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The future of fuels: Uncertainty quantification study of mid-century ammonia and methanol production costs

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ABSTRACT

Fuels supplied 76% of global final energy consumption in 2021. Although ongoing electrification efforts can significantly reduce this dominant share, fuels will continue to play a leading role in the global energy system. Hydrogen is the most studied candidate for decarbonizing fuels, but storage and distribution challenges render it impractical and uneconomical for many applications. Hence, the present study focuses on ammonia and methanol that preserve the practical benefits of traditional petroleum fuels. Four low-carbon fuel production pathways are compared using cost and performance projections to the year 2050: solid fuels (coal/biomass blends) with CO_2 capture and storage (CCS), natural gas with CCS, renewables (wind & solar), and nuclear. These pathways are assessed in Europe as a typical fuel importer and in various exporting regions where the cheapest primary energy is available. A thorough uncertainty quantification exercise is conducted for all pathways to map out the likely range of future levelized costs. Results show that there are virtually no plausible scenarios where electrolytic fuels (renewables or nuclear) can compete with fuels produced from hydrocarbons equipped with CCS. Ammonia or methanol from solid fuels present a particularly attractive solution for affordable carbon-negative energy security, whereas ammonia from natural gas offers a promising decarbonized alternative to liquified natural gas exports. Based on these findings, a technology-neutral policy framework is recommended instead of targeted support for electrolytic fuels.

1. Introduction

Fuels drive the global economy. According to the latest World Energy Outlook from the IEA [1], fossil and biogenic fuels constituted 90 % of the global energy supply in 2021. While renewables and nuclear are set to largely displace fuels in electricity production, the IEA World Energy Outlook still predicts hydrocarbons to account for 74 % and 57 % of mid-century energy supply in the Stated Policies and Announced Pledges scenarios, respectively. Medium-term market outlooks see continued mild growth in oil [2], gas [3], and coal [4] demand, indicating that the Stated Polices pathway remains the most likely scenario at the time of writing. Fossil fuels dominate present-day fuel consumption, leading to about 34 gigatonnes of CO_2 emissions per year [5]. These emissions are unequivocally contributing to global warming, causing widespread and rapid changes to the earth's systems [6]. Consequently, practical and economical low-carbon fuels are essential to a just energy transition, considering that about half the global population still lives on less than 200 $/month [7].

Hydrogen has received a lot of attention as a potential carbon-free fuel [8]. However, its low volumetric energy density makes it costly to transport and store [9–11], limiting its value and practicality in many applications and leading to interest in alternatives such as ammonia [12] and methanol [13]. Like hydrogen, ammonia can be combusted without CO_2 emissions, but it can be liquefied relatively easily (–33 °C for NH_3 vs. −253 °C for H_2 at atmospheric pressure). Although methanol contains carbon, it has large practicality benefits since it is a liquid even under atmospheric conditions. In addition, methanol synthesis is relatively simple and efficient, and the product can be carbon–neutral if produced from biogenic or atmospheric carbon sources. Next to traditional uses of ammonia and methanol in fertilizers and chemicals, which are projected to see considerable growth [14], new energy-related applications include shipping [15], heavy-duty/long-distance road transport [13], and power plants operating at low capacity factors to facilitate high shares of variable renewables [11,16]. Ammonia is also seen as the most economical general-purpose hydrogen carrier for international trade [17].

Today, both ammonia and methanol are produced almost exclusively from fossil fuels with large CO_2 emissions: natural gas is preferred as feedstock in most of the world, except for China, where coal is favoured. In ammonia production, CO_2 must be separated from hydrogen used in the ammonia synthesis process, making it ideally suited for CO_2 capture and storage (CCS). Techno-economic assessments of advanced process configurations have shown CO_2 avoidance of more than 90 % is feasible with negative abatement costs compared to commercial processes [18–20]. In methanol production from fossil fuels, there is a greater limit

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Nomenclature

Acronyms

ACF	Annual cash flow
ASU	Air separation unit
CCS	CO_2 capture and storage
CPU	CO_2 purification unit
DAC	Direct air capture
DOE	Department of Energy
EOR	Enhanced oil recovery
EU	European Union
IEA	International Energy Agency
IP	Intermediate pressure
Gen IV	Fourth generation (nuclear technology)
GSR	Gas switching reforming
HGCU	Hot gas clean-up
HP	High pressure
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCOA	Levelized cost of ammonia
LCOM	Levelized cost of methanol
LCOP	Levelized cost of product
LP	Low pressure
MAWGS	Membrane-assisted water–gas shift
NETL	National Energy Technology Laboratory
NPV	Net present value
OX	GSR oxidation step
PEM	Polymer-electrolyte membrane (electrolyzer)
PSA	Pressure swing adsorption
PV	Photovoltaic
RED	GSR reduction step
REF	GSR reforming step
SEA	Standardized economic assessment
SOEC	Solid oxide electrolysis cells
SMR	Steam methane reforming
T&S	Transport and storage
WGS	Water-gas shift

to how much the carbon intensity of the fuel can be reduced, since part of the fossil carbon will be contained in the product and will be emitted to the environment as CO_2 if the methanol is combusted without CO_2 capture. Nonetheless, process modelling has shown that advanced process integrations for low-carbon methanol production from natural gas can reduce direct CO_2 emissions by 60 % while modestly reducing costs relative to a conventional process [21]. Alternatively, natural gas and coal used for methanol and ammonia production can be replaced, partially or entirely, by renewable biogas [22,23] or solid biomass [23,24], potentially allowing for negative emissions when combined with CCS [19,25].

Another widely studied alternative is to produce renewable methanol and ammonia from electrolytic hydrogen generated from wind and solar power. Primary renewable electricity for such plants can come from dedicated wind/solar parks or excess grid electricity, with the latter potentially offering some integration benefits [26]. Although the additional conversion step of hydrogen to ammonia or methanol brings additional costs, it will facilitate long-term storage and international trade of renewable electricity by means of these energy carriers [9]. Recent review papers on these so-called power-to-X processes for ammonia [27,28] and methanol [29,30] indicate high interest in this topic.

However, in the coming decades, demand for renewable electricity is expected to be intense – the IEA expects global electricity consumption to double from 2021 to 2050, while variable renewables are simultaneously expected to mostly displace fossil fuels in electricity supply [1]. It is therefore of critical importance that valuable renewable electricity, which will face increasing constraints with growing market share due to high land use [31] and material intensity [32], should be allocated to markets where they are most competitive. Consequently, an abundance of recent studies has investigated the cost of renewable fuel production. Most agree that currently these technologies are not competitive with fossil fuels [33–38]. However, expected decreases in the cost of solar and wind power, as well as electrolysers, and increasing CO_2 taxes will make these technologies more competitive, with several studies drawing favourable conclusions regarding their longer-term prospects. Most notably, for hydrogen, IRENA predicts future hydrogen costs of less than 1 \$/kg H_2 [39], in which case renewable hydrogen would outcompete even unabated fossil fuel hydrogen, creating a cheap feedstock for green methanol and ammonia production. For methanol, for example, Schorn et al. [40] concluded that renewable methanol could be competitive with methanol from fossil fuels by 2030, while Gu et al. [41] concluded that a carbon tax of only about 70 €/ton CO_2 would make a renewable methanol plant in China competitive with a conventional coal-based plant. Similarly, for ammonia, Bouaboula et al. [33] suggests that renewable ammonia could be competitive against fossil fuel-based ammonia in Morocco by 2030, while Fasihi et al. [35] implies that renewable ammonia might be competitive with ammonia from natural gas by 2040, and with ammonia from coal in China already by 2030.

Despite these promising findings, a closer inspection of recent techno-economic assessments of renewable methanol and ammonia reveals several important methodological issues that result in over-optimistic conclusions.

- Several studies base their conclusions on comparisons of calculated production costs against historical market prices [33,35–37,42–44]. Since ammonia and methanol are globally traded commodities, their market prices will be set by the costliest producers, implying that most producers will have production costs well below the market price. This is particularly relevant to studies assessing green fuel production in optimal locations for potential international exports [33,42,43]. To accurately assess the competitiveness of renewable fuels, production costs must be directly benchmarked against production costs of relevant alternatives.
- Aside from the authors' own work [18,21], the literature review failed to find recent studies conducting a systematic bottom-up techno-economic benchmarking study of renewable ammonia and methanol against relevant low-carbon alternatives. Given all the uncertainties involved in economic assessments, such direct benchmarking studies are vital to standardize as many assumptions as possible between the technologies being compared.
- Large wind/solar/battery/electrolyzer cost reductions are generally assumed for longer term perspectives [24,33–35,38,45], but the possibility of advances in low-carbon production from hydrocarbon fuels and further economic gains from an efficient and standardized rollout of many such plants over these multi-decade timeframes are rarely considered.
- Many studies only assume a constant levelized cost of electricity or hydrogen in their assessment [23,24,36,37,44,46], without modelling hourly variability in renewable electricity input and accounting for the additional cost of storing electricity, hydrogen, and CO_2.
- Studies that correctly model the variability of renewable electricity generally assume perfect optimization, most often over a single year, with no contingency accounting for interannual variability and the complexities of constructing and operating an interconnected plant with multiple energy conversion and storage steps [33,34,42,43,45].

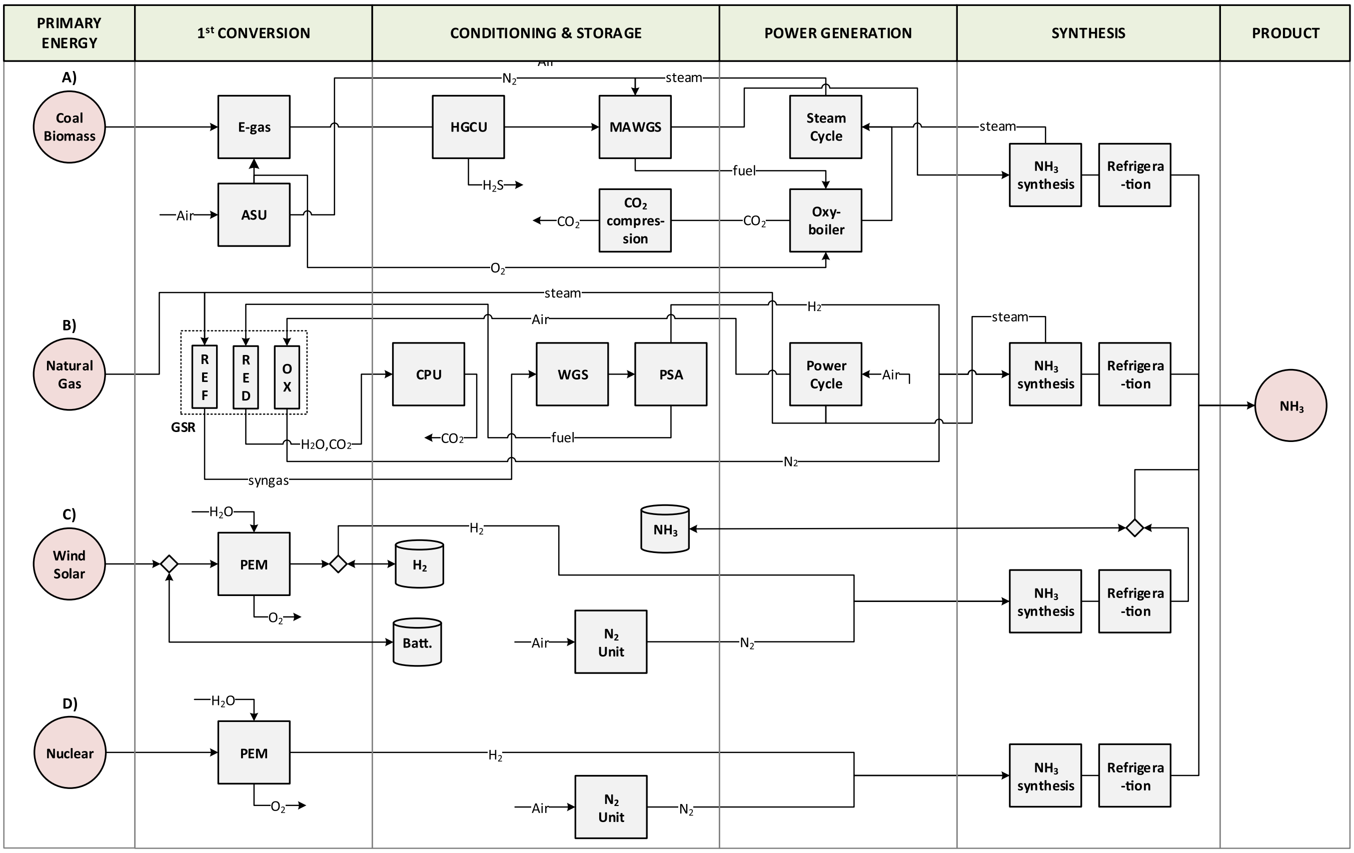

Fig. 1. Simplified process diagrams of ammonia production plants: (A) solid fuels, (B) natural gas, (C) renewables, (D) nuclear.

- Multiple studies for methanol from renewable hydrogen considered CO_2 captured from fossil fuel power or processing plants as carbon source [36,38,41,44]. In such cases, the produced methanol would not be renewable, and can lead to a significant environmental opportunity cost by diverting renewable electricity from the grid [47]. Renewable methanol would require direct air capture (DAC) or the use of captured biogenic CO_2.

In addition, the current literature does not adequately address the uncertainty involved in the wide range of economic assumptions required in such assessments. Most studies only perform single-parameter sensitivity studies on the most important parameters [18,19,21,24,25,35,36,41,44,45], making it difficult the assess the full range of possible future scenarios.

To address these gaps in the current body of literature, the present study aims to provide a clearer understanding of the long-term competitiveness of various large-scale production pathways for low-carbon ammonia and methanol. Considering a realistic mid-century timeframe for large-scale adoption of ammonia and methanol fuels, renewable fuels are simulated with hourly resolution and large technology cost reductions and compared against advanced CCS benchmarks fed by natural gas and solid fuels. To broaden the comparison, electrolytic fuel production from nuclear power is also considered. Direct air capture is selected as the primary source of renewable CO_2 for methanol production, while the alternative of hybrid gasification/electrolysis plants is included as the optimal pathway for exploiting fixed fossil/biogenic carbon and the O_2 by-product from electrolysis. All pathways are assessed with a consistent methodology and assumptions, distinguishing between production in importing and exporting regions. Most importantly, a rigorous uncertainty quantification is performed for all uncertain parameters, in line with recommendations for techno-economic assessments of novel technologies [48]. This approach reveals important insights regarding the future of fuels from different production pathways, and the uncertainties that govern their competitiveness.

2. Methodology

The methodology will be presented in four parts: (1) process layouts for the four pathways for low-carbon production of ammonia and methanol, (2) the consistent techno-economic assessment methodology employed, (3) the uncertainty quantification method, and (4) key performance metrics.

2.1. Process layouts

The plants assessed in this study have been published in prior works based on a consistent techno-economic assessment methodology. Nuclear plants are the only exception, but they are easily assessed as a simplified version of the renewable plant. This section will summarize the layout of each plant, referring the reader to prior publications for more details. Although simplified process diagrams are presented here for brevity, detailed process layouts with stream tables can be viewed in Section 1 of the Supplementary Material.

Fig. 1 illustrates the ammonia plants. Given the mid-century timeframe, solid fuel [19] and natural gas [18] plants utilize advanced configurations that deliver an average cost reduction relative to conventional benchmarks of 22 % and 12 % respectively (see Section 2 of the Supplementary Material). Renewable plants are assessed using a system-scale optimization model [18] to minimize the cost of converting variable wind and solar electricity into a steady ammonia outflow. Nuclear plants follow the same layout, only without the need for energy storage due to their steady power output.

The solid fuel plant (Fig. 1A) [19] converts a blend of coal and

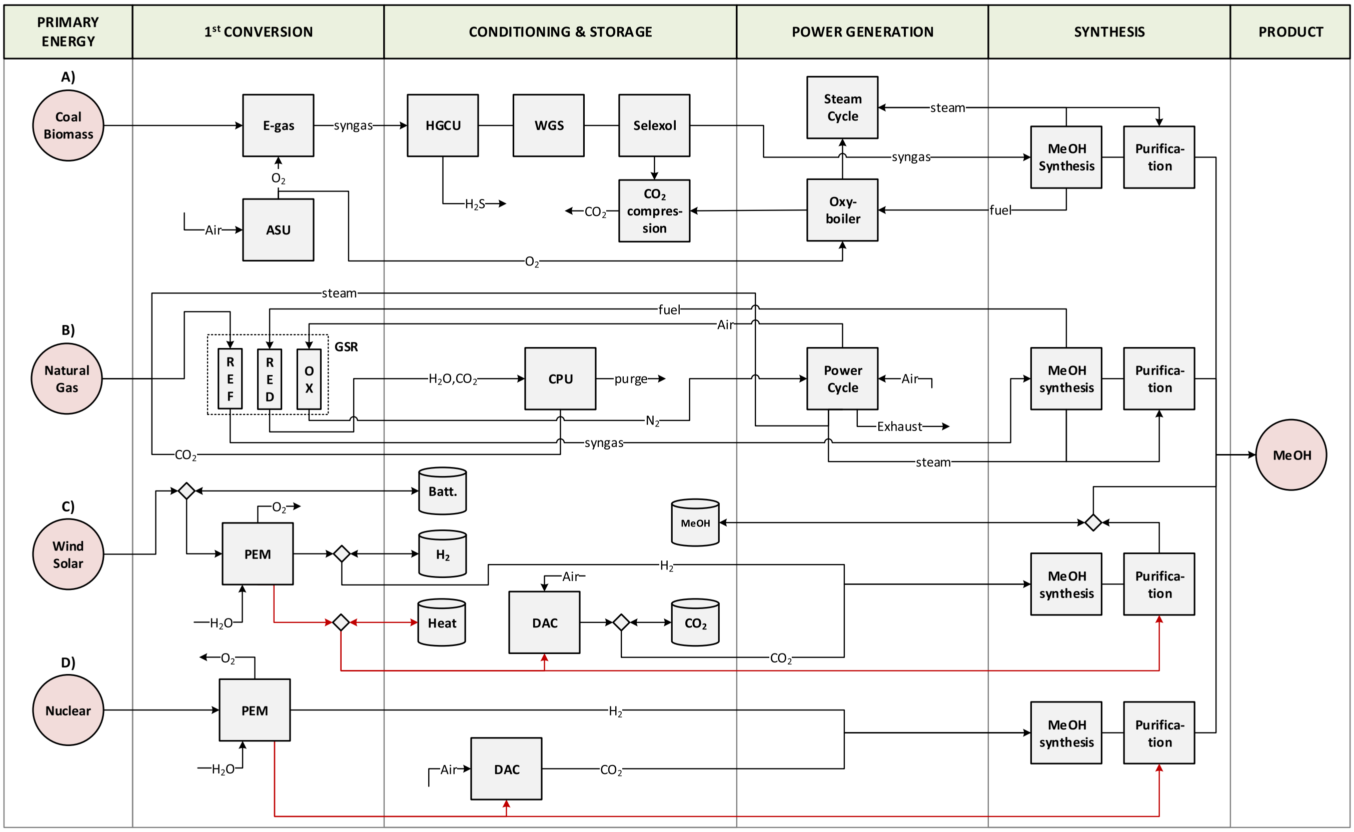

Fig. 2. Simplified process diagrams of methanol production plants: (A) solid fuels, (B) natural gas, (C) renewables, (D) nuclear.

biomass into syngas using a two-stage oxygen-blown E-gas gasifier with a chemical quench in the second stage to improve cold gas efficiency. After cooling, the syngas is desulphurized in a hot-gas clean-up unit before being sent to the membrane-assisted water–gas shift (MAWGS) unit [49]. The MAWGS reactor contains a standard water–gas shift (WGS) catalyst and H_2 perm-selective membranes to simultaneously shift CO and H_2O into H_2 and CO_2 and extract a pure stream of H_2. The pressure inside the membranes is maximized by using a sweep of pressurized N_2 (the stoichiometric amount for ammonia synthesis) from the air separation unit (ASU) and steam from a back-pressure steam turbine that generates power from high-pressure (HP) steam raised by cooling various process streams. This pressurized H_2-rich permeate stream is cooled to condense out the water before being further compressed and fed to the ammonia synthesis loop. A significant amount of 120 °C water can be raised from this condensation and cooling for district heating. The retentate (CO_2-rich) stream from the MAWGS reactor retains a small amount of fuel gases and is sent to an oxy-boiler for combustion with additional O_2 from the ASU to raise additional HP steam for the steam cycle while converting all fuel gases to CO_2 and H_2O. Since this stream retains its pressure (~67 bar), it requires only minor CO_2 compression duty after cooling and drying before transport and storage.

The natural gas plant (Fig. 1B) [18] employs the gas switching reforming (GSR) concept [50] to drive the endothermic steam methane reforming (SMR) reaction by combusting off-gas fuel from the pressure swing adsorption (PSA) unit with integrated CO_2 capture. The GSR unit employs a Ni-based oxygen carrier material that is first oxidized by air to generate heat and a high-purity N_2 stream for ammonia synthesis, then reduced by the PSA off-gas fuel to generate a high-purity pressurized stream of CO_2 and H_2O, and finally used to catalyze the SMR reaction using heat stored in the oxygen carrier and steel rods for extra thermal mass. Thus, the PSA off-gas is combusted with inherent CO_2 separation. The syngas resulting from the reforming step of the GSR unit is fed to downstream WGS and PSA processes to produce separate streams of pure H_2 and CO_2-rich off-gas fuel. The pure H_2 is mixed with purified N_2 from the GSR oxidation step and compressed for feeding to the ammonia synthesis loop. The GSR power cycle scheme consists of an air compressor to deliver pressurized air to the cluster, as well as a back-pressure steam turbine were HP steam produced from the plant heat sources is partially expanded to produce additional electricity before being fed to the GSR reforming step.

The renewable plant (Fig. 1C) [18] consists of a wind/solar farm for renewable electricity production, an electrolysis plant for converting electricity into hydrogen, an ASU for producing a stream of pure N_2, and an ammonia synthesis loop to convert the H_2 and N_2 streams into ammonia. Given the variability of the wind/solar resource, energy can be stored as electricity in batteries after the wind/solar farm, compressed hydrogen in tanks or salt caverns after the electrolyzer, or liquid ammonia in tanks after the ammonia synthesis loop, to guarantee a steady supply of product. Each of these units is sized and dispatched optimally to minimize the total cost of ammonia in an hourly simulation of one year of wind/solar variability. The nuclear plant (Fig. 1D) follows the same value chain as the renewable plant, only without the need for storage.

Similar layouts are used for methanol production (Fig. 2). Here, the advanced solid fuel [25] and natural gas [21] plants deliver somewhat lower cost reductions of 19 % and 8 % relative to conventional benchmarks (see Section 2 of the Supplementary Material). The electrolytic renewable and nuclear plants now require the addition of a direct air capture (DAC) unit to supply carbon for methanol synthesis.

The solid fuel plant (Fig. 2A) [25] uses the same E-gas gasifier followed by a hot gas clean-up unit as the ammonia plant. Subsequently, conventional WGS and Selexol CO_2 removal units are employed to produce a syngas with a suitable module $\left(\frac{[H_2]-[CO_2]}{[CO]+[CO_2]} \approx 2\right)$ for methanol synthesis. The purge stream from the methanol synthesis loop is oxy-combusted in the same manner as the ammonia plant to ensure complete

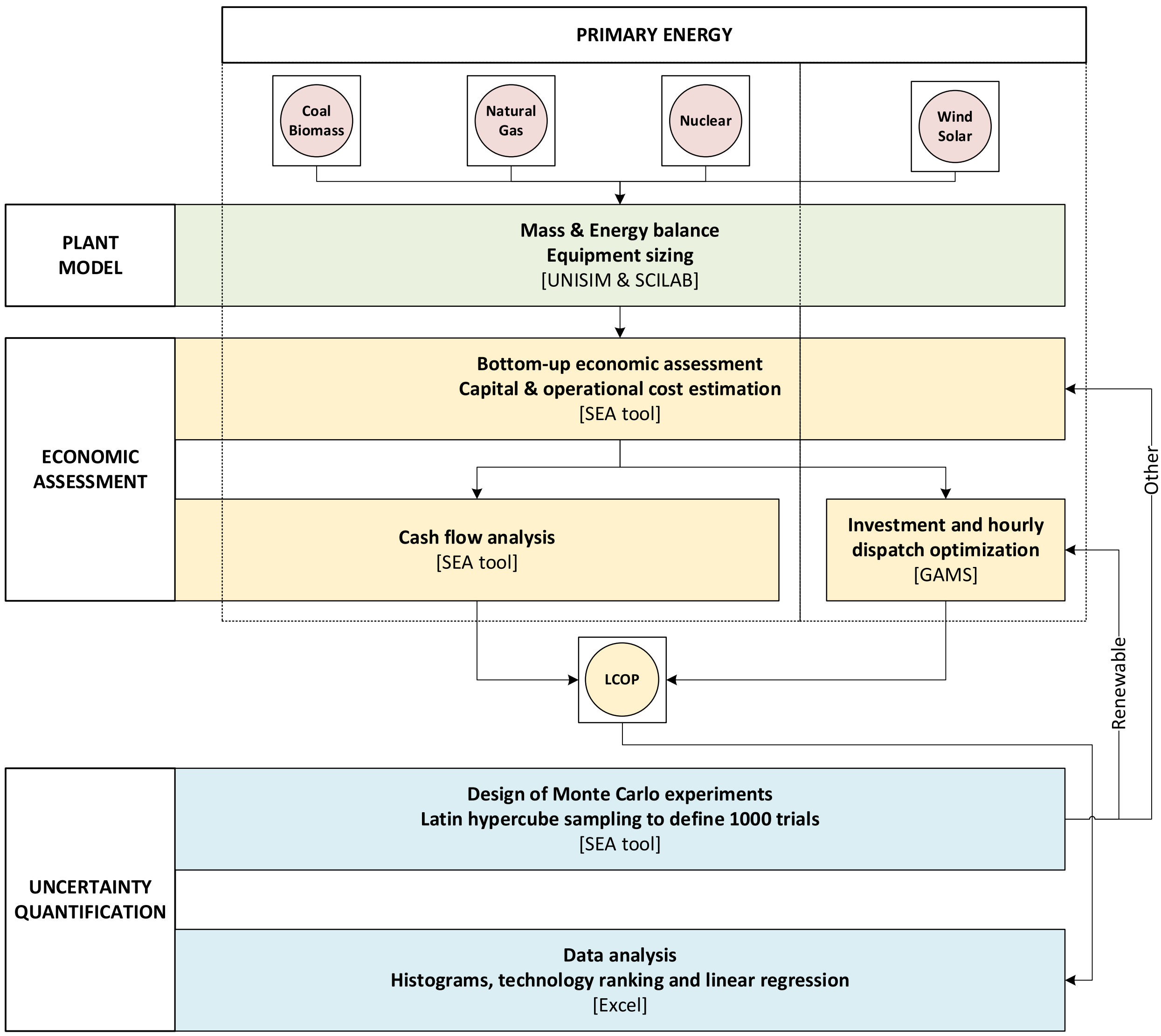

Fig. 3. Visualization of the techno-economic assessment tools and workflow.

CO_2 capture, generating HP steam to produce electricity in a steam cycle.

Analogously to the ammonia production concept from natural gas, the methanol plant (Fig. 2B) [21] employs the GSR technology for reforming. However, this configuration uses the purge from the methanol synthesis loop as fuel in the GSR reactor cluster and displaces some steam with CO_2 from the CO_2 purification unit as oxidant during reforming to ensure the optimal syngas module for synthesis, while increasing the carbon efficiency. The GSR power cycle scheme consists of an air compressor to deliver O_2 to the GSR, an N_2 expander to produce electricity from the N_2-rich hot outlet stream, and a back-pressure steam turbine where HP steam produced from the plant heat sources is partially expanded to produce additional electricity. IP and LP steam from the turbine is supplied at the appropriate pressures to the GSR reforming and MeOH purification steps.

The same hourly optimization approach is followed to assess the renewable plant (Fig. 2C) [21], which now requires the addition of a DAC unit and associated CO_2 storage to buffer any misalignment between CO_2 production from DAC and consumption in the methanol synthesis loop. The low-grade heat required by the DAC unit is assumed to be drawn from electrolyzer waste heat that is also stored in a buffer between variable production and relatively steady consumption. Suitable amounts of electrolytic H_2 and air-captured CO_2 are then fed to the methanol synthesis loop. The same process train is used in the nuclear plant, only without the storage units.

2.2. Techno-economic assessment

The basic methodology and the tools employed to assess the levelized cost of ammonia or methanol from each plant are summarized in Fig. 3 similar to prior studies [18,21]. Most plants are simulated using Unisim Design [51], followed by a bottom-up techno-economic assessment using the SEA tool [52] based on correlations from Turton et al. [53], except for the renewable plant that required dedicated optimization in GAMS [54]. However, techno-economic data for the electrolyzer and synthesis loops used in the GAMS model were also derived from Unisim and SEA tool assessments of these respective units. The complete SEA tool files and GAMS models are available online.[1]

The Peng-Robinson thermodynamic property package was the default choice for process simulations. However, the Redlich-Kwong-Soave equation of state was used in the synthesis loops, due to a better prediction of vapour liquid equilibrium [55], and ASME steam tables were chosen for streams containing water/steam. The gas switching

[1] https://bit.ly/FuelUQ

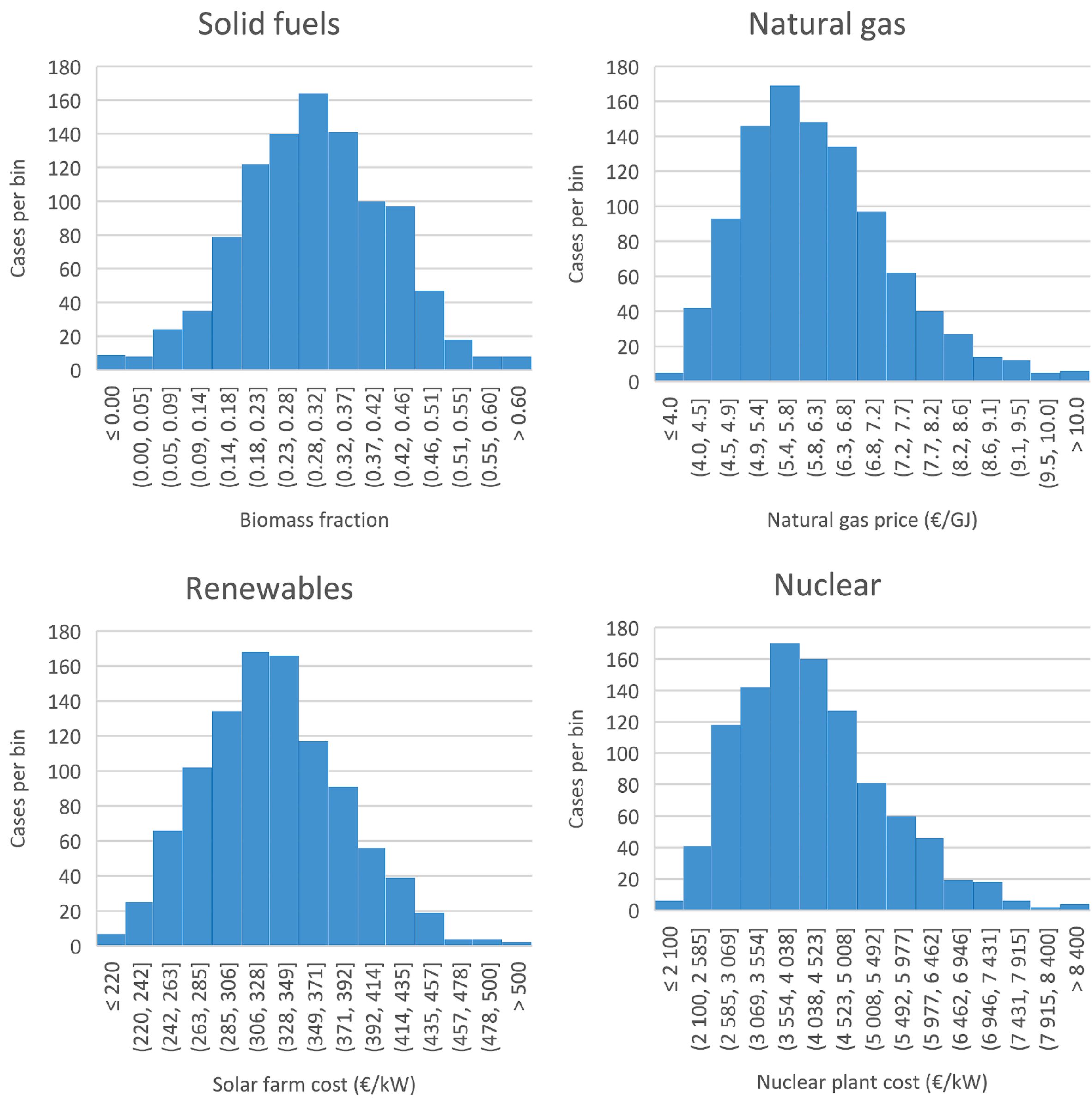

Fig. 4. Distributions of the most influential parameter in each plant for mid-century ammonia production in Europe.

reforming (GSR) and membrane assisted water gas shift (MAWGS) reactors were modelled in Scilab using an internal property estimation package called *Patitug*. Details of these reactor models are available in previous works [18,56]. Outputs from the GSR and MAWGS model were connected to Unisim via a CAPE-OPEN unit operation.

Optimization of the renewable plants in GAMS was completed using the CPLEX linear programming solver. The problem was defined via balances for each energy vector (electricity, hydrogen, and NH_3/MeOH) where supply must equal demand in every simulated hour, supplemented by various additional constraints (e.g., production rates cannot exceed installed capacity). One year of hourly wind/solar variability was simulated where the capacity investment and hourly dispatch of all available technologies (e.g., wind/solar generators, electrolyzers, synthesis loops, and battery/tank storage) were optimized to achieve the lowest possible cost of the final NH_3/MeOH product. The models are described in greater detail in prior works [18,21].

The levelized costs of ammonia or methanol were determined using a discounted cash flow analysis achieving a net present value (NPV) of zero over the plant lifetime (Eq. (1)). The NPV is calculated by summing the annual cash flows (ACF) from each year (t) of plant construction and operation with a discount rate (i) applied to diminish the importance of cash flows in future years to account for the time-value of money. As shown in Eq. (2), the ACF is comprised of revenues from fuel sales (S_{fuel}), variable operating and maintenance costs (C_{VOM}), capital expenditures ($C_{capital}$) and fixed operating and maintenance costs (C_{FOM}). Fuel sales and variable operating costs are dependent on the capacity factor (ϕ) whereas capital expenditures and fixed operating costs remain constant regardless of the rate of plant utilization. The levelized cost of ammonia or methanol is the price required to achieve revenues from fuel sales resulting in zero NPV.

$$\mathrm{NPV} = \sum_{t=0}^{n} \frac{\mathrm{ACF_t}}{(1+\mathrm{i})^{\mathrm{t}}} \quad (1)$$

$$\mathrm{ACF_t} = \phi \cdot (\mathrm{S_{fuel}} - \mathrm{C_{VOM}}) - \mathrm{C_{capital}} - \mathrm{C_{FOM}} \quad (2)$$

Such assessments involve many uncertainties, especially when projecting costs several decades into the future. Hence, the most important uncertain parameters involved in the assessment of each pathway were varied over carefully defined ranges (described in detail in Tables A1–A5

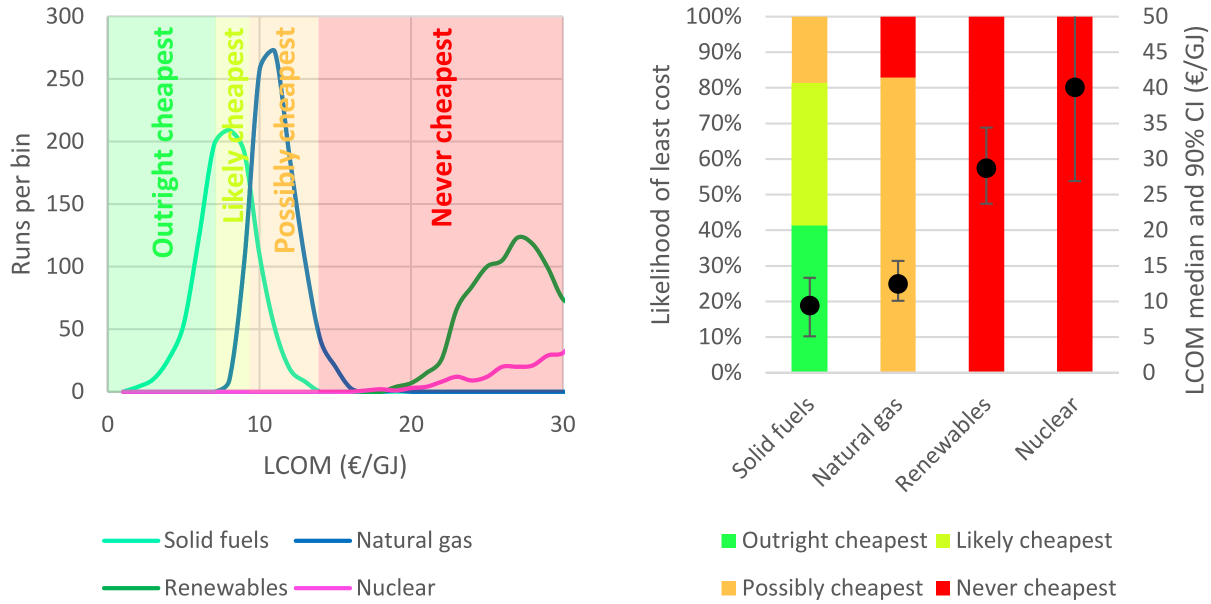

Fig. 5. Visualization of the categorization of technology competitiveness for the case of methanol production in Europe. The bin size is set to 1 €/GJ.

in the Appendix) in the uncertainty quantification exercise described in the next subsection.

2.3. Uncertainty quantification

The uncertainty quantification methodology is built on Monte Carlo simulation with Latin Hypercube sampling to ensure a good distribution of samples throughout the parameter space. The values of each parameter are distributed according to a skewed normal distribution defined by three values: low, mid, and high. The median of the normal distribution is set to the mid value, after which the standard deviation and skewing of the distribution are set to contain 99 % of the values between the low and high values. Some examples of the distributions resulting from this methodology are given in Fig. 4.

A set of 1000 runs is compiled for every case, simultaneously varying all the uncertain variables described in the Appendix. This number of runs ensured <1 % difference in the median levelized cost when the exercise is repeated with a new randomly generated sample of runs, thus ensuring that additional uncertainty stemming from the uncertainty quantification methodology is negligible. The methodology is integrated into the SEA tool [52].

When comparing technologies based on the degree of overlap between their respective uncertainty ranges, it is very important that the parameters included in the uncertainty quantification of different technologies should be uncorrelated. If influential parameters with highly correlated effects on different technologies are included in the uncertainty quantification, spurious overlaps in the uncertainty ranges can occur. For example, an increase in the discount rate will increase the levelized cost of all technologies. If this parameter is included in the uncertainty quantification, the implicit assumption is made that it can vary independently for the different technologies, which is not realistic.

Thus, the uncertain parameters are separated into two groups. Most of the parameters are largely uncorrelated between different technologies (Table A1–A4 in the Appendix) and these are included in the formal uncertainty quantification study. However, two parameters with highly correlated effects on the different technologies (discount rate and CO_2 price) are varied in a sensitivity analysis to accurately visualize the correlated effects they have on the different technologies. The full uncertainty quantification exercise was completed for low, mid, and high levels of these two parameters (shown in Table A5) to calculate the median levelized cost and the 90 % confidence interval. These results are then plotted as bands to visualize the regions under which the uncorrelated uncertainty ranges start to overlap.

The analysis is conducted from the perspective of Europe as an energy importer. Thus, levelized costs are calculated both for local production (importing region) and various low-cost locations globally (exporting regions). Production in exporting regions will be significantly cheaper than local production in Europe, but the global market prices at which Europe must buy internationally traded fuels will generally be significantly higher than the production cost of low-cost exporters. In addition, these prices can fluctuate considerably in response to unpredictable international developments, raising significant energy security concerns. Thus, it is important to quantify the cost penalty of the energy security offered by more expensive local production. Europe is selected as the importing region, with Southern Spain chosen for renewable production due to its good wind/solar resources. Exporting regions are Brazil for solid fuels (due to a large supply of low-cost biomass), the Middle East for natural gas (due to low-cost conventional gas resources) and renewables (due to the excellent solar resource), and Russia for nuclear (due to low nuclear power plant construction costs). Tables A1–A4 in the Appendix detail the different assumptions employed for the importing and exporting regions.

2.4. Key performance indicators

The result from each run in the uncertainty quantification exercise is the levelized cost of ammonia or methanol in €/GJ_{LHV}. Using the levelized cost results from 1000 runs for each technology, the competitive ranking can be determined with greater confidence. First, histograms of the levelized costs from all runs are plotted to visually inspect the competitiveness of the different technologies. Next, the median (50th percentile) and 90 % confidence bounds (5th and 95th percentiles) are reported.

Another ranking mechanism is devised where the runs for each technology are subdivided into four categories:

- Outright cheapest: The percentage of runs for a given technology that achieves lower levelized costs than any runs for any other technology.
- Likely cheapest: The percentage of runs of the cheapest technology in bins that overlap with other technologies but contain more runs than the competing technology in those bins.

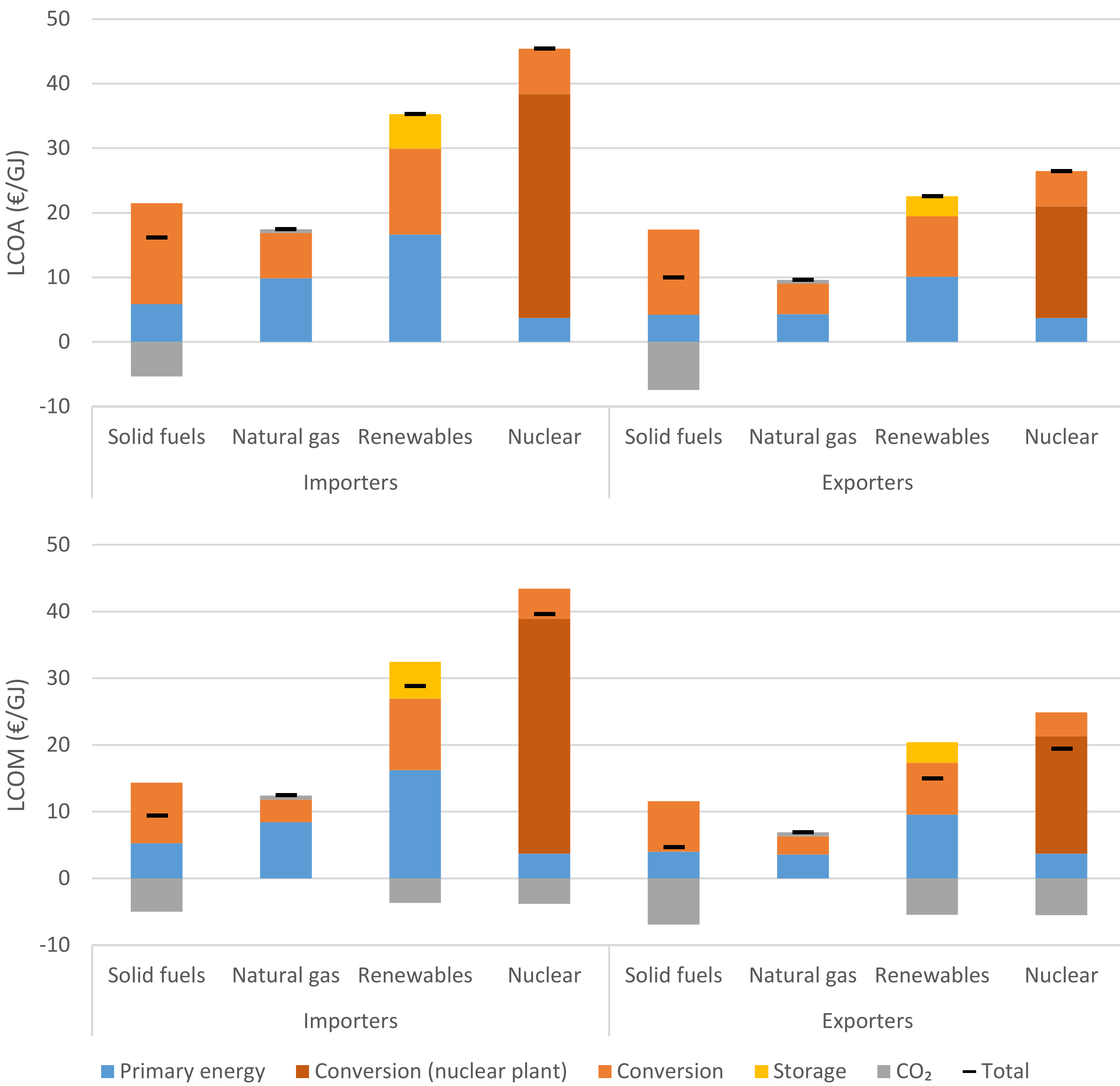

Fig. 6. Cost breakdown of the levelized costs of NH_3 (top) and MeOH (bottom) for central assumptions (Mid values in Tables A1–A5). Only production-phase CO_2 emissions are considered (i.e., use-phase CO_2 emissions from methanol fuel are not considered).

- Never cheapest: The percentage of runs of a given technology with a higher cost than any run of the cheapest technology.
- Possibly cheapest: All runs not classified in the above three categories.

These categorizations are visualized for the example of methanol in Fig. 5. The shading in the left-hand panel indicates the regions where the four categorizations apply, and the right-hand panel shows the percentage of the 1000 runs completed for each technology that falls into each category.

To gain further insights into the results, a linear regression is performed on the data for each case to rank the parameters in order of importance. Most parameters had a near-linear effect on the levelized costs of ammonia or methanol, producing a good fit of the linear regression model. The influence of each parameter was then quantified as the change in levelized cost caused by changing the parameter in question across half the distance between its low and high values (the bounds containing 99 % of the runs for each parameter).

3. Results and discussion

Results are presented and discussed in three subsections. First, a breakdown of the levelized costs for the central cases is given to understand the main cost contributors. Second, the full uncertainty quantification results are presented and analysed. Finally, a sensitivity to two factors influencing all cases is presented: the discount rate and the CO_2 price.

3.1. Central cases

Fig. 6 illustrates the cost breakdown for all cases using central assumptions (detailed in the Appendix). On average, ammonia and methanol from solid fuels and natural gas are 63 % cheaper than fuels from renewables and nuclear, fuel production costs in exporting regions (Brazil for solid fuels, Saudi Arabia for natural gas and renewables, and Russia for Nuclear) are 44 % lower than in the importing region (Europe), and methanol is 26 % cheaper than ammonia.

Solid fuels and natural gas generally present the lowest costs, with solid fuels being slightly more attractive due to the large CO_2 credit (150

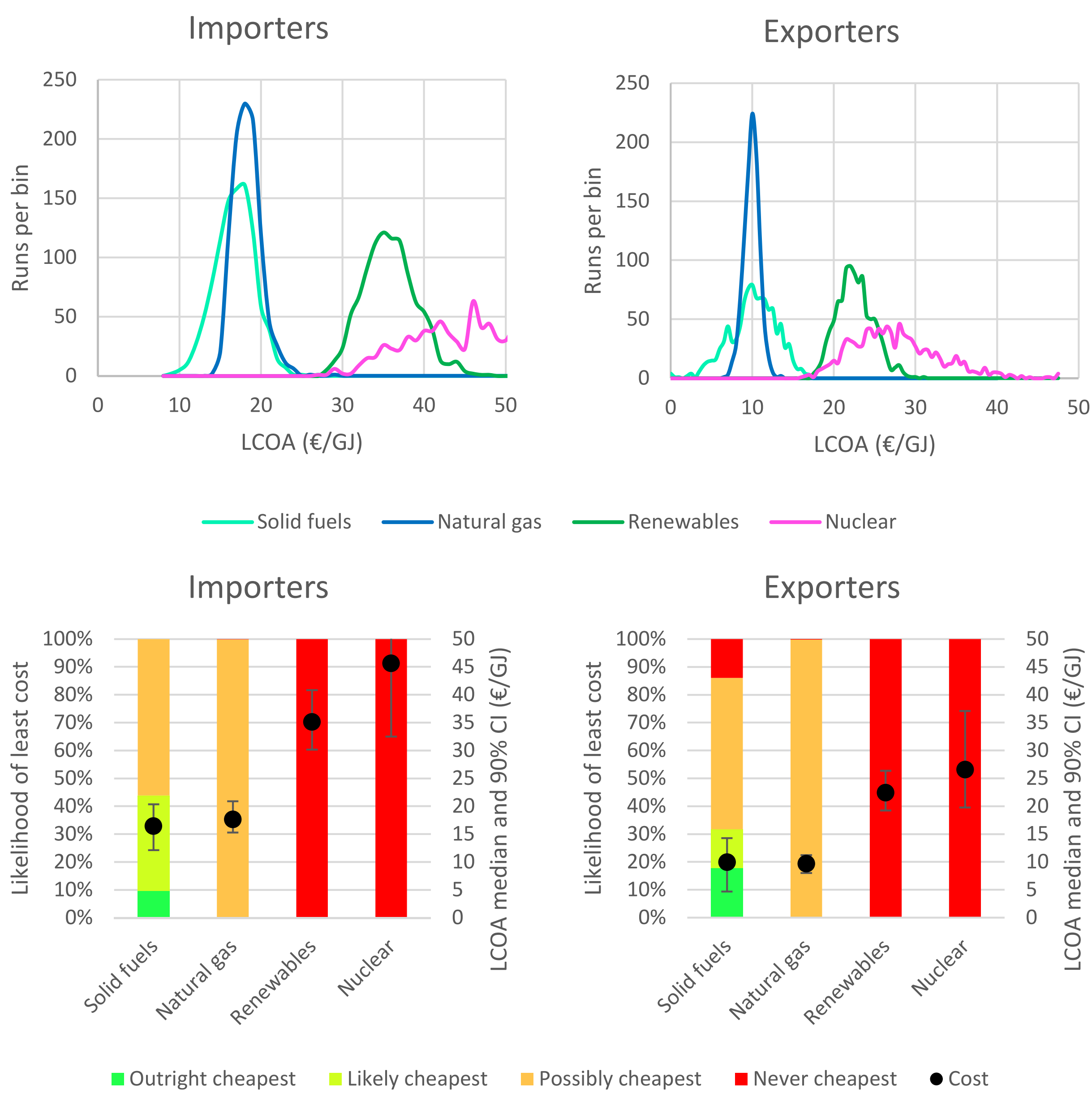

Fig. 7. Uncertainty quantification results on the levelized cost of ammonia. Top: histograms of LCOA results obtained from 1000 runs for each technology (the bin size is set to 1 €/GJ for importers and 0.5 €/GJ for exporters). Bottom: Categorization of each technology according to the possibility of being the cheapest option (see Fig. 5).

€/ton) which is assumed to be received by mid-century for capturing and storing biogenic CO_2. Without this credit, the higher capital costs of solid fuel plants would cancel out the benefit of cheaper fuels. It should also be mentioned that advanced concepts are modelled for this mid-century study. As described in Section 2 of the Supplementary Material, these concepts offer about 10 % lower costs in the case of natural gas and 20 % lower costs in the case of solid fuels compared to currently available technologies.

Renewable plants rely heavily on solar PV technology, assumed to achieve approximately 3x lower costs by mid-century, reaching 330 €/kW in Spain (importing region) and 248 €/kW in the Middle East (exporting region). Despite the very low solar PV cost and excellent solar resource in the Middle East, the primary energy cost of the renewable plants remains well above that of the other options. Additional costs for energy conversion and energy storage equipment are also higher than the conversion costs involved in solid fuel and natural gas plants, especially when considering methanol production where DAC is required to capture CO_2 for the methanol synthesis reaction. These costs originate because renewable fuel plants require large oversizing of electrolyzers and large H_2 storage capacities so that fluctuating solar output can be converted into hydrogen, which is stored for feeding a relatively steady input to the ammonia or methanol synthesis loop [18,21].

Nuclear plants provide a steady power output and do not require any electrolyzer oversizing or energy storage. Primary nuclear energy (uranium fuel rods) is also much cheaper than solar energy. However, these benefits are overpowered by the high cost of the nuclear power plant itself, making fuels from nuclear origin significantly more expensive than those from renewable origin, especially in the importing region (Europe) where nuclear plants tend to be very costly. If high-temperature nuclear reactors are successfully commercialized, nuclear fuels could benefit from hydrogen production pathways displacing some electricity consumption with high-grade heat such as solid oxide electrolysis cells (SOEC). For example, if the net electrolysis LHV efficiency can be increased from 71 % for low-temperature electrolysis to 95 % for high-temperature SOEC with a 50 % higher capital cost (estimated from

Table 1
Ranking of uncertain factors for ammonia production via linear regression. The numbers represent the change in LCOA (€/GJ) when increasing each parameter across half its uncertainty range (see Tables A1–A4).

Solid fuels		Natural gas		Renewables		Nuclear	
Importers							
Biomass fraction	−3.99	Natural gas	3.68	Solar	6.45	Nuclear plant	26.35
Gasifier	2.56	Electricity	1.24	Electrolyzer	3.05	Capacity factor	−3.58
CO_2 T&S	1.98	GSR reactors	0.87	Contingency	3.03	Nuclear fuel	3.49
Coal	1.89	CO_2 T&S	0.85	H_2 storage	2.91	Contingency	2.06
Contingency	1.87	Capacity factor	−0.45	Capacity factor	−2.34	Electrolyser	0.98
Capacity factor	−1.81	Contingency	0.44	Wind	0.54		
Biomass	1.45			Battery	0.26		
Membrane	0.60						
Heat	−0.58						
HGCU & oxy	0.55						
Electricity	0.44						
Exporters							
Biomass fraction	−5.93	Natural gas	1.53	Solar	4.40	Nuclear plant	13.12
CO_2 T&S	3.15	CO_2 T&S	1.52	H_2 storage	2.23	Nuclear fuel	3.51
Gasifier	2.03	GSR reactors	0.65	Electrolyzer	2.18	Capacity factor	−1.85
Coal	1.56	Electricity	0.62	Contingency	1.88	Contingency	1.09
Contingency	1.50	Capacity factor	−0.33	Capacity factor	−1.41	Electrolyser	0.74
Capacity factor	−1.45	Contingency	0.33	Battery	0.24		
Biomass	1.43			Wind	0.00		
Membrane	0.53						
HGCU & oxy	0.45						
Electricity	0.33						
Heat	−0.11						

Buttler and Spliethoff [57]), the cost of nuclear fuels fall by about 20 % to the level of renewable fuels – a significant improvement but still uncompetitive against solid fuels and natural gas.

Fuel production in exporting regions almost halves costs relative to importing regions. For solid fuels (Brazil), the benefit originates from a larger availability of cheap biomass to reduce fuel costs and increase the CO_2 credit for negative emissions and a 20 % capital cost reduction relative to Europe. Natural gas (Middle East) benefits from much lower fuel prices at the point of production and a 25 % reduction in capital costs. Renewable plants (Saudi Arabia) enjoy a 25 % lower capital cost for all equipment and a better solar resource. Nuclear plants (Russia) are assumed to cost only half as much in exporting regions. From the viewpoint of energy importers, however, it may still be advisable to invest in local fuel production because international market prices will be set by the most expensive producer (plus shipping costs), which will always be well above the production costs in the most cost-effective exporting regions considered here. International prices could also experience great volatility during times of global economic upheaval.

Methanol is generally cheaper than ammonia due to the simpler energy conversion process. Even in the renewable and nuclear plants, this benefit outweighs the added cost of DAC. Large DAC cost reductions by mid-century result in an energy-exclusive levelized cost of only 58 €/ton of CO_2 captured at a 90 % capacity factor. In addition, it is assumed that the electrolyzer can be operated at sufficiently high temperatures so its waste heat can regenerate the DAC sorbent (the LCOM increases by about 10 % if heat must be supplied by a heat pump instead). As a result, Fig. 6 shows a substantial negative contribution of CO_2 in the renewable and nuclear methanol plants because the 150 €/ton credit for removing CO_2 from the atmosphere outweighs the cost of DAC. However, if the methanol is to be used as a fuel and the 150 €/ton CO_2 tax is levied on the resulting emissions, the overall costs of methanol will increase by 10.4 €/GJ for all feedstocks, making it 20 % more expensive than ammonia when averaged across all cases.

As ammonia and methanol expand beyond their traditional niches (e.g., fertilizers and petrochemicals) into much larger energy markets, they will likely continue to differentiate into specialized market segments. Although ammonia will be the cheaper option when CO_2 emissions from methanol combustion are taxed at CO_2 prices exceeding 100 €/ton, the liquid state of methanol at room temperature offers a valuable practical benefit, especially in the transportation sector. Thus, it is likely that methanol emerges as the fuel of choice for smaller vehicles operated by laymen (e.g., private cars) despite its CO_2 emissions, whereas ammonia could become the preferred fuel for larger vehicles operated by professionals (e.g., trucks and ships). Methanol could also outcompete ammonia in centralized stationary processes where CO_2 can be captured, but the direct use of fossil fuels will likely offer a cheaper solution in such cases. There is also a potential market for methanol and ammonia in power plants operating at low capacity factors to balance variable renewables due to the ease of storing these fuels for longer timescales of wind/solar variability [16]. However, CCS from methanol power plants operated at low capacity factors will not be economical due to the high cost of underutilizing capital-intensive CO_2 capture, transport, and storage infrastructure and technical challenges with handling large intermittent CO_2 fluxes [58].

3.2. Uncertainty quantification

This section will be subdivided in discussions on ammonia and methanol, followed by a section investigating renewable-rich or nuclear-friendly fuel-importing regions. The uncorrelated parameters that are varied in this uncertainty quantification exercise are listed in Tables A1–A4 in the Appendix, while the shared parameters investigated in the following section are kept constant at their central values (discount rate = 8 % and CO_2 price = 150 €/ton). It is noted that advanced solid fuel and natural gas processes are considered given the mid-century timeframe, but the conclusions will not change significantly if such processes fail to be commercialized (see Section 3 of the Supplementary Material).

3.2.1. Ammonia

Fig. 7 summarizes the uncertainty quantification results for ammonia production from all four technological routes. The most important observation from these results is that there are no cases where ammonia from renewables or nuclear would be the cheapest option. Costs only become comparable under the most pessimistic assumptions for solid fuels and natural gas and the most optimistic assumptions for renewables and nuclear. As mentioned in the introduction, even though projected renewable ammonia costs in exporting regions are comparable with average market prices (as observed in prior studies [9,33–35]), Fig. 7 clearly shows that this is not a useful competitiveness metric, since producers in fossil fuel exporting countries would be able to produce low-carbon, fossil-based ammonia far below the market price.

In practice, the likelihood of an overlap between the electrolytic and hydrocarbon histograms would be even more remote than suggested by Fig. 7. For example, if unexpectedly rapid cost reductions in renewables and/or nuclear enable more sectors to be electrified, the demand for fossil fuels will be significantly reduced, thus also lowering prices. For example, projected natural gas prices in the IEA World Energy Outlook [1] for mid-century Europe are 8.8 €/GJ in the Stated Policies Scenario, where demand stays constant, and 3.6 €/GJ in the Net Zero Emissions scenario, where vast renewable expansions contribute to a 70 % drop in natural gas demand. Thus, cases on the left of the renewable and nuclear histograms will correlate with cases toward the left of the natural gas histogram.

The main sources driving uncertainty in this assessment are ranked in Table 1. These will now be discussed in turn.

For **solid fuels (**Table A1**)**, the biomass weight fraction, varied over a range of 0–60 % for importers and 20–80 % for exporters, is the primary factor influencing the LCOA due to the large CO_2 credit assumed for the storage of biogenic CO_2. At a CO_2 credit of 150 €/ton, each GJ of biomass fuel produces CO_2 worth €15 when successfully captured and stored, which is 2.1–3.8 times more than the central biomass prices assumed (7 €/GJ for importers and 4 €/GJ for exporters). However, the cost of CO_2 capture, transport, and storage necessary to earn this large credit can consume most of this margin, especially if suitable CO_2 storage facilities are not locally available. Aside from the cost of CCS, exploiting the economic benefits of higher biomass fractions will depend on the availability of sustainably produced biomass and technological progress in gasification technology (only 30 % biomass fraction has been demonstrated to date [59]). It should be noted, however, that an efficiency penalty for higher biomass fractions has almost no effect when assuming a 150 €/ton CO_2 credit because the larger quantity of biogenic CO_2 captured per GJ of produced fuel cancels out the costs associated with reduced process efficiency. Further increases in the CO_2 credit begin favouring lower efficiency – a counter-productive incentive to be discussed in more detail in the sensitivity analysis section.

The IEA sees solid biomass production expanding to about half current coal supply by 2050 in terms of energy content [1]. Assuming global coal supply stays constant, a 43 % (by weight) biomass fraction would result in a 2:1 (by energy) coal/biomass ratio. Keeping all other parameters at their central values, this ratio would make solid fuels the preferred ammonia producing technology in the EU and slightly superior to natural gas in exporting regions. Such coal/biomass blending is a viable long-term strategy considering that the world has over 3 millennia of coal resources left [1] and the CO_2 storage capacity to match [60].

Gasifier bare erected costs (123–490 €/$kW_{fuel,in}$) is the next most important component for importers. Like nuclear plants, this cost component depends on the degree of standardization and efficiency in the value chain. For once-off plants using unstandardized gasifier designs, costs can be expected to be at the upper end of the range, whereas a standardized decades-long rollout will achieve costs on the lower end. Scope exists for such an efficient rollout because the 250 EJ/year of global coal and biomass resources available [1] puts the upper limit at ~8000 plants, each with 1 GW fuel input.

CO_2 transport and storage is the third-most important factor for importers (5–30 €/ton) and the second-most important for exporters (−10–30 €/ton) due to the larger uncertainty range that considers the potential for revenues from enhanced oil/gas recovery in Brazil. Solid fuel plants produce large quantities of CO_2, so the cost of handling this output has a considerable impact on the economics. Since the mass of ammonia produced is only about a third of the mass of CO_2 produced and ammonia can be distributed as a liquid under mild refrigeration or pressurization, most plants will probably be built close to CO_2 storage or utilization opportunities to minimize CO_2 handling costs.

Average fuel costs across the plant lifetime are the next most important factor. In general, coal costs (1–4 €/GJ) would be toward the lower end of the range if local resources close to the plant can be exploited and toward the upper end if imported resources are used. Biomass costs for importers (4–12 €/GJ) and exporters (2.5–8 €/GJ) may tend to cancel out some of the large effect of the biomass fraction discussed earlier. If a high CO_2 credit encourages overexploitation of biomass, the price will rise to moderate the benefit of replacing more coal with biomass.

Contingency (10–50 %) and capacity factor (70–95 %) also have a significant impact. Like the gasifier cost, this uncertainty will be most influenced by the efficiency of the technology rollout, where standardization will allow reliable (high capacity factor) plants to be built at a low cost (low contingency). Together with the gasifier cost uncertainty, these factors have an effect 56 % larger than the biomass fraction for importers, emphasizing the importance of an efficient technology rollout.

Other factors have a modest impact. The most important of these is membrane costs of the MAWGS reactor (2600–13,000 €/m^2) which remains uncertain since this technology is just starting commercial deployment. In importing regions, the ability to sell available 120 °C heat (selling price range of 0–40 €/MWh) also has a significant impact that could be considered when siting the plant.

Natural gas (Table A2**)** presents a simpler uncertainty picture. Here, the natural gas price for importers (4–10 €/GJ) and exporters (1.5–4 €/GJ) is the most important factor. It is important to note that this is the lifetime average price, and prices will temporarily exceed these bounds multiple times over the plant lifetime, especially for importers. The advanced plant configuration considered also consumes considerable amounts of electricity, making the electricity price an important factor in importing regions (40–120 €/MWh) but less important in exporting regions with cheap electricity (20–60 €/MWh).

CO_2 transport and storage costs (−30–15 €/ton) is the second-most important factor in exporting regions. Even though natural gas-based plants only produce about half the CO_2 per unit fuel output as solid fuel plants, effective utilization of the produced CO_2 can still bring significant economic benefits. Natural gas producers will often be in a good position to productively use the captured CO_2 for enhanced oil/gas recovery, thus lowering costs and extending the productive lifetime of local oil and gas fields. Ideally, all the extra hydrocarbons extracted via enhanced oil/gas recovery will be decarbonized via on-site ammonia production, thus maintaining a minimal climate impact.

Other factors have smaller influences, including the GSR reactor bare erected cost (65–260 €/$kW_{fuel,in}$) which remains subject to high uncertainty. The capacity factor and contingency assumptions also have a relatively small impact due to the relatively low capital cost typical of natural gas processing facilities.

Solar PV costs dominates the uncertainty picture for **renewable energy (**Table A3**)** plants in importing (220–500 €/kW) and exporting (165–375 €/kW) regions, since the optimized plants primarily use solar power, instead of wind, as primary energy input. It remains uncertain how successfully further technological learning will counteract inflationary trends from rising material and energy prices. In importing regions like Europe, other factors like public resistance and the need to reduce the current near-complete import dependence on China may also have a considerable inflationary impact. Although not considered in the present study, limited opportunities for cheaper green fuel production may arise in future electricity markets with very high wind/solar shares where a significant amount of curtailment is required. Utilizing otherwise curtailed electricity for green hydrogen production eliminates primary energy costs (i.e., the need for dedicated wind/solar capacity), but it also imposes very low utilization rates on electrolyzers and downstream storage/conversion equipment, cancelling out most of the expected benefit [61].

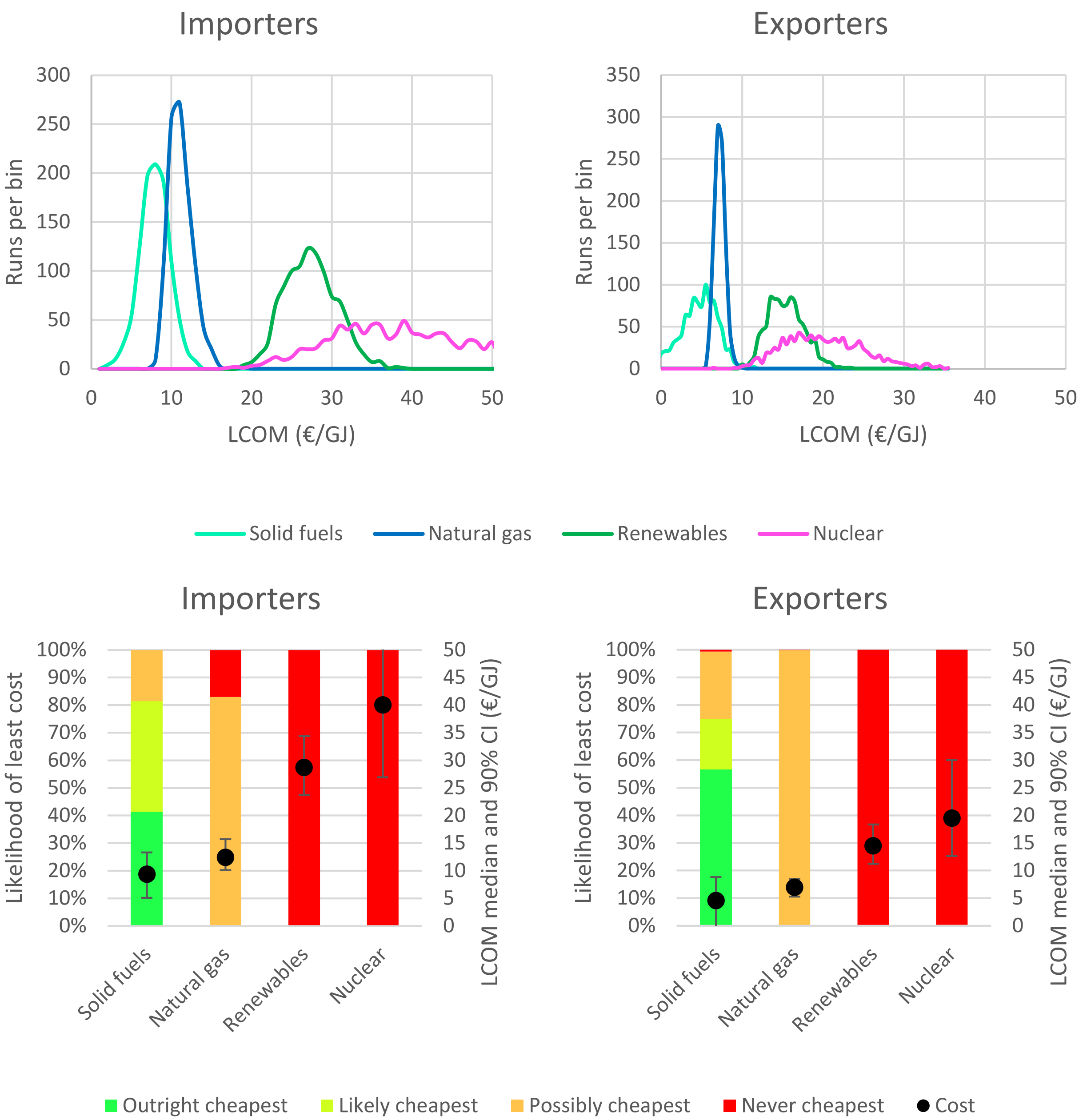

Fig. 8. Uncertainty quantification results on the levelized cost of methanol. Top: histograms of LCOM results obtained from 1000 runs for each technology (the bin size is set to 1 €/GJ for importers and 0.5 €/GJ for exporters). Bottom: Categorization of each technology according to the possibility of being the cheapest option (see Fig. 5). Only production-phase CO_2 emissions are considered (i.e., taxes levied on use-phase CO_2 emissions from methanol fuel are omitted).

Electrolyzer cost is the second-most important factor for importers (270–605 €/kW_{H2}) and the third-most for exporters (203–454 €/kW_{H2}), while hydrogen storage cost is the second-most important for exporters (1.5–22.5 €/kWh) and the fourth most for importers (2–30 €/kWh). These cost contributions are high because it is optimal to oversize electrolyzers to produce hydrogen from the fluctuating solar resource and use storage to buffer the resulting intermittent hydrogen fluxes before the ammonia synthesis loop. Access to salt cavern storage can reach the lower end of the hydrogen storage uncertainty range, but suitable formations for such storage are very unevenly distributed [62]. This imposes an important constraint because the large solar farm required for green ammonia plants (covering about 70 km^2 for the 1 GW plant simulated in this study) would need to be built close to the salt cavern to avoid large additional costs from the oversized pipeline infrastructure to transport intermittent hydrogen fluxes to distant storage sites.

Given the high capital costs of green ammonia plants, the contingency (5–25 %) and the capacity factor (90–100 %) also have significant impacts. Contingency is often ignored in green ammonia studies, but a minimal contingency is required to compensate for the obviously over-optimistic assumption of perfect equipment sizing for only one year of simulated wind/solar variability. In addition, the complexity of interconnected green ammonia plants with large quantities of on-site hydrogen buffer storage will likely impose significant additional costs beyond the sum of isolated installations of the solar farm, electrolyzers, storage vessels, N_2 production facility, and ammonia synthesis loop. 100 % plant availability is also a common over-optimistic assumption because the value chain contains several process plants and turbomachines that will impose some planned and unplanned downtime.

The deployment of wind turbines and batteries is limited, hence their costs have only a minor impact on ammonia production costs. The exporting region (Middle East) deploys only solar, meaning that wind

Table 2
Ranking of uncertain factors for methanol production via linear regression. The numbers represent the change in LCOM (€/GJ) when increasing each parameter across half its uncertainty range (see Tables A1–A4).

Solid fuels		Natural gas		Renewables		Nuclear	
Importers							
Biomass fraction	−3.82	Natural gas	3.84	Solar	5.95	Nuclear plant	27.36
Gasifier	1.90	GSR reactors	1.02	Contingency	3.28	Capacity factor	−3.75
Coal	1.74	Electricity	0.37	H_2 storage	2.97	Nuclear fuel	3.64
Biomass	1.47	Contingency	0.26	Electrolyzer	2.84	DAC	2.29
Contingency	1.12	Capacity factor	−0.26	DAC	2.72	Contingency	2.19
CO_2 T&S	1.07			Capacity factor	−2.33	Electrolyser	1.00
Capacity factor	−0.84			Wind	1.26		
Electricity	0.30			Heat storage	0.56		
HGCU	0.22			Battery	0.27		
				CO_2 storage	0.25		
Exporters							
Biomass fraction	−5.59	Natural gas	1.60	Solar	4.47	Nuclear plant	13.71
CO_2 T&S	1.72	GSR reactors	0.76	Electrolyzer	2.12	Nuclear fuel	3.67
Coal	1.58	Contingency	0.21	Contingency	2.10	Capacity factor	−2.10
Gasifier	1.53	Capacity factor	−0.20	DAC	1.94	DAC	1.72
Biomass	1.39	Electricity	0.18	H_2 storage	1.38	Contingency	1.19
Contingency	0.90			Capacity factor	−1.30	Electrolyser	0.77
Capacity factor	−0.67			Heat storage	0.40		
Electricity	0.22			Battery	0.39		
HGCU	0.19			Wind	0.02		
				CO_2 storage	0.01		

farm costs (720–1275 €/kW) have no impact.

For **nuclear (**Table A4**)**, the cost of the nuclear power plant in importing (2050–8200 €/kW) and exporting (1025–4100 €/kW) regions is by far the most important factor due to the wide ranges assumed for covering the complex techno-political uncertainties facing new nuclear projects. Accessing the lower end of the range will require a high degree of standardization and an effective rollout of publicly accepted nuclear technology (e.g., small modular reactors and other Gen IV designs). Even though nuclear fuel is quite cheap (0.1–2 €/GJ), it also has a significant effect due to all the conversion losses in the nuclear plant, the electrolyzer, and the ammonia synthesis loop. The small uncertainty ranges of capacity factor (80–95 %) and contingency (0–10 %) also has a significant influence due to the capital-intensive nature of this ammonia production pathway. Electrolyzer costs are much less important in this case than in the renewable plant because the steady electricity supply avoids the need for any equipment oversizing.

3.2.2. Methanol

Fig. 8 shows a broadly similar competitiveness picture for methanol compared to ammonia (Fig. 7). One significant difference is that solid fuels gain a clearer advantage over natural gas. The advanced GSR concept used for the natural gas plant offers only modest gains over the conventional benchmark, whereas the advanced solid fuel plant maintains a similar performance gain as for ammonia production (see Section 2 of the Supplementary Material). In addition, the greater scalability of methanol synthesis (~2300 MW of output relative to ~700 MW for ammonia) due to a simpler synthesis loop operating at lower pressures and temperatures, grants economies of scale that benefit the more capital-intensive solid fuel plant more than the natural gas plant.

Table 2 also shows similar trends to Table 1 discussed in detail in the previous section. The biomass fraction remains the most important factor in the **solid fuel (**Table A1**)** plants. CO_2 transport and storage costs only have about half the influence it had for ammonia (Table 1) because about half the carbon in the fuel ends up in methanol and does not need to be stored as CO_2. Fuel cost effects remain similar since ammonia and methanol conversion processes have similar efficiencies. The gasifier influence reduces due to economies of scale, whereas the contingency and capacity factor effects reduce even more because the methanol plant is simpler with a cheaper synthesis loop.

For **natural gas (**Table A2**)**, the largest difference relative to ammonia is that no CO_2 transport and storage is required. Electricity consumption in the methanol plant is also considerably lower, and lower capital costs minimize the effect of contingency and capacity factor.

For the **renewable (**Table A3**)** and **nuclear (**Table A4**)** plants, the biggest change is the addition of DAC and some temporary CO_2 storage to act as a buffer between production from DAC and consumption in the methanol synthesis loop. DAC costs (200–600 €/tpa for importers and 150–450 €/ton for exporters) introduce an uncertainty of a similar magnitude to the electrolyzer in the renewable plant. The DAC uncertainty is only slightly higher in the renewable plant than in the nuclear plant, indicating that the optimal solution is to operate the DAC plant at a relatively high capacity factor. This is also the reason why the renewable methanol plant deploys more wind than the renewable ammonia plant: Supplementing solar with wind achieves a steadier production profile to supply the electricity demand of DAC.

3.2.3. Renewables-rich or nuclear-friendly fuel importers

One scenario where ammonia and methanol produced via electrolytic routes will be more competitive is in fuel-importing regions with excellent solar resources (e.g., Morocco or Chile) or nuclear-friendly policies (e.g., South Korea). This scenario was simulated by comparing the costs for renewable and nuclear fuels from exporting regions to solid fuel and natural gas cases simulated with the assumptions for importing regions. However, capital costs were reduced by same 20 % (solid fuels) or 25 % (natural gas) applied to exporting regions because the countries where this set of circumstances apply would mostly be developing economies.

Fig. 9 shows how this modification resulted in a more competitive technology landscape. There is now a possibility that renewable or nuclear fuels can be the cheapest solution, although it remains unlikely. The solid fuel alternative extends its advantage over natural gas since its capital-intensive cost structure benefits more from the developing-world capital cost reduction assumed.

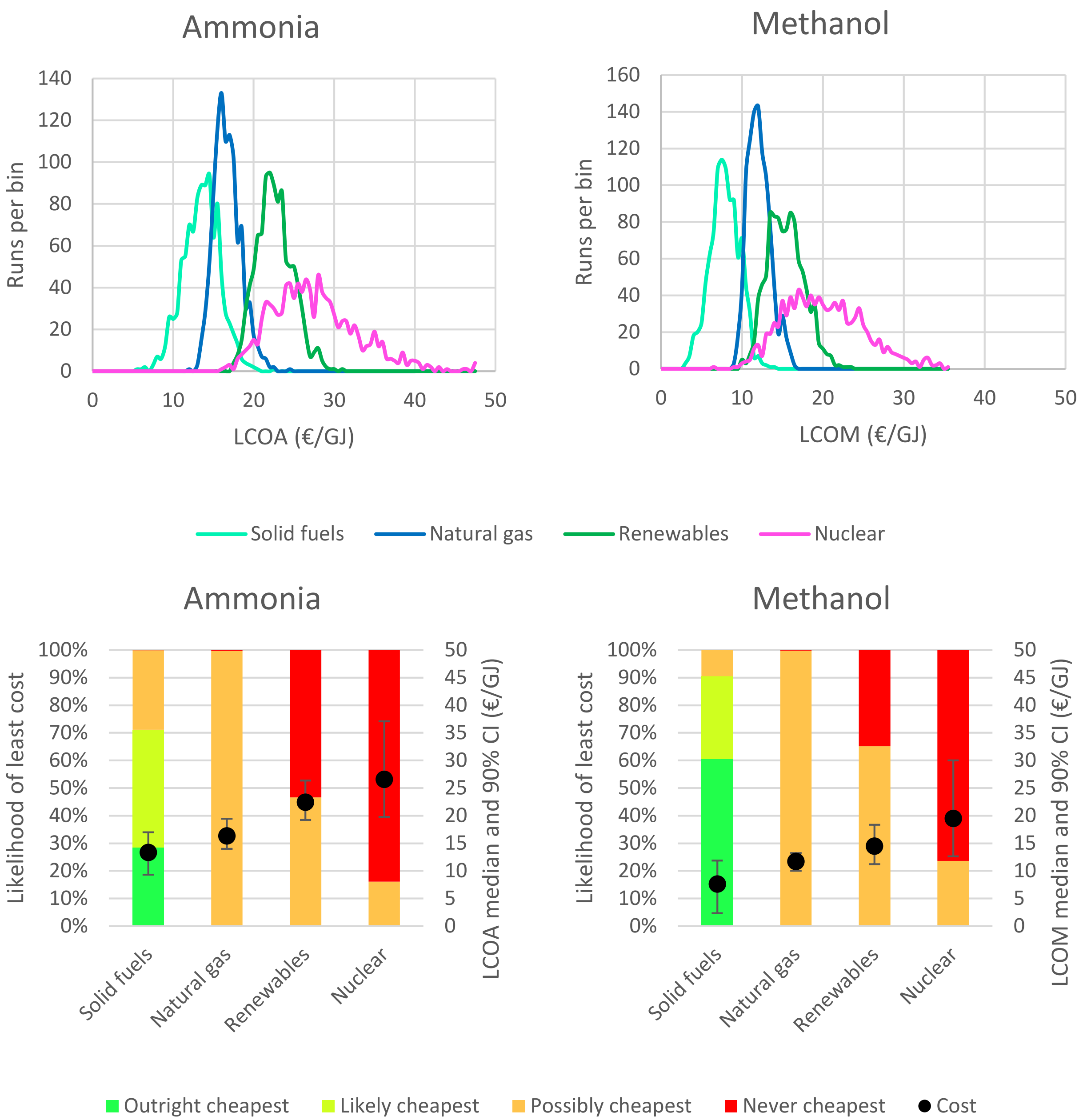

Fig. 9. Uncertainty quantification results on the levelized cost of ammonia and methanol in renewables-rich or nuclear-friendly fuel-importing regions. Top: histograms of LCOA and LCOM results obtained from 1000 runs for each technology (the bin size is set to 0.5 €/GJ). Bottom: Categorization of each technology according to the possibility of being the cheapest option (see Fig. 5). Only production-phase CO_2 emissions are considered (i.e., taxes levied on use-phase CO_2 emissions from methanol fuel are omitted).

3.3. Sensitivity analysis

This section isolates the sensitivity of the results to important uncertainties regarding discount rate and CO_2 price (the effect of plant lifetime can be viewed in Section 4 of the Supplementary Material). When considering methanol, the prospects of a hybrid electrolytic-solid fuel plant will also be investigated.

3.3.1. Ammonia

Fig. 10 illustrates the sensitivity of the different technologies to the discount rate and CO_2 price in importing and exporting regions. As expected, the discount rate affects plants with high capital costs most intensely, i.e., renewable and nuclear plants are the most sensitive, solid fuel plants show moderate sensitivity, and natural gas plants are the least sensitive. However, even at the lowest discount rate of 4 %, there is no overlap between the 90 % confidence bounds of the nuclear and renewable plants with those of the solid fuel and natural gas plants. As discussed in Section 4 of the Supplementary Material, such low discount rates are only applicable to a steady-state economy and energy system in the long-term future where capital investments are primarily concerned with replacing equipment reaching end-of-life. The rapid energy system transformation and growth required in the 21st century demands higher discount rates for economically efficient capital allocation.

CO_2 prices only have a significant influence on the solid fuel plant, which benefits from higher prices due to the credit received for negative emissions. If this credit reduces, the LCOA of the solid fuel plant rises

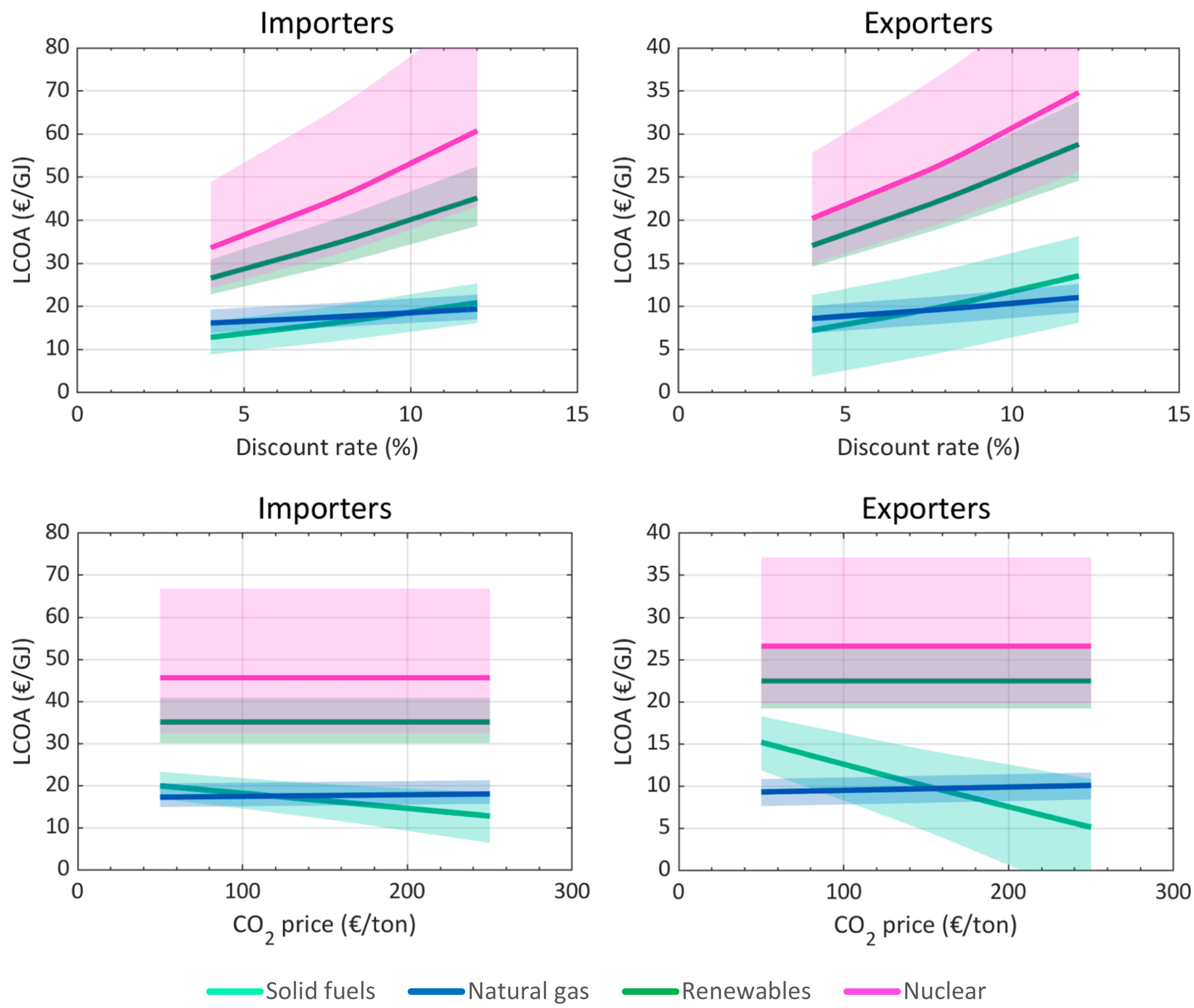

Fig. 10. Sensitivity of the levelized cost of ammonia to changes in the discount rate and CO_2 price. Lines indicate the median and transparent bands the 90% confidence interval.

above that of natural gas and the uncertainty range narrows because the most influential factor, the biomass fraction (see Table 1), loses its influence. For example, a CO_2 credit of 50 €/ton reduces the biomass fraction influence close to zero because the CO_2 credit shrinks to a level where it just cancels out the biomass price premium over coal.

However, the opposite is true at high CO_2 prices where the LCOA can even become negative when high biomass fractions are applied in exporting regions. Although the market conditions facilitating such extremely low costs (e.g., concurrent occurrence of high biomass fractions, low biomass prices, and high CO_2 prices) is highly unlikely, this result is an important warning of how biomass with CCS can become too attractive when CO_2 prices rise to very high levels. In fact, at a CO_2 credit beyond 150 €/ton, it may become economically preferable to use biomass as a type of direct air capture solution where a cheap and simple combustion process with CO_2 capture is used to turn biomass into CO_2 yielding a credit of more than 15 €/GJ of biomass input. Such a scenario can lead to large overexploitation of biomass resources without any added value through energy supply to the economy and should be avoided by careful policy design.

Given this important challenge, it is worth considering the market dynamics that may result from large biogenic CO_2 credits in more detail. If sequestering biogenic CO_2 becomes too lucrative compared to alternative pathways (e.g., the growing cost advantage of solid fuels at CO_2 prices above 150 €/ton in Fig. 10), plant operators will be willing to pay more for biomass fuel. These high prices, in turn, will incentivize increasingly unsustainable and environmentally destructive biomass production practices such as large-scale deforestation and the conversion of productive farmland into energy crops. For example, energy crops can be produced for 4 €/GJ on marginal land [63], presumably with lower costs achievable on high-quality agricultural land. If high CO_2 credits cause biomass prices to approach the upper bound assumed in this study (12 €/GJ), energy crops will become much more profitable than food crops, potentially creating serious issues regarding food security and biodiversity. Regulatory policies will be required to prevent such counterproductive outcomes. The simplest policy would be to limit the credit for sequestered biogenic CO_2 below the CO_2 tax such that biomass prices remain low enough to avoid environmentally destructive production. Alternatively, biomass production practices leading to large environmental damages or food insecurity must be subject to additional taxes or prohibited outright. Such regulations will prevent the market conditions in Fig. 10 where solid-fuel plants return much lower LCOA than the closest alternative (natural gas).

3.3.2. *Methanol*

Fig. 11 repeats the sensitivity analysis for methanol. Note that direct CO_2 emissions from methanol fuel combustion are included here as opposed to Figs. 6 and 8 where these downstream emissions are not considered. It must be included here to provide the full picture of how

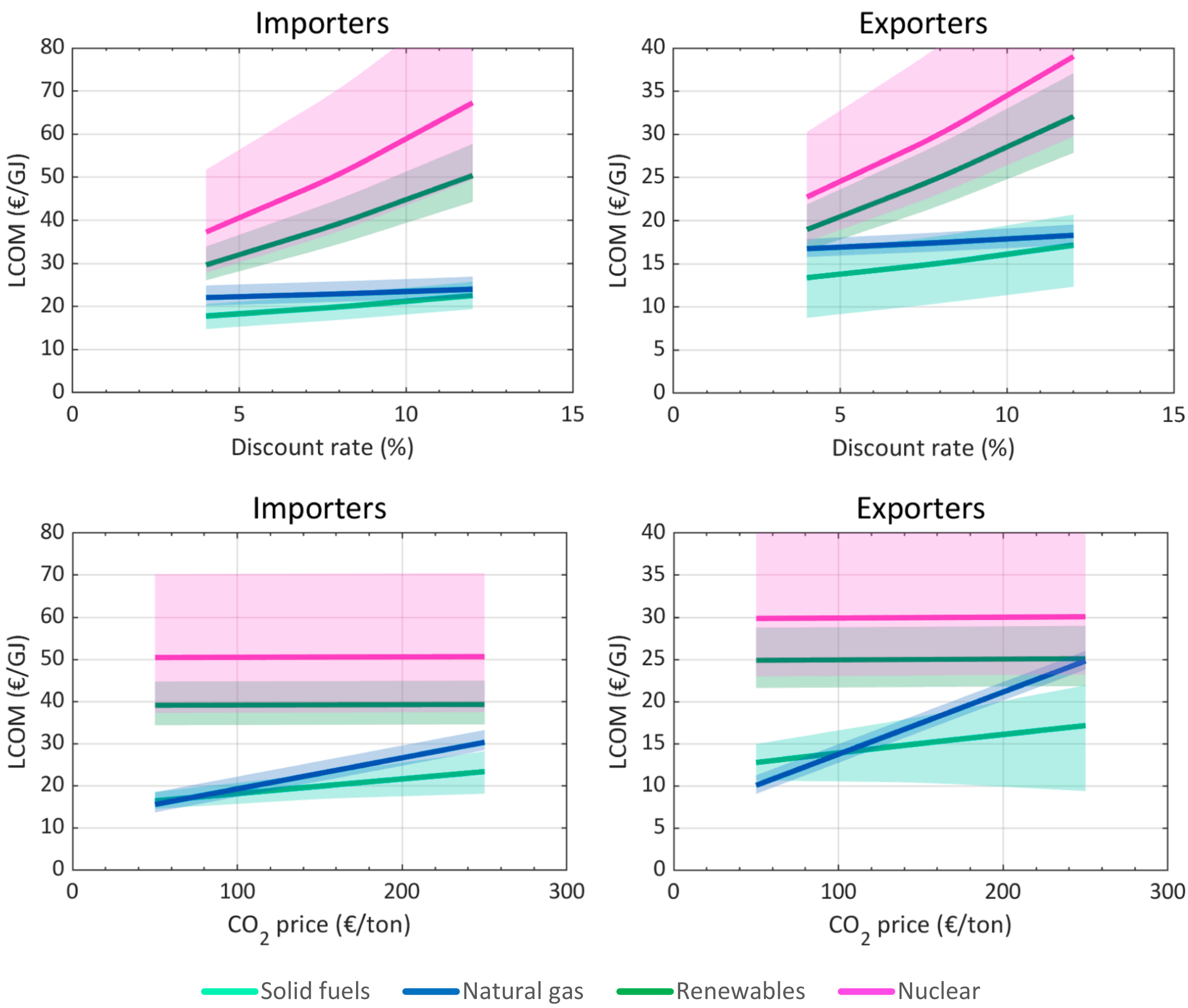

Fig. 11. Sensitivity of the levelized cost of methanol to changes in the discount rate and CO_2 price. Lines indicate the median and transparent bands the 90% confidence interval. LCOM values include direct CO_2 emissions assuming that the fuel is combusted in an end-use application.

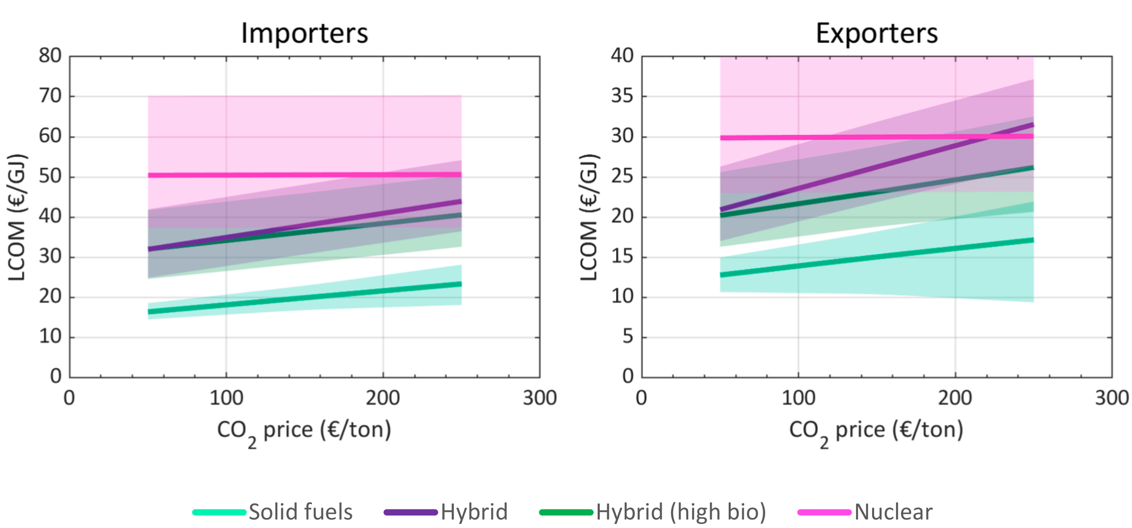

Fig. 12. Sensitivity of the levelized cost of nuclear-solid fuel hybrid plants to changes in the CO_2 price. Lines indicate the median and transparent bands the 90% confidence interval. LCOM values include direct CO_2 emissions assuming that the fuel is combusted in an end-use application.

methanol production pathways compare at different CO_2 prices, assuming that most methanol will be used in applications such as transportation and low capacity-factor power production where CCS is not viable.

Trends are similar to those observed for ammonia, although some overlap of the renewable plant with the natural gas plant can be observed in exporting regions at the lowest discount rate and the highest CO_2 price assumed. The improved competitiveness is made possible by the DAC systems (with free heat supply from electrolyzer waste heat) capturing CO_2 from the atmosphere for well below the 150 €/ton CO_2 price, allowing renewable and nuclear plants to slightly close the gap on solid fuel and natural gas plants that do not employ DAC.

The shrinking gap between methanol from natural gas and methanol from renewables or nuclear at elevated CO_2 prices is clearly visible in in Fig. 11. Since the figure includes use-phase emissions, renewable and nuclear plants are essentially CO_2 neutral (the same amount CO_2 captured by DAC is released to the atmosphere when the methanol fuel is combusted), whereas methanol from natural gas must pay a CO_2 tax on the fossil-based CO_2 released in the use phase. The solid fuel plants are less affected because the biomass fraction reduces overall emissions both through the negative emissions from sequestering CO_2 from biogenic origin and by reducing the amount of fossil-derived CO_2 released from the methanol in end-use applications. Due to these two effects, methanol from solid fuels becomes CO_2-neutral (insensitive to the CO_2 price) when the biomass weight fraction is 54 %, at which point the fossil-derived CO_2 emitted in the use phase is exactly cancelled by the biogenic CO_2 stored in the production phase. As a result, methanol from solid fuels gains a large advantage over the other process routes at high CO_2 prices, requiring careful regulation to prevent biomass over-exploitation as described at the end of the previous section.

An important observation can be made regarding the higher CO_2 price levels assumed in Fig. 11. If DAC technology achieves the cost reductions assumed in the present study, it will place a cap on global CO_2 prices because 150 €/ton would suffice to incentivize rapid large-scale deployment of DAC, which does not face the scaling constraints of biomass. For example, levelized energy-exclusive DAC costs under the central assumptions amount to 58 €/ton. In addition, DAC requires around 5 MJ/kg of low-grade heat and 0.8 MJ/kg of electricity. At a low-grade heat cost of 20 €/MWh, an electricity cost of 60 €/MWh, and an additional CO_2 compression and storage cost of 20 €/ton, the total amounts to 119 €/ton. Thus, under the assumptions employed in the present study, CO_2 prices beyond 150 €/ton can at best be a temporary phenomenon when DAC technology is rapidly scaling up, after which CO_2 prices will settle below 150 €/ton at a level ensuring profitable operation of the DAC fleet. Such an upper bound on CO_2 prices created by standalone DAC technology will also help to prevent the over-exploitation of biomass resources discussed earlier.

3.3.3. Hybrid methanol plants

Another interesting aspect of methanol production is the opportunity to construct a hybrid plant combining electrolytic hydrogen with carbon-rich syngas from solid fuel gasification. The addition of electrolytic hydrogen corrects the H:C ratio to 4:1 as required for methanol synthesis and the oxygen by-product from the electrolyzer can be employed as oxidizing agent in the gasifier, avoiding the need for an air separation unit [25]. Most importantly, such a hybrid plant does not require CO_2 supply from DAC like a pure electrolytic methanol plant or transport and storage/utilization of excess CO_2 like a pure solid fuel methanol plant.

Some studies on renewable fuels assume a substantial credit on the O_2 by-product from electrolysis to improve economics [36,37,41,44,46]. For the large-scale plants considered in the present study, however, such a strategy will only be viable if very large quantities of O_2 can be productively utilized on-site. O_2 production via large-scale air separation technology is cheap (30–40 €/ton [64]) and can be deployed anywhere, so the need to export produced O_2 will quickly erode any economic benefit. Renewable plants will also incur a substantial additional cost to buffer intermittent O_2 fluxes from the electrolyzers. These considerations limit the viable options for O_2 consumption to large co-located oxycombustion, autothermal reforming, or gasification plants. Oxy-combustion for power production in regions where electricity is so cheap that it can be converted into fuels will not be economical. Similarly, there is no business case for using the O_2 in a co-located reforming or gasification process with CO_2 capture because the fuels from such a process employing an ASU for O_2 supply will be substantially cheaper (Figs. 7 and 8). Thus, a hybrid methanol plant integration [25] with the important benefit of avoiding any need for DAC or CO_2 handling is the only viable alternative for productively utilizing the O_2 by-product in large-scale electrolytic fuel plants.

Fig. 12 illustrates the LCOM resulting from such a hybrid methanol plant in response to changes in the CO_2 price. The nuclear plant is chosen to power the electrolyzer, but conclusions will be similar when renewable power is used. Two hybrid options are considered: (1) a standard plant where the biomass fraction is kept at the same levels as in the pure solid fuel plant and (2) a plant where the biomass fraction is increased to result in the same overall rate of biomass consumption, meaning that the energy content of electrolytic hydrogen only displaces coal.

As expected, the hybrid configuration ends up between the pure electrolytic and the pure solid fuel options. When the CO_2 price is low, it is closer to the pure solid fuel option, but higher CO_2 prices make it approach or even exceed the cost of the pure electrolytic option. Since part of the carbon in the methanol from the hybrid plant originates from coal and there is no biogenic CO_2 storage to partially offset these emissions, a higher CO_2 price will always increase the LCOM. However, this effect is attenuated by the high-bio case where the share of fossil carbon in the methanol is lower.

As outlined in the previous section, the technological progress in DAC assumed in this study will cap CO_2 prices in the range of 100–150 €/ton, where the hybrid plants fall almost exactly between the costs of the pure electrolytic and pure solid fuel plants. Although there is significant overlap between the 90 % confidence bounds of the hybrid and pure nuclear plants in this CO_2 price range, it is noted that much of this overlap is artificial because the nuclear-related uncertainties will be highly correlated.

Thus, even though the pure solid fuel plant will always be significantly cheaper, the hybrid option could be an interesting solution in regions that do not have CO_2 storage/utilization possibilities. Such a configuration could be especially interesting if the regions are, in addition, renewable-rich or nuclear-friendly and dependent on fuel imports, as discussed in Section 3.2.3.

4. Conclusions

This study presented a thorough techno-economic uncertainty quantification exercise comparing four different pathways for mid-century low-carbon ammonia and methanol production. Results show there are almost no plausible scenarios where renewable or nuclear fuels will be competitive against alternatives from solid fuels or natural gas. One notable exception is in renewable-rich or nuclear-friendly fuel-importing regions, where electrolytic fuels have a low likelihood of competitiveness.

Although ammonia and methanol are more expensive to produce from solid fuels than from natural gas, a policy framework granting a CO_2 credit for sequestered biogenic CO_2 could give solid fuels the advantage. At likely future CO_2 prices (150 €/ton was the central assumption in the present study), the use of biomass with CO_2 capture becomes highly attractive because sequestered biogenic CO_2 can be worth more than double the cost of the biomass fuel. However, regulatory policy will be required to prevent large biogenic CO_2 credits from elevating biomass prices to levels incentivizing unsustainable and environmentally destructive production practices. Advances in direct air capture (DAC) technology can help avoid biomass overexploitation by imposing a long-term CO_2 price ceiling. For example, the central DAC cost assumptions employed for CO_2 supply to methanol production from renewables and nuclear would return a levelized CO_2 removal cost around 120 €/ton. Next to the CO_2 credit, capital cost uncertainties have the largest influence on the cost of ammonia and methanol from solid fuels, emphasizing the importance of an efficient and standardized capacity rollout.

If negative emissions are rewarded with a CO_2 credit, solid fuels offer an attractive pathway to cost-effective and carbon-negative energy security. When the limited available flow of sustainable biomass is augmented with coal (which also provides practical gasification benefits), the potential fuel production rate strongly increases. Since the world has around three millennia of remaining coal resources and the CO_2 storage capacity to match, this is a viable long-term solution for removing about 8 Gton of CO_2 per year (a quarter of current energy-related CO_2 emissions).

Natural gas-based ammonia or methanol production is most compelling in natural gas exporting regions. Ammonia production for carbon-free fuel exports becomes particularly attractive when the captured CO_2 can profitably be used for enhanced oil/gas recovery from local reservoirs. Ideally, all extracted hydrocarbons would be converted to ammonia on-site and the resulting CO_2 returned to the reservoirs at a profit for deep decarbonization of oil & gas operations.

In regions with no access to CO_2 storage/utilization opportunities, hybrid methanol plants blending electrolytic hydrogen with carbon-rich syngas from solid fuels to achieve the correct H:C ratio offer an interesting solution. Such hybrid configurations significantly outperform pure electrolytic routes while eliminating the uncertainties related to CO_2 supply via direct air capture.

Methanol is generally cheaper to produce than ammonia, but a CO_2 tax of 100 €/ton on CO_2 emissions from methanol combustion makes ammonia the cheaper option in most scenarios. Even so, the liquid state of methanol at room temperature and pressure will likely secure its role in certain niches like fuelling private vehicles where practicality and operational safety are highly valued.

On average, ammonia and methanol production in exporting regions with cheap primary energy costs 44 % less than in Europe. However, the international market price for such easily tradable fuels will be well above the production cost of the most cost-effective exporters and can be volatile. Thus, local production of at least part of the European fuel supply can still be recommended. Solid fuels are the best candidate for this role due to energy security benefits and the potential for negative emissions.

These findings question the efficacy of the ongoing policy drive toward renewable electrolytic fuels. Aside from being substantially more expensive than alternatives from solid fuels or natural gas in almost all scenarios, electrolytic fuels would consume scarce low-carbon electricity that could be more productively employed in other sectors. Hence, a technology-neutral approach to low-carbon fuel production, e.g., a CO_2 tax and elimination of all technology-specific incentives, is recommended. Energy importers may also consider a technology-neutral energy security policy such as a tax on all imported energy to incentivise local fuel production.

CRediT authorship contribution statement

Schalk Cloete: Conceptualization, Methodology, Formal analysis, Investigation, Writing – original draft, Visualization. **Carlos Arnaiz del Pozo:** Formal analysis, Investigation, Writing – original draft, Visualization. **Jan Hendrik Cloete:** Formal analysis, Writing – original draft, Writing – review & editing. **Ángel Jiménez Álvaro:** Writing – review & editing, Visualization, Funding acquisition.

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.

Data availability

Data for the economic assessments and energy system optimization modelling performed in this study are available online (https://bit.ly/FuelUQ).

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Appendix A. Uncertainty ranges

The following tables describe the ranges for all the parameters included in the uncertainty quantification study. For Tables A1–A4, trials were described by a skewed normal distribution where 99 % of the cases fall between the low and high values with the median at the mid value.

Nuclear-solid fuel hybrid plants combine elements from Tables A1 and A4.

Table A5 lists three important parameters that will have highly correlated effects on the different plants. Hence, these parameters are investigated separately to avoid introducing correlated variance into the uncertainty quantification study that leads to spurious overlaps between uncertainty ranges. Outside of the sensitivity analyses dedicated to these parameters, they are kept at their mid points.

Table A1
Cost ranges assumed for solid fuel plants. The EU and Brazil are the importing and exporting regions.

Cost item	Values assumed	Justification
Coal	Low: 1 €/GJ_{LHV} Mid: 2 €/GJ_{LHV} High: 4 €/GJ_{LHV}	Half price if local coal industry is fully developed IEA [1] Announced Pledges Scenario price for EU in 2050 Double price if local industry coal industry is phased out causing dependence on imports from a tight global market
Biomass in the EU	Low: 4 €/GJ_{LHV} Mid: 7 €/GJ_{LHV} High: 12 €/GJ_{LHV}	Middle of the European supply curve [65] + 2 €/GJ for transport and pre-processing 95th percentile of the European supply curve [65] + 3 €/GJ for transport and pre-processing High prices caused by demand exceeding sustainable local supply or long transportation distances
Biomass in Brazil	Low: 2.5 €/GJ_{LHV} Mid: 4 €/GJ_{LHV} High: 8 €/GJ_{LHV}	Strategic deployment at available resources and advancements to minimize pre-processing costs Plants in regions with large biomass potential [66] + 2 €/GJ for transport and pre-processing High prices caused by demand exceeding sustainable supply
Biomass fraction in the EU	Low: 0 % Mid: 30 % High: 60 %	Standard coal gasification Demonstrated biomass blending mass fraction [59] Double biomass fraction due to future advances
Biomass fraction in Brazil	Low: 20 % Mid: 40 % High: 80 %	Severe limitations on local biomass availability A mild 10 %-point advancement beyond proven fractions [59] Strong technological advances to maximize negative-emission value from Brazilian biomass resources
Baseload electricity price in the EU	Low: 40 €/MWh Mid: 80 €/MWh High: 120 €/MWh	Future breakthroughs (e.g., Gen IV nuclear) Perfectly optimized renewables-rich electricity system [67] Suboptimal rollout of a renewables-rich electricity system
Baseload electricity price in Brazil	Low: 30 €/MWh Mid: 60 €/MWh High: 90 €/MWh	25 % lower prices than the EU due to the large hydropower potential in Brazil
District heat price in the EU	Low: 0 €/MWh Mid: 10 €/MWh High: 40 €/MWh	No district heating integration possible A quarter of plants sell heat at 40 €/MWh All plants sell heat at 40 €/MWh
District heat price in Brazil	Low: 0 €/MWh Mid: 5 €/MWh High: 10 €/MWh	No district heating integration possible An eighth of plants sell heat at 40 €/MWh A quarter of plants sell heat at 40 €/MWh
CO_2 T&S cost in the EU	Low: 5 €/ton Mid: 15 €/ton High: 30 €/ton	Plants located at storage site with costs from IEAGHG [68] Storage with 1000 km of onshore pipeline [68,69] Double cost from complexities such as public resistance
CO_2 T&S cost in Brazil	Low: −10 €/ton Mid: 10 €/ton High: 30 €/ton	Significant EOR revenues [70] from local oil industry Storage with 500 km of onshore pipeline [68,69] Triple cost from complexities such as public resistance and long transportation distances
GE gasifier cost	Low: 169 €/$kW_{fuel,in}$ Mid: 246 €/$kW_{fuel,in}$ High: 369 €/$kW_{fuel,in}$	33 % cost reduction from achieving full standardization and economies of scale in a large rollout Bare erected cost from NETL [71] 50 % cost increase due to a stunted and inefficient rollout
E-gas gasifier cost	Low: 123 €/$kW_{fuel,in}$ Mid: 245 €/$kW_{fuel,in}$ High: 490 €/$kW_{fuel,in}$	Halving costs when achieving full technology potential plus standardization and economies of scale in a large rollout Bare erected cost from NETL [71] Doubling costs due to suboptimal technology performance and an inefficient unstandardized rollout
HGCU and oxyfuel cost	Low: 66 €/$kW_{fuel,in}$ Mid: 99 €/$kW_{fuel,in}$ High: 149 €/$kW_{fuel,in}$	33 % cost reduction from achieving full standardization and economies of scale in a large rollout Detailed cost assessment using Turton [53] including a 30 % contingency for HGCU and a 10 % contingency for oxyfuel combustion 50 % cost increase due to a stunted and inefficient rollout

(continued on next page)

Table A1 (*continued*)

Cost item	Values assumed	Justification
H_2-perm selective membrane cost	Low: 2000 €/m^2 Mid: 5000 €/m^2 High: 10,000 €/m^2	High value recovery when replacing membranes DOE target for membrane cost [72] assuming no cost recovery upon replacement. An additional 30 % process contingency is added to the membrane reactor (reactor body and membranes) due to its novelty. Poor technological improvement and/or large increase in Pd prices due to competition from other technologies
Project contingency	Low: 10 % Mid: 30 % High: 50 %	20 %-points lower contingency for smooth construction of highly standardized plants Relatively high project contingency due to the complexity of solid fuel chemical plants 20 %-points higher contingency for suboptimal execution due to lack of standardization and demand
Availability	Low: 70 % Mid: 85 % High: 95 %	Substantial operational challenges force regular shutdowns in plants that lack optimization and standardization Typical capacity factor assumed for gasification facilities High reliability achieved through standardization and process optimization
Capital costs in Brazil		The capital cost assessment is completed for the EU and a 20 % lower cost is assumed due to lower labour and material costs in South America [73]

Table A2
Cost ranges assumed for natural gas plants. The EU and the Middle East are the importing and exporting regions.

Cost item	Values assumed	Justification
Natural gas in EU	Low: 4 €/GJ$_{LHV}$ Mid: 6 €/GJ$_{LHV}$ High: 10 €/GJ$_{LHV}$	Lower price if global market remains oversupplied IEA [1] Announced Pledges Scenario price for EU in 2050 Higher price if global market remains undersupplied
Natural gas in the Middle East	Low: 1.5 €/GJ$_{LHV}$ Mid: 2.5 €/GJ$_{LHV}$ High: 4 €/GJ$_{LHV}$	Lower costs from technological enhancements and synergy with CO_2 enhanced gas recovery Centre of the supply curve from Welsby et al. [74] 90th percentile of supply curve from Welsby et al. [74]
Baseload electricity price in EU	Low: 40 €/MWh Mid: 80 €/MWh High: 120 €/MWh	Future breakthroughs (e.g., Gen IV nuclear) Perfectly optimized renewables-rich electricity system [67] Suboptimal rollout of a renewables-rich electricity system
Baseload electricity price in the Middle East	Low: 20 €/MWh Mid: 40 €/MWh High: 60 €/MWh	Half the cost assumed in the EU due to access to low-cost natural gas and excellent solar resources
CO_2 T&S cost in the EU	Low: 5 €/ton Mid: 15 €/ton High: 30 €/ton	Plant located at storage site with costs from IEAGHG [68] Storage with 1000 km of onshore pipeline [68,69] Double cost from complexities such as public resistance
CO_2 T&S cost in the Middle East	Low: −30 €/ton Mid: 0 €/ton High: 15 €/ton	Deep EOR [70] integration with local oil & gas industry EOR revenues sufficient to cancel out transport costs Geological storage with 1000 km of onshore pipeline [68,69]
GSR island cost	Low: 65 €/kW$_{fuel,in}$ Mid: 130 €/kW$_{fuel,in}$ High: 260 €/kW$_{fuel,in}$	Halving costs by achieving full standardization and economies of scale in a large rollout Detailed bare erected cost assessment using Turton [53] + 20 % contingency Doubling costs due to a stunted and inefficient rollout
Project contingency	Low: 10 % Mid: 20 % High: 30 %	10 %-points lower contingency for smooth construction of highly standardized plants Typical project contingency assumed for chemical plants 10 %-points higher contingency for suboptimal execution due to lack of standardization and demand
Availability	Low: 80 % Mid: 90 % High: 95 %	Operational challenges force more regular shutdowns in plants that lack optimization and standardization Typical capacity factor assumed for reforming facilities High reliability achieved through standardization and process optimization
Capital costs in the Middle East		The capital cost assessment is completed for the EU and a 25 % lower cost is assumed due to lower labour and material costs in the Middle East [73]

Table A3
Cost ranges assumed for renewable plants. The EU and the Middle East are the importing and exporting regions.

Cost item	Values assumed	Justification
Wind in the EU	Low: 960 €/kW	Rapid technology development and no scaling problems
	Mid: 1280 €/kW	IEA [1] Announced Pledges Scenario price for EU in 2050
	High: 1700 €/kW	Problems with public resistance and high material costs
Solar in the EU	Low: 220 €/kW	Rapid technology development and no scaling problems
	Mid: 330 €/kW	IEA [1] Announced Pledges Scenario price for EU in 2050
	High: 500 €/kW	Problems with high material, energy, and labour costs, supply chain diversification, and public resistance
Wind and solar in the Middle East		25 % lower cost than the EU due to lower labour costs and less public resistance (e.g., IEA [1] Announced Pledges Scenario prices for China in 2050)
Electrolysis in the EU	Low: 270 €/kW$_{H2}$	Rapid technology development and no scaling problems
	Mid: 405 €/kW$_{H2}$	15 % below the bottom-up installed PEM electrolyzer cost (including engineering and owner's costs) assuming full economies of scale and low material use [25]
	High: 605 €/kW$_{H2}$	Slower technological progress and problems with high material costs and supply chain diversification
Electrolysis in the Middle East		25 % lower cost than the EU due to lower labour and material costs (IEA [1] Announced Pledges Scenario prices for 2050 fall between EU and Middle East assumptions)
Direct air capture in the EU	Low: 200 €/tpa	Learning curve projection to 2050 [75]
	Mid: 400 €/tpa	Double the low case, which is just 50 % above the capital cost of CO_2 capture from a natural gas power plant [76] with 100x higher CO_2 concentrations in the gas stream
	High: 600 €/tpa	Limited progress due to slow upscaling
Direct air capture in the Middle East		25 % reduction from EU costs due to lower labour and material costs in the Middle East [73]
Battery storage in the EU	Low: 67 €/kWh	Rapid technology development and no scaling problems
	Mid: 100 €/kWh	80 % of IEA [1] Announced Pledges Scenario in 2050 with the same cost applied to power rating in €/kW
	High: 150 €/kWh	Problems with high material costs and supply chain diversification
Hydrogen storage in the EU	Low: 2 €/kWh	Plant co-located with salt cavern storage [77]
	Mid: 15 €/kWh	Underground pipe storage [78]
	High: 30 €/kWh	Pessimistic upper bound due to cost uncertainty
Temporary CO_2 storage in the EU	Low: 3 €/kg Mid: 23 €/kg High: 46 €/kg	Assuming CO_2 has the same storage costs as hydrogen per unit volume
Heat storage in the EU	Low: 11 €/kWh	Optimistic lower bound due to cost uncertainty
	Mid: 22 €/kWh	Latent heat thermal energy storage from Beck et al. [79]
	High: 44 €/kWh	Pessimistic upper bound due to cost uncertainty
Storage costs in the Middle East		25 % reduction from EU costs due to lower labour and material costs in the Middle East [73]
Project contingency	Low: 5 %	Smooth execution with only a small contingency for over-optimistic model assumptions (perfect optimization and only one year of wind/solar variability)
	Mid: 15 %	10 %-points additional contingency from challenges in constructing tailored value chains transforming site-specific mixes of intermittent renewables into a steady fuel supply
	High: 25 %	10 %-points higher contingency for suboptimal execution
Availability	Low: 90 %	Occasional unplanned shutdowns in elements such as electrolyzers and synthesis loops
	Mid: 95 %	High reliability from the relative simplicity of the chemical processing units in green plants
	High: 100 %	Perfect reliability

Table A4
Cost ranges assumed for nuclear plants. The EU and Russia are the importing and exporting regions.

Cost item	Values assumed	Justification
Nuclear in the EU	Low: 2050 €/kW	Public acceptance of Gen IV nuclear technology allows for an optimized and standardized large-scale rollout
	Mid: 4100 €/kW	IEA [1] Announced Pledges Scenario price for EU in 2050
	High: 8200 €/kW	Continued problems with public resistance and lack of standardization
Nuclear in Russia	Low: 1025 €/kW Mid: 2050 €/kW High: 4100 €/kW	Half the costs of the EU due to a less stringent policy environment and lower labour costs (e.g., current Russian or Korean nuclear plant costs [80])
Nuclear fuel	Low: 0.1 €/GJ	Fast breeder technology renders fuel costs negligible
	Mid: 1 €/GJ	Standard nuclear fuel costs [80]
	High: 2 €/GJ	High demand causes fuel prices and disposal costs to double
Electrolysis in the EU	Low: 270 €/kW$_{H2}$	Rapid technology development and no scaling problems
	Mid: 405 €/kW$_{H2}$	15 % below the bottom-up installed PEM electrolyzer cost (including engineering and owner's costs) assuming full economies of scale and low material use [25]
	High: 605 €/kW$_{H2}$	Slower technological progress and problems with high material costs and supply chain diversification
Electrolysis in Russia		25 % lower cost than the EU due to lower labour and material costs (IEA [1] Announced Pledges Scenario prices for 2050 fall between EU and Middle East assumptions)
Direct air capture in the EU	Low: 200 €/tpa	Learning curve projection to 2050 [75]
	Mid: 400 €/tpa	Double the low case, which is just 50 % above the capital cost of CO_2 capture from a natural gas power plant [76] with 100x higher CO_2 concentrations in the gas stream
	High: 600 €/tpa	Limited progress due to slow upscaling
Direct air capture in Russia	Low: 150 €/tpa Mid: 300 €/tpa High: 450 €/tpa	25 % reduction from EU costs due to lower labour and material costs in Eastern Europe [73]
Project contingency	Low: 0 %	Perfect execution in connecting the value chain
	Mid: 5 %	Low contingency due to the simplicity of this steady-state value chain (nuclear contingency is included in the wide range of nuclear plant costs investigated)
	High: 10 %	5 %-points higher contingency for suboptimal execution
Availability	Low: 80 %	Operational challenges force more regular shutdowns in plants that lack optimization and standardization
	Mid: 90 %	Typical capacity factor for nuclear plants
	High: 95 %	High reliability achieved from standardization and process optimization

Table A5
Shared parameter assumptions.

Cost item	Values assumed	Justification
CO_2 price	Low: 50 €/ton	Lower end of range [1]
	Mid: 150 €/ton	Middle of the range given in the IEA [1] Announced Pledges Scenario for the EU
	High: 250 €/ton	Upper end of range [1]
Discount rate	Low: 4 %	Long-term future scenario where the rate of change in the energy system and the associated technology risk are low
	Mid: 8 %	Standard discount rate for chemical plants
	High: 12 %	A relevant near-term scenario with high capital demand and risk associated with a rapid expansion of relatively new technologies
Lifetime	Low: 15 years	Technical challenges or adverse market conditions demand early decommissioning
	Mid: 30 years	Conventional economic lifetime for energy technologies (at an 8 % discount rate, longer lifetimes have little effect)
	High: 60 years	Judicious long-term planning ensures the attractiveness of lifetime extensions and repowering

Appendix B. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enconman.2023.117701.

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