ambient conditions and moreover does not pose any risk of climate impacts due to leakages. Thereby, the cost of importing “green” methanol is highly sensitive to the CO_2 provision costs; a competitive “green” methanol supply can be ensured by means of biogenic carbon source or a closed cycle.

Future research may explore the impact of technological advancements on energy supply cost, particularly in technologies not yet deployed at large scale, such as DAC or reconversion processes. Expanding the economic modeling to include aspects like the potential utilization of existing infrastructures or risk-adjusted investment frameworks could enhance the robustness of such energy supply chain assessments. Furthermore, embedding the performed modeling into broader energy system models could, e.g., enable comparisons between renewable energy import options and local supply solutions and a linking of the supply options with the demand side.

CRediT authorship contribution statement

Fabian Carels: Writing – original draft, Visualization, Validation, Methodology, Investigation, Data curation, Conceptualization. **Stefan Bube:** Writing – review & editing, Validation, Conceptualization. **Martin Kaltschmitt:** Writing – review & editing, Supervision, Conceptualization.

Data availability

Data will be made available on request.

Funding

This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

Declaration of competing interest

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.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2025.06.128.

References

[1] Statista. EU-28. Energy dependency rate 2008-2020 | Statista [December 16, 2024]; Available from: https://www.statista.com/statistics/267588/dependency-on-energy-imports-in-the-eu/.
[2] Eurostat. Energy import dependency by products. Eurostat; 2024.
[3] Eurostat. Energy production and imports [December 16, 2024]; Available from: https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Energy_production_and_imports.
[4] European Commission, European Parliament. European climate law. 2021.
[5] European Commission. REPowerEU plan. 2022.
[6] Seck GS, Hache E, Sabathier J, Guedes F, Reigstad GA, Straus J, et al. Hydrogen and the decarbonization of the energy system in europe in 2050: a detailed model-based analysis. Renew Sustain Energy Rev 2022;167:112779. https://doi.org/10.1016/j.rser.2022.112779.
[7] Andreola S, Menos-Aikateriniadis C, Paxton A, Preißler H, Miehling H. No-regret hydrogen: charting early steps for H_2 infrastructure in Europe. 2021.

[8] Staiß F, Adolf J, Ausfelder F, Erdmann C, Hebling C, Jordan T, et al. Optionen für den Import grünen Wasserstoffs nach Deutschland bis zum Jahr 2030. 2022. acatech - Deutsche Akademie der Technikwissenschaften.

[9] Sterner M, Hofrichter A, Meisinger A, Bauer F, Pinkwart K, Maletzko A, et al. 19 Import options for green hydrogen and derivatives - an overview of efficiencies and technology readiness levels. Int J Hydrogen Energy 2024;90:1112–27.

[10] Sievert K, Schmidt TS, Steffen B. Considering technology characteristics to project future costs of direct air capture. Joule 2024;8(4):979–99. https://doi.org/10.1016/j.joule.2024.02.005.

[11] Young J, McQueen N, Charalambous C, Foteinis S, Hawrot O, Ojeda M, et al. The cost of direct air capture and storage can be reduced via strategic deployment but is unlikely to fall below stated cost targets. One Earth 2023;6(7):899–917. https://doi.org/10.1016/j.oneear.2023.06.004.

[12] IRENA - International Renewable Energy Agency. Global hydrogen trade to meet the 1.5 °C climate goal: Part II - technology review of hydrogen carriers. 2022.

[13] Ortiz Cebolla R, Dolci F, Weidner E. Assessment of hydrogen delivery options. Luxembourg: Publications Office of the European Union; 2022.

[14] Hampp J, Düren M, Brown T. Import options for chemical energy carriers from renewable sources to Germany. 2021.

[15] Moritz M, Schönfisch M, Schulte S. Estimating global production and supply costs for green hydrogen and hydrogen-based green energy commodities. Int J Hydrogen Energy 2023;48(25):9139–54. https://doi.org/10.1016/j.ijhydene.2022.12.046.

[16] Carels F, Sens L, Kaltschmitt M. Synthetic natural gas as a green hydrogen carrier – technical, economic and environmental assessment of several supply chain concepts. Energy Convers Manag 2024;321:118940. https://doi.org/10.1016/j.enconman.2024.118940.

[17] Schühle P, Stöber R, Semmel M, Schaadt A, Szolak R, Thill S, et al. Dimethyl ether/CO 2 – a hitherto underestimated H 2 storage cycle. Energy Environ Sci 2023;16(7):3002–13. https://doi.org/10.1039/D3EE00228D.

[18] Noh H, Kang K, Seo Y. Environmental and energy efficiency assessments of offshore hydrogen supply chains utilizing compressed gaseous hydrogen, liquefied hydrogen, liquid organic hydrogen carriers and ammonia. Int J Hydrogen Energy 2023;48(20):7515–32. https://doi.org/10.1016/j.ijhydene.2022.11.085.

[19] Heuser P-M, Ryberg DS, Grube T, Robinius M, Stolten D. Techno-economic analysis of a potential energy trading link between Patagonia and Japan based on CO2 free hydrogen. Int J Hydrogen Energy 2019;44(25):12733–47. https://doi.org/10.1016/j.ijhydene.2018.12.156.

[20] Okunlola A, Giwa T, Di Lullo G, Davis M, Gemechu E, Kumar A. Techno-economic assessment of low-carbon hydrogen export from Western Canada to Eastern Canada, the USA, the Asia-Pacific, and europe. Int J Hydrogen Energy 2022;47(10):6453–77. https://doi.org/10.1016/j.ijhydene.2021.12.025.

[21] Johnston C, Ali Khan MH, Amal R, Daiyan R, MacGill I. Shipping the sunshine: an open-source model for costing renewable hydrogen transport from Australia. Int J Hydrogen Energy 2022;47(47):20362–77. https://doi.org/10.1016/j.ijhydene.2022.04.156.

[22] Al-Breiki M, Bicer Y. Liquified hydrogen vs. liquified renewable methane: evaluating energy consumption and infrastructure for sustainable fuels. Fuel (Guildf) 2023;350:128779. https://doi.org/10.1016/j.fuel.2023.128779.

[23] Lee J-S, Cherif A, Yoon H-J, Seo S-K, Bae J-E, Shin H-J, et al. Large-scale overseas transportation of hydrogen: comparative techno-economic and environmental investigation. Renew Sustain Energy Rev 2022;165:112556. https://doi.org/10.1016/j.rser.2022.112556.

[24] Hank C, Sternberg A, Köppel N, Holst M, Smolinka T, Schaadt A, et al. Energy efficiency and economic assessment of imported energy carriers based on renewable electricity. Sustain Energy Fuels 2020;4(5):2256–73. https://doi.org/10.1039/D0SE00067A.

[25] Staiß F, Schmidt M, Stephanos C, Stöcker P, Wurbs S. Optionen für den Import grünen Wasserstoffs nach Deutschland bis zum Jahr 2030. 2022. Materialband. Materialband (Schriftenreihe Ener-.

[26] Sens L, Neuling U, Wilbrand K, Kaltschmitt M. Conditioned hydrogen for a green hydrogen supply for heavy duty-vehicles in 2030 and 2050 – a techno-economic well-to-tank assessment of various supply chains. Int J Hydrogen Energy 2022. https://doi.org/10.1016/j.ijhydene.2022.07.113.

[27] Pfennig M, Böttger D, Häckner B, Geiger D, Zink C, Bisevic A, et al. Global GIS-based potential analysis and cost assessment of Power-to-X fuels in 2050. Appl Energy 2023;347:121289. https://doi.org/10.1016/j.apenergy.2023.121289.

[28] Fasihi M, Bogdanov D, Breyer C. Long-term hydrocarbon trade options for the Maghreb region and Europe—renewable energy based synthetic fuels for a net zero emissions world. Sustainability (Basel) 2017;9(2):306.

[29] Schorn F, Breuer JL, Samsun RC, Schnorbus T, Heuser B, Peters R, et al. Methanol as a renewable energy carrier: an assessment of production and transportation costs for selected global locations. Adv Appl Energy 2021;3:100050. https://doi.org/10.1016/j.adapen.2021.100050.

[30] Ericsson K. Biogenic carbon dioxide as feedstock for production of chemicals and fuels A techno-economic assessment with a European perspective. Lund. Miljö- och energisystem, LTH, Lunds universitet; 2017.

[31] Rodin V, Lindorfer J, Böhm H, Vieira L. Assessing the potential of carbon dioxide valorisation in Europe with focus on biogenic CO2. J CO2 Util 2020;41:101219. https://doi.org/10.1016/j.jcou.2020.101219.

[32] Liebich A, et al. Detailanalysen zum Systemvergleich speicherbarer Energieträger aus erneuerbaren Energien: Anhang zum Abschlussbericht. 2020.

[33] Reiter G, Lindorfer J. Evaluating CO2 sources for power-to-gas applications – a case study for Austria. J CO2 Util 2015;10:40–9. https://doi.org/10.1016/j.jcou.2015.03.003.

[34] Ozkan M, Nayak SP, Ruiz AD, Jiang W. Current status and pillars of direct air capture technologies. iScience 2022;25(4):103990. https://doi.org/10.1016/j.isci.2022.103990.

[35] IEA. Direct Air Capture: a key technology for net zero. 2022.

[36] Heß D, Klumpp M, Dittmeyer R. Nutzung von CO2 aus Luft als Rohstoff für synthetische Kraftstoffe und Chemikalien. 2020.

[37] Hank C, Holst M, Thelen C, Kost C, Längle S, Schaadt A, et al. Site-specific, comparative analysis for suitable Power-to-X pathways and products in developing and emerging countries. 2023.

[38] IEAGHG. Global assessment of direct air capture costs. 2021.

[39] TES H2. Green cycle | TES H2. Available from: https://tes-h2.com/green-cycle; January 13, 2025.

[40] Yara. New liquid CO2 ship for Yara. Available from: https://www.yara.com/news-and-media/news/archive/2015/new-liquid-co2-ship-for-yara/.

[41] Orchard K, Durusut E, Skagestad R, Hay M, Ombudstvedt I. The status and challenges of CO2 shipping infrastructures. 2020.

[42] Al Baroudi H, Awoyomi A, Patchigolla K, Jonnalagadda K, Anthony EJ. A review of large-scale CO2 shipping and marine emissions management for carbon capture, utilisation and storage. Appl Energy 2021;287:116510. https://doi.org/10.1016/j.apenergy.2021.116510.

[43] Habibic A. Northern Lights: first-of-their-kind liquid CO2 carriers launched in China. Offshore Energy 2024. Available from: https://www.offshore-energy.biz/northern-lights-first-of-their-kind-liquid-co2-carriers-launched-in-china/. [Accessed 13 January 2025].

[44] Riviera News. Capital Maritime orders world's largest LCO2 carriers. Available from: https://www.rivieramm.com/news-content-hub/news-content-hub/capital-maritime-orders-worlds-largest-lco2-carriers-77037; 2025.

[45] Yoo B-Y, Choi D-K, Kim H-J, Moon Y-S, Na H-S, Lee S-G. Development of CO2 terminal and CO2 carrier for future commercialized CCS market. Int J Greenh Gas Control 2013;12:323–32. https://doi.org/10.1016/j.ijggc.2012.11.008.

[46] Schmidt M, Schwarz S, Stürmer B, Wagener l, Zuberbühler U. Technologiebericht 4.2a power-to-gas (Methanisierung chemisch-katalytisch). In: Institut Wuppertal, Fraunhofer ISI, IZES, editors. Technologien für die Energiewende. Teilbericht 2 an das Bundesministerium für Wirtschaft und Energie (BMWi); 2018. Wuppertal, Karlsruhe, Saarbrücken.

[47] Peters R, Baltruweit M, Grube T, Samsun RC, Stolten D. A techno economic analysis of the power to gas route. J CO2 Util 2019;34:616–34. https://doi.org/10.1016/j.jcou.2019.07.009.

[48] Adolf J, Balzer C, Kofod M, Lenz B, Lischke A, Knitschky G, et al. Liquefied natural gas - new energy for ships and trucks?: facts, trends and perspectives. Shell LNG Study; 2019.

[49] Bube S, Voß S, Bullerdiek N, Neuling U, Kaltschmitt M. Electricity-based methanol. In: Bullerdiek N, Neuling U, Kaltschmitt M, editors. Powerfuels. Cham: Springer Nature Switzerland; 2025. p. 667–711.

[50] Dieterich V, Buttler A, Hanel A, Spliethoff H, Fendt S. Power-to-liquid via synthesis of methanol, DME or Fischer–Tropsch-fuels: a review. Energy Environ Sci 2020;13(10):3207–52. https://doi.org/10.1039/D0EE01187H.

[51] Bajohr S. Power-to-gas technologies: STORE&GO workshop. 2020.

[52] Lehner M, Tichler R, Steinmüller H, Koppe M. Power-to-Gas: technology and business models. Springer; 2014.

[53] Schildhauer TJ, Gantenbein A. Methanation. In: Bullerdiek N, Neuling U, Kaltschmitt M, editors. Powerfuels. Cham: Springer Nature Switzerland; 2025. p. 565–603.

[54] Billig E, Decker M, Benzinger W, Ketelsen F, Pfeifer P, Peters R, et al. Non-fossil CO2 recycling—the technical potential for the present and future utilization for fuels in Germany. J CO2 Util 2019;30:130–41. https://doi.org/10.1016/j.jcou.2019.01.012.

[55] IEA. Global hydrogen review 2022. 2022.

[56] Schmidt P, Zittel W, Weindorf W, Raksha T. Renewables in Transport 2050: empowering a sustainable mobility future with zero emission fuels from renewable electricity. 2016.

[57] Lowell D, Wang H, Lutsey N. Assessment of the fuel cycle impact of liquefied natural gas as used in international shipping. 2013.

[58] Howarth RW. The greenhouse gas footprint of liquefied natural gas (LNG) exported from the United States. Energy Sci Eng 2024.

[59] Purus. Hull No. SN2584, 2585, 2598, 2619: 180,000 m3 class LNG carrier (ME-GA). 2024.

[60] Oni AO, Anaya K, Giwa T, Di Lullo G, Kumar A. Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions. Energy Convers Manag 2022;254:115245. https://doi.org/10.1016/j.enconman.2022.115245.

[61] Pruvost F, Cloete S, Del Arnaiz Pozo C, Zaabout A. Blue, green, and turquoise pathways for minimizing hydrogen production costs from steam methane reforming with CO2 capture. Energy Convers Manag 2022;274:116458. https://doi.org/10.1016/j.enconman.2022.116458.

[62] Tinoco RR, Bouallou C. Hydrogen production from natural gas: auto-thermal reforming and CO2 capture. Chem. Eng. Transac. 2010.

[63] Ciambelli P. Catalytic autothermal reforming for hydrogen production: from large-scale plant to distributed energy system. In: van der Voorde M, editor. Hydrogen production and energy transition. De Gruyter; 2021.

[64] H-vision. Blue hydrogen as accelerator and pioneer for energy transition in the industry: feasibility study report. 2019.

[65] Baltac S, Wilson M, O'Sullivan C, Leguijt C, Beeftink Mart, Nieuwenhuijse Isabel. Low-carbon hydrogen from natural gas: global roadmap. 2022.

[66] Vos M, Douma J, van den Noort A. Study on the import of liquid renewable energy: technology cost assessment. 2020.

[67] Sadler D, Solgaard Anderson H, Sperrink Martin, Cargill Al. H21 North of England. 2018.

[68] Wismann ST, Engbæk JS, Vendelbo SB, Bendixen FB, Eriksen WL, Aasberg-Petersen K, et al. Electrified methane reforming: a compact approach to greener industrial hydrogen production. Science 2019;364(6442):756–9. https://doi.org/10.1126/science.aaw8775.

[69] Saeidi S, Sápi A, Khoja AH, Najari S, Ayesha M, Kónya Z, et al. Evolution paths from gray to turquoise hydrogen via catalytic steam methane reforming: current challenges and future developments. Renew Sustain Energy Rev 2023;183:113392. https://doi.org/10.1016/j.rser.2023.113392.

[70] Topsoe Haldor. eREACT™ Hydrogen: the future of blue hydrogen | Equipment | Products | Topsoe. October 12, 2023. Available from: https://www.topsoe.com/our-resources/knowledge/our-products/equipment/ereact-hydrogen.

[71] Müller B. Chemiekonzerne weihen ersten elektrischen Steamcracker ein [February 03, 2025]; Available from: https://www.chemietechnik.de/anlagenbau/basf-sabic-und-linde-weihen-demonstrationsanlage-ein-992.html.

[72] Niermann M, Beckendorff A, Kaltschmitt M, Bonhoff K. Liquid organic hydrogen carrier (LOHC) – assessment based on chemical and economic properties. Int J Hydrogen Energy 2019;44(13):6631–54. https://doi.org/10.1016/j.ijhydene.2019.01.199.

[73] Schemme S, Breuer JL, Köller M, Meschede S, Walman F, Samsun RC, et al. H2-based synthetic fuels: a techno-economic comparison of alcohol, ether and hydrocarbon production. Int J Hydrogen Energy 2020;45(8):5395–414. https://doi.org/10.1016/j.ijhydene.2019.05.028.

[74] Boretti A. Renewable hydrogen to recycle CO2 to methanol. Int J Hydrogen Energy 2013;38(4):1806–12.

[75] CRI - Carbon Recycling International. George Olah - industrial scale renewable methanol plant. Available from: https://carbonrecycling.com/projects/george-olah; December 18, 2024.

[76] CRI - Carbon Recycling International. Jiangsu sailboat - chemical products from recycled CO2. Available from: https://carbonrecycling.com/projects/sailboat; [December 18, 2024.

[77] Wärtsilä. Methanol carrier MILLENNIUM EXPLORER [December 18, 2024]; Available from: https://www.wartsila.com/encyclopedia/term/methanol-carrier-millennium-explorer.

[78] Kang S, Boshell F, Goeppert A, Prakash SG, Landälv I, Saygin D. Innovation outlook: renewable methanol. Abu Dhabi: International Renewable Energy Agency; 2021.

[79] Svanberg M, Ellis J, Lundgren J, Landälv I. Renewable methanol as a fuel for the shipping industry. Renew Sustain Energy Rev 2018;94:1217–28. https://doi.org/10.1016/j.rser.2018.06.058.

[80] Maersk. Maersk to deploy first large methanol-enabled vessel on Asia - Europe trade lane. 2023.

[81] Andersson J, Grönkvist S. Large-scale storage of hydrogen. Int J Hydrogen Energy 2019;44(23):11901–19. https://doi.org/10.1016/j.ijhydene.2019.03.063.

[82] Hos T, Sror G, Herskowitz M. Autothermal reforming of methanol for on-board hydrogen production in marine vehicles. Int J Hydrogen Energy 2024;49:1121–32. https://doi.org/10.1016/j.ijhydene.2023.08.315.

[83] Meca VL, d'Amore-Domenech R, Crucelaegui A, Leo TJ. Large-scale maritime transport of hydrogen: economic comparison of liquid hydrogen and methanol. ACS Sustainable Chem Eng 2022;10(13):4300–11. https://doi.org/10.1021/acssuschemeng.2c00694.

[84] Kundu A, Shul YG, Kim DH. Methanol reforming processes. In: Zhao TS, Kreuer K-D, van Nguyen T, editors. Advances in fuel cells. Amsterdam, San Diego CA, Oxford: Elsevier; 2007. p. 419–72.

[85] Luk HT, Lei HM, Ng WY, Ju Y, Lam KF. Techno-economic analysis of distributed hydrogen production from natural gas. Chin J Chem Eng 2012;20(3):489–96. https://doi.org/10.1016/S1004-9541(11)60210-3.

[86] Niermann M, Timmerberg S, Drünert S, Kaltschmitt M. Liquid Organic Hydrogen Carriers and alternatives for international transport of renewable hydrogen. Renew Sustain Energy Rev 2021;135:110171. https://doi.org/10.1016/j.rser.2020.110171.

[87] Sens L, Piguel Y, Neuling U, Timmerberg S, Wilbrand K, Kaltschmitt M. Cost minimized hydrogen from solar and wind – production and supply in the European catchment area. Energy Convers Manag 2022;265:115742. https://doi.org/10.1016/j.enconman.2022.115742.

[88] IEA. Global hydrogen review 2024. 2024.

[89] Fasihi M, Breyer C. Baseload electricity and hydrogen supply based on hybrid PV-wind power plants. J Clean Prod 2020;243:118466. https://doi.org/10.1016/j.jclepro.2019.118466.

[90] Bähr C, Bothe D, Brändle G, Klink H, Lichtblau K, Sonnen L, et al. Die Zukunft energieintensiver Industrien in Deutschland: Eine Studie von IW Consult und Frontier Economics im Auftrag des Dezernat Zukunft. 2023.

[91] Kamiya S, Nishimura M, Harada E. Study on introduction of CO2 free energy to Japan with liquid hydrogen. Phys Procedia 2015;67:11–9. https://doi.org/10.1016/j.phpro.2015.06.004.