Electronic Supplementary Material (ESI) for Energy & Environmental Science.

Supplementary Information 2 – The HyPE model

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The HyPE (Hydrogen Pathway Exploration) model is a dynamic optimisation model focusing on global clean hydrogen supply and transport. It provides cost-optimal production and trade routes for clean hydrogen, considering all potential production sites and possible transport options. HyPE represents in a detailed manner the value chain for clean hydrogen and its derivatives, from production until the point of final consumption (**Figure SI2.1**).

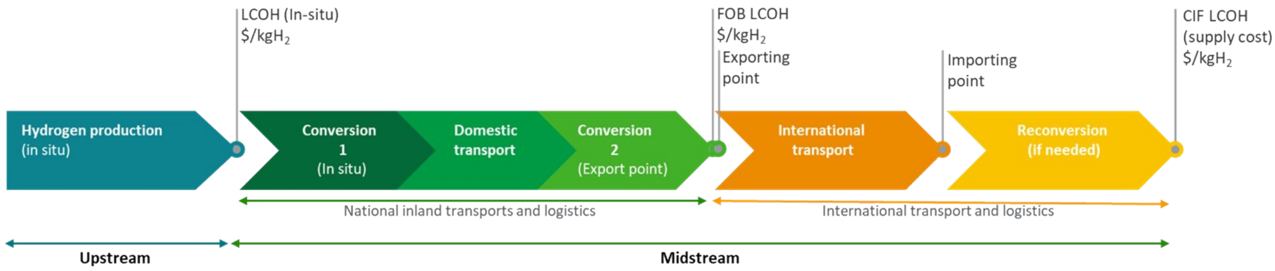

Figure SI2.1. Hydrogen trade value chain in the HyPE model. LCOH is the acronym for the levelized cost of hydrogen production, FOB (freight on board) represents the levelised cost of hydrogen at the export point, including the transport and conversion costs in the exporting region, and CIF (cost, insurance and freight) represents the landed cost of hydrogen in the importing region adding the cost of international transport and reconversion (if needed) on the FOB.

The modelling uses linear programming to choose the cost-minimum way to satisfy global hydrogen demand (represented in different demand clusters) considering different production options (e.g., green hydrogen from renewables, blue hydrogen from natural gas), transport modalities (e.g., trailers, pipelines and bunkers) and physical medium (e.g., gaseous or liquefied hydrogen, ammonia) and end-use commodities (pure hydrogen, ammonia, methanol and synthetic kerosene). The resulting cost structure, therefore, includes hydrogen supply cost, transport cost and conversion and reconversion costs depending on the transport option and end-use molecule. The optimisation is performed in a global and technology-neutral way, minimising the overall cost of the hydrogen supply and delivery from 2025 up to 2060.

Hydrogen production

Green Hydrogen

In HyPE, green hydrogen can be produced either via electrolysis of variable renewable energy sources (wind and solar power) or from processes based on biomass (biomass reformation, bio-pyrolysis) which can in some cases allow negative emissions. From a system-level optimisation perspective, green hydrogen from biomass can be produced to offset the residual emissions linked to some processes such as blue hydrogen production in a carbon-neutrality context. Without this offset opportunity, green hydrogen production from biomass (providing negative emissions) cannot result from the optimisation as it is significantly more expensive than other clean hydrogen supply options. This study focuses on global clean hydrogen value chain without constraints on emission offsetting.

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Therefore, the focus is mainly on green hydrogen production via electrolysis excluding biomass-based hydrogen production from the scope of the paper.

The production of green hydrogen from wind and solar power depends on local factors such as wind speed and solar irradiation as well as the availability of suitable land and water access. The methodology developed for HyPE for the estimation of feasible solar and wind resources for the production of green hydrogen is based on Ruiz et al.[1] and Levene et al.[2].

HyPE calculates the available wind and solar potential for green hydrogen production via mapping the world with an adjustable grid from 1° to 2.5° cells that are projected on the selected countries around the globe, for a total of up to 38,000 cells. For each cell both an annual wind speed hourly time series and an annual solar irradiation hourly time series from the Copernicus - ERA5 dataset[d] were used to calculate the solar and wind capacity factors at the centroid location of that cell. For each cell, an optimisation module determines the solar PV, onshore or offshore wind capacities to install for each MW of electrolyzers to minimize the LCOH given the hourly profiles of load factors with a reference weather year (2016) Using these timeseries, hourly wind and solar capacity factors are linked to annual potential hydrogen production. For onshore wind turbines, a hub height of 130 meters and the Vestas V150 4000 turbine's power curve were[e] considered to obtain the hourly wind capacity factors at every cell. Fixed ground-mounted PV systems with optimised tilt angles (as a function of the cell latitude) were considered to represent solar power plants in the model.

Green hydrogen supply potential was calculated using the maximum available land on each cell for wind and solar installations. This available land includes total surface of the cell excluding the land covered with water bodies, forests, natural parks, cities, and the land that is currently in use (or planned to be) for any economic activity, such as industry, or agriculture. These renewable potentials were used to determine the potential of green hydrogen supply at each cell (**Figure SI2.2**) Following the ENSPRESO database assumptions[1] only 5% and 1.5% of the remaining unused land are considered for the potential deployment of wind turbines and solar panels. The capacity that can be installed over a given surface can be calculated using power density of solar and wind power technologies. This report considers 85 MW/km^2 of power density for solar power and 10MW/km^2 for onshore wind power[3].

Water availability and competition with other uses is a major topic in particular in regions with resource scarcity as in some parts of Middle East, North Africa, Sub-Saharan Africa, Australia and Chile. Concerning the current study, Middle East and North Africa are the key clean hydrogen exporters to Europe. To internalise this issue, we follow a similar approach as that commented by IRENA in its global hydrogen trade outlook[4]. We assume that for acceptability reasons all water consumption of electrolysers comes from seawater desalination. Accordingly, only sites within 300 km from the sea are considered and the associated costs of water supply are included in the LCOH calculations.

Water desalination is already supplying about 95 million m^3/day of water and producing 142 million m^3/day of brine[5]. Curto et al.[6] discuss the state of play of desalination technologies and affirms the next frontier for key commercial technologies such as reverse osmosis (RO), multi-stages flash desalination (MSF) and multi-effect distillation (MED), is to be powered by renewable sources. We

[d] https://cds.climate.copernicus.eu/cdsapp#!/dataset/reanalysis-era5-single-levels?tab=overview
[e] https://www.thewindpower.net/turbine_en_1490_vestas_v150-4000-4200.php

base our water cost calculations on the technoeconomic figures reported by them for the different technologies considered in the model.

We estimate water cost by adopting an amortisation logic to desalination plants which includes capital and operational expenditures over its economic lifetime. We assume that the electricity used by desalination units comes from the power grid of the countries considered. Hence, our operational costs include costs of the electricity used, and the expenditures for offsetting the associated emissions of grid electricity. With the data of the electricity mix in each of the countries we estimate average electricity prices. The carbon intensity of the electricity supply leads to a carbon footprint of the desalinated water. We apply a carbon tax in line with the EU ETS, reaching €250/tCO_2 by 2050 penalising the associated emissions, and more importantly, to implement a level-playing field between countries with different electricity mixes (this is currently being discussed in the design of carbon border adjustment mechanisms). These values are compared to the water production cost estimated by the World Bank[7] and calibrated based on these values.

Renewable energy sources cannot be installed at any rate and annual growth in the renewable installed capacities is constrained via technology- and country-specific deployment rates. These deployment rates are set to mimic industrial and regulatory rigidities preventing the industry to be developed overnight. We assume a deployment rate of 10% (in compound annual growth rate) for both of the wind and solar power capacities and electrolyser installations.

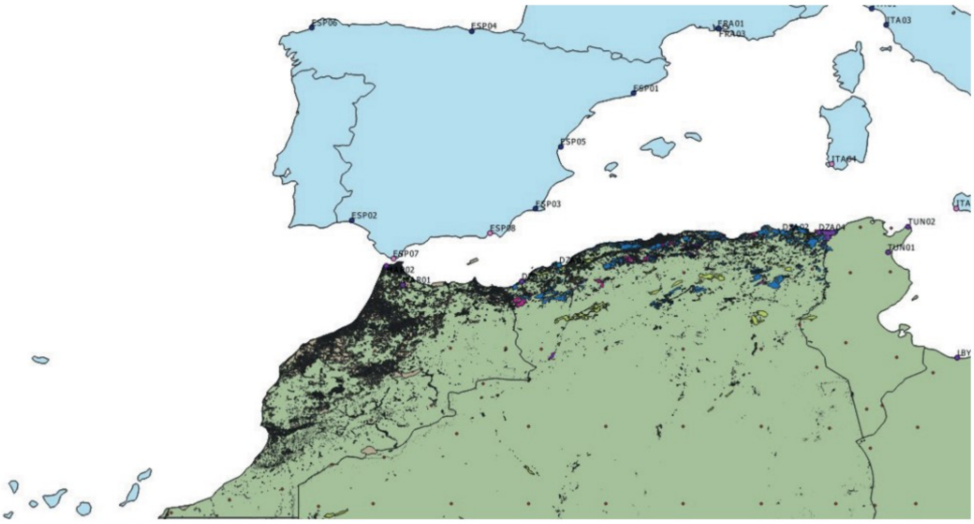

Figure SI2.2. Illustrative example on the determination of the maximum available space for the installation of renewable energies using land-use data. Black, blue, red and green dots represent the surface that cannot be used for wind and power installations.

HyPE computes the levelised cost of hydrogen (LCOH) for every cell of the globe and over the modelled timespan, respecting the aforementioned land-use constraints. This calculation uses economic characteristics such as equipment costs (**Table SI2.1** and **Table SI2.2**) and local factors (e.g., financing costs, natural resources, wage level). This methodology enables to compute the global map of LCOH with a high resolution as seen in the equation 1, below.

$$\begin{cases} CAPEX_{tech,\,y}: & Initial\ investments\ for\ a\ given\ production\ technology\ t \\ OPEX_{tech,\,y}: & Maintenance\ and\ operational\ costs\ for\ a\ given\ tech\ an \\ WACC_{tech,\,y,\ country}: & Weighted\ Average\ Cost\ of\ Capital\ in\ the\ country\ and\ y \\ E_{tech,\,cell}: & Annual\ energy\ output\ per\ tech\ on\ a\ prodcution\ cell\ in\ k \\ CF_{h,\,tech,\ cell}: & Capacity\ Factor -\ Energy\ produced\ out\ of\ one\ kW\ of \\ & in\ kWh,\ per\ hour\ h,\ tech\ on\ a\ production\ cell \\ \eta_{electrolysis}: & Consumption\ of\ electricity\ of\ the\ electrolyser\ in\ kg/kV \\ lt_{tech}: & Lifetime\ of\ the\ production\ technology\ tech\ considered \end{cases}$$

$$LCOH_{tech,y,\,country} = \frac{CAPEX_{tech,y} + \sum_{t=1}^{lt_{tech}} \frac{OPEX_{tech,\,y}}{(1+WACC_{tech,\ y,\,country})^t}}{\sum_{t=1}^{lt_{tech}} \frac{E_{tech,\,cell}}{(1+WACC_{tech,\ y,\,country})^t}} \qquad \text{(Equation 1.a)}$$

$$E_{tech,\,cell} = \sum_{h=1}^{8760} CF_{h,\ tech,\,cell} \times \frac{1}{\eta_{electrolysis}} \qquad \text{(Equation 1.b)}$$

Figure SI2.3 shows the global distribution of green hydrogen LCOH based on the calculations of Equations 1.a and 1.b.

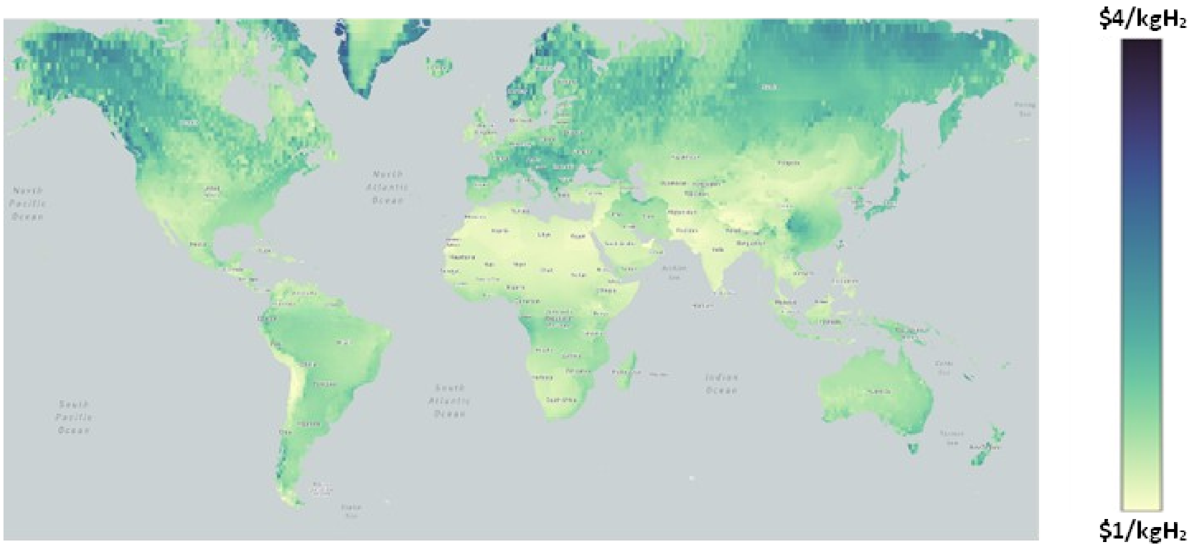

Figure SI2.3. Global map of green hydrogen LCOH in 2050. A very significant amount of clean hydrogen can be produced for very low LCOH values thanks to ample availability of wind and solar power over the globe. This figure shows that 2,400 MtH_2 of green hydrogen can be produced for $1.5/$kgH_2$ by 2050.

Table SI2.1. Hydrogen production technologies' cost data. Variable costs include water for electrolysers and natural gas cost for reformers. The values are based on IEA[8], Seck et al.[9] and Schmidt[10].

Technology	**Efficiency (%)**	**Lifetime (years)**	**Overnight cost ($/kW$_{out}$)**	**Fixed O&M costs ($/kW$_{out}$)**	**Variable O&M costs ($/kg$H_{2out}$)[f]**

[f] For natural gas-based hydrogen production technologies (SMR, SMR with CCS, ATR with CCS, GHR with CCS and pyrolysis) the values varies by the local natural gas price and methane abatement progress.

	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
SMR	75.8	75.8	25	25	934	934	44	44	0.8 - 1.47	1.68 - 2.11
SMR + CCS	72.2	72.2	20	20	1397	1314	42	39	0.47 - 1.18	0.67 - 1.22
GHR + CCS	83.3	83.3	20	20	870	870	27	27	0.48 - 1.13	0.46 - 0.85
ATR + CCS	73.5	73.5	15	20	812	812	24	24	0.50 - 1.20	0.48 - 0.92
Pyrolysis	57.1	57.1	20	20	2312	2312	104	104	0.2 - 1.09	0.14 - 0.71
Alkaline electrolysis	69	75	20	20	447	295	7	4	0.61	0.61
PEM electrolysis	64.5	80	7	9	585	440	17	13	0.61	0.61

Table SI2.2. Renewable power production technologies' cost data. The values are based on IEA[11-13], Tröndle[3] and Seck et al[9].

Technology	Energy density (MW/km2)		Lifetime (years)		Overnight cost ($/kW$_{out}$)[g]		Fixed O&M costs ($/kW$_{out}$)	
	2030	2050	2030	2050	2030	2050	2030	2050
Solar PV	85	85	25	25	662 - 480	455 - 280	12	9
Onshore wind	10	10	22	22	1120	1040	38	36

Blue hydrogen

The domestic consumption trajectories of natural gas-producing countries and their commercial balance for natural gas have been assessed following the IEA's net-zero pathway in its latest World Energy Outlook[11]. All producing countries with a positive export balance and the main producing countries with negative balance (notably China, United Kingdom and United Arab Emirates) were considered. Given that natural gas infrastructure is well developed in these countries, production facilities are assumed to be installed near the location of the current exit points for natural gas trade (pipeline and/or terminal) to avoid additional inland transport costs. The figures of natural gas production, commercial balance of natural gas and reserves available for each considered country have been extracted from the latest BP's Statistical Review of World Energy[12] (BP, 2022). The evolution of these figures has been adjusted to be in line with IEA's net-zero pathway[13], considering no new investments in exploration activities.

This paper fixes environmental standards for blue hydrogen to become available for global trade. This reasoning follows the definition of sustainable or low-carbon hydrogen that has appeared recently in the policymakers' agendas such as the European Union (EU Taxonomy[h]), United Kingdom (Low Carbon Hydrogen Standard[i]), and United States (Clean Hydrogen Production Standard[j]) for the creation of sustainability standards for clean hydrogen. To date, the most stringent of these sustainability

[g] For PV production, the overnight cost varies regionally to account for differences in labour and land costs
[h] https://ec.europa.eu/sustainable-finance-taxonomy/
[i] https://www.gov.uk/government/consultations/designing-a-uk-low-carbon-hydrogen-standard
[j] https://www.energy.gov/eere/fuelcells/articles/clean-hydrogen-production-standard

definitions is the United Kingdom's "Low Carbon Hydrogen Standard" that requires blue hydrogen to have lower than 2.4 $kgCO_{2eq}/kgH_2$ of GHG footprint in 2025, covering direct emissions (i.e., uncaptured residual CO_2 emissions from CCS technologies) and methane emissions associated with natural gas supply. To identify the blue hydrogen that can be traded over the outlook period, this most stringent standard of 2.4$kgCO_{2eq}/kgH_2$ in 2025 is extrapolated to reach to zero in the second half of this century, as reaching to net-zero means also a full scope 3 emission reduction not only in the downstream but also in the upstream (**Figure SI2.4**). Blue hydrogen can never reach complete carbon neutrality as it is impossible to abate all the upstream natural gas emissions and to capture all of the residual CO_2 emissions from reformers with CCS. This implies an eventual phase-out of blue hydrogen by 2070. Therefore, blue hydrogen supply should peak no later than 2040, as the new investments in the reformation plants should be avoided from this date on to avoid stranded assets (assuming a plant lifetime of 30 years for reformers with CCS).

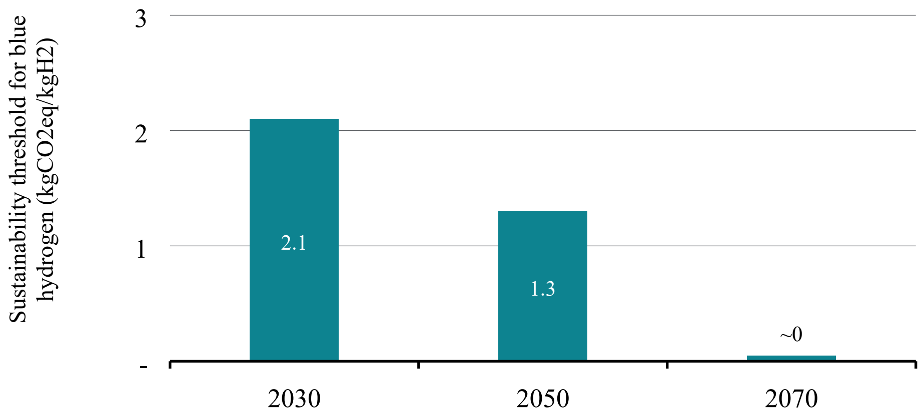

Figure SI2.4. Sustainability threshold definition that natural gas-based low-carbon hydrogen production should respect to be considered low-carbon, and therefore, eligible for the global trade. Among 23 considered potential blue hydrogen exporters (countries with domestic natural gas production), only 10 can export their blue hydrogen production in the short run, 13 can export by 2040. By the adoption of best available technologies on methane abatement starting from 2040, all of the considered countries can provide low-carbon blue hydrogen for exports by 2050, nevertheless, none can reach to zero GHG footprint by 2070, leading to a full phase-out of blue hydrogen in the second half of the century.

Two set of natural gas-based low-carbon hydrogen supply technologies are assessed:

- Reformers with CCS: steam methane reforming (SMR), autothermal reforming (ATR) and gas-heated reforming (ATR/GHR CCS), all coupled with carbon capture and storage (CCS). A calculation of the average cost of CO_2 transport and storage[k] follows the assumption that depleted oil and gas fields and rock formations were available within a reasonable distance around the production sites[14].
- Methane pyrolysis (carbon black by-product revenues included): methane pyrolysis is assumed to be commercially available from 2030 onwards.

The corresponding technico-economic assumptions for these technologies can be found in Table 1. The cost of natural gas supply for low-carbon hydrogen production was assumed to follow regional natural gas prices of IEA's net-zero scenario[11], which was reassessed by calculation of wellhead natural

[k] it was assumed that CO_2 storage volumes at those sites are at least 10 $MtCO_2$ injected per year which would lead to transport and storage cost of around $12.5/tonne (after considering economies of scale) based on the H21 North of England report[13].

gas levelised supply cost for each region. The wellhead natural gas prices were verified by benchmarking them against typical average wellhead cost of basins of similar type for each region (i.e., onshore, deep, shallow, ultra-deep). Our estimated prices are strongly converging with IEA's regional natural gas prices, as this study follows IEA's logic of no new investments in oil and gas exploration and production in a net-zero world. Calculated natural gas prices include no tax, nevertheless, the compensation for unabated CO_2 emissions (for reformers with CCS), as well as upstream methane emissions were accounted for by assuming IEA's net-zero carbon price values for each considered region[11].

Capture rate of CCS units are assumed to be 90% in the beginning of the outlook period, increasing linearly to 95% by 2050 which is considered to be the maximal carbon capture rate[15]. For each country, the climate footprint of blue hydrogen supply can be calculated via summing its residual uncaptured CO_2 emissions and its upstream methane emissions (emissions associated with oil and gas exploration and production, gas gathering and boosting and gas processing) from natural gas production until blue hydrogen production. These values are gathered from the country-specific scientific publications[18,19], emissions reported to United Nations Framework Convention on Climate Change[l] and IEA methane tracker explorer[m]. Then these upstream methane emission values are converted to CO_2-equivalent (CO_{2eq}) terms considering a global warming potential[n] (GWP) of 20 years (GWP_{20} of methane is equal to 82.5 CO_{2eq}[20])[o]. We assume adoption of best available technologies in methane abatement starting from 2040 and maturing by 2050 following the abatement potential of different technologies in IEA methane tracker emission reduction potentials (the values are the same as in the Hydrogen for Europe project's 2022 edition[p], with a best available technology (BAT) adaption date of 2040 rather than 2030).

Commodities

This study considers the supply of pure hydrogen and its main derivatives as commodities which can satisfy the demand for clean hydrogen: ammonia (NH_3), methanol (CH_3OH) and synthetic kerosene-based jet fuels (referred to as e-kerosene following $C_{12}H_{26}$ formula). The CO_2 used for the production of methanol and e-kerosene are assumed to come from direct air capture of CO_2 (DAC). DAC is a highly energy-intensive process that requires between 6.57 GJ (1.83 MWh) and 8.81 GJ (2.45 MWh) of energy (mostly with high temperature)[22] for capturing 1 tonne of CO_2. In our analysis, we only considered the economic cost of DAC, including the cost of the required energy consumption that has been included in the price of captured CO_2 via DAC. The price of CO_2 capture is assumed to evolve from \$168/tCO_2 to \$126/tCO_2 between 2020 and 2045, remaining the same for 2050[22]. The transport cost is assumed to be constant over the whole analysis period (\$45/tCO_2)[23].

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[l] https://unfccc.int/topics/mitigation/resources/registry-and-data/ghg-data-from-unfccc

[m] https://www.iea.org/data-and-statistics/data-tools/methane-tracker-data-explorer

[n] Global Warming Potential (GWP) is one of the most widely used climate metrics to assess the relative potency of different GHG emissions (such as CH_4), in comparison to the reference gas: CO_2. GWP can be estimated over a chosen time frame, 20 (GWP_{20}) and 100 (GWP_{100}) years being the most common time frames. Both metrics have evolved to be the 'default' metrics in the policy arena. Most scientific literature, assessing the impacts of greenhouse gases on climate change assess longer time effects, using GWP_{100}. However, IPCC in its last assessment report[20] highlights that the metric highly depends on the considered context and the period during which the CO_2 emissions should be stabilised in the atmosphere.

[o] According to Abernethy et al.[21], in case of choosing GWP as the metric, the considered reference GWP period should include the period between the assessment year (2023) and the methane concentration stabilisation year (2045), that is closest to GWP_{20}.

[p] https://www.hydrogen4eu.com/

The corresponding conversion costs from hydrogen and the specific transport costs for each commodity are calculated and follow a linear optimisation logic. The constraints on the production capacities are shared for the different commodities, leading to an optimal choice of the commodity produced on each cell, in order to minimise the total cost of hydrogen and its derivatives' supply and delivery cost.

Hydrogen transport

Depending on the distance between production and delivery points, several transportation paths are currently envisaged and integrated into the modelling framework in accordance with the overall technology-neutral approach.

National transport

For national inland transports, multiple options have been considered: hydrogen trucks (either with compressed hydrogen or ammonia trucks) and when available in the country, domestic hydrogen-repurposed gas pipelines. For the green hydrogen supply, off-site production of hydrogen via the electric grid (mainly for regions with advanced power grid such as Europe) has also been considered. For hydrogen derivatives (ammonia, methanol and SAF), the conversion was considered only at the consumption location for domestic use, and at the export site for export purposes.

International transport

The main hydrogen transport options across countries are pipelines and maritime routes via tankers (transporting hydrogen or one of its derivatives). Assuming that continuously phasing out of natural gas is mandatory to reach climate-neutrality targets by 2050, we consider that natural gas pipelines could be partially repurposed for hydrogen transport by 2040, or sooner if it is explicitly mentioned by a regional roadmap[q]. Some of these pipelines are expected to be unidirectional while others could allow bidirectional hydrogen flows for an optimal trade allocation. For calculating the LCOH component of hydrogen transmission by pipeline, assumptions on the interconnectors, its route, length, and capacity have been collected on the global gas infrastructure tracker[r] by Global Energy Monitor (**Table SI2.3**). Repurposed pipelines are assumed to enable the same energy exchange capacity of the natural gas pipeline before repurposing. Hydrogen injection to the pipelines is located according to the gas network topology and existing compression stations, where only a single injection and withdrawal point per country is considered.

Table SI2.3. Considered retrofitted pipelines. Following European REPowerEU plan in response to Russian invasion of Ukraine, potential commodity trades between Russia and the OECD countries have been excluded from the trade options in this study

Exporting country	Importing country	Repurposing year	Max volume (MtH_2/year)	Length (km)
USA	CAN	2040	15.1	3848
USA	MEX	2040	5.57	302
IRN	TUR	2040	3.71	2577
NOR	BEL	2040	14.2	1150
TUN	ITA	2030	6.17	155
DZA	ITA	2030	6.17	1075

[q] Such as European Hydrogen Backbone project which assumes the availability of European hydrogen transmission pipeline availability by 2030, and partial repurposing of natural gas pipelines connecting North Africa to Europe from 2040 onwards[24].

[r] https://globalenergymonitor.org/projects/global-gas-infrastructure-tracker/

DZA	ESP	2040	3.10	757
DZA	ESP	2040	3.10	210
DZA	ESP	2040	4.80	1082
MAR	ESP	2040	4.80	45
TUR	GRE	2040	3.07	110
RUS	CHN	2040	13.1	1067
UZB	CHN	2040	6.12	1645
KAZ	CHN	2040	7.65	1115
TKM	CHN	2040	37.3	1833

The most convenient option to transport hydrogen across the globe is shipping. The opportunity to develop the appropriate terminals for maritime trade has been enabled for every country geographically eligible (landlocked countries can still access the ports of their neighbouring countries). Therefore, the HyPE model includes 95 seaborne terminals and more than 1,500 trade routes between them. The corresponding maritime distances have been calculated considering tankers can navigate through Suez Canal, but not through Panama Canal as currently big LNG tankers are not able to bypass the latter.

Pure hydrogen can be transported as liquefied hydrogen, Liquid Organic Hydrogen Carriers, or converted into ammonia before reconversion at the import terminal. This latter option is the least expensive over long distances. Hydrogen derivatives can also be converted before being exported via shipping for reduced transport costs. The cost assumptions for the transport of hydrogen and its derivatives are presented in **Table SI2.4** and **Table SI2.5**.

Table SI2.4. Grid, pipeline and truck transport costs for hydrogen and its derivative molecules transport. Grid transport considers transport of renewable electricity to the electrolysers where applicable, which costs less than hydrogen transport via other options. Nevertheless, such a transport option is considered only for the regions with advanced power grid (notably Europe).

Transport option	Production	Conversion[s] (If any)	Transport[t]	Reconversion (If any)		Unit
Electricity transport via the grid for hydrogen production in consumption point	From all renewable energy sources available in the cell		Grid (2030) Cost = 0.45 D (2050) Cost = 0.39 D D: Distance		Injection point (Consumption cluster or exporting terminal)	$/kgH_2/1000km$
Pipeline			Hydrogen pipelines Cost = 0.13 D + 0.01 D: Distance			
	From all sources		Gasified trucks			

[s] Conversion and reconversion costs account for the investment costs of the conversion reactors and electricity consumption for the processes. Electricity prices are modelled and calculated separately for each country and vary between \$15/MWh and \$150/MWh in 2030 and \$20/MWh and \$175/MWh in 2050 depending on the considered country.

[t] Transport costs account for the investments and operation and maintenance costs of the electric transmission lines and associated power electronics for the transport via power grid, for investments in vehicles, compression, and fuel costs for transport via trucks and for the refurbishment and compression costs for transport via refurbished natural gas pipelines. Methanol and synthetic aviation fuels can be transported in the same tankers as ammonia. Therefore, fixed and variable transports costs of these hydrogen derivatives can be derived from the extrapolation of transports costs of ammonia via a stochiometric analysis based on their mass and volumetric energy densities.

		(2030) Cost = 3.02 D + 0.29 (2050) Cost = 2.92 D + 0.27 D: Distance				
Hydrogen transport via liquid ammonia trucks		Ammonia Synthesis (2030) 0.44 (2050) 0.35	(2030) Cost = 0.66 D + 0.05 (2050) Cost= 0.51 D + 0.03 D: Distance			
Liquid ammonia trucks				Ammonia calalytic cracking (2030) 0.27 (2050) 0.22		
Methanol trucks		Methanol Synthesis (2030) 1.60 (2050) 1.36	Liquid methanol trucks (2030) Cost = 0.51 D + 0.03 (2050) Cost= 0.39 D + 0.02 D: Distance			
Synthetic aviation fuel trucks		SAF Synthesis (2030) 1.50 (2050) 1.26	Liquid SAF trucks (2030) Cost = 0.16 D + 0.01 (2050) Cost= 0.13 D + 0.01 D: Distance			

Table SI2.5. Shipping costs for hydrogen and its derivative molecules.

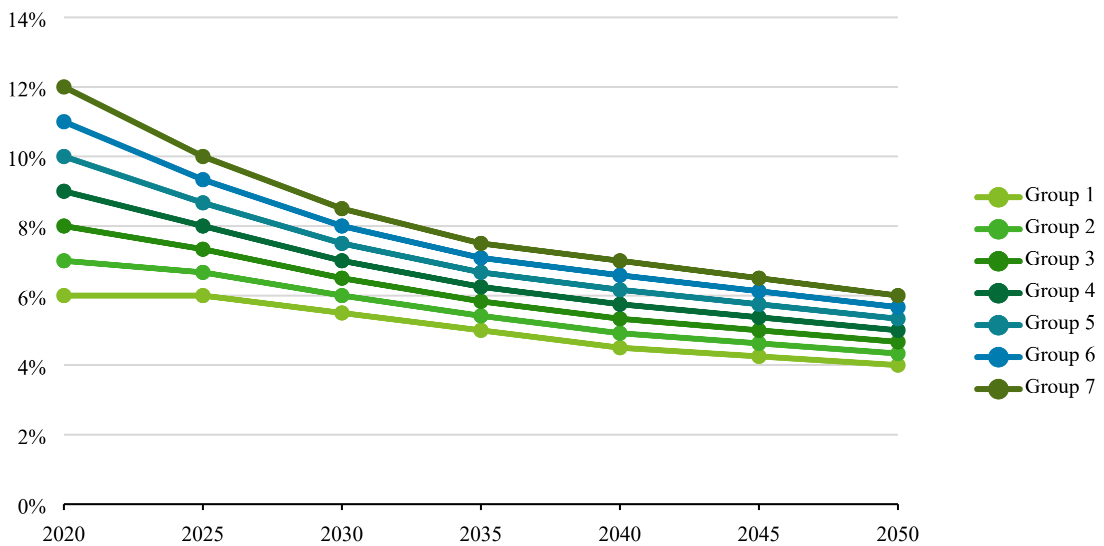
Transport option	Commodity at the exporter port		Conversion[u] (If any)	Transport[v]	Reconversion (If any)		Commodity at the importer port	Unit
Hydrogen shipping via liquified hydrogen	Hydrogen	New dedicated exporting terminals including storage		Liquified hydrogen shipping (2030) Cost = 0.09 D + 0.88 (2050) Cost= 0.08 D + 0.68 D: Distance		Importer ports – Refurbished dedicated importing terminals	Hydrogen	$\$/kgH_2/1000km$
Hydrogen shipping via ammonia	Hydrogen		Ammonia synthesis (2030) 0.44 (2050) 0.35	Liquified ammonia shipping (2030) Cost = 0.02 D + 0.09 (2050) Cost= 0.01 D + 0.07 D: Distance	Ammonia catalytic cracking (2030) 0.27 (2050) 0.22		Hydrogen	
Ammonia shipping	Hydrogen		Ammonia synthesis (2030) 0.44 (2050) 0.35	Liquified ammonia shipping (2030) Cost = 0.02 D + 0.09 (2050) Cost= 0.01 D + 0.07 D: Distance			Ammonia	
	Ammonia							
Methanol shipping	Hydrogen		Methanol synthesis (2030) 1.60 (2050) 1.36	Liquified Methanol shipping (2030) Cost = 0.01 D + 0.08 (2050) Cost= 0.01 D + 0.06 D: Distance			Methanol	
	Methanol							
Synthetic Aviation	Hydrogen		SAF synthesis	Liquid SAF shipping			Liquified Ammonia	

Fuels shipping			(2030) 1.50 (2050) 1.26	(2030) Cost = 0.01 D + 0.03 (2050) Cost= 0.01 D + 0.02 D: Distance			shipping		
	SAF								

Country-specific cost of capital

As any investment, the cost of capital of clean hydrogen projects must reflect their risk profile, including in particular local regulatory and political risks. This will impact LCOH calculation. In practice, countries are divided into seven different groups according to the OECD country risk classification for officially supported export credits[w]. The lower and higher bound of current WACC levels were derived from IRENA's 'Renewable Power Generation Costs in 2021'[25], while future values were extrapolated to match with the expectations found in the literature. This methodology allows to approximate a country dependent risk adjusted weighted average cost of capital (WACC) for the LCOH calculation.

We consider a range of WACC going from 6% in 2020, in economically stable countries such as Western Europe, North America or Australia to more than 12% in countries such as Iran or Argentina, that face long-lasting political or monetary instability (**Figure SI2.5**). WACC trajectories are decreasing as progressive adoption of hydrogen technologies and uptake in demand will lower projects risks and are as well converging across country groups which models the effects of growing financial risk transfer mechanisms or resort to concessional (or international) finance.



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[u] Conversion and reconversion costs accounts for the overnight costs of the conversion and reconversion reactors, for their annual operation and maintenance costs and for the electricity consumption for the conversion and reconversion processes. Electricity prices are modelled and calculated separately for each country and vary between $15/MWh and $150/MWh in 2030 and $20/MWh and $175/MWh in 2050 depending on the considered country.

[v] Shipping costs consist of the investments and fixed operation and maintenance costs of the shipment terminals, the overnight and annual operation and investment costs of the tankers for shipping and fuel costs of the tankers, levelised per kg of commodity shipped.

[w] https://www.oecd.org/trade/topics/export-credits/arrangement-and-sector-understandings/financing-terms-and-conditions/country-risk-classification/

Figure SI2.5. Country-specific WACC (weighted average cost of capital) used in LCOH calculations. These values are used based on the OECD country risk classification values. Group 1 represents Europe, North America, Australia and Chile, Group 2 represents China, Saudi Arabia and United Arab Emirates, Group 3 represents India, Qatar, Mexico and Morocco, Group 4 consists of Colombia and South Africa, Group 5 representing Brazil, Egypt and Turkey, Group 6 Namibia, Nigeria and Ukraine and Group 7 represents Argentina, Iran and Tunisia.

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