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EWI Working Paper, No 22/03

March 2022

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ISSN: 1862-3808

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Abstract

This paper analyses the impact of supply technology choices and costs on structures and prices on the emerging low-carbon hydrogen market using a novel, integrated natural gas and hydrogen market model. It shows that natural gas-based low-carbon hydrogen production pathways predominate in technology-neutral scenarios in 2050. In scenarios where hydrogen production is gas-based, hydrogen is produced close to the point of consumption. Natural gas prices determine local hydrogen prices. In scenarios characterised by high shares of RES-based low-carbon hydrogen production, long-distance, cross-border trade in pure hydrogen becomes an economically viable proposition due to the heterogeneous distribution of low-cost RES potentials and significant hydrogen price spreads between countries with high hydrogen demand but poor RES potentials, and countries that are well endowed with cost-competitive RES. Trade is conducted almost exclusively via pipeline. The analysis finds the most significant potential for cross-border trade in and around Europe. It suggests that it would be economical for Europe to import substantial quantities of low-carbon hydrogen from North Africa.

Keywords: Hydrogen

JEL classification: Q40, Q42, Q49.

1. Introduction

Hydrogen is an essential industrial feedstock produced almost exclusively from fossil fuels today. According to the International Energy Agency (IEA), roughly 75% of global hydrogen production is natural gas-based. The remainder is produced mainly from coal, while less than one per cent is produced through the electrolysis of water. The reliance on unabated fossil fuels makes the production of hydrogen very emission-intensive (IEA, 2019c). At the same time, hydrogen is almost always produced at or very close to the point of consumption, often as an intermediate or by-product of refining or chemical synthesis processes. Therefore, as of today, no true market exists for hydrogen as a commodity.

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However, this may change over the next three decades: low-carbon hydrogen—hydrogen the production of which releases little or no CO_2 into the atmosphere—is projected to take on an increasingly important role in a decarbonising global economy, both as an alternative energy carrier and as a feedstock for the production of synthetic fuels and various other industries. Major reports examining decarbonisation pathways for the global energy system (e.g. IRENA (2019), BP (2020), Shell (2020), IEA (2020a,b, 2021a,b)) all foresee the emergence of substantial demand for low-carbon hydrogen by 2050.

The low-carbon hydrogen production pathways currently seen as most relevant on a global scale are water electrolysis powered by electricity from renewable energy sources (RES) and natural gas reforming (NGR) in combination with carbon capture and utilisation/storage (CCUS) (IEA, 2019c, 2020a,b, 2021b; Brändle et al., 2021).[1] The evolution of the future market for low-carbon hydrogen will thus likely be shaped by the competition between RES- and natural gas-based production pathways, as well as the interaction of the latter with the natural gas market.

This paper addresses the following research question: what role do technology costs and technology choices play in shaping the potential evolution of a future market for low-carbon hydrogen based on natural gas- and RES-based hydrogen production pathways, both spatially and over time?

Methodologically, it applies a new, integrated, partial equilibrium model of the global natural gas and hydrogen markets. A review of the existing, peer-reviewed literature suggests that this model is the first partial equilibrium model in which both the natural gas market and the emerging market for low-carbon hydrogen are simulated together. This is important because it allows for an explicit consideration of the link between the natural gas and the hydrogen market when hydrogen production is natural gas based.

This work joins two distinct literature streams. The first stream is concerned with analysing future supply costs of low-carbon hydrogen based on different production chains, most notably electrolysis using renewable electricity and natural gas reforming (NGR), and the analysis of long-distance trade in hydrogen using pipelines or ships. The second stream involves modelling global energy markets, most notably for natural gas, using partial equilibrium models. Such models commonly comprise a spatially disaggregated representation of the individual players in the upstream (production), midstream (transportation) and downstream (distribution and consumption) segments of the market. They are typically used to analyse market structures, commodity flows and prices.

Several recent publications have assessed low-carbon hydrogen supply costs and potentials on a global scale.

Brändle et al. (2021) estimate production costs of hydrogen from RES and natural gas for 89 countries until 2050, as well as the costs associated with the transport of hydrogen by ship or pipeline from each of these countries to Germany, Japan and the United States. They produce a ranking of suppliers by

[1] Coal gasification with CCUS is also expected to play a role, but at significant scale only in China (IEA, 2019c).

cost, considering both domestic production and imports. They find that NGR, in combination with carbon capture and storage (CCS), will be the most cost-efficient low-carbon hydrogen production technology in the medium term (2020-2030). However, hydrogen production from RES could become competitive in the long run (2030-2050) if RES and electrolyser investment costs decrease significantly. The cost-optimal long-term hydrogen supply of each country depends on regional characteristics, such as RES potentials and gas prices. Imports are cost-effective where the domestic production potential is small or cost-intensive. Due to the high cost of seaborne transport, hydrogen trade will most likely develop regionally along pipeline networks.

Heuser et al. (2020) perform a techno-economic analysis of a global supply system for RES-based hydrogen. They estimate hydrogen production costs and potentials for selected countries and regions in 2050 and the potential global demand for hydrogen, broken down by region. Production and consumption regions are linked by an infrastructure consisting of pipelines and liquefied hydrogen (LH_2) carriers. The authors also conclude that trade will occur primarily within regional clusters due to the high cost of transporting hydrogen.

Other studies have examined individual supply chains in more detail: Heuser et al. (2019) conceptualise and analyse a potential supply chain for wind-based hydrogen linking Patagonia and Japan using LH_2 carriers. Timmerberg and Kaltschmitt (2019) analyse the possibility of producing RES-based hydrogen in North Africa and blending it into natural gas pipelines to facilitate the early development of hydrogen production in the region and reduce the carbon footprint of Europe's natural gas supply.

Partial equilibrium models of global energy markets are generally used to tackle questions related to the structure of the respective markets, most notably the impact of supply disruptions or the strategic behaviour of suppliers on prices and trade volumes. More recently, such models have also been used to assess the impact of decarbonisation policies on individual commodity markets.

The following papers showcase how partial equilibrium models are applied to analyse market structures, trade flows and price effects on global commodity markets.

Berk and Çam (2020) use a partial equilibrium model to analyse the structure of the global crude oil market for the 2013-2017 period, concluding that while an oligopolistic setup generates model results that are closest to actual market outcomes, low prices point to a reduction in the market power potential of the Organisation of Petroleum Exporting Countries (OPEC), a cartel of 13 oil-exporting countries, in the latter part of the period under investigation.

Schulte and Weiser (2019) apply a partial equilibrium model of the global gas market to analyse the potential of Turkey to exercise market power as a gas transit hub of the European Union (EU)'s Southern Gas Corridor. Looking forward to 2030, they find that if the European market is characterised by oligopolistic competition, Turkey will be able to influence European gas market prices by restricting gas transits. If the market is competitive, however, less gas flows along the Southern Gas Corridor in general, limiting the potential of Turkey to exercise market power.

Growitsch et al. (2014) use the same model to study the price and quantity effects of supply shocks on the global natural gas market. Using the potential disruption of LNG flows through the Straits of Hormuz as an example, they find that Japan— entirely dependent on LNG—would be most affected by the price spike, while Europe—more reliant on pipeline gas—would be less affected. They also find that the high interconnectedness of the European pipeline system limits the ability of individual suppliers to increase prices by exercising market power.

Mendelevitch (2018) employs a partial equilibrium model of the global steam coal market to analyse the impact of supply-side measures designed to reduce coal production and consumption.

This paper integrates the data on the potential future cost of low-carbon hydrogen production and transport published by Brändle et al. (2021) into a partial-equilibrium model of the global natural gas and hydrogen markets. The model, scenarios and key assumptions are presented in Section 2. Section 3 presents the main results of the model-based analysis, which are discussed in Section 4. Section 5 concludes the paper.

2. Methodology

The paper at hand quantifies the potential impact of technology costs and choices on the ramp-up of a global market for low-carbon hydrogen through a scenario analysis using a detailed partial equilibrium model of the global markets for natural gas and low-carbon hydrogen, covering 97 countries. To capture the impact of natural gas-based hydrogen production on the price of natural gas and vice versa, the model fully represents the up- and midstream segments of the global natural gas value chain. It is adapted from COLUMBUS, a partial equilibrium model of the global natural gas market, developed by Hecking and Panke (2012), and subsequently applied in analyses by Growitsch et al. (2014) and Schulte and Weiser (2019).

2.1. Model Description

The extended model covers the following stages of natural gas and hydrogen value chains: production, transportation, storage, and consumption. It is formulated as a mixed complementarity problem (MCP).

The time structure of the model is given by a set $t \subset T$ of points in time. For the paper at hand, an annual resolution was chosen. Spatially, the model is defined by nodes $n \subset N$ connected through arcs $n \rightarrow n1$. Nodes are divided into natural gas and hydrogen production, liquefaction, regasification, and consumption nodes, and the arcs connecting them represent pipelines and LNG/LH_2 shipping routes.

The model is populated by different profit-maximising agents: exporters, producers, transmission system operators (TSOs), liquefiers, regasifiers and shippers. Subject to various constraints, they maximise their profits by making optimal decisions with respect to the production, sale and transport of natural gas or hydrogen; and through optimal investments into production and transportation infrastructure.

The respective optimisation problems of the individual agents situated along the natural gas and hydrogen value chains and their corresponding first-order optimality conditions are outlined in the following subsections. The partial equilibrium model is formed by combining the first-order optimality conditions with the market clearing conditions of the respective markets.

2.1.1. The exporter's problem

Exporters $e \in E$ sell natural gas and/or hydrogen $f \in F = \{H_2, NG\}$ to consumers. They are affiliated with at least one natural gas or hydrogen production node $p \in P$. They purchase fuel from associated production nodes and sell ($sell_{e,f,d,t}$) it to consumers located in consumption nodes $d \in D$. The exporter's payoff function is the following:

$$\begin{aligned} &\max_{sell_{e,f,d,t}} \prod_{eI}(sell_{e,f,d,t}) \\ &= \sum_t \sum_d \Big((1 - cv_e) * \beta_{f,d,t} + cv_e * \beta_{f,d,t}(\sum_e sell_{e,f,d,t}) - \lambda_{e,f,d,t}\Big) * sell_{e,f,d,t}, \qquad (1) \\ &sell_{e,f,d,t} \geq 0 \end{aligned}$$

where $\lambda_{e,f,d,t}$ corresponds to the cost associated with production and delivery of the respective fuel f to a consumption node d and $\beta_{f,d,t}$ is the market price for fuel f at consumption node d. The conjectural variation parameter cv_e determines whether an exporter can exert market power or behaves as a price taker. If $cv_e = 1$, the exporter faces a linear inverse demand function and thus implicitly considers the impact of its own sales and those of others on the market price $\beta_{f,d,t}$. Otherwise, if $cv_e = 0$, it observes market price directly and behaves as a price taker.

Long-term contracts (LTCs) play an important role in determining trade flows in the natural gas market. They are modelled as a constraint, which ensures that an exporter's sales to consumers with which a long-term contract is in place are always equal or greater than the contractually defined minimum delivery obligation ($mdo_{e,f,d,t}$):

$$\sum_t sell_{e,f,d,t} - mdo_{e,f,d,t} \geq 0 \qquad \forall\ e, f, d, t \qquad (\chi_{e,f,d,t}) \qquad (2)$$

The first-order optimality condition of the exporter's profit maximisation problem is defined by the first partial derivative of the Lagrangian $\mathcal{L}_{eI}$ with respect to the variable $sell_{e,f,d,t}$:

$$\begin{aligned} &-\beta_{f,d,t} + (cv_e + 1) * \mathrm{slope}_{f,d,t} * sell_{e,f,d,t} - \chi_{e,f,d,t} + \lambda_{e,f,d,t} \geq 0 \\ &\qquad\qquad \perp \quad sell_{e,f,d,t} \geq 0 \qquad \forall\ e, f, d, t. \end{aligned} \qquad (3)$$

Sales have to be matched by actual physical deliveries of natural gas or hydrogen. This is modelled as a separate optimisation problem:

$$
\begin{aligned}
&\max_{flow_{e,f,n,n1,t}} \prod_{eII}(flow_{e,f,n,n1,t}) \\
&= \sum_{t}(\lambda_{e,f,n1,t} - \lambda_{e,f,n,t} - varcost^{tra}_{f,n,n1,t} - varcost^{tra}_{f,r,t}) * flow_{e,f,n,n1,t}
\end{aligned} \tag{4}
$$

Exporters choose the least-cost supply route ($flow_{e,f,n,n1,t}$) to fulfil their delivery obligation, where $\lambda_{e,f,n,t}$ is the marginal cost of gas supplied by exporter s to node n and $\lambda_{e,f,n1,t}$ is the marginal cost of gas or hydrogen delivered by s to node $n1$. $varcost^{tra}_{f,r,t}$ is the cost of regasifying a unit of natural gas or hydrogen if n is a regasification node [$r(n)$], while $varcost^{tra}_{f,n,n1,t}$ is the short-run marginal cost of transporting natural gas or hydrogen from node n to node $n1$. If $n1$ is a liquefaction node [$l(n1)$], $varcost^{tra}_{f,n,l,t}$ is equivalent to the short-run marginal cost of liquefying the commodity. If n and $n1$ are connected by pipeline, $varcost^{tra}_{f,n,n1,t}$ denotes the short-run marginal cost of pipeline deliveries. Finally, if the node pair are a liquefaction node [$l(n)$] and a regasification node [$r(n1)$], $varcost^{tra}_{f,l,r,t}$ expresses the short-run marginal cost of transporting the respective commodity f by tanker.

The transportation problem expressed in Equation 4 is subject to physical capacity constraints. Equation 5 describes the pipeline capacity constraint, with total pipeline capacity given by the sum of exogenous capacity ($cap^{pipe}_{f,n,n1,t}$) and additional, endogenous investments ($inv^{pipe}_{f,n,n1,t}$):

$$
cap^{pipe}_{f,n,n1,t} + inv^{pipe}_{f,n,n1,t} - \sum_{e} flow_{e,f,n,n1,t} \geq 0 \qquad \forall \;\; f,n,n1,t \qquad (\phi_{f,n,n1,t}) \tag{5}
$$

Equations 6, 7 and 8 outline the liquefaction, regasification and shipping capacity constraints, respectively. The maximum available shipping capacity on a given route is derived taking into account the average capacity of an LNG or LH_2 tanker (cap^{ship}_{f}), the number of vessels invested in ($inv^{ship}_{f,t}$), their average speed in km/h (*speed*) and the round-trip distance ($dist_{l,r}$).

$$
cap^{liq}_{f,l,t} + inv^{liq}_{f,l,t} - \sum_{e}\sum_{n} flow_{e,f,n,l,t} \geq 0 \qquad \forall \;\; f,l,t \qquad (\zeta_{f,l,t}) \tag{6}
$$

$$
cap^{reg}_{f,r,t} + inv^{reg}_{f,r,t} - \sum_{e}\sum_{d} flow_{e,f,r,d,t} \geq 0 \qquad \forall \;\; f,r,t \qquad (\gamma_{f,r,t}) \tag{7}
$$

$$
\begin{aligned}
&\left(cap^{ship}_{f} * inv^{ship}_{f,t}\right) * 8760/12 * speed \\
&- \sum_{e}\sum_{l}\sum_{r} 2 * (flow_{e,f,l,r,t} * dist_{l,r}) \geq 0 \qquad \forall \;\; f,t \qquad (\iota_{f,t})
\end{aligned} \tag{8}
$$

The associated first-order condition of the transportation problem defined in Equation 4 is derived by taking the first partial derivative of the Lagrangian $\mathcal{L}_{eII}$ with respect to the variable $flow_{e,f,n,n1,t}$:

$$
\begin{aligned}
&-\lambda_{e,f,n1,t}+\lambda_{e,f,n,t}+varcost^{tra}_{f,n,n1,t}+varcost^{tra}_{f,r,t}+\phi_{f,n,n1,t}\\
&+\zeta_{f,l,t}+\gamma_{f,r,t}+\iota_{f,t}*2*dist_{l,r}\geq 0 \quad \perp \quad flow_{e,f,n,n1,t}\geq 0 \qquad \forall\ e,f,n,n1,t.
\end{aligned} \tag{9}
$$

2.1.2. The producer's problem

Producers operate a single production node $p \in P$ and maximise their profits by selling natural gas or hydrogen to their affiliated exporter e. They act as price takers, which means that, in essence, a producer and an exporter together behave like a single, vertically integrated firm. The producer payoff functions differ slightly depending on the fuel that is produced and—in the case of hydrogen—the production pathway that is chosen.

Natural gas production is modelled as a piecewise linear supply function with $c \subset C$ cost steps, which reflects the short-run marginal cost of existing production and the long-run marginal cost of prospective developments. The producer payoff function for natural gas is given by Equation 10, where $\lambda_{e,NG,p,t}$ is the marginal value of gas in production node p, $prod_{NG,c,p,t}$ is the production volume of natural gas and $varcost^{prod}_{NG,p,c,t}$ the marginal production cost:

$$
\max_{prod_{NG,p,c,t}} \prod_{pI}(prod_{NG,p,c,t})=\sum_{t}\sum_{c}(\lambda_{e,NG,p,t}*prod_{NG,c,p,t}-varcost^{prod}_{NG,p,c,t}*prod_{NG,p,c,t}) \tag{10}
$$

Equation 11 describes the payoff function of hydrogen producers. The model considers both RES- and natural gas-based low-carbon hydrogen production pathways. For hydrogen, investment decisions are modelled explicitly. Producers can therefore invest into additional production capacity ($inv^{prod}_{H2,p,c,t}$), incurring investment costs ($invcost^{prod}_{H2,p,c,t}$). Here, $c \subset C$ stands for different hydrogen production pathways. The term $purch_{p,t} * \beta_{NG,p,t}$ is specific to natural gas-based hydrogen production and expresses the opportunity cost of purchasing natural gas for hydrogen production, with $\beta_{NG,p,t}$ denoting the price of natural gas in the respective production node:

$$
\begin{aligned}
&\max_{\substack{prod_{H2,p,c,t}\\ inv^{prod}_{H2,p,c,t}}} \prod_{pII}(prod_{H2,p,c,t}, inv^{prod}_{H2,p,c,t})\\
&=\sum_{t}\sum_{c}(\lambda_{e,H2,p,t}*prod_{H2,c,p,t}-varcost^{prod}_{H2,p,c,t}*prod_{H2,p,c,t}-purch_{p,t}*\beta_{NG,p,t})\\
&+\sum_{t}\sum_{c}(invcost^{prod}_{H2,p,c,t}*inv^{prod}_{H2,p,c,t})
\end{aligned} \tag{11}
$$

The producers are subject to capacity and—in the case of RES-based hydrogen—availability constraints. Natural gas production is limited to the maximum production capacity ($cap^{prod}_{NG,p,c,t}$) of the respective cost step c (Equation 12).

$$cap^{prod}_{NG,p,c,t} - prod_{NG,c,p,t} \geq 0 \qquad \forall\ p,c,t \qquad (\mu_{NG,p,c,t}) \tag{12}$$

Hydrogen production is limited by the installed capacity, including endogenous investments ($cap^{prod}_{NG,p,c,t} + inv^{prod}_{H2,p,c,t}$). RES-based hydrogen production is further constrained by the capacity factor ($cf^{prod}_{H2,c,p,t}$) of the respective renewable energy source (Equation 13). The capacity factors are calculated for cost-optimal combinations of a renewable energy source and an electrolyser, taking into account the full cost of both components and differences in the quality and variability of the RES in the 89 countries covered by the model. A detailed description of the underlying methodology and estimates is provided in Brändle et al. (2021).

$$(cap^{prod}_{H2,p,c,t} + inv^{prod}_{H2,p,c,t}) * cf^{prod}_{H2,c,p,t} - prod_{H2,c,p,t} \geq 0 \qquad \forall\ p,c,t \qquad (\mu_{H2,p,c,t}) \tag{13}$$

As shown in Equation 14, natural gas-based hydrogen production technologies $[ngb(c)]$ are further constrained by the amount of natural gas purchased for hydrogen production ($purch_{p,ngb,t}$) in the respective production node p, which must be equal or greater than the amount of hydrogen produced ($prod_{H2,p,ngb,t}$), divided by the process efficiency ($eff^{prod}_{H2,p,ngb,t}$).

$$purch_{p,ngb,t} - \frac{prod_{H2,p,ngb,t}}{eff^{prod}_{H2,p,ngb,t}} \geq 0 \qquad \forall\ p, ngb \subset C, t \qquad (\omega_{p,ngb,t}) \tag{14}$$

The first-order optimality condition of the natural gas producer's maximisation problem (Equation 10) is given by the partial derivative of the Lagrangian $\mathcal{L}_{pI}$ with respect to the variable $prod_{NG,p,c,t}$:

$$-\lambda_{e,NG,p,t} + varcost^{prod}_{NG,p,c,t} + \mu_{NG,p,c,t} \geq 0 \quad \perp \quad prod_{NG,p,c,t} \geq 0 \qquad \forall\ f,p,c,t \tag{15}$$

Finally, the first-order conditions of the hydrogen producer's maximisation problem (Equation 11) are derived by taking the partial derivatives of the Lagrangian $\mathcal{L}_{pI}$ with respect to the variables $prod_{H2,p,c,t}$, $purch_{p,t}$ and $inv^{prod}_{H2,p,c,t}$:

$$-\lambda_{e,H2,p,t} + varcost^{prod}_{H2,p,c,t} + \mu_{H2,p,c,t} + \omega_{p,t} \geq 0 \quad \perp \quad prod_{H2,p,c,t} \geq 0 \qquad \forall\ f,p,c,t \tag{16}$$

$$-\omega_{p,ngb,t} + \beta_{NG,p,t} \geq 0 \quad \perp \quad purch_{p,ngb,t} \geq 0 \qquad \forall\ f,p,t \tag{17}$$

$$invcost^{prod}_{H2,p,c,t} - \mu_{H2,p,c,t} \geq 0 \quad \perp \quad inv^{prod}_{H2,p,c,t} \geq 0 \qquad \forall\ p,c,y \tag{18}$$

2.1.3. The transmission system operator's problem

TSOs are players that control pipeline arcs ($n \rightarrow n1$). They allocate transmission capacity to exporters and are in turn compensated for the short-run marginal cost of transmission ($varcost^{tra}_{f,n,n1,t}$)[2] and the

[2]Which thus cancels out in the payoff function.

congestion rent ($\phi_{f,n,n1,t}$), which is determined by the transmission capacity constraint (Equation 5). TSOs invest in additional pipeline capacity if the long-run marginal cost of transmission expansion is less than the congestion rent. Their payoff function is as follows:

$$\begin{aligned}&\max_{inv^{pipe}_{f,n,n1,t}} \prod_{TSO} (inv^{pipe}_{f,n,n1,t}) \\ &= \sum_{t} \left[\phi_{f,n,n1,t} * (cap^{pipe}_{f,n,n1,t} + inv^{pipe}_{f,n,n1,t}) \right] - inv^{pipe}_{f,n,n1,t} * invcost^{pipe}_{f,n,n1,t}\end{aligned} \tag{19}$$

Taking the partial derivative of the Lagrangian $\mathcal{L}_{TSO}$ with respect to the variable $inv^{pipe}_{f,n,n1,t}$ yields the first-order optimality condition:

$$invcost^{pipe}_{f,n,n1,t} - \phi_{f,n,n1,t} \geq 0 \quad \perp \quad inv^{pipe}_{f,n,n1,t} \geq 0 \qquad \forall \ f, n, n1, t. \tag{20}$$

2.1.4. The liquefier's problem

Liquefiers (l) receive natural gas or hydrogen and liquefy it. They allocate liquefaction capacity to exporters and in exchange for the short-run liquefaction cost ($varcost^{tra}_{f,n,l,t}$) and the congestion rent ($\zeta_{f,l,t}$). The congestion rent is determined by the liquefaction capacity constraint (Equation 6). They maximise their payoff in accordance with Equation 21:

$$\max_{inv^{liq}_{f,l,t}} \prod_{l} (inv^{liq}_{f,l,t}) = \sum_{t} \left[\zeta_{f,l,t} * (cap^{liq}_{f,l,t} + inv^{liq}_{f,l,t}) \right] - inv^{liq}_{f,l,t} * invcost^{liq}_{f,l,t} \tag{21}$$

Their first-order optimality condition is:

$$invcost^{liq}_{f,l,t} - \zeta_{f,l,t} \geq 0 \quad \perp \quad inv^{liq}_{f,l,t} \geq 0 \qquad \forall \ f, l, t. \tag{22}$$

2.1.5. The regasifier's problem

Regasifiers (r) receive LNG or LH_2 and regasify it. They allocate regasification capacity to exporters, who pay for the short-run regasification cost ($varcost^{tra}_{f,r,t}$) and the congestion rent ($\gamma_{f,r,t}$). The congestion rent is determined by the regasification capacity constraint (Equation 7). Their payoff function is described by Equation 23:

$$\max_{inv^{reg}_{f,r,t}} \prod_{r} (inv^{reg}_{f,r,t}) = \sum_{t} \left[\gamma_{f,r,t} * (cap^{reg}_{f,r,t} + inv^{reg}_{f,r,t}) \right] - inv^{reg}_{f,r,t} * invcost^{reg}_{f,r,t} \tag{23}$$

Their first-order optimality condition is:

$$invcost^{reg}_{f,r,t} - \gamma_{f,r,t} \geq 0 \quad \perp \quad inv^{reg}_{f,r,t} \geq 0 \qquad \forall \ f, r, t. \tag{24}$$

2.1.6. The shipper's problem

The market for LNG or LH_2 shipping capacity is modelled as a single player (the shipper) who behaves competitively. The shipper allocates shipping capacity to exporters, passing on operating costs ($varcost^{tra}_{f,l,r,t}$) and congestion rent ($\iota_{f,t}$). The shipper invests into additional shipping capacity until the associated long-run marginal cost exceeds the congestion rent, which is determined by the shipping capacity constraint (Equation 8). Its payoff function is given by Equation 25:

$$\begin{aligned} &\max_{inv^{ship}_{f,t}} \prod_{LNG}(inv^{ship}_{f,t}) \\ &= \sum_t \left[\iota_{f,t} * 8760/12 * speed * (cap^{ship}_f * inv^{ship}_{f,t}) \right] - inv^{ship}_{f,t} * invcost^{ship}_{f,t} \end{aligned} \tag{25}$$

The first-order optimality condition is derived by taking the partial derivative of Lagrangian $\mathcal{L}_{LNG}$ with respect to $inv^{ship}_{f,t}$:

$$invcost^{ship}_{f,t} - \iota_{f,t} * 8760/12 * speed \geq 0 \quad \perp \quad inv^{ship}_{f,t} \geq 0 \qquad \forall \ f,t. \tag{26}$$

2.1.7. Market clearing conditions

The first-order optimality conditions of the individual optimisation problems described above and the following market-clearing conditions comprise the partial equilibrium model.

Equation 27 ensures that trades ($sale_{e,f,d,t}$) are matched by production and/or net inflows:

$$\begin{aligned} &\sum_c prod_{f,p,c,t} - sell_{e,f,d,t} + \sum_{n1 \in (n1,n)} flow_{e,f,n1,n,t} - \sum_{n1 \in (n,n1)} flow_{e,f,n,n1,t} = 0 \\ &\perp \quad \lambda_{e,f,n,t} \quad \text{free} \qquad \forall \ e,f,n,t. \end{aligned} \tag{27}$$

Equations 28 (for natural gas) and 29 (for hydrogen) assure that aggregate sales ($sell_{e,f,n,t}$) match demand ($dem_{f,d,t}$) and, in the case of natural gas, gas purchases for hydrogen production ($purch_{p,t}$). The dual variable ($\beta_{f,n,t}$) can be interpreted as the market price of the respective fuel:

$$\sum_e sell_{e,NG,d,t} - dem_{NG,d,t} - \sum_{ngb \in (C)} purch_{p,ngb,t} = 0 \quad \perp \quad \beta_{NG,d,t} \quad \text{free} \qquad \forall \ f,d,t. \tag{28}$$

$$\sum_e sell_{e,H2,d,t} - dem_{H2,d,t} = 0 \quad \perp \quad \beta_{H2,d,t} \quad \text{free} \qquad \forall \ f,d,t. \tag{29}$$

2.2. Scenarios and Assumptions

The scenarios underpinning the analysis presented in the paper at hand are adapted from the IEA's Sustainable Development Scenario (SDS) (IEA, 2019d, 2020a,b), supplemented by additional assumptions on the distribution of the aggregated natural gas and hydrogen demand estimates provided by the IEA to the individual countries covered by the model. The SDS's natural gas and hydrogen demand trajectories postulate rapid decarbonisation of the global economy, reaching net-zero emissions globally by 2070.

The model simulates RES-, natural gas-, and coal-based low-carbon hydrogen production pathways: electrolysis using electricity from either onshore wind, offshore wind, or solar PV (RES-based), NGR+CCUS (natural gas-based) and coal gasification (CG)+CCUS (coal-based).[3] CG+CCUS is considered as an option for China specifically[4], which operates more than 80% of the world's coal gasification capacity today, making it by far the world's largest producer of hydrogen from coal (IEA, 2019c).

Four scenarios are simulated, analysed, and compared to assess the impact of supply technology choices and costs on structures and prices on the emerging market for low-carbon hydrogen.

In the first two scenarios (labelled *open transition* [OPT]), the different hydrogen production technologies compete solely based on their levelised cost of production in all modelled regions. In the *OPT (central)* scenario, the future decline in RES and electrolyser investment costs follows the central trajectory presented in Brändle et al. (2021)[5], while in the *OPT (optimistic)* scenario, the assumed cost decline corresponds to the optimistic projection. Investment costs and efficiencies for NGR+CCUS and CG+CCUS do not vary between the scenarios.

In the third and fourth scenario, a so-called green transition (GRT), where RES-based production technologies dominate the global low-carbon hydrogen supply mix from the beginning as a matter of policy choice, is modelled. In the *GRT (central)* scenario, the future decline in RES and electrolyser investment costs follows the central trajectory, while in the *GRT (optimistic)* scenario, the assumed cost decline corresponds to the optimistic projection.

In all scenarios, natural gas and hydrogen markets are assumed to be perfectly competitive.

The four scenarios represent extreme cases, and either one is highly unlikely to describe how the global low-carbon hydrogen market will develop in reality. The purpose of the scenarios is not to sketch out "best estimate" development pathways that consider regional political and commercial specificities but to assess the impact of technology costs and fundamental choices regarding production pathways on the nascent market for low-carbon hydrogen.

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[3] Pyrolysis, an alternative natural gas-based low-carbon hydrogen production technology, is not considered because of the high uncertainty surrounding cost estimates and expected availability at scale compared to NGR+CCUS. Furthermore, this analysis focuses on evaluating the impact of the fundamental choice between RES-based or natural gas-based hydrogen in general, rather than comparing individual, natural gas-based processes.

[4] In the future, China is likely to keep using the technology—with the addition of CCUS—to meet some of its future low-carbon hydrogen requirements, while coal production is projected to decline substantially or be phased-out entirely in most other parts of the world (IEA, 2020a,b).

[5] Brändle et al. (2021) provide detailed, disaggregated information on RES potentials and costs for the countries represented in the model. There are two cost cases for RES-based hydrogen: in the central case, RES and electrolyser costs decline. In locations with above-average onshore wind or PV conditions, the levelised cost of hydrogen drops to around \$2/kg by 2050. In the optimistic case, higher RES investment cost reductions are achieved, in particular for solar PV, and levelised hydrogen production costs dip to \$1/kg in locations with good solar potentials.

The key differences between the scenarios are summarised in Table 1.

Table 1: Scenarios

	OPT (central)	**OPT (optimistic)**	**GRT (central)**	**GRT (optimistic)**
RES/electrolyser cost case	central	optimistic	central	optimistic
NGR+CCUS	available	available	unavailable	unavailable
CG+CCUS	available	available	unavailable	unavailable

Identical low-carbon hydrogen demand, natural gas demand and CO_2 price trajectories are assumed for all four scenarios. The consumption pathways are based on the IEA SDS and, therefore, consistent with a global transition to net-zero emissions by 2070 (IEA, 2020a,b).

Global natural gas demand (excluding consumption to produce low-carbon hydrogen, which is determined endogenously by the model) continues to grow to 3945 bcm in 2030 before declining to 3285 bcm in 2040 and 2534 bcm in 2050 as a result of the pressure to decarbonise.

Global demand for low-carbon hydrogen is projected to rise from 35 Mt in 2030 to 102 Mt in 2040 and 258 Mt in 2050. In 2050, 37% of the low-carbon hydrogen is consumed in the transport sector[6] 34% in industry[7] and 10% in buildings. The remaining 19% are consumed in other sectors, in particular, the power sector, where hydrogen provides an essential source of backup power for intermittent RES (IEA, 2020a).

Figure 1 shows the assumed development of the global demand for low-carbon hydrogen, broken down by region.

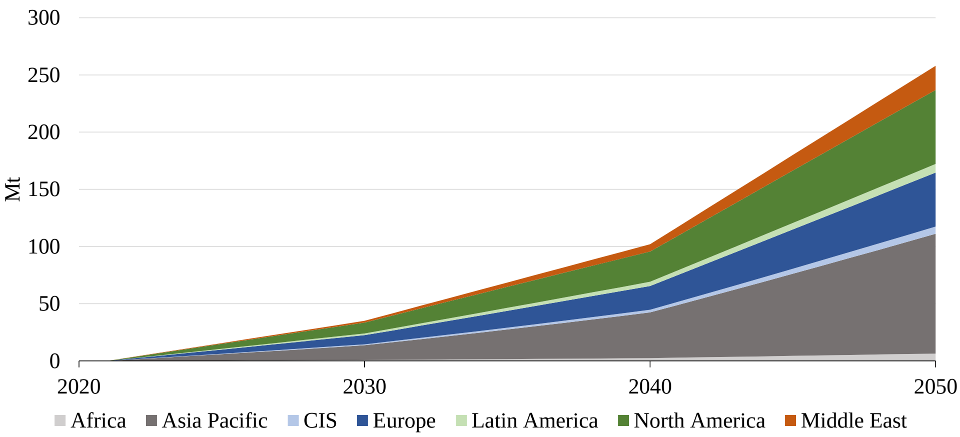

Figure 1: Assumed annual demand for low-carbon hydrogen

[6]Including hydrogen used for the production of synthetic fuels.

[7]Including hydrogen used in refining and for the production of low-carbon ammonia.

Detailed information on the data used and the assumptions made to derive the aforementioned low-carbon hydrogen and natural gas demand trajectories is provided in Appendix A.

As mentioned above, data on current and future investment costs, operating costs, and the conversion efficiencies of RES- and natural gas-based hydrogen production technologies is taken from a comprehensive global assessment of low-carbon hydrogen production costs published by Brändle et al. (2021). Investment costs, operating costs and conversion efficiencies for CG+CCUS in China are obtained from IEA (2019c, p. 51).[8]

For NGR+CCUS and CG+CCUS, the cost of transporting and storing CO_2 underground is an important cost component. Country-level CO_2 storage cost assumptions (see Table A.3) are based on CO_2 transport costs and reservoir-specific storage costs provided by Roussanaly et al. (2014) and Rubin et al. (2015).[9]. NGR+CCUS and CG+CCUS are assumed to have a CO_2 capture efficiency of 90%. The residual emissions are subject to the local CO_2 price.[10]

The direct decarbonisation of the power sector generally represents a more cost-efficient use of RES-based electricity than hydrogen production (Dickel, 2020). For this paper, it is assumed that the highest quality RES potentials are developed first and employed to decarbonise the direct use of electricity, which is itself projected to increase substantially in the SDS (IEA, 2020b). This reduces the potential available for hydrogen production.

The scale of RES expansion in a given country thus becomes an important constraint on the potential domestic supply of RES-based hydrogen. IEA (2020b) and IEA (2019b) provide installed PV and wind energy capacities for regions and selected countries in the SDS until 2040. For the 2040 to 2050 period, a continuation of the linear trend observed between 2030 and 2040 is assumed. Unless provided directly, regional figures are allocated to individual countries based on their 2018 share in the respective region's total RES capacity (IRENA, 2020). To determine the residual RES potentials available for hydrogen production in the model, the 2050 capacities thus derived are deducted from the theoretical, country-level RES capacity potentials found in (Brändle et al., 2021), assuming that the best potentials are generally developed first.[11]

[8]The weighted average cost of capital (WACC) plays an important role in shaping the economics of capital-intensive production technologies. A WACC of 8% is assumed to apply to investments into hydrogen production and liquefaction infrastructure. A WACC of 5% is assumed to apply to investments into hydrogen regasification and transmission (pipeline) infrastructure.

[9]Potential limitations to the underground storage of CO_2 in certain areas are not considered. In some cases, nearby reservoirs may not be readily available, and the CO_2 would have to be transported over greater distances to suitable disposal sites, increasing the associated cost. However, as shown by Brändle et al. (2021), the impact of an escalation in the cost of CO_2 transport and storage on the levelised cost of hydrogen produced by NGR+CCUS is relatively low.

[10]In reality, CO_2 prices would likely vary from scenario to scenario, in particular, if hydrogen or hydrogen-based technologies are the marginal abatement option. However, since this link cannot be captured by the partial equilibrium model used for this study, an exogenous global CO_2 price, based on IEA (2019c) and IEA (2020b), is assumed instead. It increases from \$89/tCO_2 in 2030 to \$165/tCO_2 in 2050 in advanced economies and \$70/tCO_2 in 2030 to \$145/tCO_2 in 2050 in less advanced economies in all four scenarios.

[11]This represents a conservative assessment of the available potential since some of the RES capacity assumed to be installed by 2050 in the IEA SDS is already for hydrogen production.

For NGR+CCUS and CG+CCUS, the cost of transporting and storing CO_2 underground is an important cost component. Since geological formations that permit the large-scale storage of CO_2 underground are ubiquitous and dispersed globally (Consoli, 2016; Baines et al., 2020), it is assumed that suitable reservoirs (depleted oil and gas fields and/or saline aquifers) are available in all countries represented in the model. Country-level costs associated with the transportation and storage of CO_2 captured when producing low-carbon hydrogen via natural gas reforming are estimated based on Roussanaly et al. (2014) and Rubin et al. (2015), taking country specificities into account. These include the availability of depleted oil/gas fields and whether suitable storage sites are located onshore or offshore. More details can be found in Appendix A.

For the land-based transport of hydrogen, pipelines are considered the lowest cost technology to transport significant volumes of hydrogen over large distances. Projected investment and operating costs for new, dedicated hydrogen pipelines are sourced from Brändle et al. (2021).[12]

Seaborne transport is assumed to be based on liquid hydrogen, as it could potentially be the lowest-cost shipping solution in the long run if the desired end product is pure hydrogen.[13]

For the seaborne transport of hydrogen, we model an infrastructure consisting of hydrogen liquefaction terminals, liquid hydrogen (LH_2) tankers and regasification terminals, with projected investment and operating costs of all three elements sourced from Brändle et al. (2021).

Natural gas production is modelled as a piecewise linear supply function. Country-specific natural gas supply curves are built from granular, field-level cost and capacity data provided by Rystad Energy (2020).

Existing cross-border natural gas pipeline capacities are obtained from an in-house database maintained by the Institute of Energy Economics at the University of Cologne. LNG liquefaction/regasification capacities (existing and sanctioned) are sourced from IGU (2021). Current long-term contracts (LTCs) for pipeline gas and LNG are also modelled, with contract volumes and durations obtained from Rystad Energy (2020). Existing LTCs are assumed not to be renewed after expiry. Investment costs for natural gas pipelines and LNG infrastructure come from various sources, including company reports and publications by the Oxford Institute for Energy Studies (Songhurst, 2018; Steuer, 2019).

3. Results

The main results of the model-based analysis of the four scenarios, focusing on the global hydrogen supply technology mix, the market's spatial structure, and the resulting price levels, are presented below.

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[12] Brändle et al. (2021) assume the specific cost for the transmission of hydrogen through new, large-scale, dedicated hydrogen pipelines to fall to \$240 per tonne of H_2 per 1000 km by 2030.

[13] In the medium term, the conversion to ammonia is likely to be the cheapest way of transporting hydrogen by sea, in particular, because existing port infrastructure and LPG tankers could be used for this purpose. However, expenditures and energy losses associated with the process of cracking ammonia to obtain hydrogen impose additional costs (IEA, 2019c). Some studies show LH_2 to potentially yield a lower cost in the long run, provided the technology improves further and economies of scale are harnessed (Brändle et al., 2021).

3.1. Global hydrogen supply mix

In the *OPT (central)* scenario, where RES and electrolyser investment costs follow the central trajectory described in Brändle et al. (2021) and hydrogen production technologies compete only based on cost, fossil fuel-based hydrogen production remains the dominant pathway to 2050 (Figure 2). Since hydrogen production is overwhelmingly natural gas-based, it becomes a significant consumer of natural gas relative to other sectors, accounting for 10% of global natural gas consumption in 2030 and 30% in 2050 (Figure B.8 in Appendix B). Nevertheless, total natural gas demand stagnates due to declining consumption in other sectors of the economy, and natural gas prices are low by historical standards in most major consumption regions (Figure B.9 in Appendix B). The low gas price environment explains the persistent competitive edge of natural gas over RES-based hydrogen production in this scenario.

In the *OPT (optimistic)* scenario, RES and electrolyser investment costs follow the optimistic trajectory set out in Brändle et al. (2021). In this scenario, RES and electrolyser costs decline sufficiently to make the production of low-carbon hydrogen using electrolysis—especially when paired with solar PV—the most economical choice in several regions, especially after 2040. In 2050, more than a third of global hydrogen production is RES-based (Figure 2). Figure 3 displays the share of RES-based hydrogen production in the hydrogen production technology mix of each modelled country in the year 2050. It shows that RES-based hydrogen production is concentrated in regions with good solar energy potentials, such as the Middle East and North Africa, southern Europe and South America. RES-based low-carbon hydrogen also plays a role in regions with comparatively high gas prices, including China and Southeast Asia. In other regions, however, low natural gas prices, less favourable available RES potentials or a combination of both allow natural gas-based hydrogen production to retain its competitiveness even in the long run. The upshot is that even in this scenario, natural gas-based hydrogen production is a major user of natural gas, accounting for 22% of global gas consumption in 2050 (Figure B.8).

In the *GRT (central)* and *GRT (optimistic)* scenarios, the development of global low-carbon hydrogen production is fully RES-based from the beginning due to an assumed global preference for RES-based hydrogen. In both the central and the optimistic cost cases, electrolysis powered by PV-based electricity becomes the dominant production pathway, accounting for, respectively, 90% and 95% of global low-carbon hydrogen production in 2050. In the central cost case, by comparison, the share of hydrogen production based on wind energy is slightly greater since it is cost-competitive in regions with good wind but poor solar resources, such as northwestern Europe.[14]

[14] The strong performance of PV-based hydrogen relative to wind after 2030 is due to the assumed investment cost reduction trajectories for solar PV and onshore/offshore wind energy. A less pronounced decline in PV investment costs, or a steeper fall in the cost of onshore or offshore wind energy, would lead to higher shares of wind-based hydrogen production in the global supply mix.

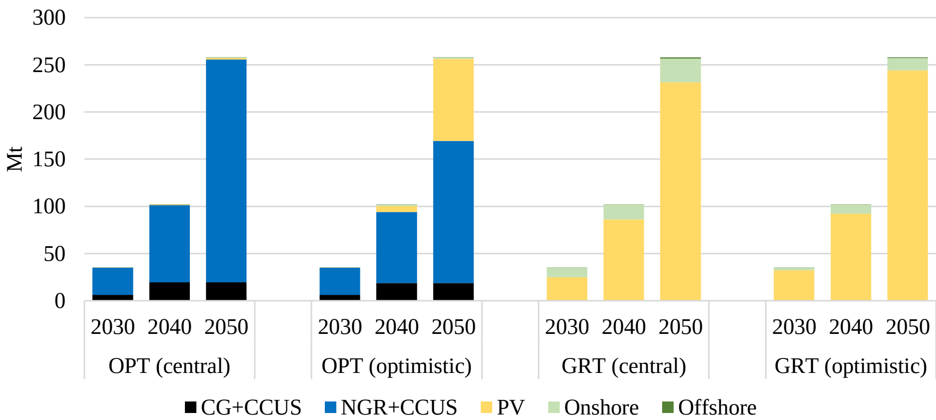

Figure 2: Global low-carbon hydrogen production by pathway

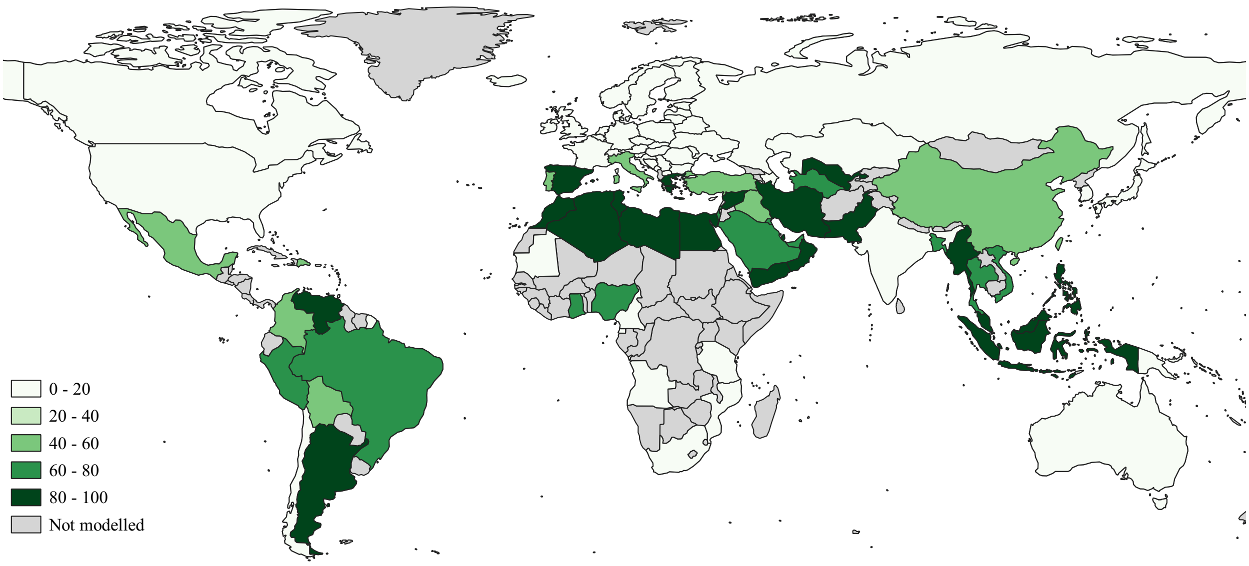

Figure 3: Share of RES-based hydrogen production in the OPT (optimistic) scenario in 2050, by country (in %)

A comparison of the scenarios illustrates the potential impact of a substantial increase in natural gas-based low-carbon hydrogen production on the natural gas market. Figure B.9 displays the modelled natural gas prices for major consumers by scenario. It shows that the additional demand from natural gas-based hydrogen production contributes to a stabilisation of gas prices over the 2030-2050 period in the *OPT (central)* and *OPT (optimistic)* scenarios. In *GRT* scenarios by contrast, natural gas demand declines more steeply (see Figure B.8), causing prices to fall further as well.

3.2. Spatial structure of the market

The low-carbon hydrogen market simulated in the *OPT (central)* and, to a lesser degree, the *OPT (optimistic)* scenarios, is essentially an adjunct to the natural gas market. Due to a higher volumetric energy density and existing infrastructure, natural gas is less costly to transport than hydrogen. As a result, natural gas-based low-carbon hydrogen is always produced in the country where it is also consumed.

In the *OPT (optimistic)* scenario, around 33% of global hydrogen production is RES-based in 2050. Differences in the quality of RES potentials between countries and regions are significant enough to make the long-distance transmission of RES-based hydrogen an economically viable option in several cases. In 2050, 4% of the hydrogen produced is traded across international borders, all of it via pipeline.

In the *GRT (central)* and *GRT (optimistic)* scenarios, by contrast, a significant fraction of the low-carbon hydrogen produced is traded across international borders, since production cost gaps between countries with low-cost RES potentials and countries with less favourable RES potentials located in the same general region are wide enough to make trade economical.

Trade is based almost exclusively on hydrogen pipelines. Although the model permits the seaborne transportation of liquid hydrogen in all scenarios, due to its high cost, it is only relevant in the *GRT (central)* and *GRT (optimistic)* scenarios, and only in the case of Japan.[15]

Most of the cross-border trade in hydrogen takes place in Europe. Cross-border flows into and inside Europe account for 98% of the total international trade in pure hydrogen in 2050 in the *GRT (central)* and 94% in the *GRT (optimistic)* scenario. Figure 4 displays the modelled hydrogen pipeline flows and national hydrogen prices in Europe and the vicinity in the *GRT (central)* scenario. 78% of the pure hydrogen consumed in Europe in 2050 is imported from outside the region, with 20.7 Mt supplied by Morocco, 12.1 Mt by Algeria and 2.4 Mt sourced from Iran. Within Europe, hydrogen flows from south to north, with Spain, France and Italy transiting substantial volumes destined for northwestern Europe. Hydrogen production in Europe itself amounts to only 10.4 Mt in the *GRT (central)* scenario, consisting mainly of PV-based production in Spain and Onshore wind-based production in Scandinavia.

Countries are mostly self-sufficient in hydrogen in the rest of the world, even in the GTR scenarios. However, there is substantial long-distance pipeline transmission in large countries such as China, Russia or the United States that are modelled as multiple nodes. The pipelines link more remote areas with good RES potentials, such as Western China, Southwestern Russia or the Southwestern United States, to consumption centres in the same countries.

[15] Due to the high cost of domestic RES-based hydrogen production and the lack of pipeline-based import options, Japan sources 64% of the hydrogen it consumes in the form of liquid hydrogen imports from Oman in 2050 in the *GRT (central)* scenario. The production cost gap between Japan and Oman is wide enough to offset the cost of liquefying, shipping and regasifying the hydrogen plus the associated infrastructure cost.

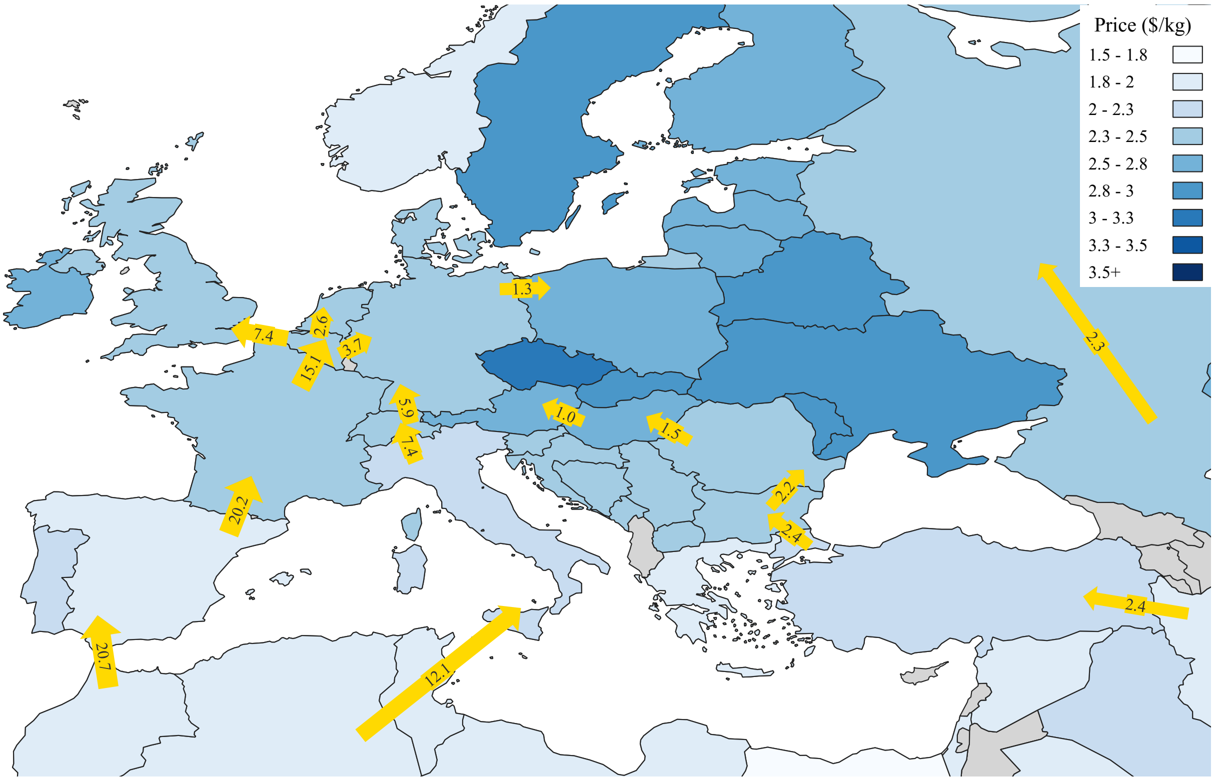

Figure 4: Hydrogen pipeline flows (in Mt/a) and hydrogen prices (in $/kg) in Europe and the vicinity in the GRT (central) scenario

3.3. Hydrogen prices

Figure 5 displays consumption-weighted average local hydrogen prices in four important hydrogen consumption regions (China, Europe, Japan and the US). Taken together, they account for 64% of global low-carbon hydrogen demand in 2050.

In the OPT scenarios, the availability of natural gas-based low-carbon hydrogen, leveraging comparably low natural gas prices, keeps prices below $2/kg in all regions for the 2030 to 2050 period. By contrast, in the GRT scenarios, prices are high early on and fall over time due to the assumed decline in RES and electrolyser investment costs.

From the large hydrogen consumers shown in Figure 5 the US exhibits the lowest prices overall in both the OPT and the GRT scenarios since it combines large, high-quality renewable energy potentials with low natural gas prices due to an abundance of low-cost supply.

The highest prices are found in Japan. In the OPT scenarios, the country relies entirely on more expensive LNG to produce natural gas-based low-carbon hydrogen. In the GRT scenarios, owing to its insularity and high-cost RES potentials, Japan imports liquid hydrogen, its marginal cost setting the local hydrogen price.

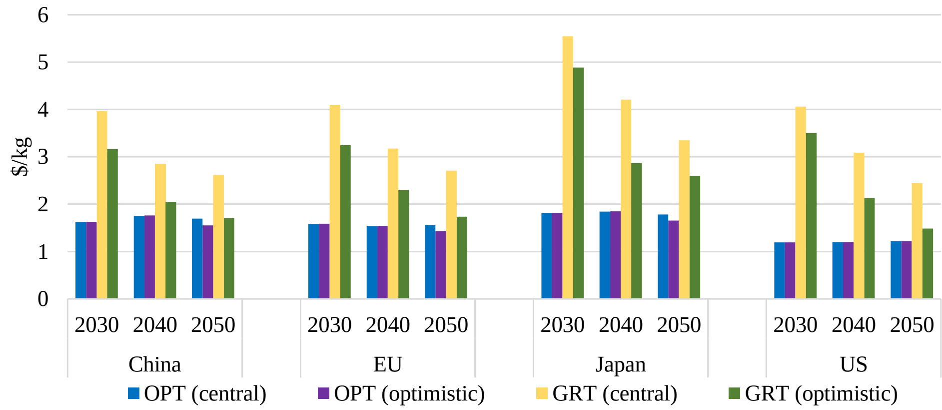

Figure 5: Estimated hydrogen prices for major consumers by scenario

Table 2 displays the mean, country-level global hydrogen price, its standard deviation and the volume-weighted mean global hydrogen price, by scenario and year. It illustrates that when RES-based hydrogen production is the dominant pathway globally (*GRT (central)* and *GRT (optimistic)* scenario), mean price levels are higher. Standard deviations are greater, meaning price differentials between different countries and regions are larger. The latter is due to the spatial heterogeneity of RES potentials, resulting in more significant differences in hydrogen production costs between countries well-endowed in RES and RES-poor countries.

Maps depicting country-level hydrogen prices calculated by the model for the year 2050 can be found in Appendix B (Figures B.10 to B.13).

Table 2: Mean price ($\overline{x}_p$), standard deviation (σ_p) and volume-weighted mean price ($\overline{x}_{p,weighted}$)

	OPT (central)			**OPT (optimistic)**			**GRT (central)**			**GRT (optimistic)**		
	2030	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
$\overline{x}_p$	1.4	1.5	1.5	1.4	1.4	1.2	3.5	2.7	2.3	3.1	1.9	1.5
σ_p	0.4	0.4	0.4	0.5	0.4	0.4	1.3	1.5	1.5	1.8	1.3	1.3
$\overline{x}_{p,weighted}$	1.5	1.6	1.5	1.5	1.5	1.3	3.8	2.8	2.3	3.2	1.9	1.5

4. Discussion

Although the four scenarios presented in the previous section are unlikely to represent how the global low-carbon hydrogen market will develop in reality, they yield important insights on the impact of technology costs and technology choices on the potential structure and evolution of the market for low-carbon hydrogen.

4.1. Key findings and implications

RES potentials and access to low-cost natural gas determine a country's or region's position in the global low-carbon hydrogen supply curve.

Notable is the general resilience of natural gas-based hydrogen production. The OPT scenarios illustrate that if low-carbon hydrogen production is predominantly natural gas-based, the hydrogen market is essentially an adjunct to the natural gas market. Natural gas is transported over large distances, and hydrogen is produced chiefly close to the point of consumption. There are two primary reasons for this: First, due to its lower volumetric energy density, hydrogen is more costly to transport than natural gas, in particular by ship. Secondly, there already is an extensive infrastructure for the transportation of natural gas, which can be leveraged to support the development of natural gas-based hydrogen production. The OPT scenarios also show that natural gas-based low-carbon hydrogen production is not merely a bridge towards a RES-based future, but a potential long-term solution for many countries, especially if global natural gas prices trend downwards as the world decarbonises and the demand for natural gas in other sectors decreases. This finding is robust even if electrolyser and RES investment costs continue to decrease substantially, following an optimistic cost trend.[16]

The analysis shows that long-distance trade in pure hydrogen is unlikely to occur on a relevant scale until RES-based low-carbon hydrogen production makes up a substantial share of the global supply mix. Countries with substantial hydrogen demand but poor RES potentials face higher prices than countries well endowed with cost-competitive RES. As a result, a long-distance, cross-border trade in hydrogen becomes an economically viable proposition under some circumstances. The scenario analysis shows that the greater the share of RES-based production in the global low-carbon hydrogen supply mix, the greater the amount of hydrogen traded across borders. The model-based analysis confirms the hypothesis of Brändle et al. (2021) that the comparably high cost of transporting pure hydrogen would lead to the emergence of regional rather than a global market for low-carbon hydrogen. These regional markets are organised around hydrogen pipeline networks. Seaborne trade based on the far more energy-intensive liquefaction of hydrogen, on the other hand, was shown not to be economical in the long run, except for cases like Japan, which combine limited, relatively high-cost domestic production potentials with a geographic location that makes importing hydrogen via pipeline infeasible. However, it should be emphasised that this finding pertains strictly to pure hydrogen. Other analyses (e.g., Hank et al., 2020; Hampp et al., 2021; Moritz et al., 2022) suggest that when the desired end product is a synthetic, hydrogen-based energy commodity, such as ammonia or methanol, producing the commodity in countries with low-cost RES and then shipping it to the destination may be cost competitive.

[16] While a pessimistic cost trajectory for RES and electrolysers was not explicitly considered in the analysis presented above, the results of the *OPT (central)* scenario, where the global supply mix is almost entirely natural gas-based even in 2050, suggest that such an outcome would further reinforce the competitive edge of natural gas-based hydrogen production technologies.

The high cost of transporting pure hydrogen over long distances means that scenarios with high shares of RES-based hydrogen production feature greater price differentials between countries than when production is primarily natural gas-based. Existing natural gas pipeline networks and LNG ensure that the global gas market exhibits a significant degree of price convergence, which feeds through into the production cost of, and thus price for, natural gas-based hydrogen. In scenarios where RES-based hydrogen production pathways predominate, the highest hydrogen prices are found in RES-poor regions, such as Central and Eastern Europe and parts of East Asia. If production is mainly natural gas-based, hydrogen prices are effectively set by the local prices for natural gas, which are highest in East Asia. In scenarios dominated by natural gas-based hydrogen production pathways and in scenarios dominated by RES-based pathways, some of the lowest hydrogen prices are found in North America, particularly the United States. The region combines a large natural gas resource base with high-quality PV and Onshore wind potentials located not too far from prospective hydrogen consumption centres along the West Coast and the Eastern Seaboard.

The model-based analysis further suggests that imports may play an important role in the European hydrogen supply mix if strong demand for RES-based low-carbon hydrogen develops, indicating that it would be economical for the region to import significant quantities of hydrogen from North Africa, primarily Algeria and Morocco. The high reliance on imports is mainly driven by the lower availability and increased competition for low-cost RES in Europe. The potential dependence on a limited number of large suppliers raises issues around diversification and security of supply that are already familiar with natural gas, albeit on a smaller scale and involving different actors.

Generally, the results presented above confirm the inference of Brändle et al. (2021) on the global low-carbon hydrogen supply curve and the structure of the market: natural gas-based hydrogen appears to be a broadly competitive option even in the long-run, while the high cost of transporting pure hydrogen, in particular by sea, leads to the emergence of regional markets organised around pipeline networks.

4.2. Limitations and opportunities for further research

There are limitations to the analysis presented in this paper, creating opportunities for future research.

Firstly, the emerging market for low-carbon hydrogen and the global market for natural gas is assumed to be perfectly competitive. However, in reality, this may not be the case. On the natural gas market, individual suppliers have at times been in a position to exercise market power (Growitsch et al., 2014; Schulte and Weiser, 2019). Furthermore, policy choices, strategic objectives and geo-economic considerations will also shape the future evolution of the low-carbon hydrogen market (see, e.g., Van de Graaf et al., 2020).

The model presented in the paper at hand is able to simulate potential strategic behaviour of market participants (Cournot competition) and thus lends itself to future extensions of this work in that direction. Furthermore, additional scenarios considering country-specific policy choices and strategic objectives could be defined to gain a deeper understanding of plausible market development pathways.

Secondly, the production and consumption of hydrogen-based synthetic energy commodities, such as ammonia or methanol, is treated as exogenous to the model. These energy commodities are likely to increase in relevance as economies decarbonise, and separate markets for them may thus emerge. As mentioned above, once produced, these energy commodities are less costly to transport over large distances than pure hydrogen, in particular by ship. It is thus not inconceivable to potentially see more robust price convergence and market integration for these commodities than for pure hydrogen. Production of these commodities would likely be concentrated in regions with low-cost renewable energy potentials that are otherwise not well-positioned geographically to export pure hydrogen to major consumers, for example, because the establishment of pipelines is infeasible. Future research could thus entail an extension of the model developed for this analysis to cover hydrogen-based energy commodities.

Thirdly, the potential impact of higher energy costs implicit in the scenario setup used for this analysis on economic growth and energy consumption is not considered since it is a partial equilibrium analysis focusing on the impact of hydrogen supply technology choices and costs on the global market for low-carbon hydrogen.

Low-carbon hydrogen demand is treated as inelastic and assumed not to vary between scenarios, even though the analysis shows that hydrogen prices can differ significantly between countries, particularly in scenarios with high shares of RES-based low-carbon hydrogen production. Future research to estimate the expected price-responsiveness of hydrogen demand, for example, using large-scale, global energy system models, would therefore be necessary to derive additional insights on the impact of supply technology choices on hydrogen demand itself.

Furthermore, the link between energy costs and the cost of energy technologies is not modelled. Investment costs are exogenous to the model, and potential variations are captured through scenarios representing a central and optimistic cost trend for RES and electrolysers. However, some analyses predict a decline in the energy return on energy invested (EROI) of the global energy system when comparably energy-dense fossil fuels are phased out in favour of less energy-dense renewables. This would increase the materials intensity of the world economy (see, e.g. Sers and Victor, 2018; Capellán-Pérez et al., 2019; Jackson and Jackson, 2021), which could, in turn, translate into higher than anticipated investment costs for energy technologies such as solar panels and electrolysers. Future research into the interaction between falling energy yields, increasing investment requirements and energy costs in a decarbonising global economy would be helpful to project better the evolution of the total cost of different low-carbon hydrogen production pathways, allowing for further refinement of the assumptions underpinning hydrogen market models such as the one presented in this paper.

5. Conclusions

This paper analyses the impact of supply technology choices and costs on structures and prices on the emerging low-carbon hydrogen market using a novel, integrated natural gas and hydrogen market model. Four scenarios are simulated, analysed, and compared to assess the impact of supply technology choices and costs on the potential evolution of the emerging global market for low-carbon hydrogen until 2050, focusing on the supply technology mix, the spatial structure of the market and market prices. The scenarios are based on the IEA's Sustainable Development Scenario and assume a deep decarbonisation of the global economy until 2050.

The model-based analysis shows that natural gas-based low-carbon hydrogen production pathways predominate in technology-neutral scenarios in 2050, even when the decline in RES and electrolyser investment costs follows an optimistic trend. The strong economic performance of natural gas-based technologies is supported by natural gas prices that are low by historical standards in most regions. The low natural gas price environment results from an assumed decline in natural gas consumption in sectors other than hydrogen production as major economies decarbonise. In scenarios where hydrogen production is mostly gas-based, the hydrogen market is effectively an adjunct to the natural gas market. Pure hydrogen is more costly to transport than natural gas. Therefore, the latter is transported over large distances and the former is mainly produced close to the point of consumption. Natural gas prices thus determine local hydrogen prices.

In scenarios characterised by high shares of RES-based low-carbon hydrogen production, long-distance, cross-border trade in hydrogen becomes an economically viable proposition. This is due to the heterogeneous distribution of low-cost RES potentials, which widens hydrogen price spreads between countries with substantial hydrogen demand but poor RES potentials and countries well endowed with cost-competitive RES. However, due to the high cost of transporting pure hydrogen, trade is regional rather than global and organised around hydrogen pipeline networks. Seaborne trade based on liquid hydrogen was shown not to be economical in most cases. The analysis finds the most significant potential for cross-border trade in and around Europe. It suggests that it would be economical for Europe to import significant quantities of hydrogen from North Africa.

Acknowledgements

Financial support for this research by the "Research Programme Hydrogen: The Role of Gas in the Energy Transition", an initiative of the Society of Benefactors to the EWI (Gesellschaft zur Förderung des EWI e.V) is gratefully acknowledged. I thank Marc Oliver Bettzüge for his valuable guidance and support. I also thank Gregor Brändle and Simon Schulte for their suggestions and feedback.

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Appendix A. Assumptions

Appendix A.1. Demand for low-carbon hydrogen

Projections for the future development of global demand for natural gas and low-carbon hydrogen used in the paper at hand are based on the Sustainable Development Scenario (SDS) of the International Energy Agency (IEA). The SDS describes a scenario in which international climate and energy access goals are met and the world is on track to achieve net-zero greenhouse gas emissions by 2070 (IEA, 2020a).

The IEA (2020a) projects global demand for low-carbon hydrogen to increase sharply after 2030, rising from 35 Mt to 258 Mt until 2050. In 2050, 37% is consumed in the transport sector[17] 34% in industry[18] and 10% in the buildings sector. The remaining 19% are consumed in other sectors, where hydrogen provides an important source of backup power for intermittent RES (IEA, 2020a).

IEA (2020a,b) do not provide a breakdown of low-carbon hydrogen demand by country or region. In order to derive the country-level estimates required for this analysis, additional assumptions have to be made.

Firstly, due to its higher cost relative to other, albeit more carbon-intensive fuels, hydrogen is likely to be used in high-income economies first. As a simple approximation, it is therefore assumed that 80% of global low-carbon hydrogen is consumed by high-income economies[19] plus China and the remaining 20% by other medium- and low-income countries.

Secondly, industrial and transport sector hydrogen demand is allocated to individual countries based on their share in the projected combined GDP (OECD, 2018) of all of countries in their respective income group. The underlying rationale is that since higher absolute GDP tends to correlate with higher absolute industrial output and transportation demand and thus energy consumption, sectoral hydrogen demand can be distributed accordingly as well. Hydrogen consumed in other sectors, most importantly buildings, on the other hand, is mainly used for heating. Some of it is also blended into natural gas grids (IEA, 2020a,b). In sectors other than transport and industry, the spatial distribution of low-carbon hydrogen demand within an income group is assumed to mirror that of natural gas, its direct substitute.

The assumed regional distribution of low-carbon hydrogen demand is shown in Figure 1 in Section 2.2.

Appendix A.2. Demand for natural gas

In the SDS, global natural gas demand peaks around 2025 at 4166 bcm and then declines to 3554 bcm in 2040 (IEA, 2020b, p. 339). However, demand trends differ between regions: a rapid decline in Europe and North America is contrasted by growth in the Asia Pacific, primarily China and India (IEA, 2020b, p.

[17] Including hydrogen used for the production of synthetic fuels.

[18] Including hydrogen used in refining and for the production of low-carbon ammonia.

[19] As per the current World Bank classification (World Bank, 2021).

48). After 2040, consumption in Asia peaks as well, and global natural gas demand declines to 3195 bcm[20] by 2050.

Since the demand projections in IEA (2020b) are only provided for regional groupings and large countries, the residual regional gas demand is distributed to the remaining countries covered by the model based on their share in the respective region's 2018 residual natural gas consumption, obtained from IEA (2019a). Gas demand projections for selected African countries come from IEA (2019d).

It should be noted that a part of the natural gas consumption presented above is associated with the natural gas-based production of low-carbon hydrogen. However, since the level of gas-based hydrogen production is an outcome of the model, hydrogen-related natural gas consumption as projected by the IEA has to be deducted from the total natural gas demand presented above to arrive at a consistent estimate of the residual, non-hydrogen-related natural gas demand. Since this information is not provided directly by IEA (2020b), further assumptions have to be made. According to IEA (2020a), approximately 50% of the low-carbon hydrogen consumed in the SDS is produced from fossil fuels with CCS—mostly natural gas. Therefore, by taking half of the low-carbon hydrogen demand presented above and dividing by the efficiency of a natural gas reformer with carbon capture and storage (CCS) technology (69%) (Brändle et al., 2021), it is possible to derive a rough estimate of hydrogen-related natural gas consumption in the SDS, which is deducted from the total natural gas consumption given by (IEA, 2020b) to estimate global non-hydrogen-related natural gas consumption. The resulting distribution of the global demand for natural gas, broken down by region, is shown in Figure A.6: After peaking in the mid-2020s, non-hydrogen-related natural gas demand declines to 3945 bcm in 2030 and 2534 bcm in 2050.

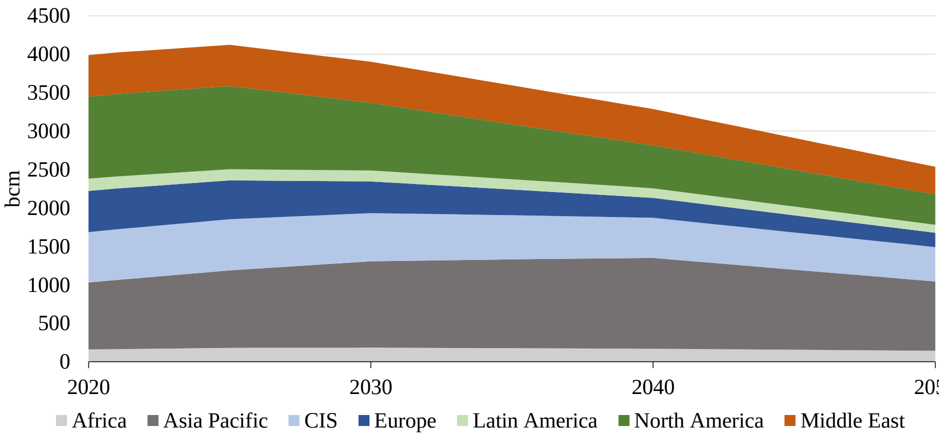

Figure A.6: Assumed annual demand for natural gas (excluding for hydrogen production)

[20]Since neither IEA (2020a) nor IEA (2020b) provide an estimate for global gas demand in 2050, this value was interpolated between the 2040 projection given in IEA (2020b) (3554 bcm) and a 2070 estimate provided in IEA (2020a) (2048 Mtoe). The latter was converted to bcm by dividing it by the energy density ($\frac{Mtoe}{bcm}$) of global gas demand in 2040 (0.828) (IEA, 2020b).

Table A.3: Country-specific CO_2 storage cost used in the model

Country	CO_2 storage assumptions		
	Formation	Location	Cost ($/t$CO_2$)
Algeria	Depleted oil & gas field	Onshore	17.6
Angola	Depleted oil & gas field	Offshore	23.3
Egypt	Depleted oil & gas field	Onshore	17.6
Equatorial Guinea	Depleted oil & gas field	Offshore	23.3
Libya	Depleted oil & gas field	Onshore	17.6
Nigeria	Depleted oil & gas field	Onshore	17.6
Ghana	Depleted oil & gas field	Offshore	23.3
Morocco	Saline formations	Onshore	23.4
Tunisia	Depleted oil & gas field	Onshore	17.6
Mozambique	Depleted oil & gas field	Offshore	23.3
Australia	Depleted oil & gas field	Onshore	17.6
Brunei Darussalam	Depleted oil & gas field	Offshore	23.3
Indonesia	Depleted oil & gas field	Onshore	17.6
Malaysia	Depleted oil & gas field	Offshore	23.3
Myanmar	Depleted oil & gas field	Offshore	23.3
Bangladesh	Depleted oil & gas field	Offshore	23.3
China	Saline formations	Onshore	23.4
India	Depleted oil & gas field	Onshore	17.6
Japan	Saline formations	Offshore	36.2
Korea	Saline formations	Onshore	23.4
Philippines	Depleted oil & gas field	Offshore	23.3
Pakistan	Depleted oil & gas field	Onshore	17.6
Singapore	Depleted oil & gas field	Offshore	23.3
Thailand	Depleted oil & gas field	Offshore	23.3
Taiwan	Saline formations	Offshore	36.2
Vietnam	Depleted oil & gas field	Offshore	23.3
Azerbaijan	Depleted oil & gas field	Offshore	23.3
Kazakhstan	Depleted oil & gas field	Onshore	17.6
Russian Federation	Depleted oil & gas field	Onshore	17.6
Turkmenistan	Depleted oil & gas field	Onshore	17.6
Uzbekistan	Depleted oil & gas field	Onshore	17.6
Ukraine	Saline formations	Onshore	23.4
Georgia	Saline formations	Onshore	23.4
Denmark	Depleted oil & gas field	Offshore	23.3
Netherlands	Depleted oil & gas field	Offshore	23.3
Norway	Depleted oil & gas field	Offshore	23.3
United Kingdom	Depleted oil & gas field	Offshore	23.3
Austria	Saline formations	Onshore	23.4
Baltic States	Saline formations	Onshore	23.4
Belgium	Saline formations	Onshore	23.4
Bulgaria	Depleted oil & gas field	Offshore	23.3
Belarus	Saline formations	Onshore	23.4
Switzerland	Saline formations	Onshore	23.4
Czech Republic	Saline formations	Onshore	23.4
Germany	Depleted oil & gas field	Offshore	23.3
Spain	Saline formations	Onshore	23.4
Finland	Saline formations	Onshore	23.4
France	Saline formations	Onshore	23.4
Greece	Saline formations	Onshore	23.4
Hungary	Saline formations	Onshore	23.4
Ireland	Saline formations	Onshore	23.4
Italy	Saline formations	Onshore	23.4
Poland	Saline formations	Onshore	23.4
Portugal	Saline formations	Onshore	23.4
Romania	Depleted oil & gas field	Offshore	23.3
Sweden	Saline formations	Onshore	23.4
Slovenia	Saline formations	Onshore	23.4
Slovakia	Saline formations	Onshore	23.4
Turkey	Depleted oil & gas field	Offshore	23.3
Moldova	Depleted oil & gas field	Offshore	23.3

Yugoslavia	Saline formations	Onshore	23.4
Argentina	Depleted oil & gas field	Onshore	17.6
Bolivia	Depleted oil & gas field	Onshore	17.6
Peru	Depleted oil & gas field	Onshore	17.6
Trinidad and Tobago	Depleted oil & gas field	Offshore	23.3
Venezuela	Depleted oil & gas field	Offshore	23.3
Brazil	Depleted oil & gas field	Onshore	17.6
Chile	Saline formations	Onshore	23.4
Colombia	Depleted oil & gas field	Onshore	17.6
Caribbean	Depleted oil & gas field	Offshore	23.3
Iran	Depleted oil & gas field	Offshore	23.3
Iraq	Depleted oil & gas field	Onshore	17.6
Oman	Depleted oil & gas field	Onshore	17.6
Qatar	Depleted oil & gas field	Offshore	23.3
Saudi Arabia	Depleted oil & gas field	Onshore	17.6
United Arab Emirates	Depleted oil & gas field	Onshore	17.6
Yemen	Depleted oil & gas field	Onshore	17.6
Bahrain	Depleted oil & gas field	Onshore	17.6
Kuwait	Depleted oil & gas field	Onshore	17.6
Syria	Depleted oil & gas field	Onshore	17.6
Near East	Depleted oil & gas field	Offshore	23.3
Canada	Depleted oil & gas field	Onshore	17.6
United States	Depleted oil & gas field	Onshore	17.6
Mexico	Depleted oil & gas field	Onshore	17.6
South Africa	Saline formations	Onshore	23.4
Iceland	Saline formations	Onshore	23.4
Papua New Guinea	Depleted oil & gas field	Onshore	17.6
Cameroon	Depleted oil & gas field	Offshore	23.3

CO_2 storage costs are calculated based on Roussanaly et al. (2014) and Rubin et al. (2015). An average distance of 200 km between production sites and storage reservoirs and a connection by CO_2 pipeline is assumed.

Appendix B. Supplementary Results

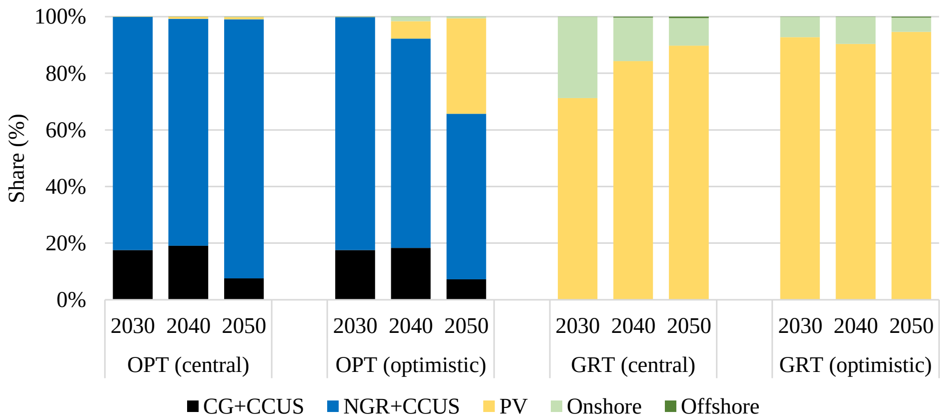

Figure B.7: Share of low-carbon hydrogen production by pathway

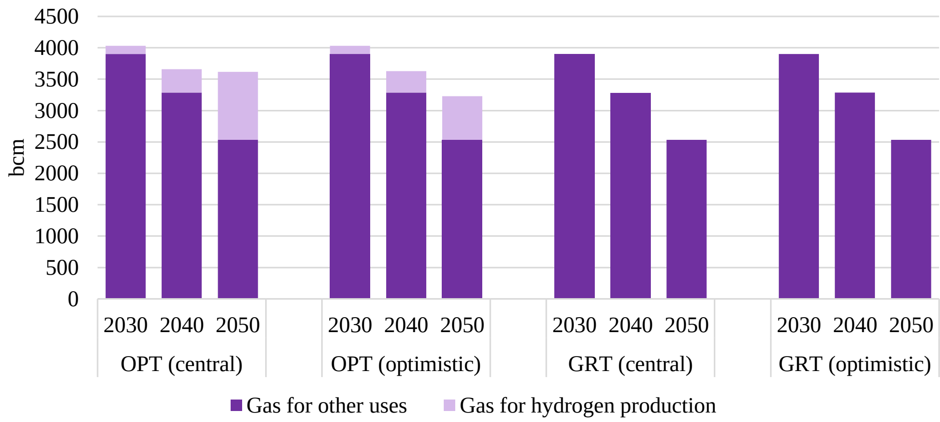

Figure B.8: Global natural gas consumption

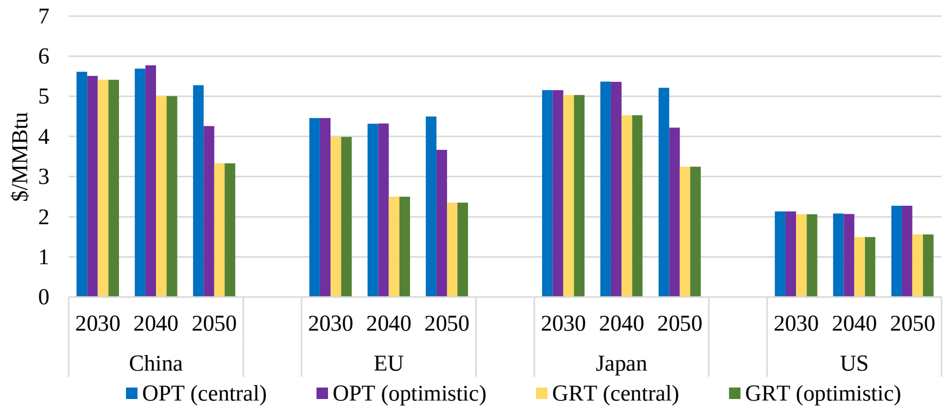

Figure B.9: Estimated natural gas prices for major consumers by scenario

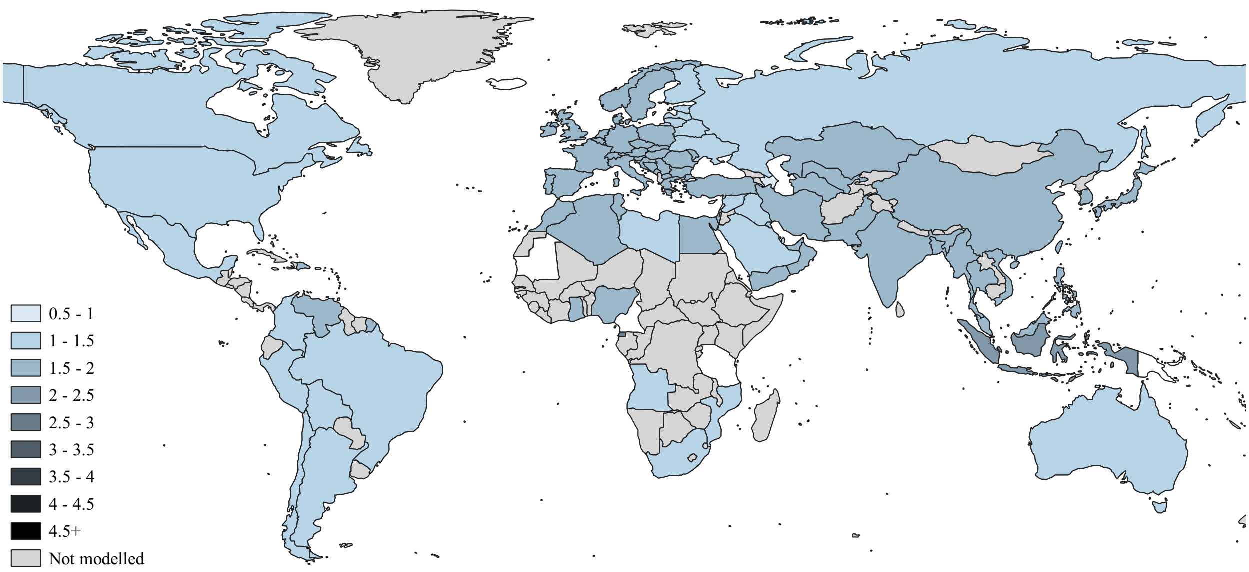

Figure B.10: Hydrogen prices in the OPT (central) scenario in 2050, by country (in $/kg)

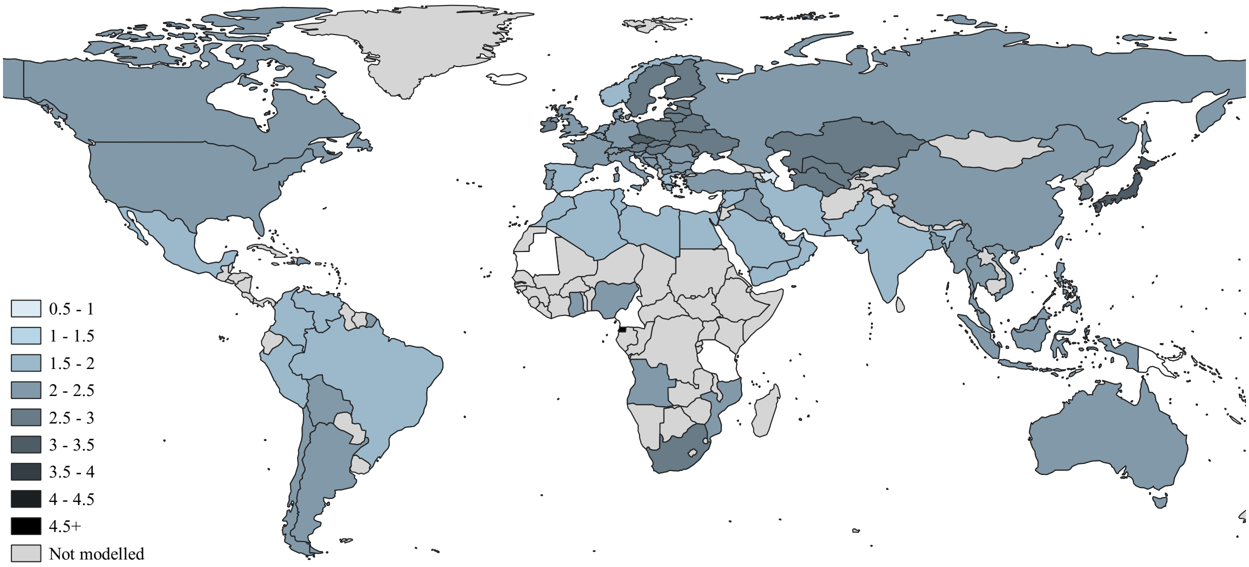

Figure B.11: Hydrogen prices in the GRT (central) scenario in 2050, by country (in \$/kg)

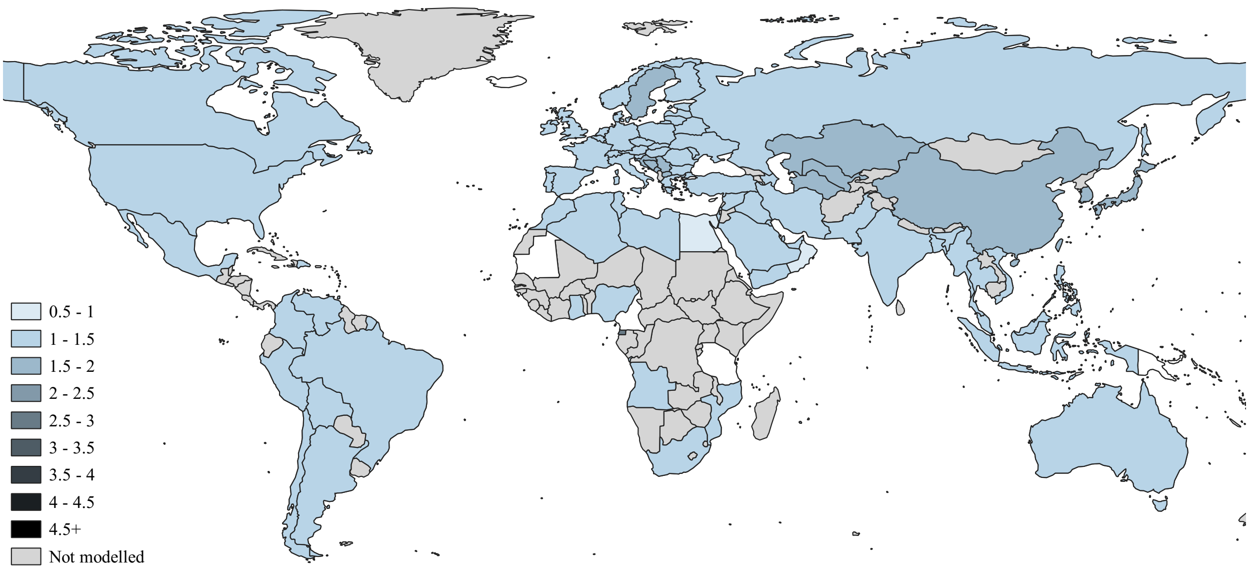

Figure B.12: Hydrogen prices in the OPT (optimistic) scenario in 2050, by country (in \$/kg)

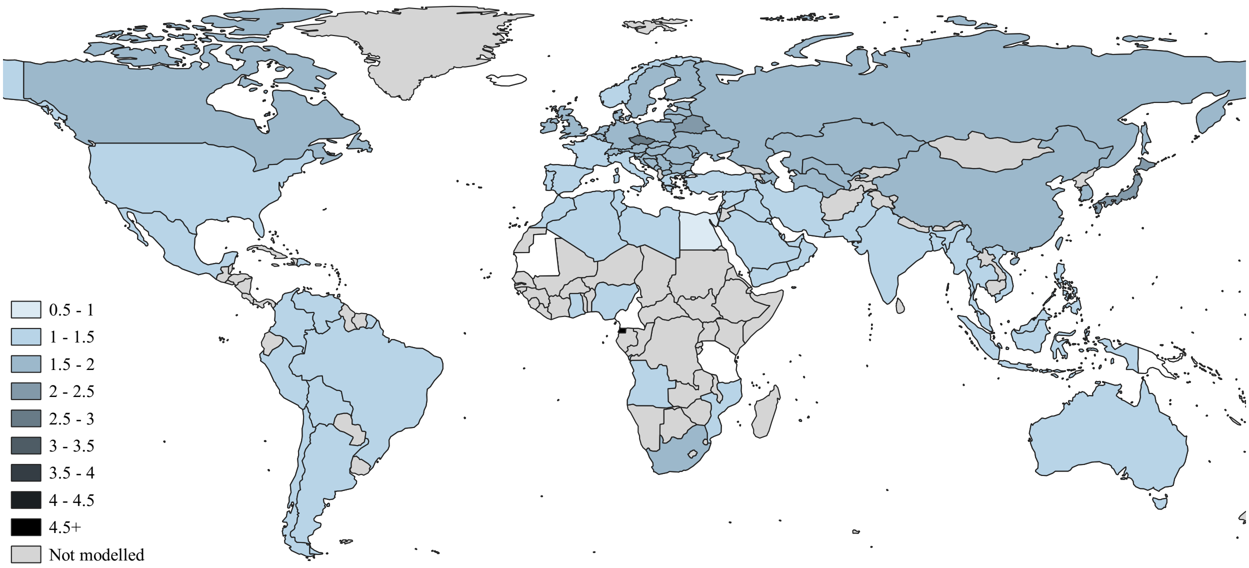

Figure B.13: Hydrogen prices in the GRT (optimistic) scenario in 2050, by country (in \$/kg)