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Abstract

We perform a model-based analysis of the impact of a renewable hydrogen quota on EU gas and electricity markets. By comparing a scenario in which a renewable hydrogen quota with tradable certificates is imposed on final gas consumption in the sectors of the economy outside the EU ETS with a reference scenario without a quota, we assess price, quantity and welfare effects. Our model simulations show that the hydrogen quota leads to a significant expansion in renewable energy sources (RES) capacity to produce renewable hydrogen and synthetic methane with Power-to-Gas (PtG) technologies. On the electricity market, the price increases substantially, rising by up to 12%—mostly due to increasing emission allowance prices—leading to a higher surplus for power producers. The quota's primary beneficiaries in the power sector are renewable energy producers. On the gas market, the quota leads to a small decrease in prices (by a maximum of -3%) and gas producer surpluses. Quota obliged gas consumers, mainly households, commercial and small industrial consumers, carry the largest part of the burden associated with the obligation. Overall, the quota leads to the redistribution of welfare from these consumers to RES and PtG producers and a significant decline in total welfare.

Keywords: Hydrogen, power-to-gas, quota obligation, renewable energy support
JEL classification: C61, Q41, Q42, Q48.

1. Introduction

In 2018, the member states of the European Union (EU)—excluding the United Kingdom (UK)[1]—consumed around 3775 TWh of natural gas, with the fuel accounting for approximately 22% of the EU's total energy consumption (Eurostat, 2020a). However, to achieve ambitious CO_2 mitigation targets, such as reducing EU net emissions to zero by 2050 (European Commission, 2020a), conventional natural gas as an

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[1]The UK left the EU on February 1st, 2020, reducing the number of member states from 28 to 27.

energy carrier must progressively be phased-out in the long-term (Scharf et al., 2021). While electrification presents an option to replace natural gas in some of the end-uses it currently dominates, full electrification may neither be technically feasible in the time frame considered for decarbonisation nor the most economical choice (Ioannis et al., 2020), in particular in sectors that are seen as hard to decarbonise. In space heating, for instance, there is a strong path dependence and high degree of technological lock-in (Gross and Hanna, 2019). The pace of the shift towards alternative heating technologies would have to increase substantially to be consistent with a full decarbonisation of the sector by 2050.

To be consistent with the net-zero objective, the gas supply would thus have to be decarbonised (Speirs et al., 2018). One way to decarbonise the gas supply is to substitute biomethane for fossil natural gas. Estimated theoretical production potentials for the EU and the UK range from 160 TWh (manure only) to 1510 TWh (all potential feedstocks) (Scarlat et al., 2018a,b).

An alternative option is the injection of low carbon hydrogen or hydrogen-derived synthetic methane[2] into the gas grid. Low-carbon hydrogen and gases derived from it can be produced in a multitude of ways, for instance, from biomass, from fossil fuels (in combination with carbon capture and storage/utilisation (CCS/U)) or from the electrolysis of water (through so-called Power-to-Gas (PtG) technologies), provided the electricity used in the process itself comes from a low carbon power source (IEA, 2019b). Supplementing the individual national hydrogen strategies of several member states (Lambert, 2020), the EU published its own hydrogen strategy in 2020, stating a clear political preference for electrolysis-based renewable hydrogen (European Commission, 2020b).

However, technologies to produce renewable hydrogen are not mature enough to compete with conventional energy sources (Speirs et al., 2018; Moraga et al., 2019), particularly at today's carbon price levels. Therefore, additional instruments are often proposed to incentivise the production and uptake of low carbon hydrogen and its derivatives (Moraga et al., 2019). These include, e.g., direct subsidies, tax breaks, loan guarantees (Dolci et al., 2019), state-backed offtake guarantees or carbon contracts for difference (Chiappinelli and Neuhoff, 2020). To encourage the injection of renewable hydrogen or synthetic methane into the natural gas grid, instruments that have been introduced to promote the deployment of renewable energy source (RES) in the power sector, such as feed-in tariffs or quotas with tradable certificates[3] (Menanteau et al., 2003) could conceivably be adapted for this purpose as well.

Against this background, in this paper, we assess and quantify the distributional effects of a renewable hydrogen quota on the electricity and natural gas markets in the EU. The assumed quota is imposed on final gas consumption outside the EU Emission Trading System (EU ETS) in order to act both as an instrument

[2]Hydrogen (H_2) and carbon dioxide (CO_2) can be used to produce synthetic methane (CH_4).

[3]Quotas with tradable certificates are or have been used in several countries to promote the adoption of RES in the electricity sector. In Europe, these include, for example, Belgium, Ireland, Sweden and the United Kingdom (CEER, 2018).

to facilitate the large-scale deployment of PtG technologies and to reduce emissions from sectors currently not subject to mandatory capping.

A renewable hydrogen quota (alternatively referred to as a renewable hydrogen obligation) is a policy instrument designed to promote renewable hydrogen and its derivatives and to contribute to the decarbonisation of the gas supply. Our definition of renewable hydrogen is based on the European hydrogen strategy. It refers to hydrogen that is "produced through the electrolysis of water [...] with the electricity stemming from renewable sources." (European Commission, 2020b, p. 3). We further include synthetic methane but exclude biogas, biohydrogen or biomethane as renewable gases to better isolate the effects of PtG on the gas and electricity markets. Furthermore, any other low-carbon hydrogen source, particularly fossil fuel-derived hydrogen with CCS, is not considered. The quota would be imposed on the demand side and requires consumers to source a minimum share of their gas-based energy from renewable hydrogen or hydrogen-derived synthetic methane (Finon et al., 2003). Quotas are a part of the toolbox of policy instruments proposed in the European hydrogen strategy. The strategy suggests the introduction of "minimum shares or quotas of renewable hydrogen or its derivatives in specific end-use sectors" (European Commission, 2020b, p. 11), such as the chemical industry or the transport sector (European Commission, 2020b). Analogous to a renewable energy obligation with tradable green certificates, a renewable hydrogen quota could in practice be based on a system of tradable certificates: once a unit of hydrogen or hydrogen-derived gas is injected into the gas grid by a PtG producer, a renewable hydrogen certificate is generated. This certificate can then be sold to a consumer, who needs to purchase enough certificates to demonstrate its compliance with the quota obligation to the regulator. A quota designed in such a manner decouples the financial from the physical hydrogen flows, allowing for "virtual blending" (European Commission, 2020b, p. 11), i.e. a variation in the injection and thus the hydrogen share in different gas grids and potentially across member states, increasing economic efficiency (Haas et al., 2004).

Under a quota with tradable certificates, PtG producers have two income sources: from selling hydrogen to gas consumers at the natural gas price and from selling renewable hydrogen certificates to quota obliged consumers. They receive the equilibrium price on the certificate market (Finon et al., 2003). Assuming the certificate market is perfectly competitive, producers are incentivised to offer certificates at their long-run marginal cost of production, which consists of the price for renewable electricity, fixed and variable operations and maintenance costs, annualised investment costs, and—if the hydrogen is converted into synthetic methane—the cost of the CO_2 feedstock required, less the natural gas price. As a result, the PtG producers with the lowest marginal cost will satisfy the demand for renewable hydrogen (Kildegaard, 2008) and the trading of certificates guarantees that the quota is met in a cost-efficient manner (Finon et al., 2003; Menanteau et al., 2001).

As mentioned above, injecting renewable hydrogen or synthetic methane into gas networks is an option for both PtG integration and gas sector decarbonisation (Speirs et al., 2018; Quarton and Samsatli, 2018).

While synthetic methane is of natural gas quality and can be injected into natural gas pipelines unrestrictedly, hydrogen can be blended with natural gas only up to a specific limit (Moraga et al., 2019), which varies from country to country and is currently 10 vol-% in Germany, 6% in France and 4% in Austria, for example (Hydrogen Europe, 2018). Injecting too much hydrogen into natural gas pipelines can damage some existing transportation, metering and end-use equipment. The level at which the injection takes place also plays a role. Hydrogen injection into gas distribution pipelines is mostly considered as less of a concern than injection into gas transmission grids (Haeseldonckx and D'haeseleer, 2007; Quarton and Samsatli, 2018).

From a market perspective, blending renewable hydrogen and synthetic methane with natural gas creates another link between the electricity and the natural gas markets. So far, gas-fired power plants are the only interface between the power and gas systems (Ordoudis et al., 2017). Several studies have assessed the interaction between gas and power markets using market models (e.g. Ordoudis et al. (2019); Yang et al. (2015); Dueñas et al. (2013)). The interaction between both markets is typically simulated by providing the natural gas demand of gas-fired power plants as an input to the gas market model and, in turn, the gas prices/gas supply availability derived using the gas market model as an input to the electricity market model. Yang et al. (2015) iteratively simulate gas and power systems in order to assess the interaction between the sectors on both a physical and an economic level. Market and system interdependence are evaluated by analysing physical (e.g. transmission limits, load variation) and economic parameters to better understand system and market reactions (e.g. market prices, outages).

A renewable hydrogen quota will lead to an expansion of PtG capacity and production. The integration of PtG into the electricity and natural gas systems increases both markets' interdependence and gives rise to additional interactions. Helgeson and Peter (2020) investigate the coupling of the European electricity and road transport sectors through—among other technologies—hydrogen and hydrogen-derived fuels (including PtG) using a multi-sector energy market model. They show that an increase in the production of hydrogen and hydrogen-derived fuels leads to a rise in marginal electricity generation costs. Vandewalle et al. (2015) present a stylised model implemented as a mixed-integer linear programme to analyse the interaction of natural gas, electricity and carbon emissions markets. They assume that PtG plants produce synthetic methane using only excess electricity from solar photovoltaics (PV) and wind turbines that would otherwise be curtailed, finding that PtG integration increases the market value of RES and triggers a decline in gas market prices. Similarly, Roach and Meeus (2020) use a stylised deterministic model formulated as a mixed complementary problem (MCP) to investigate the price and welfare effects of PtG on the gas and electricity markets. They assume that the gas and electricity market clear separately but are coupled by PtG plants. They show that electricity consumers benefit from PtG integration because it decreases RES premia. Gas consumers profit from lower gas prices, as PtG injection replaces natural gas production. Lynch et al. (2019) study portfolio effects of PtG by developing and applying a stylised, stochastic MCP with profit-maximising firms and cost-minimising consumers. Firms can endogenously invest in electricity and PtG generation capacities, whereby generation from RES receive a feed-in premium. Their results indicate that investment in PtG becomes attractive with wind penetration above approximately 50% and lead to a transfer of rents from consumers to wind power producers as PtG increases overall electricity prices.

Previous work focused mostly on either the technical impact of injecting hydrogen or synthetic methane into existing gas infrastructure or assessing gas and electricity markets' interaction using numerical models, but mostly with highly stylised system layouts. We add to the existing body of knowledge by analysing the effects and interactions associated with the integration of PtG in natural gas and electricity markets. Whereas the existing literature on the subject applies simplified models, we significantly extend the scope of the analysis by linking two large-scale, data and technology-rich models of the European natural gas and electricity markets, which are run in iterations. To isolate the impact of PtG and the renewable hydrogen quota on both markets, we compare a reference scenario with an alternative scenario in which a progressively rising renewable hydrogen quota is imposed on final gas consumption. We show how cost-optimal generation capacities change over time and how renewable hydrogen and synthetic methane injection impact natural gas prices. In addition to that, we quantify the distributional effects and the changes in rents among different producer and consumer groups on both markets.

We assume that the uptake of PtG in the EU is driven by a uniform renewable hydrogen quota on final gas consumption in sectors of the energy system not subject to the EU ETS. The EU ETS covers the power sector, large industrial emitters and aviation.

Our model simulations show that the renewable hydrogen quota leads to a significant RES capacity expansion to provide the additional electricity required by electrolysers. In the electricity sector, the quota's primary beneficiaries are RES. Since PtG producers are assumed to be obliged to source their electricity from RES simultaneously generating in the same market area, the latter's average profit margins rise significantly. However, conventional power producers also benefit from the increased electricity price, while the same effect leads to a decline in the surplus of power consumers.

On the gas market, the large scale injection of renewable hydrogen and synthetic methane leads to a slight decline in gas prices in the long run. The rents of natural gas producers decline; also because some of their production is displaced by renewable hydrogen and synthetic methane. Ultimately, quota obliged gas consumers carry most of the additional cost associated with the RES and PtG capacity expansion through purchasing the renewable hydrogen certificates needed to demonstrate compliance with the quota.

While the injection of renewable hydrogen is maximised up to the volumetric limits in all member states, synthetic methane production is not equally distributed. The EU-wide quota and tradable certificates allow for an efficient allocation of PtG production across the participating countries, and synthetic methane is produced primarily in countries that combine good RES potentials with a high gas grid capacity, such as Spain. As a consequence, these countries become net exporters of renewable hydrogen certificates.

The remainder of this paper is structured as follows: Section 2 describes the gas and electricity market models, the input data used, and the assumptions made for this analysis. Section 3 presents the results of the scenario simulations and shows the price, quantity and welfare effects. Section 4 concludes with a brief discussion of the results, the limitations of our work and the potentials for further research.

2. Methodology

In order to assess the impact of a renewable hydrogen quota on both markets, we iteratively link two partial equilibrium models of the European electricity and natural gas markets (see Figure 1). Sectoral gas demand, temporal gas demand profiles, PtG capacities and PtG injection volumes are passed from the electricity to the gas market model. The gas market model's simulated gas price is then returned to the electricity market model to initiate the next iteration.[4]

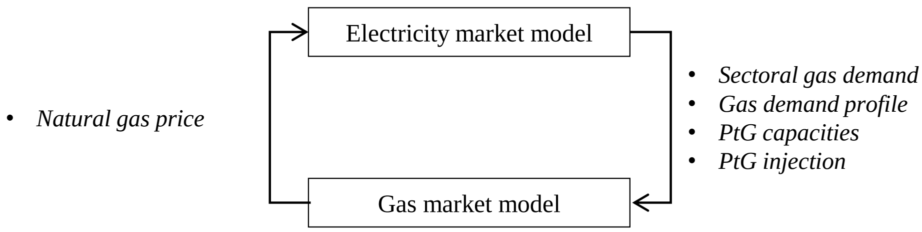

Figure 1: Applied simulation framework

2.1. Electricity market model

The electricity market model is an investment model covering electricity production and consumption in 28 countries in Europe[5]. Initially developed as a standalone electricity market model by Richter (2011), to better replicate future energy systems in which final energy consumption is increasingly electrified, it has since been extended to cover additional end-use sectors, conversion technologies and electricity-derived energy carriers (Helgeson and Peter, 2020).

We endogenously model electricity production, cross-border power flows and electricity-based hydrogen and synthetic methane production. Final electricity and natural gas demand are treated as exogenous inputs. Both are assumed to be inelastic. The electricity market is assumed to be perfectly competitive, allowing the model to be formulated as a constrained linear optimisation problem.

[4]The iteration process is stopped once the annual difference in each of the exchanged parameter between two subsequent iterations is less than 5%.

[5]Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland and the United Kingdom.

The objective function (equation 1) minimises the total system cost (TSC), which is the sum of the fixed and variable cost terms over all energy production technologies i, markets n, years y and time steps t. $\phi_{i,n,y}$ is the fixed cost vector, covering both the fixed investment and operations and maintenance (O&M) costs. Fixed costs are incurred per unit of installed capacity ($\mathbf{C}^{el,ptg}_{i,n,y}$) of all electricity ($el$) and hydrogen/synthetic methane (ptg) production technologies i. $\gamma_{i,n,y,t}$ is the variable cost vector, which comprises the fuel or feedstock costs and other variable O&M costs. Total variable costs depend on the level of production ($\mathbf{Q}^{el,ptg}_{i,n,y,t}$) of technology i.

$$\min \;\; TSC = \sum_{i,n,y,t} \phi_{i,n,y} * \mathbf{C}^{el,ptg}_{i,n,y} + \sum_{i,n,y} \gamma_{i,n,y,t} * \mathbf{Q}^{el,ptg}_{i,n,y,t} \tag{1}$$

The optimisation problem is subject to a number of constraints. The most important constraints governing the model of the electricity system are equations 2 to 5. Constraints describing the production of hydrogen, methanation and the renewable hydrogen quota are given by equations 6 to 10.

The equilibrium constraint (equation 2) ensures that electricity production ($\mathbf{Q}^{el}_{i,n,y,t}$), net imports ($\Delta\mathbf{F}^{el}_{m,n,y,t}$) and net storage flows ($\Delta\mathbf{S}^{el}_{i,n,y,t}$) in market n match the electricity demand ($\mathbf{D}^{el}_{n,y,t}$) for each time step t.

$$\mathbf{D}^{el}_{n,y,t} = \sum_{i} \mathbf{Q}^{el}_{i,n,y,t} + \sum_{m} \Delta\mathbf{F}^{el}_{m,n,y,t} + \sum_{i} \Delta\mathbf{S}^{el}_{i,n,y,t} \qquad \forall \;\; n, y, t, m \neq n \tag{2}$$

Equation 3 states that a generator's electrical output ($\mathbf{Q}^{el}_{i,n,y,t}$) cannot exceed its available capacity, which is derived by multiplying the installed capacity ($\mathbf{C}^{el}_{i,n,y}$) with the time-dependent availability ($\alpha^{el}_{i,n,y,t} \rightarrow [0,1]$). The same constraint also applies to the net transfer capacity linking two electricity markets.

$$\mathbf{Q}^{el}_{i,n,y,t} \leq \mathbf{C}^{el}_{i,n,y} * \alpha^{el}_{i,n,y,t} \qquad \forall \;\; i, n, y, t \tag{3}$$

To reduce the computational burden, the model operates with a reduced temporal resolution. Accordingly, it may not capture rare situations of extreme system stress (e.g. combinations of high load and low RES feed-in) in the time slices that are modelled. To remedy this, a peak load constraint is introduced (equation 4), which requires the sum of generation capacities ($\mathbf{C}^{el}_{i,n,y}$), weighted by their respective secure capacity values[6] ($\sigma_{i,n} \rightarrow [0,1]$), to be greater than or equal to an exogenous, market-specific annual peak load ($\mathbf{l}^{el}_{n,y}$), thereby ensuring that sufficient capacity is installed to maintain security of supply even in situations of extreme load which are not modelled directly.

[6]The capacity value is the percentage of the plant's capacity that is reliably available in situations of extreme system stress. For dispatchable power plants, the capacity value may deviate from 100% due to, e.g., unplanned outages. Weather-dependent variable RES generally have low capacity values.

$$\mathbf{l}^{el}_{n,y} \leq \sum_i \mathbf{C}^{el}_{i,n,y} * \sigma_{i,n} + \sum_m cap^{ntc}_{n,m,y} * \sigma_{n,m,y} \qquad \forall \; n, y, m \neq n \tag{4}$$

In the EU, power plants are subject to a cap on emissions imposed by the EU ETS. In the model, this is approximated by equation 5, which requires the aggregated annual emissions[7] of all power-generating technologies to be lower than the annual cap. The CO_2 emissions are calculated by dividing a generator's output ($\mathbf{Q}^{el}_{i,n,y,t}$) by its efficiency ($\eta^{el}_i$) to determine its fuel consumption, which is then multiplied with the fuel-specific emission factor (ϵ^{CO2}_i).

$$emcap^{CO2}_y \geq \sum_{i,n,t} \frac{\mathbf{Q}^{el}_{i,n,y,t}}{\eta^{el}_i} * \epsilon^{CO2}_i \qquad \forall \; y \tag{5}$$

The following constraints pertain to the production of hydrogen and synthetic methane through the electrolysis of water. Equation 6 links the production of hydrogen and synthetic methane (ptg) to the electricity system: Total electricity demand per time period ($\mathbf{D}^{el}_{n,y,t}$) is the sum of the exogenous electricity demand ($d^{el}_{n,s,y,t}$) in market n and sector s and the sum of the electricity consumed by PtG technologies i in market n. This is obtained by dividing the hourly output of a PtG process ($\mathbf{Q}^{ptg}_{i,n,y,t}$) by its conversion efficiency (η^{ptg}_i).

$$\mathbf{D}^{el}_{n,y,t} = \sum_s d^{el}_{n,s,y,t} + \sum_i \frac{\mathbf{Q}^{ptg}_{i,n,y,t}}{\eta^{ptg}_i} \qquad \forall \; n, y, t \tag{6}$$

PtG production ($\mathbf{Q}^{ptg}_{i,n,y,t}$) is limited to the installed electrolyser or methanation capacity ($\mathbf{C}^{ptg}_{i,n,y}$) (given in kW-electric), times their efficiency (η^{ptg}_i) (equation 7).

$$\mathbf{Q}^{ptg}_{i,n,y,t} \leq \mathbf{C}^{ptg}_{i,n,y} * \eta^{ptg}_i \qquad \forall \; i, n, s, y, t \tag{7}$$

Equation 8 operationalises the renewable hydrogen quota. For each year y, it requires the supply of hydrogen and synthetic methane ($\mathbf{Q}^{ptg}_{i,n,y,t}$) across all markets n to match the demand for gas in final demand sectors s, times the quota ($\kappa^{ptg}_{y,s} \rightarrow [0,1]$).

$$\sum_{i,n,t} \mathbf{Q}^{ptg}_{i,n,y,t} \geq \sum_{n,s,t} d^{gas}_{n,s,y,t} * \kappa^{ptg}_{y,s} \qquad \forall \; y \tag{8}$$

We assume that the hydrogen produced to fulfil the quota obligation is blended into the natural gas grid at the distribution grid level. Equation 9 establishes blending limits for hydrogen. The volume of hydrogen injected is derived by multiplying the production of raw hydrogen ($\mathbf{Q}^{H2}_{i,n,y,t}$) in market n with hydrogen's volumetric energy density ($ncv_{H2} = 3$ kWh/m^3). It has to be less than or equal to the volume of natural gas

[7] In tonnes of CO_2.

consumed in the final demand sectors s, which is derived by multiplying the final gas demand of each sector ($d^{gas}_{n,s,y,t}$) with the volumetric energy density of natural gas (ncv_{CH4} = 10 kWh/m^3), times the hydrogen injection limit ($\lambda_{y,s} \rightarrow [0,1]$).

$$\sum_i \mathbf{Q}^{H2}_{i,n,y,t} * ncv_{H2} \leq \sum_{n,s} d^{gas}_{n,s,y,t} * ncv_{CH4} * \lambda_{y,s} \qquad \forall \; y, t \tag{9}$$

To certify hydrogen as renewable, we presume that the electricity purchased by a PtG producer has to be produced by a RES within the same market area (usually country) and hour. Equation 10 requires the electricity consumed for the production of hydrogen or synthetic methane ($Q^{ptg}_{i,n,y,t}$) within each market n by technologies i in time step t to be matched by electricity generation from renewable energy sources $j \subseteq i$ in the respective market n and time steps t. The constraint ensures that the hydrogen produced to fulfil the quota obligation is renewable. We assume that statistical transfers of renewable electricity between markets are not allowed.

$$\sum_i \frac{\mathbf{Q}^{ptg}_{i,n,y,t}}{\eta^{ptg}_i} \geq \sum_j \mathbf{Q}^{el}_{j,n,y,t} \qquad \forall \; n, j \subseteq i, y, t \tag{10}$$

2.2. Gas market model

We use and extend a European natural gas infrastructure model to assess the impact of hydrogen and synthetic methane injection on natural gas flows and prices. The model was initially developed by Lochner (2011b) and is formulated as a linear optimisation problem that minimises the total cost of natural gas supply in Europe, subject to infrastructure and production constraints. Hence, it is assumed that the European natural gas market is perfectly competitive. The model considers commodity as well as dispatch cost. It covers most of European natural gas transmission infrastructure, consisting of pipelines, gas storage and LNG terminals. All European countries connected to the transmission grid[8] and major exporting countries (Russia, Algeria, Libya and the Southern Gas Corridor) are included with their corresponding annual gas demand and production capacities. In the following, we describe the most important equations governing the model and the extension for PtG injection. Further details on the model can be found in Lochner (2007), Lochner (2011a) and Dieckhöner et al. (2013).

The gas market model consists of a number of nodes n, connected by pipelines with a given transmission capacity. Demand, as well as storage, production and LNG regasification capacities, are assigned to these nodes. The objective function (equation 11) minimises the total cost (TSC) of the natural gas supply over all time periods $t \in T$. It is the sum of the natural gas production cost ($\mathbf{VC}^{prod}_{n,t}$), the cost of transportation ($\mathbf{VC}^{trans}_{n,m,t}$) and the cost of storage ($\mathbf{VC}^{stor}_{n,t}$).

[8]Concerning the EU, all EU member states except for Malta and Cyprus are included in the model.

$$\min \ TSC = \sum_{n,m,t} \mathbf{VC}^{prod}_{n,t} + \mathbf{VC}^{trans}_{n,m,t} + \mathbf{VC}^{stor}_{n,t} \tag{11}$$

The model is subject to a number of constraints. The energy balance condition (equation 12) ensures that the market clears in every time period and requires that the gas volume entering a node n is equal the gas volume exiting a node. Gas flows into the node can be pipeline flows ($\mathbf{F^{trans}_{m,n,t}}$), storage withdrawals ($\mathbf{S^{out}_{z,n,t}}$), production at the node ($\mathbf{Q^{prod}_{p,n,t}}$), LNG regasification ($\mathbf{Q^{lng}_{r,n,t}}$) or synthetic methane injection ($\mathbf{Q^{ch4}_{i,n,t}}$) at the node. Volumes leaving a node can be exogenous demand at the node ($d_{n,t}$), pipeline flows from the node to another node ($\mathbf{F^{trans}_{n,m,t}}$) or storage injections ($\mathbf{S^{in}_{z,n,t}}$). Hydrogen injection is modelled as a reduction of demand at the node ($\mathbf{Q^{h2}_{n,t}}$), since it is assumed to occur at the distribution grid level. Further restrictions to hydrogen injection are stated later.

$$\begin{aligned} &(d_{n,t} - \mathbf{Q}^{h2}_{n,t} * \frac{1}{gcv_{ng}}) + \sum_m \mathbf{F}^{trans}_{n,m,t} + \sum_z \mathbf{S}^{in}_{z,n,t} \\ &= \\ &\sum_m \mathbf{F}^{trans}_{m,n,t} + \sum_z \mathbf{S}^{out}_{z,n,t} + \sum_p \mathbf{Q}^{prod}_{p,n,t} + \sum_r \mathbf{Q}^{lng}_{r,n,t} + \sum_i \mathbf{Q}^{ch4}_{i,n,t} * \frac{1}{gcv_{ng}} \qquad \forall \ n,t \end{aligned} \tag{12}$$

The storage balance condition (equation 13) ensures that storage injections, withdrawals and levels are balanced over time.

$$\mathbf{S}^{level}_{z,n,t} = \mathbf{S}^{level}_{z,n,t-1} + \mathbf{S}^{in}_{z,n,t} - \mathbf{S}^{out}_{z,n,t} \qquad \forall \ z,n,t \tag{13}$$

Production, transportation, regasification and storage injection/ withdrawal are restricted to the exogenous capacities (equations 14-19), which can change over time, for instance, when pipelines are (de-)commissioned. Storage injection and withdrawal capacities additionally depend on the storage level and a factor τ_z as withdrawal rates decrease with falling storage levels due to a loss of pressure.

$$\mathbf{Q}^{prod}_{p,n,t} \leq cap^{prod}_{p,n,t} \qquad \forall \ p,n,t \tag{14}$$

$$\mathbf{Q}^{lng}_{r,n,t} \leq cap^{lng}_{r,n,t} \qquad \forall \ r,n,t \tag{15}$$

$$\mathbf{F}^{trans}_{n,m,t} \leq cap^{trans}_{n,m,t} \qquad \forall \ n,m,t \tag{16}$$

$$\mathbf{S}^{level}_{z,n,t} \leq cap^{level}_{z,n,t} \qquad \forall \ z,n,t \tag{17}$$

$$\mathbf{S}^{in}_{z,n,t} \leq cap^{in}_{z,n,t} * \tau^{in}_{z} * \mathbf{S}^{level}_{z,n,t} \qquad \forall \; z,n,t \tag{18}$$

$$\mathbf{S}^{out}_{z,n,t} \leq cap^{out}_{z,n,t} * \tau^{out}_{z} * \mathbf{S}^{level}_{z,n,t} \qquad \forall \; z,n,t \tag{19}$$

For this paper, the model is extended to model hydrogen and synthetic methane injection into the gas system. The necessary adjustments to the node balance condition were already introduced (equation 12). Further constraints on PtG are stated below. Blending hydrogen into natural gas pipelines is only feasible up to a defined limit to minimise the risk of damaging equipment (see Section 1). Equation 20 ensures that hydrogen injection at demand nodes cannot exceed a defined injection limit (λ_y), defined as a percentage of gas demand at the node. As the distribution grid level is not explicitly modelled, we split demand at a node into distribution- and transmission-level demand (for assumptions on the split into distribution and transmission demand levels see Appendix A). Large consumers, for instance, gas power plants and large industry, often withdraw directly from the transmission grid and are therefore not supplied by a gas mixture of hydrogen and natural gas. Smaller gas consumers like the residential and commercial sector and smaller industrial consumers are assumed to be connected to the distribution grid and thus allowed to be supplied with the gas mixture. The hydrogen injection, given in energy units, is converted to volumes (gcv_{H2}), as the injection limit refers to gas volumes.

The hydrogen injection limit increases over time as it is expected that technological progress and modifications of infrastructure will allow for higher hydrogen blends in the future (see IEA (2019a); Melaina et al. (2013) or, as recently announced by DVGW (2019)).

$$\sum_{i} \mathbf{Q}^{H2}_{i,n,t} * \frac{1}{gcv_{H2}} \leq \sum_{s} \mathbf{D}^{res-com,oth}_{n,t} * \lambda_y \qquad \forall \; n,t \tag{20}$$

The PtG capacities ($cap_{i,c,t}$) are exogenous parameters provided by the electricity market model. Equation 21 ensures that the country-level capacities are distributed optimally[9] to the grid nodes ($\mathbf{C_{i,n,t}}$) assigned in each country. PtG capacities define the upper limit for PtG injection ($\mathbf{Q^{prod}_{i,n,t}}$), at each node (equation 22). The timefactor tf ensures the correct scaling of capacities to generation and depends on the selected temporal resolution of the model.

$$\sum_{n} \mathbf{C}_{i,n,t} \leq cap_{i,c,t} \qquad \forall \; i,c,y \;\; n \in c \tag{21}$$

$$\mathbf{Q}^{prod}_{i,n,t} \leq \mathbf{C_{i,n,t}} * \eta_i * tf \qquad \forall \; i,n,t \tag{22}$$

[9]From the perspective of the gas transmission system.

The optimal total amount of hydrogen or synthetic methane injection in each country is determined by the electricity market model and serves as exogenous input to the gas market model. As the gas market model has a higher spatial resolution than the electricity market model, the injection volumes are allocated to nodes, constrained by the capacity assigned to each node. Equation 23 ensures that the total injection of each technology, in each country and in each time period ($q_{i,c,t}$) is consistent with the allocation by the model ($\mathbf{Q_{i,n,t}}$).

$$\sum_{n} \mathbf{Q}_{i,n,t} \leq q_{i,c,t} \qquad \forall \ i, c, y, n \in c \tag{23}$$

2.3. Assumptions and Data

To quantify the impact of a renewable hydrogen quota on final gas consumption in the sectors outside the EU ETS, we compare a reference scenario (REF) with a scenario in which a quota is imposed (EUQ). Other than the quota, assumptions for both scenarios are identical.

EU electricity and natural gas demand projections are based on the POTEnCIA Central scenario of the EU Joint Research Centre. The scenario describes the possible evolution of the EU energy system based solely on policies and measures introduced until 2017. The POTEnCIA Central scenario was explicitly designed to serve as a benchmark against which alternative pathways can be compared. Consequently, it assumes a substantial decline in CO_2 emissions in the sectors regulated by the EU ETS, most notably heavy industry and power generation. In branches of the energy system not regulated by the ETS, fossil fuel consumption and thus CO_2 emissions are assumed to decline more gradually (Mantzos et al., 2019). To increase the pace of reductions in these sectors, additional policy measures—such as a renewable hydrogen quota—would be required.

The allocation of the gas demand projections from the POTEnCIA Central scenario (classified according to NACE Rev. 2) to the EU ETS, non-EU ETS, transmission system-level and distribution-system level consumption sectors used in this paper is based on the POTEnCIA Central scenario and further own assumptions. Further details on the natural gas demand allocation are provided in the Appendix A.

We represent the EU ETS using a simplified approximation integrated into the electricity market model, in which only the power sector abates endogenously. Emissions from industry and aviation follow an exogenous path taken from the POTEnCIA Central scenario report (Mantzos et al., 2019). The assumption implicit in this setup is that marginal abatement always occurs in the power sector.

Minimum capacity targets for the technology-specific RES build-out in the power sector are taken from the *National Trends* scenario of the draft ENTSOG/ENTSO-E Ten-Year Network Development Plan (TYNDP) 2020, which reflect the latest targets of the individual member states for the development of RES in the power sector (ENTSOG/ENTSO-E, 2020). The initial installed capacities of other generating technologies are taken from Mantzos et al. (2019).

The gas market model computes natural gas prices. Price projections for steam coal and oil are taken from the IEA World Energy Outlook 2020's Sustainable Development Scenario (IEA, 2020).

Gas infrastructure data is based on the gas market model's historical database, which is updated using recent, publicly available data. Cross-border pipeline capacities are retrieved from ENTSOG (2019), LNG regasification capacities from GIE (2019) and storage capacities from GIE (2018). Entry and exit tariffs from/into market areas are set to values published by the ACER market monitoring report 2018 (ACER, 2019). If not otherwise stated in the data sources, capacities and tariffs are assumed to remain fixed over time. Regarding the future expansion of the European gas transmission system, only projects with 'final investment decision' status in the TYNDP 2018 are considered (ENTSOG, 2018).

Commodity costs, i.e. break-even prices of natural gas supply, are derived from a commercial database that covers all domestic European gas production and that of the relevant exporters of pipeline gas and LNG in a high resolution (Rystad Energy, 2020). Expected changes in gas production capacities and the corresponding break-even prices out to the year 2040 are reflected in the dataset and the decreasing gas production of European countries, such as the Netherlands or UK, as well as the increasing gas production by exporting countries, e.g. Russian pipeline exports and aggregated LNG, are thus considered in the model. A visualisation of the gas supply merit order can be found in the Appendix A (Figure A.9).

Technical injection limits of hydrogen into distribution grids vary between countries, and it is as yet unclear what injection limits will be feasible with only minor technical modifications. Currently, 10-20 vol-% are generally considered as the maximum acceptable (Melaina et al., 2013; Müller-Syring and Henel, 2014). Although limits currently differ from member state to member state, for reasons of simplification, moving forward, we assume a fixed injection limit (in vol-%) across the EU (see Table 1), which increases over time. Hence, individual injection limits due to local specificities (e.g. CNG filling stations, sensitive industrial consumers (IEA, 2019a)) are not explicitly considered.

The quota is imposed on final gas demand sectors, which are not part of the EU ETS. The rationale for excluding the EU ETS is that inside it, a renewable hydrogen quota would not lead to a decline in overall CO_2 emissions, as the reduction in emission allowances required by gas consumers would free up allowances to be used elsewhere. Outside the EU ETS, emissions are not capped, and the substitution of renewable hydrogen or synthetic methane for natural gas would reduce total emissions. We further assume that the quota is based on a system of tradable renewable hydrogen certificates, which are valid for one year and can be traded across the EU, and that PtG producers have to obtain their electricity from RES located in the same market area and generating electricity in the same hour. This ensures that there is a temporal and spatial correlation between PtG electricity consumption and RES electricity production. Assumed injection limits and the quota obligations are shown in Table 1.[10]

Table 1: Assumed injection limits in gas demand end-use sectors in vol-% and renewable hydrogen quotas in TWh-% (own assumption based on Melaina et al. (2013); Müller-Syring and Henel (2014); IEA (2019a); Moraga et al. (2019))

	year							
	quota [TWh-%]				limit [vol-%]			
Demand sector	2025	2030	2035	2040	2025	2030	2035	2040
Residential and commercial	5	10	15	20	5	10	15	20
Non EU ETS industry	5	10	15	20	5	10	15	20
EU ETS industry	0	0	0	0	0	0	0	0
Power sector	0	0	0	0	0	0	0	0
Others	5	10	15	20	5	10	15	20

3. Results

The results of the scenario simulations are summarised in this section.[11] The quantity effects (Section 3.2), price effects (Section 3.3) and distributional effects (Section 3.4) of the renewable hydrogen quota are assessed by analysing the difference between the quota scenario (EUQ) and the reference scenario (REF).

The results were generated through an iterative procedure. The electricity and gas market models were parameterised with the data and assumptions presented in Section 2.3. The models were run in iterations, exchanging gas prices, gas consumption and PtG production volumes, until the convergence criterion[12] was met.

3.1. Reference scenario

In the REF scenario, EU final electricity consumption increases by 0.6% per year on average, growing from 3054 TWh in 2025 to 3444 TWh in 2040. The development of the supply mix is illustrated in Figure 2. National renewable energy targets and rising prices in the EU ETS ensure that electricity production becomes significantly less carbon-intensive over time. RES account for 47% of EU net electricity generation in 2025 and 77% in 2040. Coal and lignite are mostly phased-out until 2040. The rapid expansion of wind and solar power between 2025 and 2030 also cuts into gas use in the power sector, depressing the load factors of gas-fired power stations. However, gas power generation stays broadly flat thereafter, with gas-fired capacity providing an essential backup power source for intermittent RES.

[10] The renewable hydrogen quota obligation has the same value as the injection limit; however, the quota refers to per cent of final gas demand in TWh, whereas the injection limit refers to vol-%.

[11] Summary tables can be found in Appendix B.

[12] We defined a less than 5% difference in annual results between two subsequent model runs as our convergence criterion.

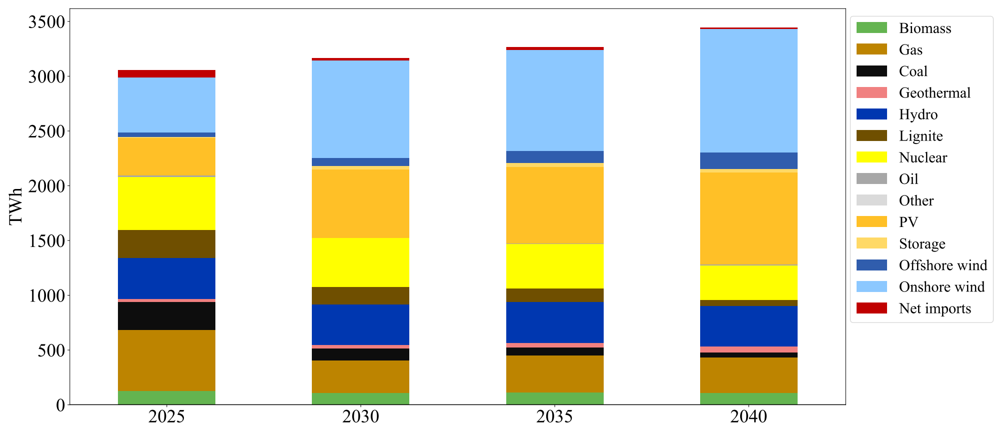

Figure 2: EU electricity generation in the REF scenario

Mainly due to the lower consumption of the power sector, EU natural gas demand drops by 360 TWh/a between 2025 and 2030 and then levels off at around 3260 to 3350 TWh/a until 2040 (see Table B.8 in Appendix B). No hydrogen and synthetic methane are produced for gas grid injection in the REF scenario.[13] EU indigenous gas production declines from around 340 TWh in 2025 to 300 TWh in 2040, but due to decreasing natural gas demand, the import share remains stable at around 90%. The most important suppliers are Russia, Norway and the LNG market, whereby Russian and LNG imports increase, and gas supply from Norway decreases over time.

3.2. Quantity effects of a quota

In the EUQ scenario, a progressively increasing renewable hydrogen quota is imposed on final gas consumption in sectors not regulated by the EU ETS, rising from 5% in 2025 to 20% in 2040 (see Table 1).

Since the quota is assumed to apply to the EU as a whole, the actual production and injection of renewable hydrogen or synthetic methane varies significantly from member state to member state.

Consequently, there is noticeable growth in electricity consumption for hydrogen production: it rises from 200 TWh in 2025 to 807 TWh in 2040. PtG production is a significant consumer of RES-based electricity: in 2025, 13% of RES electricity is already consumed—on balance—for the production of hydrogen, with the share rising to 26% in 2040.

The rise in electricity demand associated with an EU-wide renewable hydrogen quota induces changes in the electricity mix (see Figure 3). Most of the additional electricity is provided by intermittent RES, in particular solar PV and onshore wind. The additional electricity required for electrolysis also leads to a rise in gas-fired electricity production. Some of it displaces coal and lignite. This is due to the cap on CO_2

[13] In the REF scenario, around 10 GW of electrolysers are installed EU-wide by 2040 to feed a small but increasing demand for renewable hydrogen in the industrial sector. This demand is exogenous to the model and based on POTEnCIA Central Scenario assumptions (Mantzos et al., 2019).

emissions imposed by the EU ETS: in the EUQ scenario, power sector emissions are the same as in REF. At the same time, there is an increasing competition for RES-based electricity as some of the RES electricity that would have otherwise been used by other consumers is now diverted to PtG. This leads to an increase in demand for emission allowances and a rising price[14] (see Section 3.3 below), precipitating a coal-to-gas switch. Since gas-fired electricity production is less emission-intensive than coal or lignite, more electricity can be produced for the same absolute level of emissions by using gas.

Furthermore, the EUQ scenario also sees a relative increase in net electricity imports from outside the EU and slightly higher utilisation of nuclear generating capacity.

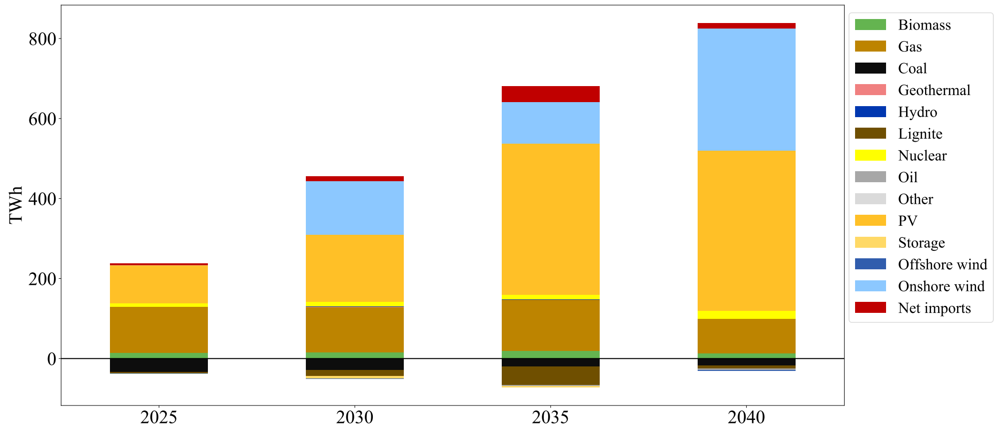

Figure 3: Additional electricity generation in the EUQ scenario

In the EUQ scenario, hydrogen and synthetic methane injection into the gas grid steadily increases, from 103 TWh in 2025 to 452 TWh in 2040. PtG production capacity rises from 26 GW to 117 GW over the same time.

Since the renewable hydrogen quota has to be fulfilled across the EU as a whole, rather than individually in each member state, hydrogen and synthetic methane production and injection vary significantly from country to country, both in absolute terms as well as as a percentage of gas consumption. Owing to the low volumetric energy density of hydrogen and the injection limits in the gas grid, the quota can not be fulfilled by injecting raw hydrogen alone. The level of PtG production in individual member states correlates with two main determinants: overall gas consumption and the availability of cost-competitive RES. Gas consumption determines how much hydrogen and synthetic methane can be absorbed by a country's gas networks. The larger the distribution-grid level gas consumption, the more hydrogen can be injected in absolute terms. Likewise, the higher the gas grid's capacity as a whole, the more synthetic methane can be absorbed by it. The production and injection of raw hydrogen into the distribution grid is maximised up to the volumetric

[14] Since we use a simplified approximation of the EU ETS with exogenous emission reduction pathways for aviation and industry, we implicitly assume that marginal abatement occurs only in the power sector.

limit in all member states since it is always more economical to produce and inject hydrogen instead of synthetic methane. Even in countries with the lowest-cost RES electricity, such as Spain, synthetic methane production, which is not subject to technical injection limits, is more costly than the production of raw hydrogen in the member states with the highest-cost RES electricity.

Figure 4 illustrates the distribution of hydrogen/synthetic methane production and its relationship to overall country-level gas demand. Measured in terms of energy, France and Spain produce slightly more synthetic gas than Germany, despite the latter's much more sizeable gas consumption. However, while in Germany, roughly half of the gas produced in energy terms is pure hydrogen, in France and Spain, most of the hydrogen produced is converted into synthetic methane since the production volumes exceed the assumed capacity of their respective distribution systems to absorb hydrogen. In the EUQ scenario, in 2025 and 2030, Denmark, Estonia, Finland, Greece, Ireland, Portugal, Spain and Sweden generate a surplus (net export) of renewable hydrogen certificates relative to the other member states. In 2040, France, Lithuania and Romania become net exporters as well, while Greece becomes a net importer.

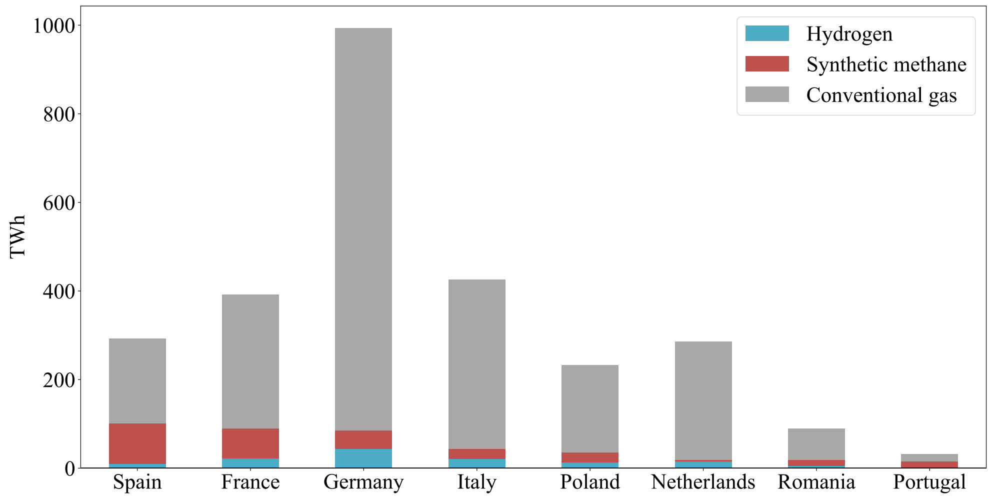

Figure 4: Conventional gas, hydrogen and synthetic methane consumption of the eighth largest gas consumers in the EUQ scenario in 2040

Total natural gas demand is slightly higher in EUQ compared to REF due to higher gas-fired power generation[15]. The difference is greatest in 2030 and 2035, where the relative gas demand in the EU is around 7% higher in the EUQ than the REF scenario. In absolute terms, the increase in demand for natural gas is between 144 TWh (2025) and up to 239 TWh (2035) (see Table B.9 in Appendix B).

While the quota has a noticeable effect on the demand side of the natural gas market, conventional production is only affected in the long term when significant amounts of natural gas are replaced by hydrogen

[15]Note that only power sector gas consumption is derived endogenously. The remaining gas consumption from other end-use sectors is based on the POTEnCIA Central Scenario (Mantzos et al., 2019) and thus unchanged compared to the REF scenario.

and synthetic methane (see Table B.9 in Appendix B). Until 2035, natural gas production hardly differs between the scenarios. Only in 2040 does gas production decrease noticeably compared to the REF scenario, by around 5.7% or 292 TWh/a over all countries that produce gas in or export gas to the EU. Most of the reduction in natural gas production occurs in gas exporting countries, with the UK and LNG experiencing the most significant decrease in relative terms (22% and 15% in 2040). In absolute terms, LNG and Russian gas imports decline the most (105 TWh/a and 103 TWh/a in 2040) relative to the REF scenario. Lower imports from gas exporting countries in the EUQ scenario lead to marked shifts in gas flows in the European gas transmission system (see Figure 5). A noteworthy observation is that the EU's indigenous natural gas production is only 7.3 TWh/a lower in the EUQ scenario. Hence, the replacement of natural gas by hydrogen and synthetic methane mostly affects the gas exporting countries that supply gas to the EU.

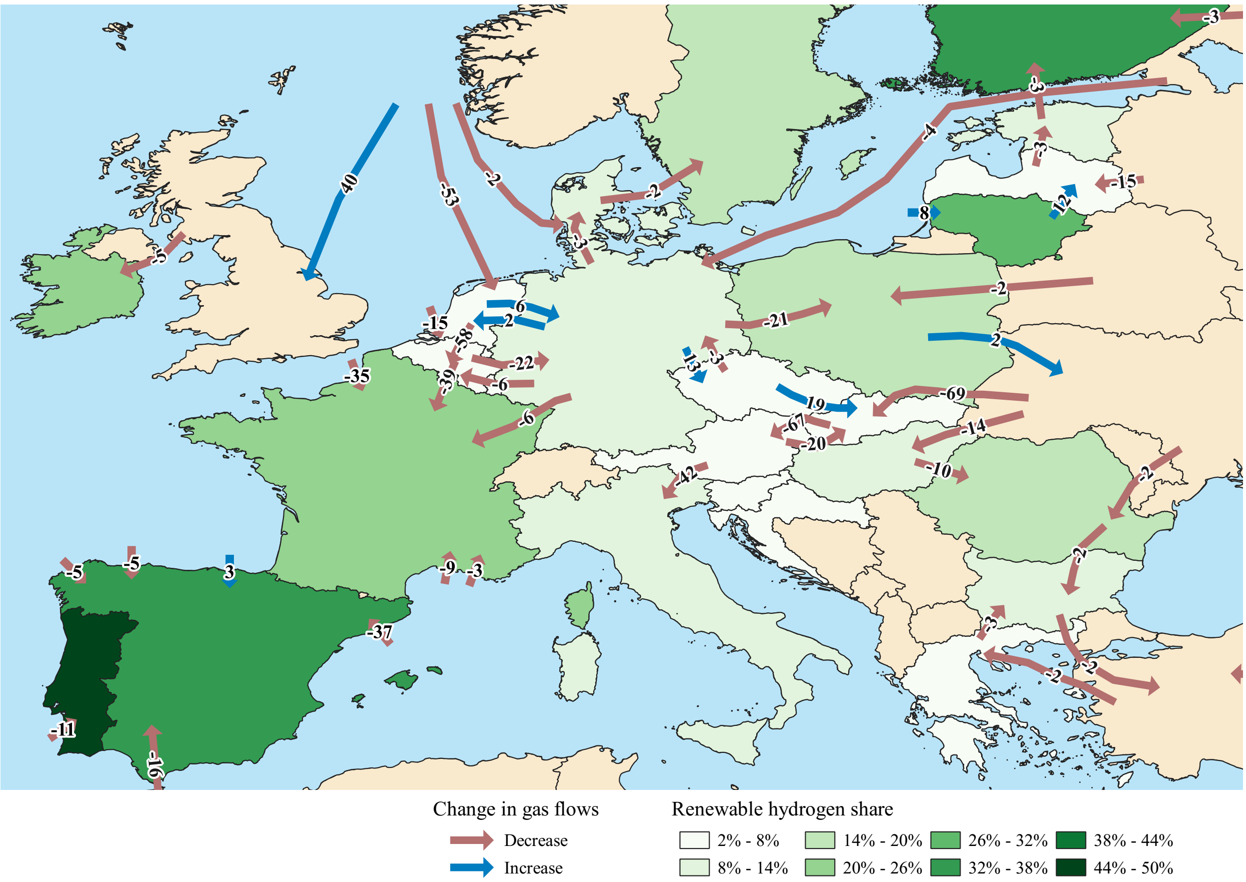

Figure 5: Renewable gas shares of total gas demand in EU countries and absolute gas flow differences between REF and EUQ in 2040 (in TWh)

3.3. Price effects of a quota

A strong relative increase in electricity and EU ETS prices can be observed (see Figure B.10 in Appendix B). The substantial relative increase in electricity demand in the EUQ scenario when compared to the REF scenario, combined with the price increase in the EU ETS and the resulting coal-to-gas switch, leads to higher prices on the electricity market.[16]

In the long run, the large-scale injection of hydrogen and synthetic methane leads to a slight gas price decrease in Europe. Until 2030, gas prices change little since the elevated consumption of natural gas in the power sector cancels out the reduction in conventional natural gas demand resulting from the quota obligation. However, the price effect becomes more significant as the share of substitute gas increases. In 2040 gas prices in the EU are on average 3% lower than in the REF scenario (see Table B.9 in Appendix B).

As defined in the paper at hand, the renewable hydrogen quota applies to the final gas consumption of sectors outside the EU ETS. However, as shown above, it results in substantially higher electricity consumption. Most of the increase in power generation comes from RES. However, some of the RES-based electricity consumed by other sectors in the REF scenario is diverted to PtG production in the EUQ scenario, leading to increased gas-fired power generation and a rise in the demand for emission allowances from the power sector. This leads to a higher price for EU ETS allowances in the EUQ scenario, with the increase rising from 29% in 2030 to 34% in 2040.

The renewable hydrogen quota itself is assumed to be implemented based on tradable renewable hydrogen certificates that gas supply companies purchase to demonstrate their compliance with the quota. We assume that certificates are valid for one year and tradable across the EU on a competitive market. Due to the assumed decline in RES and electrolyser investment costs, the gap between the cost of production and the revenue PtG producers generate through sales on the gas market shrinks over time. Accordingly, the renewable hydrogen certificate price[17] drops from 213 EUR/MWh in 2025 to 119 EUR/MWh in 2040.

As a result, non-quota obliged consumers pay up to 3% less for natural gas on the wholesale market. Quota obliged consumers—mostly households, commercial, and small industrial consumers—pay up to 114% more for a unit of gas, since they have to purchase certificates to demonstrate compliance with the quota.

3.4. Welfare effects of a quota

We assess the welfare impact of a quota on both the electricity and gas market by determining the difference in the average[18] producer and consumer surpluses between the REF and the EUQ scenario:

$$\Delta_a(\overline{W}_a^{EUQ} - \overline{W}_a^{REF}) = \sum_{c \in C} W_{a,c}^{EUQ} * \frac{q_{a,c}^{EUQ}}{\sum_c q_{a,c}^{EUQ}} - \sum_{c \in C} W_{a,c}^{REF} * \frac{q_{a,c}^{REF}}{\sum_c q_{a,c}^{REF}} \tag{24}$$

[16] At the same time, there is no detectable correlation between the amount of hydrogen produced in a country and the price on its national electricity market, since most of the additional electricity is provided by zero marginal cost RES and gas-fired generators are usually setting the price.

[17] The certificate price is derived from the shadow variable of the renewable hydrogen constraint, reflecting the marginal cost of producing and injecting an additional unit of renewable hydrogen or synthetic methane. The variable can be interpreted as the market-clearing renewable hydrogen certificate price.

[18] Expressed in Euros per unit of energy produced or consumed.

The difference in average surplus is calculated separately for each group of market participants a (i.e. producers and consumers) by subtracting their average surplus $\overline{W}^{REF}$ in the REF scenario from their average surplus $\overline{W}^{EUQ}$ in the EUQ scenario. The EU-wide average surpluses are defined as the quantity (q) -weighted sum of each countries' c average surpluses. The PtG producer's surplus includes the renewable hydrogen certificate price.

As shown by Figure 6 the primary beneficiaries of a renewable hydrogen quota on the electricity market are RES producers, who benefit from the additional payments made by PtG producers for certifiable renewable electricity.

In the longer term, operators of conventional power plants benefit as well. As explained in Section 3.2, gas-fired power stations in particular produce more electricity in the EUQ scenario. However, spark spreads are lower in 2025 because emission allowances are marginally more expensive and wholesale gas prices slightly higher. After 2025, the overall increase in the electricity market price compensates for the additional marginal cost.

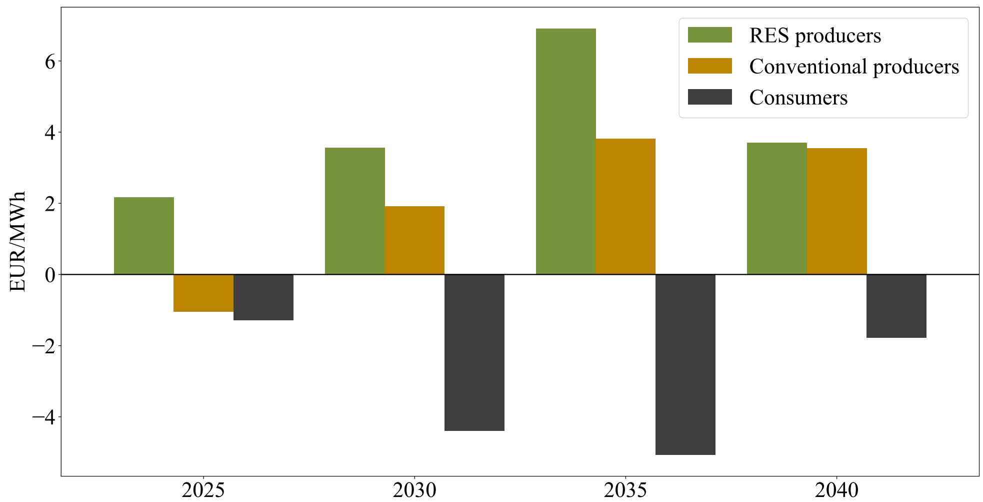

Figure 6: Change in RES producer surplus, conventional producer surplus and consumer surplus on the electricity market

On the gas market, the quota increases total gas demand due to increased generation by gas-fired power plants but reduces conventional natural gas demand because of its partial substitution with hydrogen and synthetic methane. Changes in the average surpluses of producers and consumers on the gas market are shown by Figure 7. In 2025, the increased gas demand in the EUQ scenario has a small positive welfare effect on conventional natural gas producers due to the increased gas price. However, from 2030 to 2040, the increasing replacement of natural gas with hydrogen and synthetic methane leads to lower prices and lower natural gas production in the EUQ scenario, lowering producer profit margins. Compared to conventional natural gas producers, PtG producers have an additional source of income: first, they sell hydrogen and synthetic methane to gas consumers at the natural gas price and second, they are qualified to issue and sell renewable hydrogen certificates to quota obliged gas consumers. The average surplus of PtG producers in the EUQ scenario ranges from 32 EUR/MWh in 2025 to 18 EUR/MWh in 2030.

The average surplus of non-quota obliged gas consumers depends only on the natural gas price[19]. Hence, a higher gas price in 2025 in the EUQ scenario decreases the average surplus of non-quota consumers and increases their surplus after 2025 due to lower gas prices in the EUQ scenario. Quota obliged gas consumers pay the gas price for each consumed unit of gas. Additionally, they are required to purchase renewable gas certificates in the EUQ scenario. As a consequence, quota obliged consumer's average surplus differs strongly to the REF scenario and is 10.9 EUR/MWh lower in 2025 and 23.1 EUR/MWh lower in 2040.

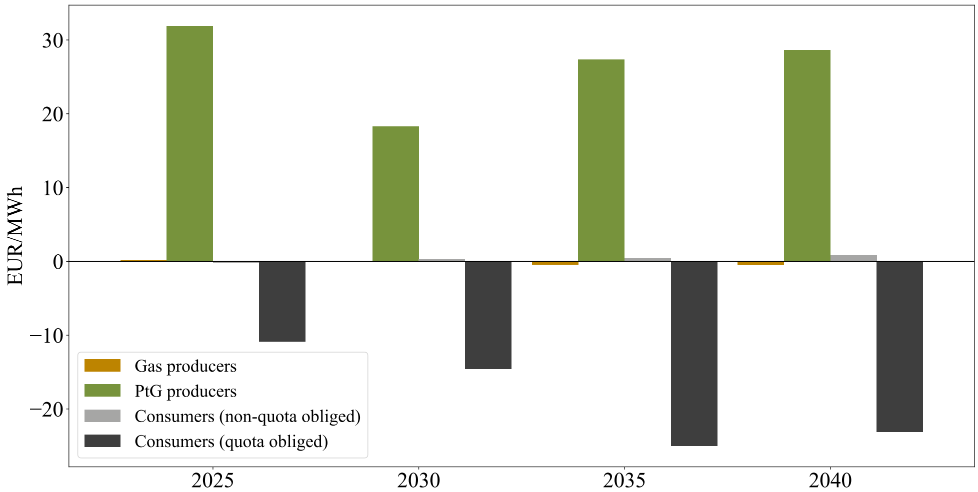

Figure 7: Change in gas producer surplus, PtG producer surplus and consumer surplus on the gas market

Taken together across both markets, the quota has a welfare-diminishing effect (see Figure 8). There is a small net benefit for producers—mostly RES and PtG—while consumers face significant losses. Considering this, it should be highlighted that we do not consider the external benefit associated with reducing emissions through the use of renewable hydrogen. However, by dividing the additional cost of the quota by the resulting reduction in emissions, we are able to derive the emission abatement cost associated with the policy measure. Since the quota applies to consumption not regulated by the EU ETS, there is no waterbed effect, i.e. the emissions that would otherwise have been produced from the combustion of the displaced natural gas are fully avoided and not merely shifted to other sectors.

The direct emission reduction in the EU amounts to 21 million tCO_2 per year in 2025 and 90 million tCO_2 per year in 2040, while the additional cost associated with the quota increases from 15 billion EUR

[19]Buyers of EU ETS certificates face a higher carbon price. This results in higher costs for the operators of conventional, fossil-fuel-fired power stations. Since the analysis at hand focuses on the electricity and gas markets, we do not quantify the cost impact of this on consumers regulated by the EU ETS that are not part of the power sector.

per year in 2025 to 43 billion EUR per year in 2040. Accordingly, we derive average marginal abatement costs of 736 EUR/tCO_2 in 2025 and 473 EUR/tCO_2 in 2040.

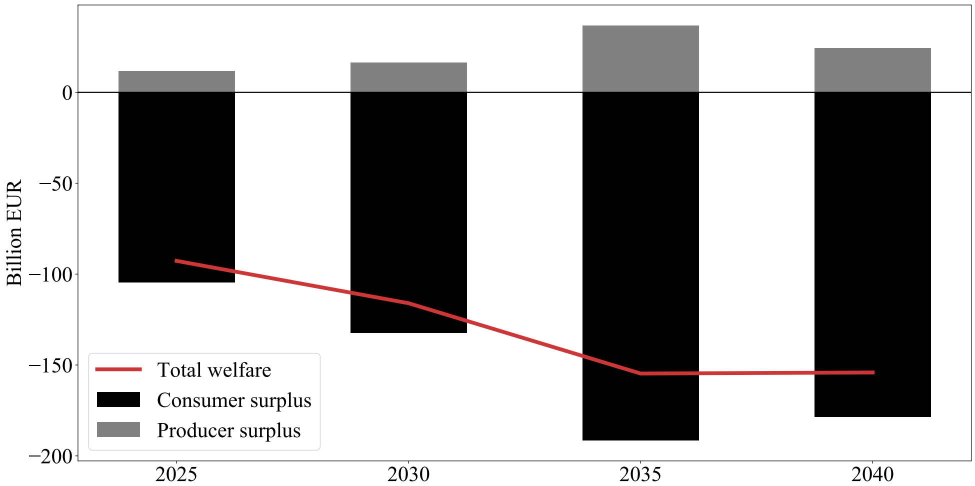

Figure 8: Change in consumer surplus, producer surplus and total welfare

4. Conclusion and Policy Implications

In the paper at hand, we study the impact of a large-scale injection of renewable hydrogen and synthetic methane into gas grids on the EU gas and electricity markets. By taking a renewable hydrogen quota on final gas consumption that is not subject to the EU ETS as an example, we analyse the resulting price, quantity and welfare effects. The analysis is conducted by comparing two numerical scenario simulations of European gas and electricity markets by linking two linear optimisation models.

Our model simulations show that the renewable hydrogen quota leads to significant RES capacity expansion since PtG producers are obliged to source their electricity from RES simultaneously generating in the same market area. The remaining electricity demand on the market may be served either by conventional or by renewable power sources. However, since the CO_2 emissions of the power sector are capped, the increased electricity demand results in a higher emission allowance price, which triggers in an accelerated coal-to-gas-switch in the quota scenario (EUQ)[20]. The result is a higher electricity price in the EUQ scenario. The quota's primary beneficiaries in the power sector are RES. Since they are the exclusive suppliers for PtG plants, their average profit margins rise significantly. However, conventional power producers also benefit from the increase in the market price, while the same effect leads to a decline in the surplus of power consumers.

On the gas market, the large scale injection of renewable hydrogen and synthetic methane leads—on balance—to a slight decline in gas prices. PtG producers enter the gas market as a must-run capacity and sell their output at the gas market price. Hydrogen and synthetic methane partially displace conventional natural gas, which leads to lower gas production and imports and a slight decline in the natural gas price. The rents of natural gas producers decline accordingly.

While renewable hydrogen injection is maximised up to the volumetric limits in all member states, synthetic methane production is not equally distributed. The EU-wide quota and tradable certificates allow for an efficient allocation of PtG production across the participating countries, and synthetic methane is produced primarily in countries that combine good RES potentials with a high capacity gas grid, such as Spain. As a consequence, these countries become net exporters of renewable hydrogen certificates.

The simulations show that different producer and consumer groups are affected differently by sector-specific renewable hydrogen quotas.

Ultimately, quota obliged gas consumers shoulder most of the additional cost associated with the RES and PtG capacity expansion by purchasing the renewable hydrogen certificates emitted by the producers in order to demonstrate compliance with the quota. Quota obliged gas consumers pay up to 25 EUR/MWh

[20] In order to simplify the model, we assume that within the EU ETS, marginal abatement occurs in the power sector. See Section 2.3 for more details.

more in the quota scenario (EUQ) compared to the reference scenario (REF)[21]. The primary beneficiaries are both PtG and RES producers since the former are required to purchase the power needed to produce hydrogen from the latter. RES producers earn up to 6.9 EUR/MWh more in the EUQ scenario[22]. Effectively, the renewable hydrogen quota thus constitutes an additional, indirect subsidy mechanism for RES.

On the electricity market, the increase in the price also leads to a decline in consumer welfare. Consequently, quota obliged consumers that consume both electricity and gas would face both higher wholesale electricity prices and higher end consumer gas prices. Considering the composition of non-EU ETS gas consumption in general, the quota would mostly affect households, the commercial sector and smaller, less energy-intensive industries.

In summary, the quota's additional cost would be covered overwhelmingly by households, commercial and small industrial gas consumers. Beneficiaries are mostly RES and conventional power producers, and PtG operators. Hence, the quota leads to a significant welfare redistribution from consumers to producers.

While the substitution of natural gas consumption outside the EU ETS leads to the full equivalent reduction in total emissions, the quota constitutes a very costly emission abatement option. However, it is effective in stimulating the deployment of electrolysers, an EU industrial policy objective. The block's hydrogen strategy proposes installing at least 40 GW of electrolyser capacity in the EU by 2030[23] (European Commission, 2020b). With a quota as modelled in the paper at hand, cumulative installations would reach 52 GW by 2030, exceeding the EU capacity target. The rapid expansion could potentially contribute to a reduction in the unit cost of electrolysers through scale and learning effects.

However, policymakers must be aware that such technology support is nearly entirely paid for by a small group of energy consumers - which might not necessarily be the same as those who benefit from a possible decline in technology costs.

Finally, it should be noted that the general price and welfare effects described in this analysis would also occur if the hydrogen were not physically blended into the gas grid, but consumed directly. While the effects on the natural gas market are contingent on hydrogen displacing natural gas, the price/quantity effects on the electricity market are independent of the fuel substituted for hydrogen, provided it is consumed in non-EU ETS end-use sectors.

To our knowledge, this paper presents the first assessment of a renewable hydrogen quota using a combination of gas and electricity market models approximating real-world systems. However, there are some limitations to our analysis that provide opportunities for future research.

[21] As a comparison, in the first half of 2020 EU household consumers paid on average 65.6 EUR/MWh and non-household consumers 31.5 EUR/MWh for natural gas respectively (Eurostat, 2020b).

[22] Average wholesale electricity prices in European countries in 2019 range from approximately 37 EUR/MWh to 64 EUR/MWh (ACER, 2021)

[23] An additional 40 GW is planned abroad for hydrogen imports into the EU

The first is that cost assumptions, particularly regarding current and future RES and electrolyser technology costs, are based on current projections (see Appendix A). We do not endogenously model technological learning, and the exogenous cost trajectory is a significant driver of the results presented in this paper. However, it should be pointed out that unless the full cost of consuming renewable hydrogen falls below that of natural gas, the *direction* of the welfare effects of a quota that forces consumers to use a more expensive fuel—hydrogen—should remain the same.[24]

Secondly, we assumed most consumers to have an inelastic demand. Due to the iterative coupling of the electricity and gas market model, we are able to capture the price-responsiveness of power sector gas demand, but not that of other consumption sectors. The same applies to the electricity demand of all consumers other than PtG producers. In reality, one would expect to observe long-run adjustments on the demand side, particularly in the sectors that see an increase in gas supply costs due to the quota. The increase in the cost of gas could accelerate the shift towards other energy carriers in sectors covered by the quota. Decreasing gas consumption would reduce gas infrastructure utilisation and lead to a decrease in gas network charges. Ultimately, an upward cost cycle could be initiated, further contributing to a shrinking attractiveness of gas as an energy carrier.

However, while considering these dynamics might affect the size of the estimates presented in the paper at hand, qualitatively, the overall direction and distribution of the cost, price, quantity, and welfare effects would likely not change fundamentally.

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[24] In terms of overall efficiency, the economic impact of a renewable hydrogen quota in our setting is similar to that of a low carbon fuel standard. Holland et al. (2009), for example, show that a low carbon fuel standard always lowers economic efficiency unless it is non-binding.

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Appendix A. Model, data and assumptions

Appendix A.1. Gas demand allocation methodology

For this paper's purposes, we subdivide country-level natural gas demand into EU ETS and non-EU ETS demand, as well as gas transmission and distribution system-level demand. The quota applies only to the demand of consumers not regulated by the EU ETS, all of which are assumed to be connected to the gas distribution grid, owing to their small size relative to the large industrial consumers and power stations subject to the EU ETS emission cap. A detailed overview of the sectoral breakdown used by the models and the respective quotas and injection limits is given in Table 1.

Since data on the breakdown of natural gas demand between sectors regulated by the EU ETS and sectors outside the EU ETS, as well as the breakdown of demand between the distribution and transmission grid levels, is scarce, simplifying assumptions were made in order to allocate the exogenous, country-level natural gas demand to the EU ETS and non-EU ETS sectors, as well as the gas transmission and distribution grid levels. Projections are obtained from the POTEnCIA Central Scenario (Mantzos et al., 2019), which provides a breakdown by NACE2 classification (Eurostat, 2008). For the split of natural gas demand, four demand categories are used, each one with an individual demand profile: (i) industrial sector (EU ETS) gas demand, (ii) power sector (EU ETS) gas demand, (iii) residential and commercial (non-EU ETS) gas demand and (iv) small industry and other (non-EU ETS) gas demand. Mantzos et al. (2019) provide a detailed, country-level breakdown of projected emissions by NACE2 economic activity, for both emissions covered by the EU ETS and total emissions from the respective industrial subsector. Similar statistics for the projected fuel consumption of the sectors regulated by the EU ETS are not provided, so for the purpose of this paper, we made the simplifying assumption that the proportion of gas consumption in each subsector that is subject to the EU ETS is equivalent to the respective subsector's share of emissions covered by the EU ETS. Table A.2 provides an overview of the share of emissions regulated by the EU ETS in each sector for the illustrative example of Germany in 2040. We further assume that the industrial gas consumption subject to EU ETS restrictions generally comes only from individual consumers large enough to be directly connected to the transmission rather than the gas distribution system. The division into EU ETS and non-EU ETS, as well as transmission and distribution-level gas consumption thus derived, align reasonably well with actually measured transmission vs distribution-grid level gas consumption where data could be obtained. A comparison with historical data from Germany and France, for example, shows that the deviation between our assumptions and real grid-level demand is acceptable: in France, the share of gas demand delivered to distribution grid consumers in 2018 amounts to 62% (Commission de Régulation de l'Énergie, 2019) compared to 64% in 2018 data derived using the approach described above. In Germany, the share of gas demand delivered to distribution grid consumers in 2018 was 81% (Bundesnetzagentur and Bundeskartellamt, 2020) compared to 74% in the modelled projection.

Table A.2: Share of emissions subject to the EU ETS by industrial subsector in Germany in 2040, as projected by Mantzos et al. (2019).

NACE2 code	Sector	2025	2030	2035	2040
cenos	Consumption in Energy sectors except power generation	83%	83%	83%	83%
isi	Iron and Steel	88%	88%	88%	88%
nfm	Non-Ferrous Metals	88%	88%	88%	88%
chi	Chemicals Industry	86%	86%	85%	85%
nmm	Non-Metallic Mineral Products	88%	88%	88%	88%
ppa	Pulp, paper and printing	87%	87%	87%	87%
fbt	Food, Beverages and Tobacco	0%	0%	0%	0%
tre	Transport Equipment	0%	0%	0%	0%
mae	Machinery Equipment	0%	0%	0%	0%
tel	Textiles and Leather	0%	0%	0%	0%
wwp	Wood and Wood Products	0%	0%	0%	0%
ois	Other Industrial Sectors	0%	0%	0%	0%

Appendix A.2. Model indices, parameters and variables

Table A.3: Model indices, parameters and variables

Name	Unit	Definition
Sets		
$t \in T$		Time
$i, j \in I$		Technologies (electricity generation, PtX)
$y \in Y$		Years
$n, m \in N$		Nodes (gas) or markets (electricity)
$s \in S$		Sectors (Electricity, industry, households, transport)
$z \in Z$		Gas storage
$p \in P$		Natural gas production locations
$r \in R$		LNG import terminals (regasifiers)
$c \in C$		Countries
Parameters		
ϕ	EUR	Fixed cost
γ	EUR	Variable cost
α	-	Generator's availability
σ	-	Secure capacity factor
l	MWh	Annual peak load
η	MWh_{el}/MWh_{th}	Generator's efficiency
ϵ	tCO_2eq/MWh	Fuel-specific emission factor
$emcap$	tCO_2eq	Annual emission cap
d	MWh	Exogenous demand
κ	-	Quota obligation
λ	-	Hydrogen injection limit
τ	-	Gas storage injection/withdrawal rate
q	MWh	Synthetic gas injection
cap	MWh/mcm	Electricity/gas infrastructure capacities
Variables		
C	MW	Installed capacity
Q	MWh	Production
F	MWh	Energy flows
S	MWh	Storage flows
D	MWh	Demand
VC	EUR	Variable cost
TSC	EUR	Total system cost

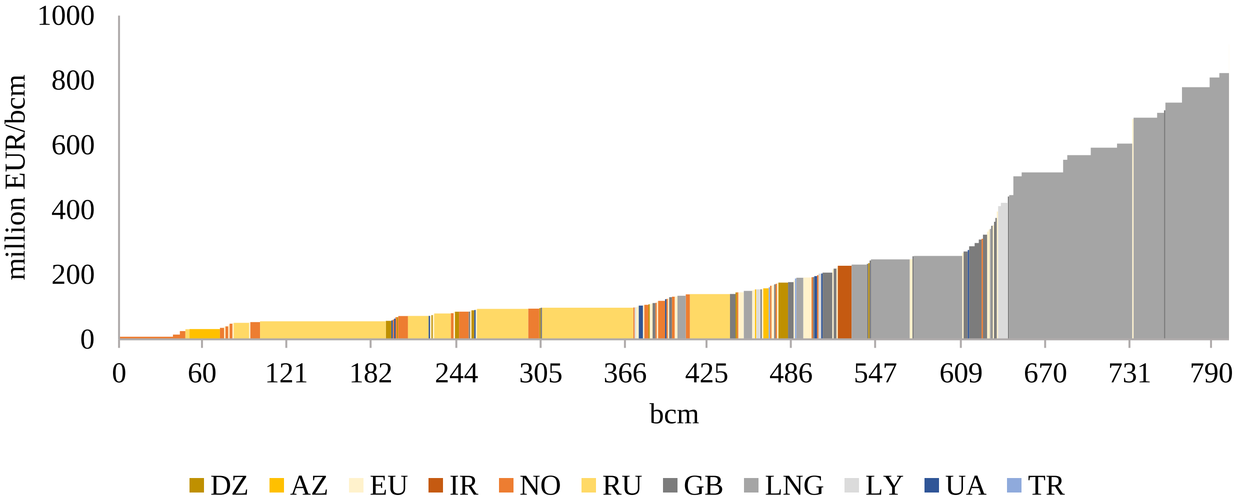

Figure A.9: European natural gas supply curve and major exporting countries in 2030 (based on Rystad Energy (2020) with own assumptions)

Table A.4: Assumed conversion factors for fuels referred to net calorific value and gross calorific value

Fuel	Unit	NCV	GCV
Hydrogen	kWh/m^3	3.00	3.54
Methane	kWh/m^3	9.97	11.05
Natural gas	kWh/m^3	10.00	11.11

Table A.5: Power-to-Gas technologies: CAPEX (no value implies that technology class is not available yet)

Technology	**CAPEX (EUR/kW_{el})**			
	2025	**2030**	**2035**	**2040**
Alkaline 1	667	530	493	456
Alkaline 2	-	530	493	456
Alkaline 3	-	-	-	456
PEM 1	1070	911	800	689
PEM 2	-	911	800	689
PEM 3	-	-	-	689
PEM 1 + Methanation	1585	1391	1252	1113
PEM 2 + Methanation	-	1391	1252	1113
PEM 3 + Methanation	-	-	-	1113

Source: Adapted from Brändle et al. (2020) (baseline assumptions) and IEA (2019b) for methanation.

Table A.6: Power-to-Gas technologies: Other assumptions

Technology	**Fixed O&M costs (EUR/kW$_{el}$/a)**	**Lifetime (Years)**	**Efficiency (LHV)**	
			H_2	**CH_4**
Alkaline 1	15.8	15	67%	-
Alkaline 2	12.5	20	68%	-
Alkaline 3	10.8	25	70%	-
PEM 1	25.3	15	62%	-
PEM 2	21.5	20	66%	-
PEM 3	16.3	25	68%	-
PEM 1 + Methanation	45.9	15	62%	48%
PEM 2 + Methanation	40.7	20	66%	50%
PEM 3 + Methanation	33.2	25	68%	52%

Source: Adapted from Brändle et al. (2020) (baseline assumptions) and IEA (2019b) for methanation. CO_2 feedstock costs for methanation are assumed to decline from 220 EUR/tCO_2 in 2025 to 120 EUR/tCO_2 in 2040.

Appendix B. Results

Table B.7: EU gas and electricity demand and PtG production in the REF scenario

Parameter	Unit	2025	2030	2035	2040
Electricity demand	TWh	3054	3167	3265	3444
Gas demand	TWh	3620	3263	3335	3343
EU gas production	TWh	340	355	342	303
PtG capacity	GW	0	0	0	0
PtG production	TWh	0	0	0	0

Table B.8: EU gas and electricity demand and PtG production in the EUQ scenario

Parameter	Unit	2025	2030	2035	2040
Electricity demand	TWh	3254	3573	3873	4252
Gas demand	TWh	3765	3486	3574	3512
EU gas production	TWh	340	356	339	296
PtG capacity	GW	26	54	84	117
PtG production	TWh	103	220	338	452

Table B.9: Differences in EU gas and electricity market results between the EUQ and REF scenario (EUQ minus REF)

Parameter	Unit	2025	2030	2035	2040
Electricity generation	TWh	199	405	608	807
Gas demand	TWh	144	223	239	169
Natural gas production (imports and EU)	TWh	38	-1	-99	-292
RES producer surplus	EUR/MWh	2.2	3.6	6.9	3.7
Conventional power producer surplus	EUR/MWh	-1.0	1.9	3.8	3.5
Power consumer surplus	EUR/MWh	-1.3	-4.4	-5.1	-1.8
Natural gas producer surplus	EUR/MWh	0.1	-0.1	-0.5	-0.5
PtG producer surplus	EUR/MWh	31.9	18.3	27.4	28.6
Gas consumer surplus	EUR/MWh	-0.2	0.3	0.4	0.7
Quota obliged gas consumer surplus	EUR/MWh	-10.9	-14.6	-25.0	-23.1
Quantity-weighted electricity price	%	2.4	9.9	12.3	11.3
Quantity-weighted natural gas price	%	0.8	-0.9	-1.7	-3.0
EU ETS CO_2-price	%	2.9	28.7	34.0	34.0

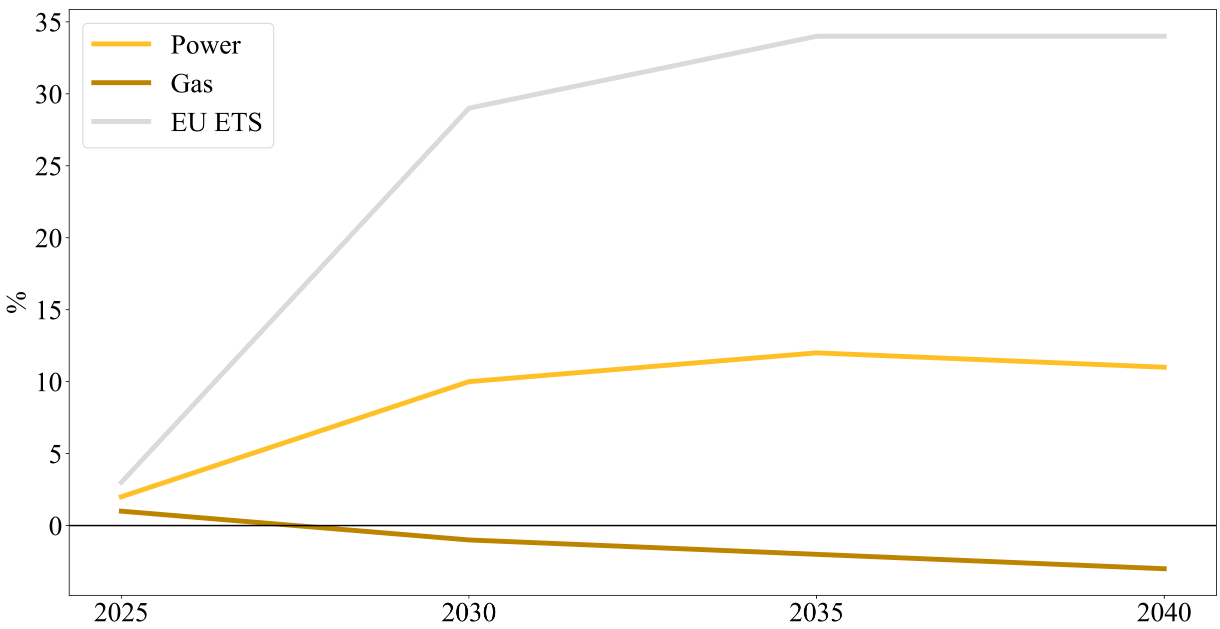

Figure B.10: Difference in power, gas and EU ETS allowance price between the EUQ and the REF scenario