Essays on the Economics of Hydrogen as an Energy Carrier

Inauguraldissertation

zur

Erlangung des Doktorgrades

der

Wirtschafts- und Sozialwissenschaftlichen Fakultät

der

Universität zu Köln

2024

vorgelegt

von

M.Sc. David Schlund

aus

Kirchheim unter Teck

Referent:	Prof. Dr. Marc Oliver Bettzüge
Korreferent:	Jun.-Prof. Dr. Oliver Ruhnau
Tag der Promotion:	08.07.2024

Acknowledgements

I want to express my sincere gratitude to my advisor, Prof. Dr. Marc Oliver Bettzüge, for his unwavering support, guidance, and mentorship throughout my doctoral research. His expertise, insightful feedback, and constructive criticism have been instrumental in shaping the direction and quality of this thesis. I would also like to thank Jun.-Prof. Dr. Oliver Ruhnau for co-refereeing my thesis .

Furthermore, I am deeply grateful to the Institute of Energy Economics at the University of Cologne, not only for providing the financial and administrative resources to back up my Ph.D. project but also for creating a unique environment for research with highly motivated co-workers and administrative staff. Also, I would like to thank my co-authors, Max Schönfisch and Philipp Theile, for the productive and inspiring collaboration. Special thanks go to my co-author, Prof. Werner Antweiler, Ph.D., not only for his collaboration on our joint research but also for giving me the opportunity to conduct research abroad at a distinguished university in Vancouver, Canada.

This research would not have been possible without the financial support of the Ministry of Economic Affairs, Industry, Climate Action and Energy of the State of North Rhine-Westphalia, the Society of Benefactors to the EWI (Gesellschaft zur Förderung des EWI e.V.), the German Academic Exchange Service (DAAD), and the German Federal Ministry for Economic Affairs and Climate Action (BMWK), and for that, I am truly grateful.

Finally, my deepest appreciation goes to Anika, my family, and my friends for their constant encouragement, understanding, and patience during this challenging journey.

David Schlund — Cologne, March 2024

Contents

List of Figures

List of Tables

1. Introduction

1.1. Motivation

The urgency to decarbonize the way we produce and use energy has motivated governments and the private sector around the world to expand renewable energy (RE), such as wind, solar photovoltaics (PV), and hydro. However, over time, studies have shown that reaching CO_2 reduction of up to 100% will require alternative strategies than just increasing the share of electricity in final energy demand and producing electricity from RE (IEA, 2021d, 2023b, IRENA, 2023, Kintner-Meyer et al., 2022). This is where hydrogen has entered the stage as an enabler to decarbonize sectors with barriers for electrification, as a long-term energy storage and backup for a renewable-dominated power sector, and as an energy carrier fostering global trade in renewable energy commodities. Hydrogen is the lightest and most frequent element in our universe. It is an odorless and colorless gas that does not emit carbon emissions when burnt or chemically transformed in fuel cells.

The idea of introducing hydrogen as an energy carrier has not been entirely new. Nicholson and Carlisle invented the process of splitting water into hydrogen and oxygen using electrical power in 1800 (Kreuter and Hofmann, 1998). Similarly, the basic principle of using hydrogen in fuel cells to produce electricity was invented in 1839 by Sir William Grove (Appleby, 1990). However, these technologies never made the breakthrough of being deployed on a large scale. Instead, hydrogen was mainly produced from fossil fuels, and utilization was limited as a feedstock in the chemical industry, e.g., for ammonia production or as rocket fuel in space travel.In the 1960s and 1970s, hydrogen was heralded as a future energy carrier, primarily motivated to strive for reduced dependency on mineral oil and other fossil fuel imports (Ball and Wietschel, 2009b). During this time, the term "Hydrogen Economy" was formed (Bockris, 1972) as an idea to fuel an entire economy with hydrogen as the predominant form of energy. From the early stages, the possibility of reducing greenhouse gas emissions through clean hydrogen production using renewable primary energy carriers was seen as one (but not the only) benefit of hydrogen as an energy carrier (Bockris, 2013).

As such, the gas can be produced from a wide range of primary energy carriers and conversion technologies, such as biomass gasification, electrolysis using electricity from RE, methane pyrolysis, coal gasification, or steam methane reforming. Carbon capture and storage (CCS) technology can be deployed for the latter two to prevent carbon emissions from escaping into the atmosphere. In the case of electrolysis, Power-to-Gas (PtG) technologies are vital elements since they allow hydrogen production using only electricity and water.

While being a very versatile and promising future energy carrier, the advent of hydrogen as an energy carrier faces several barriers, such as immature technologies, lacking infrastructure for storage and transportation, and a cost gap in competition with fossil energy carriers, even when including carbon prices. These challenges can be found along the entire value chain, resulting in a coordination problem with no supply and demand for clean hydrogen. However, both sides are essentially needed to ramp up the market (Schlund et al., 2022). As a gaseous energy carrier, the infrastructure for connecting producers and consumers is also mainly missing. Nevertheless, policymakers and private companies have set highly ambitious targets and introduced investment programs and support schemes to overcome these issues to incentivize and accelerate the development of a hydrogen market.

Against this background, the thesis at hand deals with the introduction of hydrogen as a novel energy carrier and investigates a range of economic and political issues emerging during this process. It focuses on the latest discussions on opportunities and strategies to develop this non-existent market. While considering different forms of carbon-neutral hydrogen production, PtG technologies will be the focus of most research, which is structured into four chapters:

- Chapter 2: Analyzing the Impact of a Renewable Hydrogen Quota on the European Electricity and Natural Gas Markets.[1] Joint work with Max Schönfisch, both authors contributed equally, *EWI Working Paper 21/03* and published in *Applied Energy*. See Schlund and Schönfisch (2021).
- Chapter 3: Simultaneity of Green Energy and Hydrogen Production: Analyzing the Dispatch of a Grid-connected Electrolyzer. Joint work with Philipp Theile, both authors contributed equally, *EWI Working Paper 21/10* and published in *Energy Policy*. See Schlund and Theile (2022)
- Chapter 4: Integrating Cross-Border Hydrogen Infrastructure in European Natural Gas Networks: A Comprehensive Optimization Approach, *EWI Working Paper 23/08*. See Schlund (2023).
- Chapter 5: The Emerging International Trade in Hydrogen and the Role of Environmental, Innovation, and Trade Policies. Joint work with Werner Antweiler. Contribution statement: David Schlund: conceptualization (equal), investigation (equal), methodology (supporting), resources (lead), data curation (lead), validation (supporting), writing (equal). Werner Antweiler: conceptualization (equal), investigation (equal), methodology (lead), formal analysis (lead),

[1]The published version of the paper differs slightly from Chapter 2, where parts the methodology section have been moved from the appendix to the main text.

software (lead), resources (supporting), validation (lead), supervision (lead), writing (equal). *USAEE Working Paper No. 23-589* and revised version with modifications accepted for publication in *Journal of Environmental Economics and Management*. See Antweiler and Schlund (2023).

In the next section, each chapter is summarized briefly, followed by an overview and discussion of the methodology and an outlook for further research.

1.2. Outline

Chapter 2: Analyzing the Impact of a Renewable Hydrogen Quota on the European Electricity and Natural Gas Markets

Hydrogen and its derivatives produced from renewable energy technologies face lacking market maturity and cost competitiveness with fossil-based energy carriers. One policy option to overcome this barrier is introducing a renewable hydrogen quota (or renewable hydrogen obligation). Chapter 2 analyses the effects of such a quota for renewable hydrogen and synthetic methane on EU electricity and natural gas markets. The analysis uses two separate partial-equilibrium models for the European electricity and gas markets. The models are coupled with a soft-link approach, i.e., with iterative model simulations until they sufficiently fulfill a predefined convergence criterion. The quota under study is imposed on final gas consumption and assumes the physical injection of hydrogen and synthetic methane into natural gas grids. Thus, renewable gases reduce the total demand for natural gas. Tradeable certificates allow for an economically efficient allocation of renewable hydrogen and synthetic methane production across the EU.

The model simulations show a substantial expansion of renewable generation capacity in order to serve additional electricity demand from PtG plants. On the electricity market, the price increases substantially, rising by up to 12% – primarily due to increasing emission allowance prices – leading to a higher surplus for power producers. On the gas market, the quota leads to a slight decrease in prices (by a maximum of -3%) and gas producer surpluses. Quota-obliged gas consumers, mainly households and commercial and small industrial consumers carry the highest burden associated with the obligation. The analysis shows the effectiveness of introducing such a quantity-based instrument in reaching volume targets for renewable gases without public subsidies. However, it also points out the redistribution of welfare, which implies a substantial increase in end-consumer prices for quota-obliged consumers.

Chapter 3: Simultaneity of Green Energy and Hydrogen Production: Analyzing the Dispatch of a Grid-connected Electrolyser

The production of clean hydrogen with grid-connected electrolyzers can potentially lead to unwanted side-effects, such as increased CO_2 emissions in the power sector unless the electricity generation mix is not entirely renewable-based. Policymakers in the EU aim to address this issue by introducing a simultaneity obligation ("*temporal correlation*") for grid-connected electrolyzers and binding hydrogen production to the renewable output within defined time intervals. Chapter 3 presents a model framework including a mixed-integer linear program and a Markov chain Monte Carlo simulation for stochastic electricity prices to assess a grid-connected electrolyzer's dispatch. In a case study of the German electricity market, the effect of simultaneity on the dispatch is assessed.

The results show that simultaneity reduces the CO_2 emission intensity of hydrogen while constraining profits. The choice of the simultaneity interval length affects the electrolyzer's average contribution margin from hydrogen production and the corresponding profit at risk, which results from fluctuating RE generation. Regulations aiming at the interface between hydrogen and electricity must consider the trade-off between economic viability, full load hours, and associated emissions of electricity-based hydrogen.

Chapter 4: Integrating Cross-Border Hydrogen Infrastructure in European Natural Gas Networks: A Comprehensive Optimization Approach

Like natural gas, a pan-European hydrogen pipeline network is considered a prerequisite for trans-national hydrogen trade and developing a European market. By retrofitting existing natural gas pipelines for hydrogen, costs and lead times for constructing the pipeline network can be reduced. However, in the transitional period, the security of supply for natural gas must be ensured, particularly in the presence of uncertainty about natural gas supply. In Chapter 4 a linear optimization model for natural gas transportation in Europe is extended to analyze integrated natural gas and hydrogen transportation. The model optimizes investments in cross-border pipelines for hydrogen through newly built or repurposed pipelines, hydrogen import, and storage infrastructure.

The numerical simulation results offer insights into the cost-efficient strategic planning of a European hydrogen network by simulating a range of scenarios with varying economic and technical constraints. The case study finds a dominant role of the availability of RE in shaping the network. Also, providing flexibility through time-varying imports, flexible production, or hydrogen storage becomes an essential element in a future hydrogen supply chain. The interconnection of all European countries with dedicated hydrogen pipelines is robust across all scenarios. However, the sizing and choice of large import pipelines strongly depend on the assumed techno-economic constraints.

Chapter 5: The Emerging International Trade in Hydrogen and the Role of Environmental, Innovation, and Trade Policies

The technical feasibility of producing hydrogen from various primary energy sources and converting it into other energy carriers for transport opens the possibility for global trade in hydrogen. The production, storage, and transportation supply chain is primarily driven by investment costs with comparably low operational expenditures over a project's lifetime. Furthermore, uncertainties about future price paths and the cost development of hydrogen technologies constitute a potential barrier for investors. Long-term contracts (LTC) could emerge as an enabler for investments in hydrogen supply, particularly during the early stages of the developing market. The model presented in Chapter 5 builds on the assumption of hydrogen trade emerging with LTCs and simulates global trade for a range of policy and technology scenarios to assess the effects on trade patterns.

The findings suggest that LTC trade exhibits two-way trade as vintages of contracts overlap in a market defined by endogenous innovation and policy interventions. Trade costs and the mode of transportation (pipelines or ammonia conversion) play a pivotal role and influence the relative share of hydrogen production types (green, blue, or turquoise). The analysis shows that trade with expansive use of LTCs looks quite different from conventional merchandise international trade.

1.3. Methodology

The research is built on different methodologies, mainly numerical mathematical simulations with computer-based models. Each model represents a partial-equilibrium model of the corresponding market or sub-market and uses a range of scenario-specific assumptions. It is, therefore, crucial to interpret the results against the system scope and the underlying assumptions while simultaneously creating possibilities for further research.

Chapter 2 applies two distinct models for the European electricity and natural gas markets. The models (DIMENSION and TIGER) were developed at the Institute of Energy Economics at the University of Cologne and have previously been applied in research and PhD projects. Both models are formulated as linear programs (LP) and thus assume perfect competition and perfect foresight. The models are coupled by exchanging fundamental parameters (i.e., natural gas prices, natural gas demand, PtG capacities, and renewable gas injection) and simulated iteratively for predefined scenarios. The scenarios are characterized by assumptions on electricity and natural gas demand from the industry, mobility, household, and commercial sectors, technology and production cost, and policy parameters, such as targets for RE capacities and the reduction of CO_2 emissions. Natural gas prices and natural gas consumption for electricity generation are endogenously determined. An obligation to use a defined share of renewable gases (hydrogen or synthetic methane) is imposed on natural gas consumers in the EU. Additional RE and PtG capacities are installed across the continent to comply with the quota. The results show the effects of a quota scenario with a reference case on electricity generation, installed RE and PtG capacities, prices, and welfare distribution among different market actors. The models use simplifying assumptions for natural gas and electricity demand since demand from other uses than electricity generation is assumed to be inelastic. The quota obligation leads to reactions in electricity, natural gas, and emission certificate prices. Hence, 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. Also, effects on end consumer prices cannot be captured by the model framework since it only reflects wholesale prices without, for instance, network charges, levies, and taxes. Decreasing gas consumption would reduce gas infrastructure utilization and lead to an increase in gas network charges. Ultimately, an upward cost cycle could be initiated, further contributing to a shrinking attractiveness of gas as an energy carrier. Lastly, the models assume perfectly competitive markets with perfect foresight. In reality, uncertainty constitutes a significant challenge to electricity and natural gas markets, leading to inefficient behavior of market participants.

In Chapter 3, the perspective of a single electrolyzer is chosen to assess its profitability in different economic and regulatory environments. For this, a mixed-integer linear program (MILP) is developed, which simulates the dispatch of a grid-connected electrolyzer. In order to prevent additional CO_2 emissions in the power sector through induced electricity demand for hydrogen production, a simultaneity obligation between RE and hydrogen production is introduced. The dispatch model is simulated for thousands of wind generation time series, generated with a Markov chain Monte Carlo simulation. The wind generation time series derive electricity price series in a parametric model for intraday and day-ahead electricity markets. The model framework is applied in a case study for the German electricity market. The results show a substantial effect on the electrolyzer's contribution margin and the indirect CO_2 emissions when varying the simultaneity interval. The model only reflects the dispatch decisions of a single asset and does not cover system-wide effects. Emissions from the power sector are capped under the

EU Emission Trading System (EU ETS). In particular, the interdependence between hydrogen generation and the EU ETS is not studied; however, it is highly controversial whether a regulation on the simultaneity of hydrogen and RE generation is generally needed. Further research could focus on the interplay of hydrogen production and the EU ETS. Also, the analysis does not capture the effects of various electrolyzers operating similarly. Herding behavior could lead to more severe effects on prices and emissions. The case study is only carried out for an exemplary year and does not capture future energy system developments. From a system view, the results represent conservative estimates and could be substantially higher. These effects could become accessible using energy system optimization and simulations for a larger time horizon and extended system boundaries.

Chapter 4 extends the existing natural gas dispatch model TIGER for endogenous investments in LNG import facilities, hydrogen production, import equipment, and hydrogen cross-border pipeline infrastructure. Repurposing natural gas pipelines is explicitly considered, changing the model type from LP to MILP to correctly reflect the constraint of repurposing only entire cross-border pipelines. The model is parameterized and simulated for various scenarios, altering hydrogen demand, availability of imports, hydrogen storage, and blue hydrogen production. The results provide some strategic insights into the planning and development of a European cross-border hydrogen network while ensuring the security of supply for natural gas. Similar to the proposed methodology in Chapter 2, the model assumes perfectly inelastic natural gas and hydrogen demand. Furthermore, the model only reflects coupled RE and hydrogen production assets without considering alternative electricity consumers. This limitation could be solved by coupling the model with an electricity market model. Also, the model contains cross-border pipelines but neglects domestic pipeline networks. Further research could extend the model by improving the computational efficiency and including domestic pipelines to find more detailed results on a European hydrogen grid.

In Chapter 5, the focus is shifted toward the prospects of global trade in hydrogen. An analytical model for global hydrogen trade is developed based on sequential trade with long-term contracts in a Nash-Cournot equilibrium. The model is calibrated with data on hydrogen demand, supply, transportation costs, and policy parameters. Subsequently, a range of scenarios is simulated to understand better the shape of global trade and the impact of varying input parameters. The results show an overwhelming effect of trade and transportation costs, with trade policies having a more substantial effect on global trade than environmental policies. Trade in the model is exclusively based on long-term contracts and neglects spot trading. While this assumption might hold for an early hydrogen market, spot trading is expected to evolve gradually. This could lead to decreasing profits and less attractiveness of LTC markets. More research is needed to understand better the long-term development of hydrogen markets with overlapping LTC and spot trading. Also, the lack of empirical data on hydrogen demand, supply, and trade creates the urgency to compile data on a future hydrogen market artificially. While this data allows a better understanding of the future trade in hydrogen, it fails to make real-world predictions about the market development. With improved data quality, future research could enhance the projections of future hydrogen trade.

The previous discussion of the methodological approaches and caveats only provides an overview. A more detailed discussion of the model limitations and outlooks for further research is given in each respective chapter.

2. Analyzing the Impact of a Renewable Hydrogen Quota on the European Electricity and Natural Gas Markets

2.1. Introduction

In 2018, the member states of the European Union (EU)—excluding the United Kingdom (UK)[1]—consumed around 3,775 TWh of natural gas, with the fuel accounting for approximately 22% of the EU's total energy consumption (Eurostat, 2023). 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 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 1,510 TWh (all potential feedstocks) (Scarlat et al., 2018a,b).

While the latter is equivalent to more than a third of the block's present-day natural gas consumption, it is likely that actual future production potentials will be more constrained. Biogas production from energy crops, rather than organic waste streams, is increasingly challenged on sustainability grounds and reined

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

in by national as well as EU regulation (Scarlat et al., 2018a). Also, competition for the available biomass will greatly increase in a carbon-constrained world, since it can also be used as a feedstock for the production of liquid fuels, or combusted directly to produce electricity and heat. This limits the potential of biomethane as a drop-in replacement for natural gas.

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/utilization (CCS/U)) or from the electrolysis of water (through so-called PtG technologies), provided the electricity used in the process itself comes from a low carbon power source (IEA, 2019). 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 sufficiently mature to compete with conventional energy sources (Moraga et al., 2019, Speirs et al., 2018, van Leeuwen and Mulder, 2018), particularly at today's carbon price levels. Therefore, additional instruments are often proposed to incentivize 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 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 ETS in order to act both as an instrument to

[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).

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 carbon capture and storage (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 and Menanteau, 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 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 and

Menanteau, 2003). Assuming the certificate market is perfectly competitive, producers are incentivized 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, annualized 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 and Menanteau, 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 (Quarton and Samsatli, 2018, Speirs et al., 2018, Timmerberg and Kaltschmitt, 2019). While synthetic methane is of natural gas quality and can be injected into natural gas pipelines without restriction, 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 may damage some existing transportation, metering and end-use equipment (de Vries et al., 2017). 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. Dueñas et al. (2013), Ordoudis et al. (2019), Yang et al. (2015)). 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 analyzing 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 stylized model implemented as a mixed-integer linear programme to analyze the interaction of natural gas, electricity and carbon emissions markets. They assume that PtG plants produce synthetic methane using only excess electricity from solar 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 stylized 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 stylized, stochastic MCP with profit-maximizing firms and cost-minimizing 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. Focusing on decarbonisation of natural gas demand, Horschig et al. (2018) use a method of system dynamics to gain insights into the effect of policy instruments on energy demand, investments, energy availability and capacity development. The method is an iterative procedure and is applied on assessing the effect of different policy measures on biomethane, natural gas and bio-synthetic methane supply in Germany. Koirala et al. (2021) develop an integrated energy system model covering the electricity, gas, and hydrogen systems to and analyze the interaction between the subsystems. The model is formulated as a linear program and minimizes the total cost of operating the system. The subsystems are linked by different assets, e.g., PtG links power and hydrogen systems, whereas gas power plants link the gas and power systems. Model outputs comprise system dispatch and marginal cost. The model is simulated in a case study for the Netherlands until 2050.

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 stylized system layouts. We add to the existing body of knowledge by analyzing 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.

The remainder of this paper is structured as follows: Section 2.2 describes the gas and electricity market models, the input data used, and the assumptions made for this analysis. Section 2.3 presents the results of the scenario simulations and shows the price, quantity and welfare effects. Section 2.4 interprets and discusses the results, shows the limitations of our work and highlights openings for further research. Section 2.5 concludes the chapter.

2.2. 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 2.1). 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. The iteration process is stopped once the annual difference in each of the exchanged parameters between two subsequent iterations is less than 5%.[4]

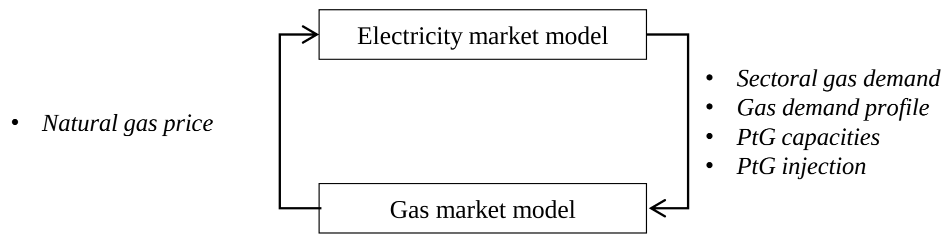


Figure 2.1.: Applied simulation framework

2.2.1. 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. The model is run in an hourly resolution for 16 typical days, which, combined, are representative for a single year (Helgeson and Peter, 2020).

[4]The electricity and gas market models employed are large-scale, data-rich models, making iterations a time-intensive process. The selected stopping criterion represents a trade-off between model convergence and the time required to achieve convergence, i.e. the number of iterations of both models. Since model convergence proceeds exponentially, we found that below 5%, the number of iterations required to achieve further measurable convergence increases substantially.

[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.

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 optimization problem.

The objective function (equation 2.1) minimizes 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 ($\mathbf{P}^{el,ptg}_{i,n,y,t}$) of technology i.

$$\min \ TSC = \sum_{i,n,y,t} \phi_{i,n,y} * \mathbf{C}^{el,ptg}_{i,n,y} + \sum_{i,n,y} \gamma_{i,n,y,t} * \mathbf{P}^{el,ptg}_{i,n,y,t} \tag{2.1}$$

The optimization problem is subject to a number of constraints. The most important constraints governing the model of the electricity system are equations 2.2 to 2.5. Constraints describing the production of hydrogen, methanation and the renewable hydrogen quota are given by equations 2.6 to 2.10.

The equilibrium constraint (equation 2.2) ensures that electricity production ($\mathbf{P}^{el}_{i,n,y,t}$), 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.

$$\mathbf{D}^{el}_{n,y,t} = \sum_{i} \mathbf{P}^{el}_{i,n,y,t} + \sum_{m} \Delta\mathbf{F}^{el}_{m,n,y,t} + \sum_{i} \Delta\mathbf{S}^{el}_{i,n,y,t} \qquad \forall \ n, y, t, m \neq n \tag{2.2}$$

Equation 2.3 states that a generator's electrical output ($\mathbf{P}^{el}_{i,n,y,t}$) 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.

$$\mathbf{P}^{el}_{i,n,y,t} \leq \mathbf{C}^{el}_{i,n,y} * \alpha^{el}_{i,n,y,t} \qquad \forall \ i,n,y,t \tag{2.3}$$

To reduce the computational burden, the model operates with a reduced temporal resolution. A year is represented by 16 typical days, which are modeled in hourly 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 modeled. To remedy this, a peak load constraint is introduced (equation 2.4), 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 modeled directly.

$$\mathbf{l}^{el}_{n,y} \leq \sum_i \mathbf{C}^{el}_{i,n,y} * \sigma_{i,n} + \sum_m cap^{ntc}_{n,m,y} * \sigma_{n,m,y} \qquad \forall \ n,y,m \neq n \tag{2.4}$$

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 2.5, 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 ($\mathbf{P}^{el}_{i,n,y,t}$) by its efficiency ($\eta^{el}_i$) to determine its fuel consumption, which is then multiplied with the fuel-specific emission factor (ϵ^{CO2}_i).

$$emcap^{CO2}_y \geq \sum_{i,n,t} \frac{\mathbf{P}^{el}_{i,n,y,t}}{\eta^{el}_i} * \epsilon^{CO2}_i \qquad \forall \ y \tag{2.5}$$

The following constraints pertain to the production of hydrogen and synthetic methane through the electrolysis of water. Equation 2.6 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 ($d^{el}_{n,l,y,t}$) in market n and sector l and the sum of the electricity consumed by PtG technologies i in market n. This is obtained by

[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.

[7] In tonnes of CO_2.

dividing the hourly output of a PtG process ($\mathbf{P}^{ptg}_{i,n,y,t}$) by its conversion efficiency (η^{ptg}_i).

$$\mathbf{D}^{el}_{n,y,t} = \sum_l d^{el}_{n,l,y,t} + \sum_i \frac{\mathbf{P}^{ptg}_{i,n,y,t}}{\eta^{ptg}_i} \qquad \forall \ n, y, t \tag{2.6}$$

PtG production ($\mathbf{P}^{ptg}_{i,n,y,t}$) is limited to the installed electrolyzer or methanation capacity ($\mathbf{C}^{ptg}_{i,n,y}$) (given in kW-electric), times their efficiency (η^{ptg}_i) (equation 2.7).

$$\mathbf{P}^{ptg}_{i,n,y,t} \leq \mathbf{C}^{ptg}_{i,n,y} * \eta^{ptg}_i \qquad \forall \ i, n, l, y, t \tag{2.7}$$

Equation 2.8 operationalizes the renewable hydrogen quota. For each year y, it requires the supply of hydrogen and synthetic methane ($\mathbf{P}^{ptg}_{i,n,y,t}$) across all markets n to match the demand for gas in final demand sectors l, times the quota ($\kappa^{ptg}_{y,l} \rightarrow [0,1]$).

$$\sum_{i,n,t} \mathbf{P}^{ptg}_{i,n,y,t} \geq \sum_{n,l,t} d^{gas}_{n,l,y,t} * \kappa^{ptg}_{y,l} \qquad \forall \ y \tag{2.8}$$

We assume that the hydrogen produced to fulfill the quota obligation is blended into the natural gas grid at the distribution grid level. Equation 2.9 establishes blending limits for hydrogen. The volume of hydrogen injected is derived by multiplying the production of raw hydrogen ($\mathbf{P}^{H2}_{i,n,y,t}$) 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 consumed in the final demand sectors l, which is derived by multiplying the final gas demand of each sector ($d^{gas}_{n,l,y,t}$) with the volumetric energy density of natural gas (ncv_{CH4} = 10 kWh/m^3), times the hydrogen injection limit ($\lambda_{y,l} \rightarrow [0,1]$).

$$\sum_i \mathbf{P}^{H2}_{i,n,y,t} * ncv_{H2} \leq \sum_{n,l} d^{gas}_{n,l,y,t} * ncv_{CH4} * \lambda_{y,l} \qquad \forall \ y, t \tag{2.9}$$

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 2.10 requires the electricity consumed for the production of hydrogen or synthetic methane ($P^{ptg}_{i,n,y,t}$) 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.

$$\sum_i \frac{\mathbf{P}^{ptg}_{i,n,y,t}}{\eta^{ptg}_i} \geq \sum_j \mathbf{P}^{el}_{j,n,y,t} \qquad \forall \ n, j \subseteq i, y, t \tag{2.10}$$

2.2.2. Gas Market Model

Furthermore, 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 (2011c) and is formulated as a linear optimization problem that minimizes the total cost of natural gas supply in Europe, subject to infrastructure and production constraints. Hence, it is assumed that European natural gas markets are perfectly competitive.[8] 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[9] and major exporting countries (Russia, Algeria, Libya and the Southern Gas Corridor) are included with their corresponding annual gas demand and production capacities. The model is run in monthly resolution. 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, e.g., Dieckhöner et al. (2013), Lochner (2007), and Lochner (2011a).

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 liquefied natural gas (LNG) regasification capacities, are assigned to these nodes. The objective function (equation 2.11) minimizes the

[8]This assumption is supported by recent market monitoring reports of the European Union Agency for the Cooperation of Energy Regulators (ACER). They show that gas hub prices converged significantly over the last years. (ACER, 2019), indicating an increasingly competitive market. Moreover, market interconnectivity and liquidity is expected to further improve in the future (Schulte and Weiser, 2019).

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

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 ($\mathbf{VC}_{n,t}^{prod}$), the cost of transportation ($\mathbf{VC}_{n,m,t}^{trans}$) and the cost of storage ($\mathbf{VC}_{n,t}^{stor}$).

$$\min \ TSC = \sum_{n,m,t} \mathbf{VC}_{n,t}^{prod} + \mathbf{VC}_{n,m,t}^{trans} + \mathbf{VC}_{n,t}^{stor} \tag{2.11}$$

The model is subject to a number of constraints. The energy balance condition (equation 2.12) 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 ($\mathbf{F_{m,n,t}^{trans}}$), storage withdrawals ($\mathbf{S_{z,n,t}^{out}}$), production at the node ($\mathbf{P_{g,n,t}^{gas}}$), LNG regasification ($\mathbf{P_{r,n,t}^{lng}}$) or synthetic methane injection ($\mathbf{P_{i,n,t}^{ch4}}$) 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 ($\mathbf{F_{n,m,t}^{trans}}$) or storage injections ($\mathbf{S_{z,n,t}^{in}}$). Hydrogen injection is modeled as a reduction of demand at the node ($\mathbf{P_{n,t}^{h2}}$), since it is assumed to occur at the distribution grid level. Further restrictions to hydrogen injection are stated later.

$$\begin{aligned} &(d_{n,t} - \mathbf{P}_{n,t}^{h2} * \frac{1}{gcv_{ng}}) + \sum_m \mathbf{F}_{n,m,t}^{trans} + \sum_z \mathbf{S}_{z,n,t}^{in} \\ &= \\ &\sum_m \mathbf{F}_{m,n,t}^{trans} + \sum_z \mathbf{S}_{z,n,t}^{out} + \sum_g \mathbf{P}_{g,n,t}^{gas} + \sum_r \mathbf{P}_{r,n,t}^{lng} + \sum_i \mathbf{P}_{i,n,t}^{ch4} * \frac{1}{gcv_{ng}} \qquad \forall \ n,t \end{aligned} \tag{2.12}$$

The storage balance condition (equation 2.13) ensures that storage injections, withdrawals and levels are balanced over time.

$$\mathbf{S}_{z,n,t}^{level} = \mathbf{S}_{z,n,t-1}^{level} + \mathbf{S}_{z,n,t}^{in} - \mathbf{S}_{z,n,t}^{out} \qquad \forall \ z,n,t \tag{2.13}$$

Production, transportation, regasification and storage injection/ withdrawal are restricted to the exogenous capacities (equations 2.14-2.19), 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.

$$\mathbf{P}^{gas}_{g,n,t} \leq cap^{gas}_{g,n,t} \qquad \forall \ g,n,t \tag{2.14}$$

$$\mathbf{P}^{lng}_{r,n,t} \leq cap^{lng}_{r,n,t} \qquad \forall \ r,n,t \tag{2.15}$$

$$\mathbf{F}^{trans}_{n,m,t} \leq cap^{trans}_{n,m,t} \qquad \forall \ n,m,t \tag{2.16}$$

$$\mathbf{S}^{level}_{z,n,t} \leq cap^{level}_{z,n,t} \qquad \forall \ z,n,t \tag{2.17}$$

$$\mathbf{S}^{in}_{z,n,t} \leq cap^{in}_{z,n,t} * \tau^{in}_{z} * \mathbf{S}^{level}_{z,n,t} \qquad \forall \ z,n,t \tag{2.18}$$

$$\mathbf{S}^{out}_{z,n,t} \leq cap^{out}_{z,n,t} * \tau^{out}_{z} * \mathbf{S}^{level}_{z,n,t} \qquad \forall \ z,n,t \tag{2.19}$$

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 2.12). Further constraints on PtG are stated below. Blending hydrogen into natural gas pipelines is only feasible up to a defined limit to minimize the risk of damaging equipment (see Section 2.1). Equation 2.20 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 modeled, 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, e.g., IEA (2019), Melaina et al. (2013) or DVGW (2019)).

$$\sum_i \mathbf{P}_{i,n,t}^{H2} * \frac{1}{gcv_{H2}} \leq \sum_l \mathbf{D}_{n,t}^{res-com,oth} * \lambda_y \qquad \forall \; n,t \tag{2.20}$$

The PtG capacities ($cap_{i,v,t}$) are exogenous parameters provided by the electricity market model. Equation 2.21 ensures that the country-level capacities are distributed optimally[10] to the grid nodes ($\mathbf{C_{i,n,t}}$) assigned in each country. PtG capacities define the upper limit for PtG injection ($\mathbf{P_{i,n,t}^{gas}}$), at each node (equation 2.22). The time factor tf ensures the correct scaling of capacities to generation and depends on the selected temporal resolution of the model.

$$\sum_n \mathbf{C}_{i,n,t} \leq cap_{i,v,t} \qquad \forall \; i,v,y \;\; n \in v \tag{2.21}$$

$$\mathbf{P}_{i,n,t}^{gas} \leq \mathbf{C_{i,n,t}} * \eta_i * tf \qquad \forall \; i,n,t \tag{2.22}$$

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 2.23 ensures that the total injection of each technology, in each country and in each time period ($q_{i,v,t}$) is consistent with the allocation by the model ($\mathbf{P_{i,n,t}}$).

$$\sum_n \mathbf{P}_{i,n,t} \leq q_{i,v,t} \qquad \forall \; i,v,y,n \in v \tag{2.23}$$

2.2.3. 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.

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

EU electricity and natural gas demand projections are based on the POTEnCIA Central scenario of the EU Joint Research Center. 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.1.

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/ENTSOE 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 and ENTSOE, 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 the ENTSO-G Transmission Capacity Map (ENTSOG, 2019), LNG regasification capacities from the GIE LNG Map (GIE, 2019) and storage capacities from the GIE Storage Map (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 visualization of the gas supply merit order can be found in Figure A.1 the Appendix A.1.

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 2.1), which increases over time. Hence, individual injection limits due to local restrictions (e.g. CNG filling stations, sensitive industrial consumers (IEA, 2019)) 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 hydrogen injection limits and the quota obligations are shown in Table 2.1.[11]

Table 2.1.: Assumed injection limits in gas demand end-use sectors in vol-% and renewable hydrogen quotas in TWh-% (own assumption based on IEA (2019), Melaina et al. (2013), Moraga et al. (2019), Müller-Syring and Henel (2014))

	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

2.3. Results

The results of the scenario simulations are summarized in this section.[12] The quantity effects (Section 2.3.2), price effects (Section 2.3.3) and distributional effects (Section 2.3.4) of the renewable hydrogen quota are assessed by analyzing 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 parameterized with the data and assumptions presented in Section 2.2.3. The models were run in iterations, exchanging gas

[11] Note that the renewable hydrogen quota refers to per cent of gas demand (in TWh) and can be complied with hydrogen and synthetic methane, whereas the injection limit only refers to pure hydrogen and refers to vol-%.

[12] Summary tables can be found in Appendix A.2.

prices, gas consumption and PtG production volumes, until the convergence criterion[13] was met.

2.3.1. 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 2.2. 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.

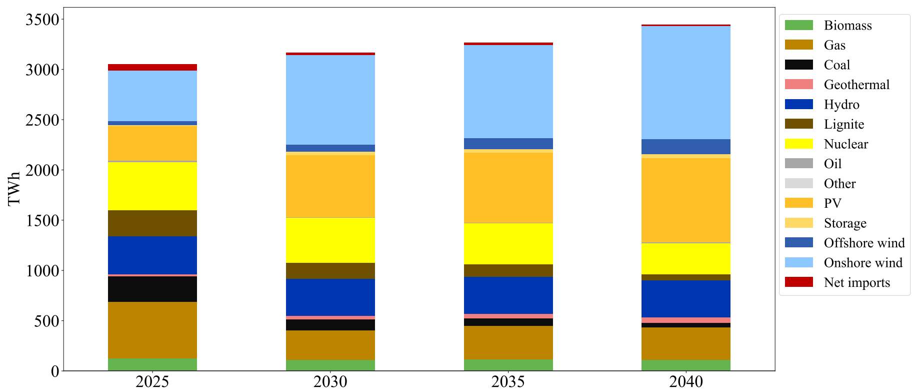


Figure 2.2.: EU electricity generation in the REF scenario

Mainly due to the lower consumption of the power sector, EU natural gas demand drops by 354 TWh/a between 2025 and 2030 and then levels off at around 3290 to 3350 TWh/a until 2040 (see Table A.6 in Appendix A.2). No hydrogen and synthetic methane are produced for gas grid injection in the REF scenario.[14] EU indigenous gas production declines from around 340 TWh in

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

[14]In the REF scenario, around 10 GW of electrolyzers 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).

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.

2.3.2. 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 2.1).

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 805 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 2.3). 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 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[15] (see Section 2.3.3 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.

[15]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.

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

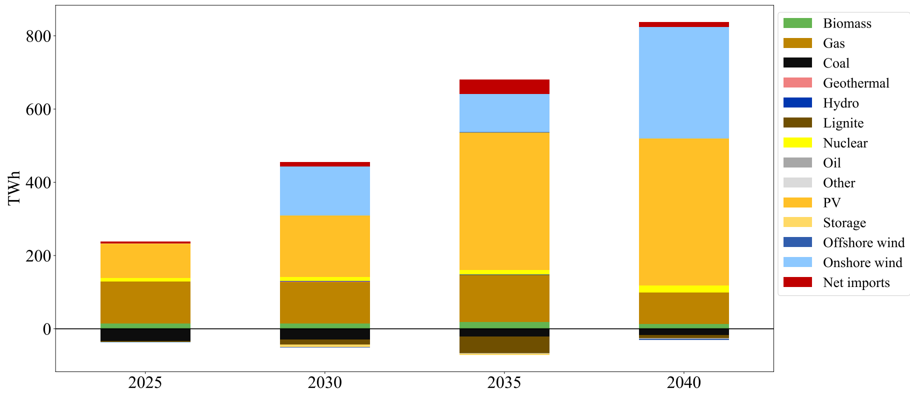


Figure 2.3.: Additional electricity generation in the EUQ scenario

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 network. 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 maximized up to the volumetric 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 2.4 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 sizable 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.

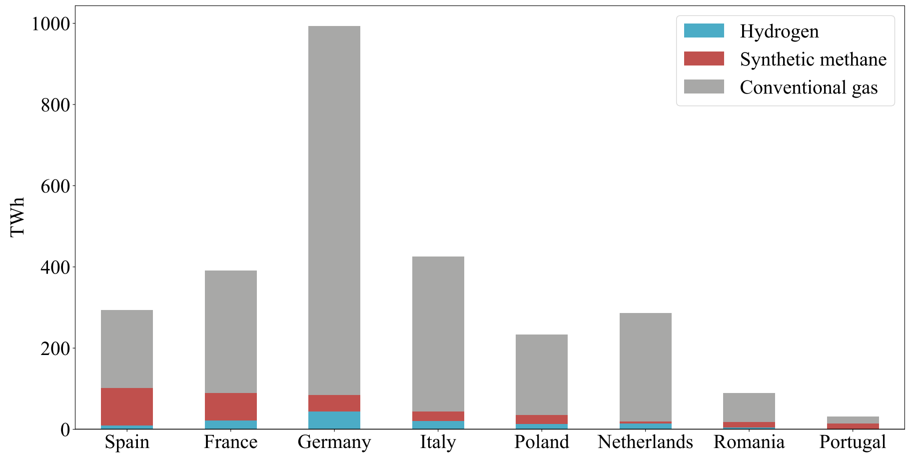


Figure 2.4.: Conventional gas, hydrogen and synthetic methane consumption of the eighth largest gas consumers in the EUQ scenario in 2040

Total natural gas demand is slightly higher in EUQ compared to REF due to higher gas-fired power generation.[16] The difference is greatest in 2030 and 2035, where the relative gas demand in the EU is around 6% higher in the EUQ than the REF scenario. In absolute terms, the increase in demand for natural gas is between 154 TWh (2040) and up to 216 TWh (2035) (see Table A.9 in Appendix A.2).

[16]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.

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 and synthetic methane (see Table A.9 in Appendix A.2). 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 5.8% or 298 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 2.5). 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.

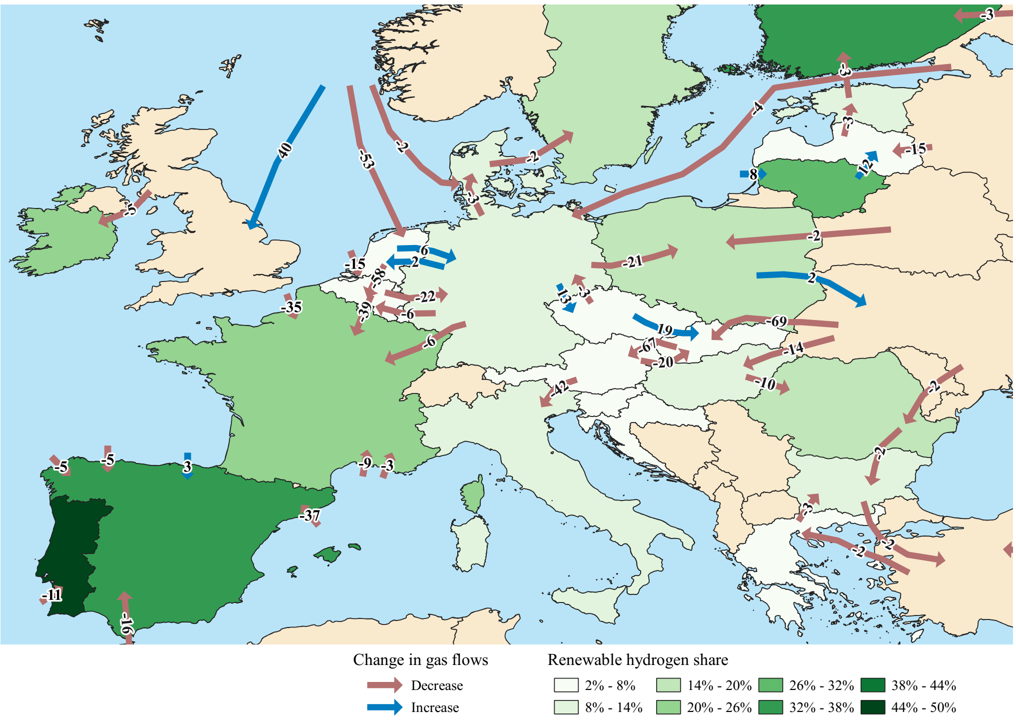


Figure 2.5.: Renewable gas shares of total gas demand in EU countries and absolute gas flow differences between REF and EUQ in 2040 (in TWh)

2.3.3. Price effects of a quota

A strong relative increase in electricity and EU ETS prices can be observed (see Figure A.2 in Appendix A.2). 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.[17]

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 A.9 in Appendix A.2).

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 electrolyzer investment costs, the gap between the cost of production and the revenue PtG producers generate through sales

[17] 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.

on the gas market shrinks over time. Accordingly, the renewable hydrogen certificate price[18] 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.

2.3.4. 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[19] producer and consumer surpluses between the REF and the EUQ scenario:

$$\Delta_a(\overline{W}_a^{EUQ} - \overline{W}_a^{REF}) = \sum_{c \in C} W_{a,c}^{EUQ} * \frac{q_{a,c}^{EUQ}}{\sum_c q_{a,c}^{EUQ}} - \sum_{c \in C} W_{a,c}^{REF} * \frac{q_{a,c}^{REF}}{\sum_c q_{a,c}^{REF}} \quad (2.24)$$

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 2.6 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 2.3.2, 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

[18]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.

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

prices slightly higher. After 2025, the overall increase in the electricity market price compensates for the additional marginal cost.

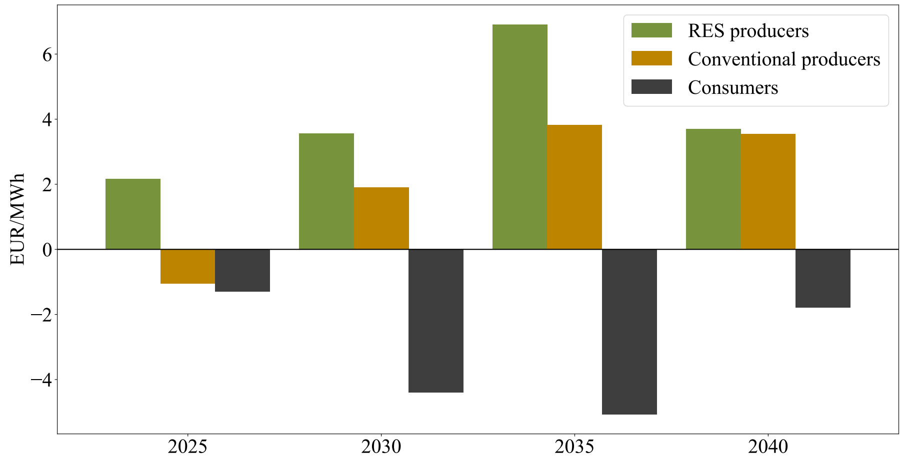


Figure 2.6.: Change in RES producer surplus, conventional producer surplus and consumer surplus on the electricity market

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 2.7. 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.[20] Hence, a higher gas price in 2025 in the EUQ scenario decreases the average surplus of non-quota consumers and increases their

[20]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.

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 11 EUR/MWh lower in 2025 and 23 EUR/MWh lower in 2040.

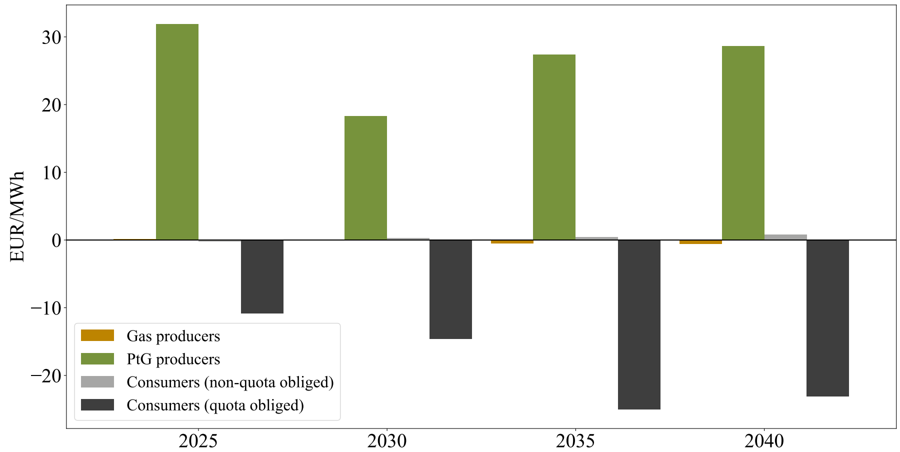


Figure 2.7.: Change in gas producer surplus, PtG producer surplus and consumer surplus on the gas market

Taken together across both markets, the quota has a welfare-diminishing effect (see Figure 2.8). 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 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.

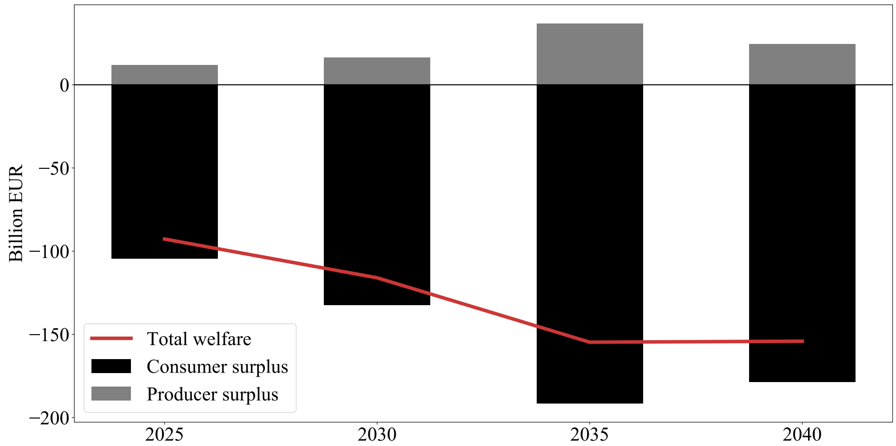


Figure 2.8.: Change in consumer surplus, producer surplus and total welfare

2.4. Discussion

The results of the simulations show that different producer and consumer groups are affected differently by sector-specific renewable hydrogen quotas. The majority of the cost burden is carried by quota obliged gas consumers, who subsidize the production and injection of renewable hydrogen through the purchase of renewable gas certificates emitted by the producers. The primary beneficiaries are both PtG producers and the producers of renewable electricity, since the former are required to purchase the power needed for the production of hydrogen from the latter.

On the electricity market, the increase in the price also leads to a decline in consumer welfare. As a consequence, quota obliged consumers which 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 therefore mostly affect households, the commercial sector and smaller, less energy intensive industries.

The quota design as suggested here could release the pressure on RES costs and they could earn additional profits and might ultimately lead to a decrease in public support for RES generation. Simultaneously, the burden would be carried by gas consumers. In our analysis, we assumed exogenous gas consumption in all sectors except the power sector. Most probably, the increasing end consumer gas price could lead to a phase out of gas utilization in these sectors, e.g. by electrification. A decreasing gas consumption would reduce the utilization of gas infrastructure and lead to an increase in gas network charges. Ultimately, an upward cost cycle could be initiated, leading to a shrinking attractiveness of gas as an energy carrier.

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.[21] Quota obliged gas consumers pay up to 25 EUR/MWh more in the quota scenario (EUQ) compared to the reference scenario (REF). 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, 2020).

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. Average wholesale electricity prices in European countries in 2019 range from approximately 37 EUR/MWh to 64 EUR/MWh (ACER, 2021b). Effectively, the renewable hydrogen quota thus constitutes an additional, indirect subsidy mechanism for RES.

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. The derived average marginal abatement costs of 736 EUR/tCO_2 in 2025 and 473 EUR/tCO_2 in 2040 are high compared to those of alternative greenhouse gas (GHG) mitigation measures.[22]

However, it is effective in stimulating the deployment of electrolyzers, an EU industrial policy objective. The block's hydrogen strategy proposes installing at least 40 GW of electrolyzer capacity in the EU by 2030[23] (European Commission, 2020b). With a quota as modeled in the paper at hand,

[21] In practice, the burden of proof would likely rest with retail gas suppliers, rather than gas consumers directly. Retailers would have to demonstrate compliance by purchasing certificates and have an incentive to pass the associated cost on to consumers through the retail tariffs.

[22] For example, emission abatement cost in the power sector range from 22 EUR/tCO_2 (onshore wind or natural gas combined cycle replacing coal) to 119 EUR/tCO_2 (solar thermal replacing coal). A gasoline tax (16-42 EUR/tCO_2), wind energy subsidies (2-234 EUR/tCO_2) or electric vehicle subsidies (315-576 EUR/tCO_2) also comprise less costly abatement measures (Gillingham and Stock, 2018).

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

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 electrolyzers through scale and learning effects. 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.

While renewable hydrogen injection is maximized 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.

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. However, as soon as the hydrogen demand of the quota obliged consumers and other new hydrogen consumers, e.g., industry, mobility and transport, exceeds a certain amount, repurposing gas networks to carry pure hydrogen may become more efficient economically than blending.

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.

The first is that cost assumptions, particularly regarding current and future RES and electrolyzer technology costs, are based on current projections (see Appendix A.1). 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 utilization and lead to an increase in gas network charges. Ultimately, an upward cost cycle could be initiated, further contributing to a shrinking attractiveness of gas as an energy carrier. Furthermore, in reality gas and electricity markets are characterized by imperfections, which differ from the perfect competition assumptions of the proposed models.

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.

2.5. Conclusions

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 European Union (EU) gas and electricity markets. By taking a renewable hydrogen quota on final gas consumption that is not subject to the EU emission trading system as an example, we analyze 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 optimization models.

[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.

Our model simulations show that the renewable hydrogen quota leads to significant expansion of renewable electricity production since power-to-gas producers are obliged to source their electricity from renewable generators 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. The result is a higher electricity price in the quota scenario. The quota's primary beneficiaries in the power sector are renewable electricity producers. Since they are the exclusive suppliers for power-to-gas 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. power-to-gas 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. Ultimately, quota obliged gas consumers carry most of the additional cost associated with the renewable electricity generation and power-to-gas capacity expansion through purchasing the renewable hydrogen certificates needed to demonstrate compliance with the quota.

The simulations show that different producer and consumer groups are affected differently by sector-specific renewable hydrogen quotas. Whereas power producers benefit from increased electricity prices and power-to-gas producers enter the market with a positive welfare, quota obliged gas consumers as well as power consumers suffer from decreased welfare due to the quota obligation.

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

3. Simultaneity of Green Energy and Hydrogen Production: Analyzing the Dispatch of a Grid-connected Electrolyser

3.1. Introduction

In the course of decarbonisation, renewable primary energy carriers substitute fossil primary energy carriers (Smil, 2017). This transformation can be achieved by electrification of natural gas and oil applications, e.g., through heat pumps or electric vehicles, or by substituting hydrocarbons with climate-neutral gases like hydrogen or synthetic natural gas (Rosen and Koohi-Fayegh, 2016, Thiel et al., 2016, Thomaßen et al., 2021). Hydrogen embodies characteristics that complement well the properties of electricity, e.g., it has a higher economic efficiency than electricity in some final energy conversion processes, such as heavy road transport, in high-temperature industry applications (Dodds et al., 2015, Parra et al., 2019), and steel production. Furthermore, it is a meaningful option for both short-term and long-term energy storage to balance fluctuating supply from intermittent wind and solar energy (Anderson and Leach, 2004). CO_2 emission reduction can only be achieved if no additional greenhouse gases are emitted for the production of hydrogen. A promising technology is, therefore, to produce renewable hydrogen from renewable energy (RE) sources and water electrolysis (Rosen and Koohi-Fayegh, 2016). The latter is referred to as power-to-gas (PtG) technology, which uses electricity to split water into hydrogen and oxygen. Besides its positive effects on the energy system transformation, the uptake of hydrogen as a future energy carrier, new markets for hydrogen technologies and hydrogen trade can stimulate economic growth (Schlund et al., 2022), acknowledged by various governmental hydrogen strategies (Lambert and Schulte, 2021). However, so far, renewable hydrogen is economically not efficient in any final energy sector (Abdin et al., 2020, Buttler and Spliethoff, 2018). Moreover, most energy systems still have substantial fossil generation in their electricity supply mix; hence, producing hydrogen from fossil-fired power stations can increase CO_2 emissions from the power sector (Hurtubia and Sauma, 2021, Schlund and Schönfisch, 2021).

Policymakers are facing the challenge of building capacity for hydrogen generation to stimulate technology development while maintaining emission reduction measures in the power sector. Defining and certifying green hydrogen is one option to separate both goals, so that exclusively emission-free hydrogen production is favored by the regulatory framework (Velazquez Abad and Dodds, 2020). The design and effectiveness of such a separation are politically and scientifically discussed. A repeated part of these discussions is establishing a temporal link between electricity-based hydrogen generation and electricity generation from RE sources. For instance, in the EU (European Commission, 2018) or German (Renewable Energy Act, 2021) legislation this temporal link is considered. This temporal link can be expressed by the *simultaneity* of the power generation from the RE source and the power consumption. While the original rationale behind such a simultaneity obligation is the prevention of unwanted side-effects in the electrolyzer dispatch from investment subsidies, it may distort the investment signals. These possible distortions on the investment incentive have not been taken into consideration so far. In this paper, we assess the structural form of these distortions that policymakers can consider when designing dispatch-oriented criteria for green energy subsidies. Therefore, we focus on a grid-connected electrolyzer, which purchases electricity at spot markets and is obliged to consume electricity from RE plants. We explicitly consider and vary the simultaneity to assess four aspects of the obligation on the electrolyzer dispatch: the general value generated by the electrolyzer, the risk from varying RE generation, the sensitivity on the price relation between hydrogen and electricity, and the translation of associated carbon emissions.

Against this background, we develop a model framework including a mixed-integer-linear program to determine the optimal dispatch of an electrolyzer, a parametrical representation of day-ahead and intraday markets, and a Monte Carlo simulation to generate random wind generation. We apply the framework to an electrolyzer located in Germany and vary the electricity prices for the year 2019. We draw random wind generation realizations for this case and evaluate the distribution of the contribution margin and full load hours (FLH). We vary the simultaneity interval and assess its structural impact on the viability and associated emissions of the electrolyzer.

The remainder of the paper is structured as follows: Section 3.2 reviews recent literature on the economics of power-to-gas technology. Section 3.3 presents the model framework and the numerical assumptions for the case study, and section 3.4 shows the results. In section 3.5, we discuss the implications of our findings. We conclude our paper and draw policy implications in section 3.6.

3.2. Literature Review

The economics of power-to-hydrogen conversion has recently been subject to broad research. A PtG plant converts electricity into hydrogen, benefiting from cross-commodity trading between these two secondary energy carriers (Baumann et al., 2013). The economic viability strongly depends on the conversion efficiency and the market prices on the input and output side (Glenk and Reichelstein, 2019). The variable costs of a PtG plant are predominantly determined by electricity prices, which are increasingly characterized by the volatility of RE generation. The electricity procurement strategy significantly affects the hydrogen production costs and the total emissions of hydrogen production (El-Emam and Özcan, 2019). It can take three distinct forms: (i) The PtG plant is co-located and physically connected with a RE generation plant (Ferrero et al., 2016). The production of hydrogen is profitable when hydrogen sales yield higher revenues than selling electricity on the market, assuming that the RE generator is connected to the grid (Glenk and Reichelstein, 2019). If the RE generator and the public grid are not connected, hydrogen sales also need to cover the total cost of electricity generation (Brändle et al., 2021). (ii) Further, the PtG plant can be both connected to the public grid and co-located with a RE generator, forming a vertically integrated portfolio that can be optimized against volatile electricity prices (Clúa et al., 2018, Glenk and Reichelstein, 2020, Hurtubia and Sauma, 2021, Jørgensen and Ropenus, 2008). Moreover, (iii) a grid-connected PtG plant can be optimized against electricity market prices to maximize hydrogen production at minimal costs (Matute et al., 2021, Nguyen and Crow, 2016), whereby a distinction of different electricity pricing schemes (e.g., flat, time-of-use, or real-time pricing) can be made (Nguyen et al., 2019). In the third case, the PtG plant is more independent from volatile RE sources and can thus increase its output; however, indirect CO_2 emissions can be induced unless the electricity is entirely produced from RE (Huber et al., 2021).

Each power purchase strategy yields economic and operational constraints for the PtG dispatch, either through the availability of power supply or through electricity cost. A grid-connected PtG plant receives its renewable characteristic from the power source, which varies both temporally and spatially, and relies on the primary energy source used (Weber et al., 2010). Currently, hydrogen can either be sold to industrial consumers at (nearly) fixed prices (Luck et al., 2017) or sold as a close substitute to natural gas (Haeseldonckx and D'haeseleer, 2007). In the future, an equilibrium price of hydrogen at competitive hydrogen markets will equal the average cost of hydrogen production (Green et al., 2011). Since hydrogen is currently mainly used as a feedstock in industrial processes, there are only vague estimates on a possible equilibrium price. Thus, literature either considers inelastic demand in use cases for the industry, mobility, or heating sector or derives hydrogen prices from conventional production or derived products like synthetic methane (Baumann et al., 2013, Breyer et al., 2015, Fragiacomo and Genovese, 2020, Glenk and Reichelstein, 2019, Matute et al., 2019).

While numerous studies have estimated hydrogen production costs from grid-connected electrolyzers with an optimization of the RE plant's and electrolyzer's utilization, few have taken into account the indirect emission effect of electricity supplied by the grid. Since policies are in place or being discussed, defining regulation on electricity withdrawals from the grid to produce hydrogen, we aim at filling the gap in literature through explicitly focusing on a simultaneity obligation and its impact on hydrogen production.

3.3. Methodology

To answer the research question we develop a novel model framework and tailor a case study to an application in Germany.

3.3.1. Model Framework

The model framework aims at capturing a realistic representation of an electrolyzer's operation, the volatility of a RE integrated electricity system, and appropriate metrics to assess the cross-commodity potential and the associated CO_2 emissions. Figure 3.1 summarizes the key components of our methodological approach.

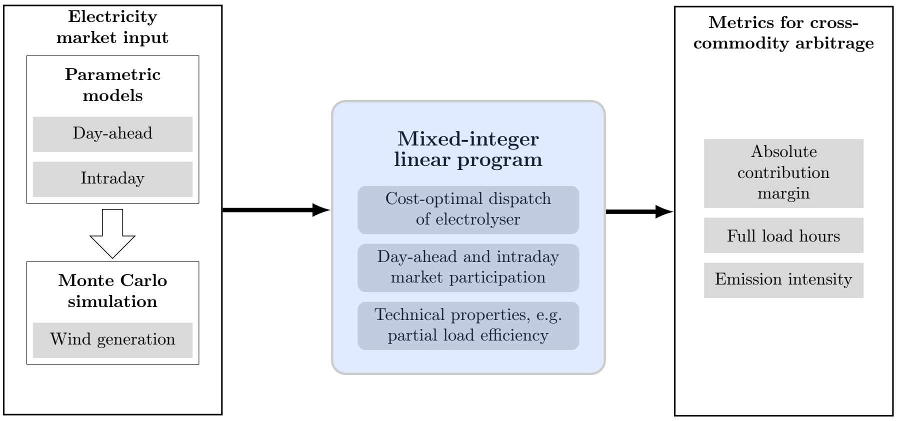


Figure 3.1.: Methodological approach consisting of a mixed-integer linear program, stochastic price time series generation, and metrics for cross-commodity arbitrage.

To estimate the optimal short-term viability of the electrolyzer, we develop a techno-economic mixed-integer linear program, which simulates the cost-optimal dispatch of an electrolyzer. The dispatch is optimized for exogenous wind generation and corresponding electricity prices. As electricity markets the day-ahead and the intraday market are considered. Other sources of revenue are not considered. Two parametric models for day-ahead and intraday electricity markets capture the relation between wind generation realizations and electricity prices. A Monte Carlo simulation of synthetic wind generation realizations includes the risk of uncertain wind generation. The models are applied in a case study for one year. Finally, we evaluate the case study with metrics for the viability and CO_2 intensity of the corresponding hydrogen production.

3.3.2. Mixed-integer Linear Program of Electrolyzer Operation

The economic viability of an electrolyzer depends on its variable cost, fixed operative and maintenance (O&M) costs, and revenues. In the short term, the cost-optimal dispatch of the electrolyzer requires that revenues are equal or higher than the associated costs of the plant's operation. These decisions are modeled in the economic dispatch model, which simulates the operation of an electrolyzer under a temporal resolution of 15 minutes. Fixed O&M and investment costs are not considered in the short-term dispatch decision and, therefore, excluded from the dispatch model.

The economic dispatch model is formulated as a mixed-integer linear program (MILP). The objective function in equation 3.1 maximizes the profit over all simulated time periods $t \in T$ from revenues R_t of hydrogen production and costs C_t of electricity supply.

$$\max \ \textit{Contribution margin} = \sum_{t}^{T} R_t - C_t \tag{3.1}$$

The revenue is calculated in equation 3.2 with an exogenous constant hydrogen price p^{H2} and the output of the plant, which depends on the load in period t and an input-output function f which converts electric input in MW into hydrogen output in kg considering a conversion efficiency. The output of the plant depends on its load L. The binary variable B determines whether the plant is switched on ($B = 1$) or off ($B = 0$). The constant δ ensures the correct time scale.

$$R_t = f(L_t, B_t) * \delta * p^{H2} \qquad \forall \ t \tag{3.2}$$

Equation 3.3 determines the variable cost of the electrolyzer. In each period t, the plant's load L purchased on power market m is dispatched, whereby the set of markets M includes the day-ahead and intraday markets. Although, the provision of grid service, e.g. control reserves, could be a relevant source of revenue for an electrolyzer (Kopp et al., 2017), they are not included in the analysis. The paper focuses on identifying the effect of a simultaneity obligation on the dispatch of an electrolyzer. Simultaneity links the renewable generation with the hydrogen production at the respective electricity price. Revenue from grid service add to the viability of the electrolyzer but may not significantly determine the effect of the simultaneity. The costs C are then calculated by multiplying the load with the corresponding electricity price p on the market and the fixed electricity surcharges α.

$$C_t = \sum_{m}^{M} L_{t,m} * (p_{t,m} + \alpha) * \delta^t \qquad \forall \ t \tag{3.3}$$

Its rated nominal capacity cap in MW_{el} limits the total load of the electrolyzer (equation 3.4).

$$\sum_m L_{t,m} \leq cap \qquad \forall\ t \tag{3.4}$$

The minimal load constraint in equation 3.5 restricts the operating range of the electrolyzer. The minimal load is expressed as a share $\beta \in (0, 1)$ of the nominal capacity cap.

$$\sum_m L_{t,m} \geq B_t * \beta * cap \qquad \forall\ t \tag{3.5}$$

The electrolyzer is assumed to be subject to a simultaneity obligation of RE and hydrogen production. The simultaneity is determined by a fixed time factor $\gamma \in T$, which defines the time interval in which RE generation and the electrolyzer's electricity consumption must be balanced. Hence, a time factor of $\gamma = 1$ obliges the electrolyzer to consume the power production within the same period. If $\gamma > 1$, the electrolyzer can virtually shift the RE production from one period to another. The following equations operationalize the balancing of RE generation and hydrogen production. The sum of the total load L of one period t and all subsequent periods within the given simultaneity interval γ must be equal or less than than the RE production in the same period. The RE production is determined by the relative RE output re multiplied by the electrolyzer capacity cap and the RE scaling factor σ, which defines the capacity ratio of the RE plant and the electrolyzer. For the first periods ($t \leq \gamma$), the equation 3.6 is modified such that the latest period valid for balancing equals one. The simultaneity constraint implies that a virtual RE power storage is generated during the electrolyzer's operation, where RE power certificates are stored with a temporal validity of γ.

$$\sum_m L_{t,m} + \sum_{j=(t-\gamma+1)}^{t-1} \sum_m L_{j,m} \leq \sum_{j=t-\gamma+1}^{t} re_j * \sigma * cap \qquad \forall\ \gamma + 1 \leq t \leq T \tag{3.6}$$

While the model formulation simplifies some technical characteristics and does not consider all the electrolyzer's business opportunities (e.g., frequency control), it has the advantage of low computation time. This allows solving the deterministic model for multiple realizations to follow a stochastic approach.

3.3.3. Synthetic Electricity Price Time Series

In a power system with a high share of RE, hydrogen production would rely on renewable primary energy carriers, such as wind and solar. The availability of these resources is intermittent, observable in electricity systems with high penetration of wind and solar generation. Since volatility will remain a crucial determinant of a RE system, we account for its impact on the electrolyzer's value. Beyond analyzing point observations based on a single weather realization, we capture the risk profile originating from the weather-dependency of renewable generation by performing two steps. First, we parameterize two linear models, one for the relation between RE generation forecasts and the day-ahead electricity prices and the other for the relation between the intraday prices, day-ahead prices, and forecast errors. Second, we generate synthetic renewable generation time-series with a Monte Carlo simulation as inputs for the independent variables in our linear models.

The first linear model captures the link between day-ahead electricity prices p_t^{DA} as the dependent variable and the residual load q_t^{res} as an independent variable. Equation 3.7 shows the corresponding model formulation (Burger et al., 2003). Note that we take the forecast residual load as an independent variable as it describes the available information at the day-ahead auction (Elberg and Hagspiel, 2015). We choose a third-degree polynomial so that it captures the non-linear relation between day-ahead prices and residual load (Ehrlich et al., 2015). The captured functional relation is not a pure estimate of the merit order but also includes the demand-side price elasticity implicitly (Elberg and Hagspiel, 2015). Additionally, ramp-up constraints, as well as scarcity situations, are addressed by the polynomial function. We fit one function per month so that the final model accounts for seasonal effects, e.g., wind generation, load, and resource prices.

$$p_t^{DA} = \epsilon_0 + \epsilon_1 q_t^{res} + \epsilon_2 (q_t^{res})^2 + \epsilon_3 (q_t^{res})^3 \tag{3.7}$$

The second polynomial model describes the relation between the intraday price p_t^{ID} as the dependent variable, and the day-ahead price p_t^{DA} and the forecast error FE_t^2 as independent variables in equation 3.8. As we vary the wind generation, we model only the impact of forecast errors and day-ahead prices on the intraday price and let other influences remain unexplained (Hagemann, 2013). We use a second-degree polynomial model of the forecast error to account for the non-linear relation (Kulakov and Ziel, 2021, Narajewski and Ziel, 2020). Thus, our functional relation implicitly captures impact factors on the intraday price like scarcity situations and ramp-up constraints (Pape et al., 2016).

$$p_t^{ID} = \zeta_0 + \zeta_1 p_t^{DA} + \zeta_2 FE_t + \zeta_3 FE_t^2 \tag{3.8}$$

The parametric models capture the functional relation between wind generation, forecast errors, and electricity market prices. Following Papaefthymiou and Klockl (2008), we draw random wind generation and forecast time series. The creation of the Markov chain and the Monte Carlo simulation are explained in Appendix B.2. With these time series and the parametric models, we compute synthetic electricity price time series.

3.3.4. Evaluation Metrics

The results are analyzed for the short-run profitability of an electrolyzer. First, the electrolyzer's annual contribution margin is evaluated, which is defined as the sum of hourly cost minus hourly revenues (see equation 3.1). Second, FLH for one year are determined: $FLH = \frac{Q}{Cap}$ (de Groot et al., 2017). Third, the CO_2 emission intensity of hydrogen is determined. Depending on the emission factor for electricity, the indirect carbon emissions of grid-connected electrolyzers can be larger than zero, whereby either marginal or average emission factors can be used (Huber et al., 2021). An exact calculation of marginal emission factors and specific CO_2 emissions of hydrogen requires time-consuming electricity market simulations (Braeuer et al., 2020, Stöckl et al., 2021), which are not compatible with our stochastic Monte Carlo approach. We approximate the emission factor with two different measures to estimate a range of emission intensity of hydrogen.

We assume that matching renewable generation and hydrogen production in every 15-minute period as the lowest temporal unit of electricity balancing purposes in the EU, which we describe as a simultaneity of a quarter-hour, has an emission factor of 0 gCO_2/kWh_{el}[1], thus represents a perfect balancing of RE

[1] We neglect embodied emissions in preliminary chains, e.g., for building, installing, and maintaining the wind generator and the electrolyzer. The emission balance should primarily capture the additional indirect emissions in the power sector from hydrogen production excluding additional embodied emissions.

and hydrogen production.[2] Each (positive) deviation of the quarter-hourly power consumption from the RE generation leads to additional electricity demand, which must be balanced by the grid, where it increases the power production from the marginal power plant. The indirectly induced emissions are calculated by multiplying the total grid-power consumption with the emission factor for electricity in each period. We apply two emission factors for electricity: (i) The marginal emission factor (MEF) equals the specific emission factor of the marginal power plant, which sets the market price on the intraday market based on its marginal cost (Fleschutz et al., 2021). Hence, the marginal emission factor is determined by mapping the quarter-hourly intraday price with the marginal costs of different power plants. The yearly average grid emission factor (YAEF) is defined as the total emissions of the power sector divided by total electricity production and is constant throughout the year. Finally, the hydrogen emission intensity is calculated by dividing the total absolute CO_2 emissions (in kg) by the total absolute quantity of hydrogen produced (in kg).

Within the analysis, the obtained distributions of these three metrics are compared regarding their arithmetic mean value and their coefficient of variation (CoV). The CoV, or relative standard deviation, sets the standard deviation in relation to the mean of the distribution and measures the dispersion of a data set. The comparison focuses on general structures represented by relative changes to the base case rather than on absolute estimations.

3.3.5. Case Study Design

We simulate the model with historical German electricity market data and exemplary inputs for the electrolyzer. Electricity market data include day-ahead and intraday spot prices of the German electricity market zone from 2015 until 2019.[3] Generation, forecast, and realized electricity demand time series are withdrawn from the data publication platform of the German federal grid agency (BNetzA, 2021). The simulation is run in quarter-hourly resolution for one year and 1000 samples of wind generation with accordingly

[2] While even in the case of quarter-hourly simultaneity the actual emissions induced by the electrolyzer might be higher, the assumption enables comparability with higher simultaneity values.

[3] The year 2020 was excluded due to its low comparability with other years caused by the covid-19 pandemic.

derived electricity prices. The resulting parametric models for the electricity prices are shown in Appendix B.

The parameterisation of the electrolyzer is based on literature data and summarized in Table 3.2. The ratio of the RE source and the electrolyzer capacity is fixed at a value of two, which is not endogenously optimized in the model and based on recent literature (Brändle et al., 2021, Glenk and Reichelstein, 2019). From the linearization of the input-output function, we receive a minimum efficiency at full load of 52%, maximum efficiency at part-load of 61%, and average efficiency of 54%. The efficiency values include peripheral equipment and refer to the higher heating value of hydrogen (Kopp et al., 2017). The assumed parameters only represent an exemplary electrolyzer. In practice, technical and economic characteristics are extensive and depend on multiple factors (see e.g., Götz et al. (2016), Saba et al. (2018), Thema et al. (2019)). Consequently, the simulation results depend on the parameterisation of the electrolyzer. Based on current German regulation, we assume electricity price surcharges of 2.39 EUR/MWh.[4]

The initial exogenous hydrogen price is set to 3 EUR/kg in the base case and varied in a subsequent sensitivity (see section 3.4.5). Currently, hydrogen is not traded on transparent and liquid markets. Instead, over-the-counter trades and bilateral contracts between producers and consumers organize volumes and prices. Here, we assume a selling price for green hydrogen as an indicator of the willingness to pay. The price is not varied over time since hydrogen can be stored, stabilizing the hydrogen prices (Green et al., 2011). The green characteristic is varied by changing the simultaneity obligation since it affects the renewable characteristic of the power supply.

A reference list mapping MEF with electricity prices is derived from Fleschutz et al. (2021), which covers the German power system for the year of 2019. Hence, the MEF used from the study coincide with the data input for the regression analysis spatially and temporally for the most recent year. A day-ahead price of less than 35.5 EUR/MWh is below the lowest marginal cost of conventional power plants in the reference list. Hence, the marginal emission factor is assumed to be 0 gCO_2/kWh_{el} for prices below that threshold. As YAEF of Germany we assume 408 gCO_2/kWh_{el} (Umweltbundesamt, 2021).

[4]The surcharges consist of 1.54 EUR/MWh electricity tax and 0.85 EUR/MWh of other surcharges.

Parameter	Value	Unit
Production capacity	1	MW_{el}
Ramping gradient	100	% $\frac{cap}{15\ min}$
Minimum load	20	% of cap
CAPEX	800	$\frac{EUR}{kW_{el}}$
Lifetime	11	years
Fixed O&M costs	1.5	% of invest
Interest rate	7	%

Table 3.1.: Electrolyzer parameter (own assumptions based on Kopp et al. (2017) and IEA (2019)).

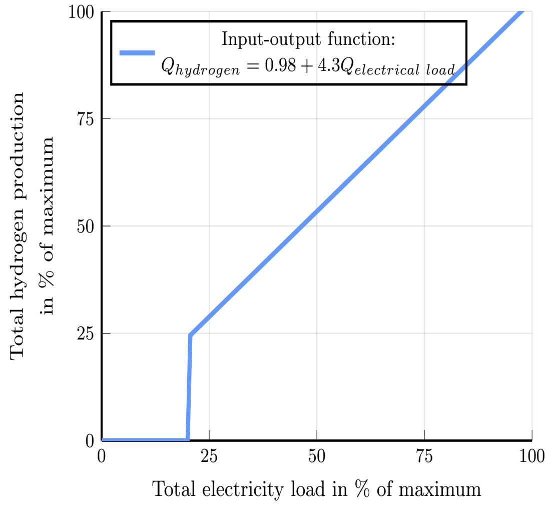


Figure 3.2.: Electrolyzer input-output-function (own assumption based on Kopp et al. (2017).

3.4. Results

We obtain results for the electrolyzer dispatch within the defined case study. First, we present the time series of randomly drawn wind generation realizations and corresponding electricity prices. For a base case, we show then the distribution of the absolute contribution margin and the FLH of a standardized electrolyzer. Fourth, we assess the impact of a simultaneity obligation on both the dispatch level and the yearly dispatch risk. Fifth, the interdependence between a simultaneity obligation and the green hydrogen selling price are analyzed. Lastly, we highlight the effect on the CO_2 emission intensity of hydrogen.

3.4.1. Price Time Series

Based on the Markov chain, we generate 1000 samples of a yearly wind generation time series in quarter-hourly resolution. Combined with the parameterized day-ahead and intraday models, these wind generation samples obtain 1000 samples of quarter-hourly intraday prices and hourly day-ahead prices. Figure 3.3 illustrates the sampled range of these three time series. The two price time series diagrams show the upper and the lower limit of the sampled price duration curves, i.e. the sorted quarter-hourly electricity prices.[5] The lower diagram shows the range of the corresponding wind capacity factors.[6]

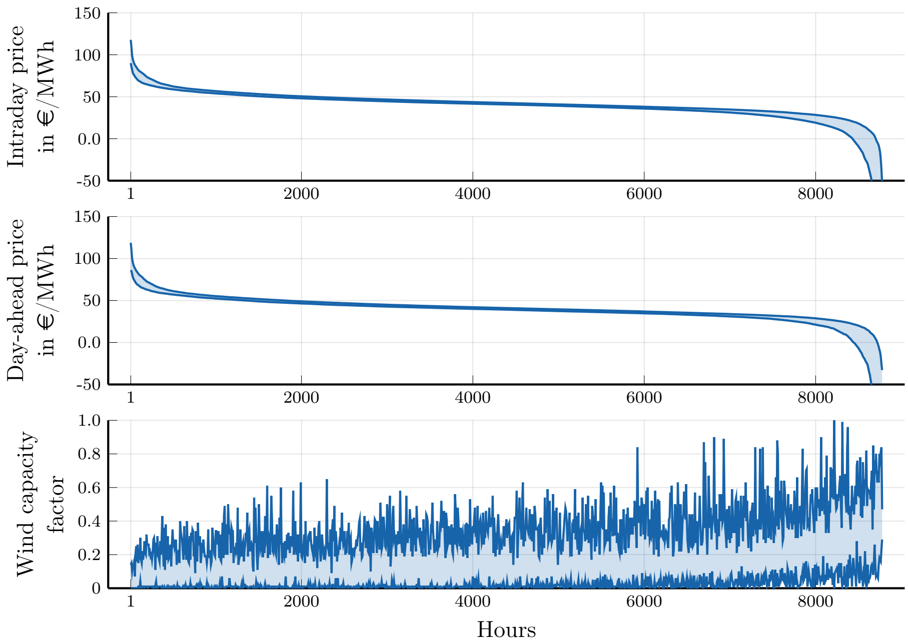


Figure 3.3.: Upper and lower limits of price duration curves and the wind generation.

The middle illustration in Figure 3.3 shows the dispersion of the day-ahead price duration curves. Towards the lower and the upper end, the price dispersion increases. In the middle part, however, the dispersion is comparably low. The parametric models in Appendix B.1 represent the

[5]The electricity prices are first sorted, and then the maximum and minimum of each sorted hour are shown in the respective diagram. They span the range of price duration curves within the total sample.

[6]The single samples are, first, sorted according to the order of the day-ahead price duration curves. Then the maximum and minimum of the wind capacity factor are shown in the diagram, also spanning the range of possible wind capacity factor realizations given the corresponding day-ahead price.

merit-order of the electricity market. The resulting price responses are stronger for particular high and low residual loads so that the differences between the samples in these periods lead to high dispersion in the price duration curves. Differences in the less extreme residuals translate into comparably low price differences. The illustrations show a negative correlation between the wind capacity factor and the electricity prices, indicating the merit-order effect of RE generation. Additionally, the figure shows that the dispersion of the wind capacity factor is higher in hours with low electricity prices. Electricity prices are mostly affected by wind generation when its feed-in is comparably high, resulting in a lower residual demand[7] (Sensfuß et al., 2008). This leads to lower prices when wind capacity factors are high and consequently to a higher dispersion of electricity prices depending on the variation of wind generation. The intraday price duration curve is quite similar to the day-ahead price duration curve as the source of variation is the wind generation forecast errors. These result in slight deviations from the day-ahead price.

Table 3.2.: Descriptive statistics of the samples wind generation and the regressed price time series.

Unit	Yearly capacity factor wind	Price day-ahead EUR/MWh	Price intraday EUR/MWh	Value factor day-ahead EUR/MWh	Value factor intraday EUR/MWh
Min	0.14	-149	-180	25	24
Max	0.18	106	106	37	37
Mean	0.16	40	41	33	33
StD	0.007	15	16	2	2

Table 3.2 shows the descriptive statistics of the simulated time series and the resulting value factors for the wind generation profile. The mean yearly capacity factor overall samples is 0.16, which equals approximately 1400 FLH. The minimum overall sampled years is 0.14 and the corresponding maximum is 0.18. The mean over all hourly electricity prices is 40 EUR/MWh for the day-ahead market and 41 EUR/MWh for the quarter-hourly intraday market, respectively. The mean of electricity price maxima deviates only in the decimals between day-ahead and intraday, while the mean of minima is 31 EUR/MWh lower on the intraday market. The value factors confirm the negative correlation between wind generation and electricity prices. With 33 EUR/MWh, it is lower than the mean average electricity price. The upper

[7] Defined as total electricity demand less RE feed-in, which is the demand being supplied by conventional power plants.

bound for the electricity market price, at which the electrolyzer is dispatched, depends on the green hydrogen selling price, which translates into an electricity break-even price through the plant-specific efficiency.

3.4.2. Dispatch of a Grid-connected Electrolyzer

A green hydrogen selling price of 3 EUR/kg and no simultaneity obligation define the base case. To understand the effects of higher simultaneity on the electrolyzer's dispatch, we first present the two main characteristics of this dispatch for the base case. First, we show the total profitability of the electrolyzer's dispatch indicated by the distribution of the absolute contribution margin (upper histogram in Figure 3.4). Consecutively, we show the electrolyzer's production rate indicated by the distribution of FLH (lower histogram in Figure 3.4).

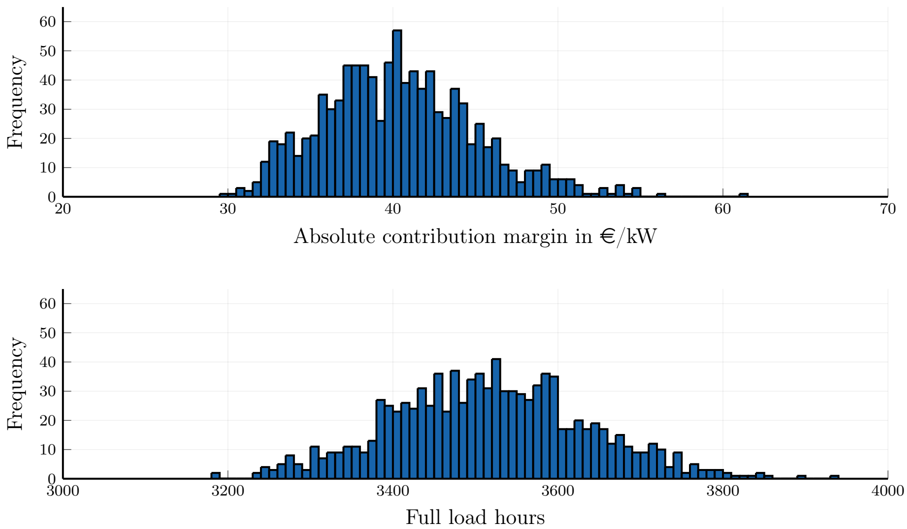


Figure 3.4.: The distribution of the absolute contribution margin (top) and the full load hours (bottom).

The absolute contribution margin for a year ranges from 30 EUR/kW in the worst case to 61 EUR/kW in the best case. In the mean, the electrolyzer would generate a margin of 40 EUR/kW with a standard deviation of 5 EUR/kW. This results in a CoV of 0.12. The distribution is slightly right-skewed since it is higher concentrated for low margins than for high margins. The underlying wind generation distribution initially causes the right skewness. Without simultaneity, it only affects the absolute contribution margin through electricity prices. The FLH show a symmetrical distribution with a mean of

3517 hours and a standard deviation of 115 hours. Since, in this case, the electrolyzer is not constraint by a wind generation profile, the FLH are determined by the hydrogen price, its corresponding electricity break-even price, and the electricity price duration curve on the market.

The mean CO_2 emission intensities are 31.9 $kgCO_2/kg_{H2}$ when applying the MEF and 30.1 $kgCO_2/kg_{H2}$ using the YAEF. The break-even price defines the range of possible marginal power plants. From the mean FLH of 3517, we can derive the finding that the electrolyzer mostly operates in periods where electricity prices are either set by generation technologies with close-to-zero marginal costs, e.g., nuclear, RE or by baseload generation technologies, such as lignite power plants. Whereas the former has an emission factor for electricity of zero, the latter has the highest emission factor of all generation technologies. Consequently, the electrolyzer either withdraws power from the grid when the MEF is particularly high or low, which leads on average to a similar emission intensity of hydrogen compared to the YAEF.

3.4.3. Simultaneity Effect on the Yearly Dispatch Level

Starting from the base case with a hydrogen selling price of 3 EUR/kg and no simultaneity, we first introduce a simultaneity of one year and increase it up to an interval of 15 minutes. The discrete intervals are *None*, 1 a, 12 hours, 8 hours, 1 hour, and 15 minutes. The hydrogen price remains constant. The results are normalized with regard to the base case. The normalized means of the contribution margin and FLH are shown in Table 3.3.

The results show that the mean contribution margin decreases with an increasing simultaneity. Without any simultaneity, the absolute mean contribution margin results in a value of 40 EUR/kW. Compared to this, the contribution margin with simultaneity of 15 minutes is 33% lower. The introduction of a yearly simultaneity would decrease the contribution margin by 2%. The electrolyzer benefits from arbitrage since electricity can be bought during low-price periods and hydrogen can be sold at a fixed price. If no simultaneity obligation is in place, implicitly, all hydrogen produced by the electrolyzer is considered green, which can be interpreted as the virtual generation of the green electricity characteristic. The electrolyzer runs in all periods with an electricity price lower than the break-even price. The introduction of simultaneity ties the electrolyzer production to the wind generation profile. The electricity consumption is only considered green within a specific time interval and after its generation by the wind generator. Therefore, already yearly simultaneity prevents the virtual generation of green electricity. Implicitly, low simultaneity allows the electrolyzer to store the green characteristic of the electricity since it can generate the green characteristic in high price periods and consume it in low price periods. The shorter the time interval, the lower the storage capability of the electrolyzer, and, hence, the lower the profit from this storage. Therefore, the case of a 15 minute simultaneity does not allow the electrolyzer to store the green characteristic and marks the lowest contribution margin with 67% of the base case. The case of yearly simultaneity, on the other hand, implies the largest virtual storage resulting in a contribution margin of 98% of the base case. Thus, the potential value of virtual green electricity storage is significant and can make up to one-third of the electrolyzer's contribution margin.

The potential value of virtual storage also becomes apparent in the FLH. Without simultaneity, the mean FLH sum up to 3517 hours, corresponding to a capacity factor of 40%. The introduction of yearly simultaneity reduces the FLH by 22%. Compared to the base case *None*, where the break-even price alone determines the FLH, the total yearly production of the wind generator limits the FLH in case of yearly simultaneity. The 22% difference marks the additional potential generation by a larger wind generation capacity for the electrolyzer. However, the 22% FLH only account for 2% of contribution margin. The electrolyzer mainly loses less profitable hydrogen generation at high electricity prices. Increasing the simultaneity further to 15 minutes results in a FLH reduction of 53% compared to the base case. Compared to the case of yearly simultaneity, the reduction is 31% points with regard to the base case. Analogously to the contribution margin, the allowance to virtually store the green electricity characteristic can make up to 50% of the electrolyzer's hydrogen production.

3.4.4. Simultaneity Effect on the Yearly Dispatch Dispersion

The sensitivity of the contribution margin and FLH dispersion to a varying simultaneity is also shown in Table 3.3 in form of the standard deviation and the coefficient of variation. The results are normalized with regard to the base case.

Table 3.3.: Relative changes to the base case of mean, standard deviation, and coefficient of variation (CoV) of contribution margin and FLH in the simultaneity sensitivity.

	Simultaneity					
in % of base case	none	1a	12h	8h	1h	15min
Mean						
Contribution margin	100	98	78	75	71	67
Full load hours	100	78	57	54	51	47
Standard deviation						
Contribution margin	100	101	99	98	96	96
Full load hours	100	110	96	96	97	101
Coefficient of variation						
Contribution margin	100	104	126	130	135	143
Full load hours	100	141	170	178	189	216

The absolute CoV of the contribution margin in the base case results in 0.12 and increases with higher simultaneity. Introducing yearly simultaneity increases the CoV by 4%. Reducing the interval to 15 minutes results in a CoV increase of 43%. The change in the CoV is mainly caused by the change of the mean as the standard deviation shows only slight deviations from the base case. The allowance to store the green characteristic of the electricity generation increases the robustness of the electrolyzer towards varying yearly wind generation. In the case of yearly simultaneity, the dispersion between years with different wind generation realizations is defined by the lower end of the price duration curve (see Figure 3.3) since the electrolyzer can shift all of its power consumption into the lowest price periods. For simultaneity of 15 minutes, the dispersion between the yearly wind generation profiles mainly determines the dispersion of the contribution margin as the electrolyzer cannot shift its consumption. The results indicate that the dispersion between the yearly RE generation is higher than the dispersion between the yearly electricity prices, which finds support in the illustration of the time series in Figure 3.3. The variation within the wind capacity factor is higher than the variation within the electricity prices (see Table 3.2). Lower simultaneity decouples the contribution margin from the risk associated with the economic value of the wind generation profile. This risk can account for one-third of the total risk from yearly varying wind generation.

The CoV of FLH increases with a higher simultaneity. In the case of yearly simultaneity, the CoV is 41% higher than in the base case (with an absolute value of 0.03). For simultaneity of 15 minutes, the CoV is 216% of the base case's CoV. The simultaneity appears to have a more significant effect on hydrogen production risk than on the contribution margin risk. As already observed for the mean of the FLH, introducing a simultaneity obligation significantly increases the CoV. Constraining the total yearly FLH to the wind generation limits the FLH of the electrolyzer, shifting the main dispatched hours to the high dispersion area at the low prices of the duration curve. Therefore, the dispersion increases significantly with the introduction of yearly simultaneity. Increasing the simultaneity further towards the 15 minutes interval increases the importance of the dispersion within the low electricity prices and the importance of the dispersion between the yearly wind generation profiles since only wind generation within periods with prices below the break-even price lead to hydrogen production. Hence, the hydrogen production risk resulting from the wind energy profile makes one-third of the total risk.

3.4.5. Interdependence of the Simultaneity and the Green Hydrogen Selling Price

The hydrogen price is a decisive factor for the electrolyzer's viability, but it is generally unknown in the absence of a liquid hydrogen market. Therefore, a sensitivity is applied to the price. We simulate the electrolyzer dispatch model for a green hydrogen price of 2, 2.5, 3, 3.5, 4 and 4.5 EUR/kg. Three cases will be presented: starting from the base case (i) without a simultaneity obligation, the sensitivity is additionally applied on the simultaneity of (ii) one year and (iii) 15 minutes. In Table 3.4 the absolute values for the mean contribution margin and the FLH are summarized. Within each case, the relative deviation from a reference price of 3 EUR/kg is computed for the mean and the CoV of the contribution margin and the FLH. Figure 3.5 illustrates the results.

The diagram on the top left in Figure 3.5 illustrates the sensitivity of the contribution margin's mean on the hydrogen price for three simultaneity cases. Regardless of the simultaneity, the contribution margin increases with a rising hydrogen price. The exact gradient of this increase diverges between the different simultaneity obligations. In the absence of simultaneity, hydrogen production is profitable for all periods with an electricity price below the

Table 3.4.: Absolute values of the mean contribution margin and the FLH at a hydrogen selling price of 3 EUR/kg

	Unit	None	1a	15min
Mean contribution margin	EUR/kW	40.4	39.4	27.2
Mean FLH	h	3516	2740	1641

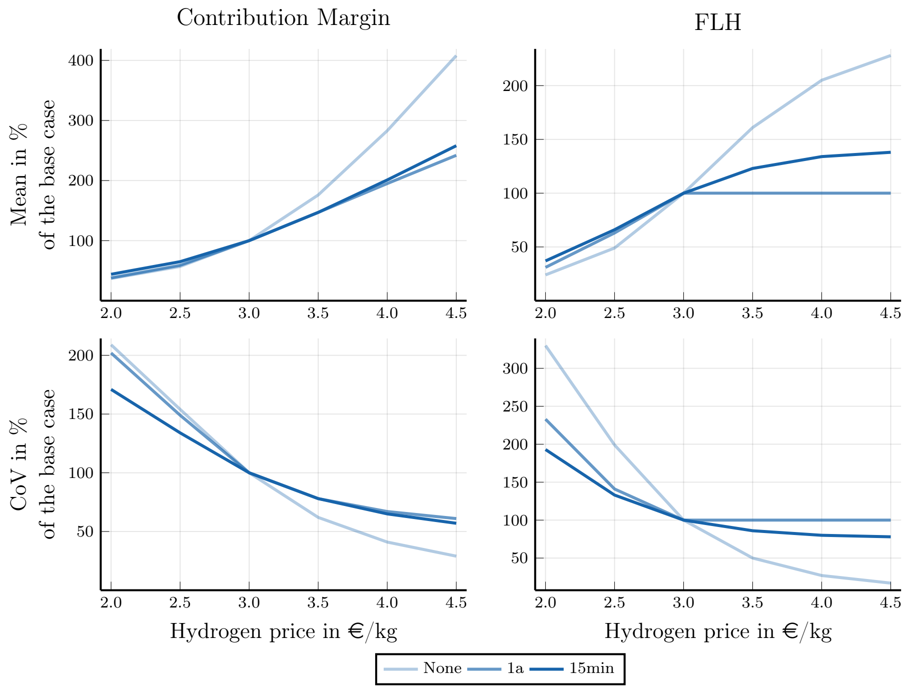


Figure 3.5.: Relative changes to the base case of 3 EUR/kg of the mean (upper) and the CoV (lower) of the contribution margin (left) and the FLH (right) in %.

break-even price. Therefore, increasing the hydrogen price increases both the contribution margin for the already profitable periods and makes additional periods profitable. This twofold effect results in a convex contribution margin increase. Increasing the hydrogen price by 1.5 EUR/kg increases the contribution margin by 408%. Introducing yearly simultaneity, the electrolyzer only profits from storing the green characteristic. As the FLH of the wind generation are limited, there is a saturation level of the contribution margin increase through higher production. Therefore, once the break-even price is sufficiently high to capture as many periods as FLH provided by the wind generator, the contribution margin increases linearly. At a hydrogen price of 4.5 EUR/kg, the contribution margin is 242% of the contribution margin at 3 EUR/kg. With quarter-hourly simultaneity, the electrolyzer is also prevented from benefiting from green characteristic storage. This significantly reduces the mean contribution margin of the base case (see Table 3.4). However, the relative increase of the mean contribution margin is higher than with yearly simultaneity. With lower simultaneity and thus larger green characteristic storage, the electrolyzer reaches already for lower hydrogen prices the saturation level of the wind generation FLH. In the absence of the storage allowance, the electrolyzer reaches the saturation level not until higher hydrogen prices.

The relative changes of the FLH, and thus the total output of the electrolyzer, are shown in the top right diagram of Figure 3.5. The change in FLH is s-shaped, with a first convex increase, followed by a concave increase with a decreasing growth rate in FLH at a hydrogen price of more than 3.5 EUR/kg. The convex and concave course becomes most visible in the case of no simultaneity. For example, the FLH can be more than doubled (plus 105%) when increasing the price from the base case (3 EUR/kg) to 4 EUR/kg, whereas it only increases by 67% points when changing from 3.5 to 4.5 EUR/kg. This shape can be explained with the price duration curves in Figure 3.3. If the price is varied at a level such that the electricity break-even price lies in the flat part of the price duration curve, the number of operating periods is very sensitive to a change in the hydrogen price. If it is varied at the upper or lower end of the price duration curve with few prices at one level, the FLH are less sensitive to hydrogen price changes. Increasing the FLH is possible to a limited extent since electricity prices eventually reach the left tail of the price duration curve with soaring prices in a few hours of the year. Introducing yearly simultaneity adds a FLH saturation level based on the wind generation capacity factor. With the given assumptions, the maximum FLH are reached with a price of 3 EUR/kg. A further increase in the price enables the electrolyzer to be dispatched in more periods from an economic perspective (as shown in the first case without simultaneity). However, total wind energy production, i.e., virtual green electricity storage, is fully utilized. For simultaneity of 15 minutes, the FLH only increase with a higher hydrogen price when periods exist which have spare wind generation and electricity market prices above the electricity break-even price. Hence, the extent to which a higher hydrogen price increases the FLH in this situation strongly depends on the correlation between wind generation and electricity prices. Here, at a price of 3 EUR/kg, there are still periods with wind power generation but without hydrogen production, which allow increasing the electrolyzer's output at higher hydrogen prices.

The diagram on the bottom left in Figure 3.5 shows the contribution margin's CoV sensitivity on the hydrogen price. The relative CoV's resulting course shows a convex decrease for each line. In the case, *None* without simultaneity, the CoV for a hydrogen price of 2.0 EUR/kg is 209% of the CoV in the base case. For a hydrogen price of 4.5 EUR/kg, however, it decreases to 29%. An increasing hydrogen price decreases the contribution margin's CoV in two ways. First, it defines the break-even price and, hence, the FLH and average short-term costs. A higher hydrogen selling price moves the break-even price along the flat part in the middle of the price duration curves. Here, the variation between the sampled years is low compared to the variation at the end of the price duration curve. With a higher hydrogen price, the share of the periods with prices, which vary little between the samples, on the total periods grows. This leads to a relative reduction of the CoV. Second, a higher hydrogen price increases the absolute contribution margin per kg produced hydrogen. As the variation in the case without simultaneity only originates from the varying electricity prices, an increase of the revenue per kg decreases the relative impact of the production costs and thus the CoV of the contribution margin. In the case of yearly simultaneity, the electrolyzer's dispatch is constrained by the total FLH of the wind generator. Therefore, it already reaches for lower hydrogen prices a saturation level of CoV reduction than without simultaneity. For a hydrogen price of 4.5 EUR/kg, the relative CoV is 61%. The electrolyzer only benefits from the first effect, i.e. the slight variation in the flat part of the price duration curve, until it reaches the wind generator's FLH. The second effect of increasing revenue compared to the cost variation remains. This also holds for the case of high simultaneity of 15 minutes. Although the FLH of the wind generator are exhausted for higher hydrogen prices (leading to a slightly higher CoV reduction rate), the CoV is mainly reduced due to the second effect for higher hydrogen prices. However, for lower hydrogen prices, the relative CoV increase is lower than for no and yearly simultaneity. While for no and yearly simultaneity, the price variation at the lower end of the price duration curve determines the CoV, the CoV in case of high simultaneity is determined by the wind generation value factor. Due to the negative correlation between electricity prices and wind generation, the wind value factor has a lower dispersion than the electricity prices (see Table 3.2).

The FLH CoV's sensitivity on the hydrogen price is shown in the bottom right diagram of Figure 3.5. All curves show a convex decrease. The decrease rate is the highest for the case of no simultaneity, falling from 330% of the base case's CoV for a hydrogen price of 2.0 EUR/kg to 17% for a 4.5 EUR/kg. Again two effects play a role in this decrease. First, the variation in the flat part of the price duration curve is lower than at its ends, resulting in a low CoV for break-even prices in this part. Second, for high hydrogen prices, the FLH of the electrolyzer are comparably high. Variation between the samples of a few hours only increases the CoV slightly. Therefore, the curve is convex in its reduction. Introducing yearly simultaneity adds a saturation level in the form of the wind generator's FLH. Therefore, once this saturation level is reached at 3 EUR/kg, the CoV does not change anymore. For lower hydrogen prices, the relative increase of the CoV is lower than in the case of no simultaneity. For 3 EUR/kg, the electrolyzer is already constrained by the FLH of the wind generator so that a further decrease of the hydrogen price is relatively a lower effect than in the case of no simultaneity. Given a quarter-hourly simultaneity, the CoV reaches the saturation level for higher hydrogen prices than under yearly simultaneity since the electrolyzer cannot shift its dispatch into periods with sufficiently low electricity prices. Analogously to the contribution margin, the CoV of the FLH increases with a lower rate for decreasing hydrogen prices.

3.4.6. Emission Intensity

The additional value from storing the green characteristic of electricity comes with a potential fading of the actual greenness of the associated electricity consumption. The additionally induced electricity generation of conventional power plants to serve the electrolyzer's demand may increase indirect emissions. This issue does not only apply to the operation of electrolyzers but also for other power consumers (e.g., battery electric vehicles (Nansai et al., 2002), demand-side response (Fleschutz et al., 2021)). The relative emission intensity of hydrogen to the base case is determined for each considered simultaneity. Furthermore, the mean emission intensities are determined for varying hydrogen prices along with the simultaneity of *None*, one year, and 15 minutes.

In Figure 3.6, the mean CO_2 emission intensity of hydrogen for the simultaneity sensitivity is visualized. Starting from the case of no simultaneity, the relative average emission intensity is shown for each considered

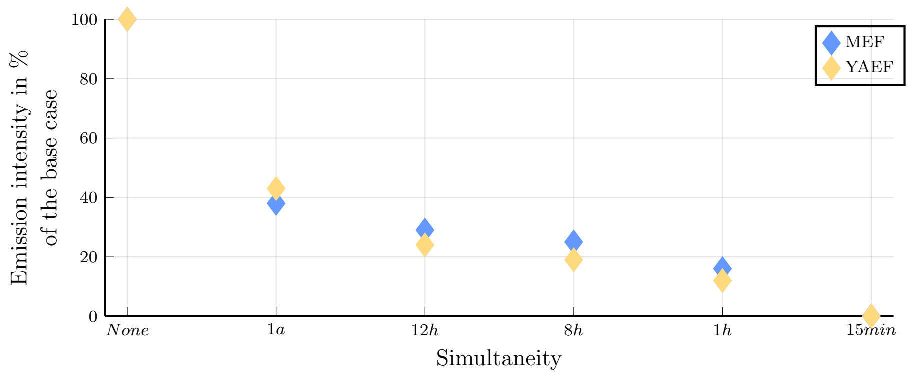


Figure 3.6.: The hydrogen emission intensity in % indicated by the MEF and the YAEF depending on the simultaneity.

simultaneity. The case without simultaneity has the highest relative emission intensity since the grid fully balances the electricity consumption. Following the assumptions in section 3.3, a quarter-hourly simultaneity corresponds to perfect balancing of RE and hydrogen generation and induces no additional indirect CO_2 emissions. Hence, the emission intensity of hydrogen is 100% lower compared to the base case. The trend indicates a reduction in emission intensity with increasing simultaneity in between these cases. The largest drop occurs when a simultaneity obligation is imposed, i.e., moving from no simultaneity towards yearly simultaneity. Here, the emission intensity decreases by more than 50% for both the YAEF and the MEF.

Moving downwards from yearly to lower simultaneity in discrete steps, the emission intensity further decreases, but the effect weakens. Note that the time intervals between the simultaneity cases differ, and the change in emission intensity must be regarded relatively to the respective interval. The difference between 12 hourly and 8 hourly simultaneity is only 6% points for the MEF and 5% points for the YAEF, respectively. With simultaneity of 8 hours, the emission intensity of hydrogen reduces by more than two-thirds compared to the base case (*None*). A substantial decrease can be noticed when moving from hourly to quarter-hourly simultaneity, i.e. to perfect balancing, where the emission intensity decreases by more than 10% points in both cases, although the step is the lowest on a time-scale. When comparing the results for yearly with quarter-hourly simultaneity, the relative emission intensity deviates by a value of 38% points. The effect of the simultaneity on the emission intensity appears to be very similar for both emission factors for electricity. This implies that higher simultaneity reduces the share of electricity balanced from the grid, but the average mean emission factor for that electricity does not change significantly.

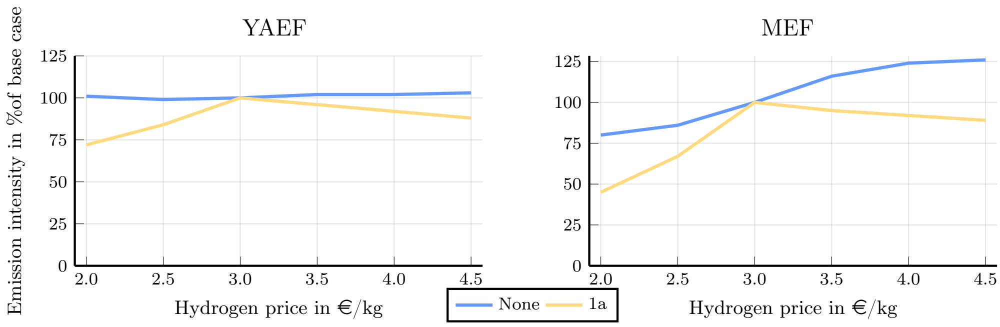


Figure 3.7.: The relative hydrogen emission intensity to the base case (3 EUR/kg) indicated by the YAEF (left) and the MEF (right) for the hydrogen price sensitivity.

Besides the simultaneity, the hydrogen price can affect the emission intensity of hydrogen since it changes the electricity break-even price and, therefore, the possible range of marginal power plants. The charts in Figure 3.7 show the relative emission intensity of hydrogen depending on the price for yearly and no simultaneity when applying the YAEF (left chart) and the MEF (right chart). The emission intensity for quarter-hourly simultaneity is not displayed, as it does not change with the price and always equals zero in absolute terms.

Applying the YAEF, the emission intensity does not change when no simultaneity obligation is in place since both the emission factor for electricity and the power balanced by the grid are constant over all prices. With yearly simultaneity, the emission intensity depends on the share of electricity which exceeds the generation from the RE sources and is balanced by the grid. The mean emission intensity of hydrogen decreases when the hydrogen price is reduced from the base case price of 3 EUR/kg. Low electricity prices usually occur when residual demand is low and when RE feed-in is high. With increasing residual demand, the electricity market price rises and the share of electricity, which is balanced by the grid, increases. Consequently, a comparably low selling price for green hydrogen limits the electrolyzer to produce only in periods with low electricity prices and accordingly high feed-in from the RE generator, which means that less power must be balanced by the grid lowering the emission intensity of hydrogen. However, a comparably higher price with yearly simultaneity also decreases the emission intensity. Here, the emission intensity hits its maximum at 3 EUR/kg and slightly decreases afterwards. While the mean FLH reach the maximum with a price of 3 EUR/kg and do not increase with higher prices (see section 3.4.5), the considered part-load efficiency allows the electrolyzer to increase the total output by using the same amount of electricity. In a small range of electricity benchmark prices, it is economically efficient for the electrolyzer to operate in partial load to increase efficiency and accept a lower output. With a higher hydrogen price, this price range increases and the operating periods with partial load shift towards higher electricity market prices. As a result, the total output of the electrolyzer increases while the consumed power remains constant, which leads to a slightly lower emission intensity of hydrogen with a higher hydrogen price.

Applying the MEF, the emission intensity of hydrogen increases with the hydrogen price when no simultaneity obligation is in place. The change is s-shaped, meaning more minor deviations from the base case with a price of 3 EUR/kg lead to more substantial emission effects than higher deviations. The MEF depends–besides the rate of power balanced by the grid–on the electricity market price. With higher prices, the electrolyzer can also be dispatched during mid and peak load periods, which can be seen by the increased FLH with a higher price (see section 3.4.5). In these periods, coal and gas-fired power plants are often marginal suppliers, which have lower emission factors in comparison to lignite power plants. Hence, the increase in indirect emissions is slowed down. With yearly simultaneity and applying the MEF, the trend of the mean emission intensity is similar to the YAEF, but the decrease at lower prices is stronger when applying the MEF. Since the MEF depends on both the share of power balanced the grid and on the electricity market price, the effect of the marginal power plant affects the emission intensity in two ways: the MEF is lower at a comparably lower hydrogen price, and the power supply from the RE generator is higher since it often produces in periods with low electricity prices. On the other hand, the emission intensity decreases with a higher hydrogen price and yearly simultaneity. The effect is analogue to the YAEF reasoned by the increase in output with the same FLH, but the emission intensity is affected by the electricity price and the change in total output.

3.5. Discussion

This paper presents the dispatch decision of an electrolyzer, highlighting the impact of a simultaneity obligation of hydrogen and electricity generation from RE sources in the presence of risk from varying wind generation. Since grid-connected electrolyzers could physically operate constantly and without restrictions from the supply side, the simultaneity obligation is a political measure to tie electricity consumption to its production from RE plants in order to prevent fossil-fired power plants from supplying PtG plants with electricity. Hence, the simultaneity can be interpreted as an allowance to store the green characteristic of the RE plant's electricity generation. In the case study, we show that this allowance improves the business case of an electrolyzer in three ways. First, the storage capability adds economic value to the dispatch of the electrolyzer. The electrolyzer benefits from time arbitrage, shifting the green characteristic from high-price to low-price periods. This arbitrage increases the electrolyzer's contribution margin. Second, the virtual storage also mitigates the RE generation risk, both price and quantity. Third, the contribution margin's sensitivity to green hydrogen price changes is higher. The electrolyzer benefits directly from higher hydrogen prices as it can shift production to periods in which the electricity price is sufficiently low. These three aspects also hold for the hydrogen production quantity.

One goal of a simultaneity obligation is the prevention of additional indirect CO_2 emissions from grid-connected electrolyzers. During the hydrogen market ramp-up, the electricity supply mix has still significant shares of conventional power generation translating, if not constrained, into a high emission intensity of hydrogen. Our results have shown that the simultaneity, indeed, affects through the electrolyzer dispatch its emissions. From a system perspective, a reduction of emissions can be achieved if additionally generated renewable electricity is used to produce renewable hydrogen. As a consequence, RE generators sourcing the electrolyzer should be installed to the existing capacities simultaneously in order to prevent additional emissions from the power sector. Otherwise hydrogen production would displace RE production from existing generators and ultimately lead to additional generation from fossil-fired plants to serve residual electricity demand (see e.g., Pototschnig (2021)). The installation of RE capacities along the electrolyzer investment needs to be ensured to meet additional electricity demand from hydrogen generation with zero-emission production. Another aspect to be considered at system level is the fact that the European power sector is part of the EU ETS, where the total emission budget is theoretically limited. However, in practice the market stability reserve (MSR) softens this limit. Increased emissions from electricity generation for the purpose of hydrogen production can lead to lower cancellation of emission allowances in the short-term or even higher emission allowance auction volumes. To which extent the emission demand from hydrogen production would displace emission demand or rather increase overall emissions, remains ambiguous. The dynamic design of the EU ETS prevents a definite determination of the emission effect from hydrogen production (Bocklet et al., 2019, Schmidt, 2020). Generally, regulation may tend to tailor different green characteristic definitions to each emission mitigation option. However, maintaining these various definitions in parallel may induce distortions not only between green and non-green technologies but also within green technologies. If a policy instrument for internalizing the costs of emissions is already in place, as the EU ETS, additional restrictions on the dispatch of electrolyzer may not be necessary. Regardless of the indirect effect on emissions in the short-term, the simultaneity obligation may have a due date since it becomes obsolete with higher shares of RE in the electricity supply mix.

Given the dependence of the short-term dispatch decision on the RE generation risk and the simultaneity, it is of interest for an investor how these conditions affect the long-term profitability. The profits must cover the annuity and other fixed costs in order to make the electrolyzer investment viable. Taking the assumptions of the case study from section 3.3.5 on investment cost, depreciation time, and interest rate, we can derive an annuity (including fixed cost) of 119 EUR/kW. Comparing the fixed and annuity costs to the mean contribution margin from the base case of 40 EUR/kW, the investment would prove as unprofitable with a financing gap of approximately 80 EUR/kW. Given a standard deviation of 5 EUR/kW, even in the more advantageous cases, the electrolyzer can not cover its long-term cost. The relative risk of the contribution margin–expressed as CoV in section 3.4–increases with the simultaneity by up to 43% when changing from *None* to quarter-hourly simultaneity. However, this increase in the risk is relatively low when comparing the absolute financing gap of 80 EUR/kW with the standard deviation of 5 EUR/kW. As a result, investors should prioritize lowering the fixed and annuity costs than reducing the risk resulting from short-term dispatch decisions. Note that this calculation only holds for representative years regarding RE feed-in and electricity market prices based on the historical observations. In the mid-term, increasing resource prices and additional renewable generation may increase the steepness at both ends of the price duration curve. For electrolyzers particularly the changes in the parts of the price-duration curve below the break-even price are relevant. Thus, price changes due to additional renewable generation allow electrolyzers to enhance their economic viability. In the long-term, the expansion of electrolyzer capacity and flexible consumers, in general, may lead to more elastic demand and hence to increased competition for low electricity prices, which could dampen the profitability of electrolyzers (see e.g., Lynch et al. (2019), Roach and Meeus (2020), Ruhnau (2022)).

3.6. Conclusions

The hydrogen market ramp-up requires large-scale investments in electricity-based hydrogen production. With substantial subsidies, policymakers aim to set sufficient incentives for investors to realize these investments. As the reduction of CO_2 remains the overall goal, introducing specific rules for the dispatch along with the investment subsidies is discussed to limit associated emissions from an electrolyzer's energy consumption. One discussed criterion is a simultaneity obligation between RE generation and electrolyzer production. While its purpose would be to limit the emissions from fossil-fired electricity generation, the measure significantly affects the dispatch of an electrolyzer and may distort the investment incentive.

With our research, we contribute to understanding these distortions that policymakers may consider when designing dispatch criteria for electricity-based hydrogen production. We set up a model framework that allows us to assess a grid-connected electrolyzer dispatch taking into account the risk from varying RE generation. The variation of RE is captured by a Markov chain Monte Carlo simulation for wind generation. Subsequently, two regression models for the intraday and day-ahead markets are calibrated with historical data from the German spot markets to calculate synthetic electricity spot market price time series. We introduce simultaneity to the dispatch model and evaluate its structural impact on the distribution of the electrolyzer's contribution margin, full load hours, and associated emissions within a case study in the German electricity market context.

In the short term, we show that the introduction of a simultaneity obligation delivers on its original goal in reducing the associated CO_2 emissions from electricity consumption. On the other hand, an absence of simultaneity comes with several significant benefits for the operator of an electrolyzer: the contribution margin and production rate increase while the risk from RE generation decreases.

Hydrogen from RE sources is part of many energy and climate policies since it provides long-term energy storage and is a close substitute to fossil energy carriers. Moreover, hydrogen has also gained interest in economic policy, since substantial economic value in hydrogen trade as an energy commodity and in an emerging market for hydrogen technology is anticipated. Investing in hydrogen today is essential to commercialize the technology and to achieve long-term learning and scaling effects. The simultaneity obligation is a regulatory measure, which concentrates on the short-term decisions of electrolyzer operation, though it also affects investment incentives. Although the effects of a simultaneity obligation on the contribution margin are significant, they are comparably low in comparison with the total financing gap, i.e. also taking into account investment cost. With the design of a simultaneity obligation policymakers are weighting two goals: ramping-up the hydrogen market in the long-term and preventing emissions from the power sector in the short-term. A low simultaneity–or even the absence of such an obligation–is in favor of a more dynamic hydrogen market ramp-up, while a strict simultaneity ensures to mitigate emissions, but may lead to less investment. While these effects are immediate results from our analysis, further aspects that need to be considered is the interplay of the simultaneity obligation with other emission abatement measures and the entire energy system, e.g., regarding carbon trading schemes and the long-term transformation of the energy system. Regardless of the actual design of the simultaneity obligation, it has a role to play in future policies addressing green hydrogen since it has a significant impact on the electrolyzer operation.

4. Integrating Cross-Border Hydrogen Infrastructure in European Natural Gas Networks: A Comprehensive Optimization Approach

4.1. Introduction

The role of hydrogen in future net-zero energy systems has widely been acknowledged by research, politics, and industry. Various energy system studies and scenario reports predict an increased uptake of clean hydrogen to decarbonize existing hydrogen demand, to deploy hydrogen in new applications in order to eliminate CO_2 emissions, and to use hydrogen as a long-term energy storage (e.g., IEA (2022b), IRENA (2023), Otsuki et al. (2023), Staffell et al. (2019), WEC (2019)). Hydrogen has physical properties making it a well-suited element for large-scale and long-term energy storage in RE dominated energy systems and facilitating global trade in clean energy commodities. Several governments have published national hydrogen strategies, and private actors are planning and developing gigantic projects to build clean hydrogen supply chains. Unlike fossil fuels, which are geographically bound to locations with natural resources, hydrogen can be produced from many different primary energy carriers. In particular, it can be produced with electrolysis, which splits water into oxygen and hydrogen. The total emission balance is zero, when electricity is exclusively sourced from RE. Globally, resources for RE are available anywhere, which enables every country to produce clean hydrogen and enables more diversified energy supply. However, potentials for RE vary significantly between regions and some countries might be favored for electricity production from RE. Against this background, inter-regional hydrogen transportation could create a new market for hydrogen as an energy commodity.

In the European Union (EU), recent geopolitical conflicts have revealed the bloc's vulnerability caused by its dependency on a few single energy exporters. The interruption of energy supplies from Russia has motivated the

EU to reduce its dependency on energy imports and increase the speed of expanding RE, in particular, the production and utilization of clean hydrogen (European Commission, 2022). One essential aspect is the development of a pan-European dedicated hydrogen infrastructure to foster trade of hydrogen in the EU and with neighboring countries, as well as to phase out fossil gases until 2050 (EUC, 2023, European Commission, 2021). Also, the EU plans to trade hydrogen globally as ammonia or other derivatives (European Commission, 2022).

An integrated European hydrogen market will need infrastructure for transportation and storage. Today, Europe already has a well-developed pipeline infrastructure for natural gas, connecting all continental countries and the British Isles with a total length of more than 200,000 km (referring to transmission pipelines) (ACER, 2021a). The partial conversion of this infrastructure to hydrogen is a promising approach to give the pipelines a second life in a climate-neutral energy system and to save the costs of building a dedicated hydrogen network. Simultaneously, increased awareness of security of energy supply, particularly of supply diversification, poses challenges to decision-makers to balance economic, political, and technical interests of all involved parties.

This paper presents an extension to an existing model for natural gas transportation and storage in Europe to incorporate investments in hydrogen infrastructure, production, storage, and import capacity while ensuring a sufficient supply of natural gas. The model formulation explicitly considers the possibility of repurposing natural gas pipelines, which is expected to be more cost-efficient than greenfield investments in a dedicated hydrogen network. While the primary focus of this paper is to introduce and explain the methodological approach of the model extension, it is also applied to a use case consisting of different scenarios to show the effect of different parameter choices on the model's investment and dispatch decision. These effects provide important insights for strategic infrastructure planning and further research on integrated European energy markets and infrastructures. The research objectives can be summarized under the following research questions: How can the development of a dedicated cross-border hydrogen infrastructure be integrated in an existing natural gas transportation model? How do different technical and economic conditions impact the cost-optimal investment and dispatch decisions?

In the paper, the natural gas infrastructure model TIGER, which was initially developed by Lochner (2011c), is extended on various levels: Investments in hydrogen infrastructure and production equipment are introduced, whereby existing natural gas pipelines can be repurposed, or new infrastructure can be built. Infrastructure assets include cross-border pipelines, seaborne hydrogen import terminals, and underground cavern storage. Production equipment can be either dedicated[1] RE (solar PV, wind onshore, wind offshore) with electrolysis, or steam methane reforming (SMR) with CCS. Since hydrogen and natural gas demand, supply, and infrastructure are integrated in one model, the simulation uses a reduced spatial resolution and only considers cross-border interconnection pipelines instead of all domestic pipeline segments. The model is applied to an exogenous data set on natural gas demand and supply, hydrogen demand, and RE production potentials. The emerging hydrogen market is characterized by high uncertainty regarding demand, supply, and technology costs. These uncertainties are captured by simulating different scenarios with varying economic and technical parameters along the supply chain to understand better the effects of the parameter choices on infrastructure development.

This work makes important contributions to the ongoing research on the economics of transforming energy systems. It is one of the first models to optimize natural gas and hydrogen infrastructure in Europe in an integrated model. This is of particular interest since security of natural gas supply must be ensured in a transitional period while ramping up a hydrogen infrastructure. Second, it considers the effect of changing geopolitical conditions and their effect on energy markets. The scenario analysis shows the model's capabilities to provide insights and plausible results for the strategic planning of a European hydrogen network, but it can also be extended in future research, e.g., through an improved integration of hydrogen, natural gas, and electricity markets.

The remainder of this paper is structured as follows: The subsequent Section 4.2 reviews recent literature on hydrogen supply chain and network modeling. The literature review emphasizes the contribution of this paper to the ongoing research in the field. In Section 4.3, the extended model formulation is introduced and numerical assumptions for the scenario analysis are defined. The results are presented in Section 4.4 along the dimensions

[1] The current model formulation only considers electricity demand from hydrogen production and neglects electricity demand from other consumers.

investment decision, dispatch decision, costs, and impact on natural gas supply. Since the model uses many numerical and conceptual assumptions, the methodology and the results are critically discussed in Section 4.5. Also, contributions of future research are suggested. Section 4.6 concludes the paper and gives a general outlook.

4.2. Literature review

This work is embedded in an existing body of literature on the uptake of hydrogen in future energy systems. Research on this topic is manifold and this paper mainly builds on two different streams of previous work.

The first stream is concerned with modeling cost-optimal investment and dispatch decisions of energy supply or infrastructures for gaseous energy carriers. These types of models typically follow the rationale of simulating energy markets as partial equilibrium models to minimize system costs. Nuñez-Jimenez and De Blasio (2022) develop a mixed-integer linear optimization model that allows them to globally analyze scenarios for cost-optimal green hydrogen supplies, including domestic production and imports. The essential decision variables represent domestic hydrogen production, trade between countries, and transportation infrastructure (pipeline diameters or number of ships). The model assumes three different options for transportation: gaseous via newly built hydrogen pipelines, shipping as liquid hydrogen, and seaborne ammonia trade. Hydrogen production is considered as production potentials and levelized cost of hydrogen (LCOH) per resource. Schönfisch (2022) develops and simulates a global hydrogen market model, which is formulated as a mixed complementarity problem. Nodes represent countries and edges are either pipelines or shipping routes. The analyzed scenarios differ in the availability and costs of different clean hydrogen production technologies, i.e., hydrogen from RE, from natural gas reforming with CCS, and from coal gasification with CCS. For Europe, the study finds that hydrogen is imported chiefly from North African countries (where it is generated with solar PV), or produced in windy Northern countries. A similar approach can be found in Lippkau et al. (2023), where a global energy system model is used to investigate the global trade of hydrogen and derived fuels. Neumann et al. (2023) analyze the trade-off between building a hydrogen network and power grid reinforcement with a linear optimization model. European countries are spatially resolved in 181 regions to improve the visibility of within-country infrastructure investments. The model optimizes investment and dispatch of energy generation, transportation, conversion, and transportation assets and is applied to four scenarios to quantify the system value of energy infrastructure expansions. Hydrogen networks can be newly built or repurposed from existing natural gas pipelines. However, natural gas supply is not considered in the model, and hydrogen pipeline imports from North African countries are out of the model's scope. Similarly, Frischmuth et al. (2022) introduce an investment and dispatch model, covering natural gas and hydrogen supply, infrastructure, and demand. Hydrogen networks can be either newly built or developed from repurposing existing natural gas pipelines. Each country is represented as one node, and pipeline interconnection capacities are aggregated. In Schlund and Schönfisch (2021), a European natural gas dispatch and an investment model for electricity are coupled to analyze the effect of a mandatory quota for green gases (hydrogen and synthetic methane) on electricity and natural gas prices, welfare distribution, and natural gas flows. Many other tools and models have been developed to determine cost-optimal designs of hydrogen pipeline networks, e.g., in Germany (Baufumé et al., 2013, Krieg, 2012, Robinius, 2015, Welder et al., 2018), in the United Kingdom (UK) (Moreno-Benito et al., 2017, Samsatli et al., 2016), or France (André et al., 2014). Most of these studies use technical and economic modeling to determine the cost-optimal trajectory of a national hydrogen grid to supply a given or endogenously determined demand at optimal cost. While many studies acknowledge the physical representation of gas flows, the technical modeling limits the spatial and temporal scope of the use cases. The option of repurposing natural gas pipelines, which is expected to reduce investment costs significantly, is addressed in only a few publications. Repurposing reduces transport capacities for natural gas and potentially endangers security of supply. Thus, incorporating natural gas supply is crucial to assess a transition from natural gas to hydrogen networks. Also, the possibility of repurposing single strings of parallel interconnection pipelines and the option of importing hydrogen via pipelines from North African countries is out of the scope of many previous analyses.

The non-academic initiative "The European Hydrogen Backbone (EHB)" regularly publishes and updates a visionary concept of a future European hydrogen network across different countries.[2] While documenting the underlying cost parameters of repurposing and constructing new hydrogen pipelines, the report doesn't introduce a methodology for the published maps of a European hydrogen network. Transmission grid operators have published similar documents for visionary network concepts on a national level, e.g., Germany (FNB, 2023), the Netherlands (Gasunie, 2023), or the UK (ENA, 2021).

The second stream of literature, which is relevant for this work, is considered with the analysis of costs and potentials of future hydrogen supply. For instance, Brändle et al. (2021) analyze the production cost of hydrogen from RE, natural gas with CCS, and pyrolysis in 94 different countries. For a set of countries, import costs are derived by calculating transportation costs for hydrogen via new or repurposed pipelines or seaborne liquefied hydrogen. Moritz et al. (2023) extend this work and consider hydrogen derivatives, such as green ammonia or synthetic methane. Kakoulaki et al. (2021) perform a spatially resolved analysis of green hydrogen substitution in the European industry sector. The authors argue that technical RE potentials exceed demand for green hydrogen in most assessed regions, even after subtracting electricity demand for electrification. Sens et al. (2022) present a method to design cost efficient systems for producing, storing, and transporting hydrogen from RE within Europe and its neighboring regions. The model considers investments in RE generation, hydrogen production, storage, and transportation equipment. Their results stress the enormous supply potentials from North African countries, which could bring down hydrogen supply costs in Europe to 2 EUR/kg in 2050. They also emphasize the relevance of hydrogen cavern storage, which decreases hydrogen supply costs for countries with high seasonality of RE. Many other papers have investigated and simulated potentials and costs of green hydrogen supply chains with data-rich models and methods (e.g., Bai et al. (2023), ElSayed et al. (2023), Franzmann et al. (2023), Heuser et al. (2020), Panchenko et al. (2023), Pfennig et al. (2023))

While previous work provides important insights in the topology of a future hydrogen grid and estimates costs, the geographical scope has often been limited to single countries or the interaction of the hydrogen infrastructure with the natural gas sector in the transition period hasn't been part of the analysis. Against this background, this work contributes to the existing body

[2]See EHB (2023) for the latest visionary hydrogen network maps and van Rossum et al. (2022) for technical details.

of literature by introducing an integrated optimization model for the investment and dispatch of hydrogen and natural gas supply in Europe.

4.3. Methodology

This section introduces the methodological approach and documents the numerical assumption for the simulation. The model extends the European natural gas infrastructure model TIGER (Lochner, 2011c) by endogenous investment decisions in hydrogen production equipment and infrastructure.

The simulation results can provide information and important insights for long-term planning and strategic decisions around hydrogen infrastructures, however, they should not be misinterpreted as technical simulations for operational grid planning.

4.3.1. Model Formulation

The TIGER model has previously been applied to various analyses of European natural gas supply (Dieckhöner, 2012, Lochner, 2011a,b, Schlund and Schönfisch, 2021). It is originally formulated as a linear program (LP) and thus assumes perfect foresight in a fully competitive market. The following extensions are made to create an integrated economic investment and dispatch model for natural gas and hydrogen: investments in (i) hydrogen production equipment (RE generation capacities, electrolyzers, SMR with CCS) and (ii) infrastructure (repurposed or new hydrogen pipeline interconnectors, seaborne hydrogen import terminals, hydrogen storage). The original TIGER model has a daily temporal resolution and covers all major gas transport pipeline segments, each individual LNG regasification terminal, and each storage site in Europe. For the extended model, the resolution is reduced for computational efficiency since the model extension increases the complexity through several new model variables. The decision to repurpose natural gas pipelines is only possible for an entire pipeline. To correctly reflect this decision, a binary variable is introduced, changing the type of the problem from an LP to a mixed-integer linear program (MILP). The extended model has a monthly temporal resolution and covers each pipeline interconnector between countries without explicitly modeling pipelines within a country. An overview of the model variables, parameters, and sets can be found in the Appendix C.1.

The objective function Eq. 4.1 minimizes total costs (TC) of natural gas and hydrogen (gas) supply in year y, which is the sum of discounted (a) capital costs (including fixed operative and maintenance costs f) for all types of investments (C_{tech}), variable commodity cost ($opex^{import}$) for natural gas and hydrogen imports (I), domestic natural gas production (P), variable cost ($opex^{CCS}$) for CCS (including CO_2 costs for uncaptured emissions), and variable cost for transportation (T) and storage flows (S). Further equations on the implementation of natural gas supply are omitted here and it is referred to the introduced previous model publications.

$$
\begin{aligned}
min \quad TC_y = & \sum_{tech,t} (a_{tech} + f_{tech}) * C_{tech,y} * capex_{tech,y} \\
& + \sum_{i,gas,t} opex^{import}_{i,gas,t} * I_{i,gas,t} \\
& + \sum_{i,ng,t} opex^{prod}_{i,ng,t} * P_{i,ng,t} \\
& + \sum_{i,H2,t} opex^{ccs}_{i,H2,t} * P^{ccs}_{i,H2,t} \\
& + \sum_{i,j,gas,t} opex^{trans}_{i,j,gas,t} * T_{i,j,gas,t} \\
& + \sum_{i,gas,t} opex^{stor}_{gas,t} * S_{i,gas,t} \qquad \forall\, t \in y
\end{aligned}
\tag{4.1}
$$

The hydrogen node balance Eq. 4.2 ensures that hydrogen flows entering a node i from another node j equal the flows exiting the node in each period t, considering transportation T, net storage flows S, aggregated production from electrolyzers and SMR P, imports I, and demand d.

$$
P^{H2}_{i,t} + S^{H2}_{i,t} + I^{H2}_{i,t} + T^{H2}_{j,i,t} \quad = \quad d^{H2}_{i,t} + T^{H2}_{i,j,t} \qquad \forall\, t, i \neq j \tag{4.2}
$$

The model allows for *green* hydrogen production, using electricity from RE and electrolysis, as well as *blue* hydrogen from SMR with CCS. The upper bound of blue hydrogen production is defined by the installed SMR capacity $C^{H2,blue}$, including the efficiency $\eta^{H2,blue}$ (Eq. 4.3). The scaling factor s

distributes annual capacities over periods t and the lower heating value ϵ converts MWh into mcm_{H2}.[3]

$$P_{i,t}^{H2,blue} \quad \leq \quad C_{i,y}^{H2,blue} * \eta_{i,t}^{H2,blue} * \epsilon * s \qquad \forall\, i, t \in y \tag{4.3}$$

Blue hydrogen production increases demand for natural gas, which is considered in the natural gas node balance Eq. 4.4. The conversion factor γ translates mcm^{ng} into mcm^{H2}.[4]

$$P_{i,t}^{NG} + S_{i,t}^{NG} + I_{i,t}^{NG} + T_{j,i,t}^{NG} \quad = \quad d_{i,t}^{NG} + T_{i,j,t}^{NG} + P_{i,t}^{H2,blue} * \frac{1}{\eta_{i,t}^{H2,blue} * \gamma} \qquad \forall\, t, i \neq j \tag{4.4}$$

Domestic green hydrogen production Eq. 4.5 is limited by electrolyzer capacities C^{H2} considering the conversion efficiency η and generation from all installed RE capacities C_{res}. Heterogeneity in RE output (defined by the location and time specific capacity factor $c_{res,i,l,t}$) is modeled through different cost levels l. Each RE cost level is characterized by an individual capacity factor and annual generation potential (Eq. 4.6). The technologies solar PV, onshore wind, and offshore wind are considered. The model allows for hybrid electricity supply, hence, the electricity can be sourced from different RE.

$$P_{i,t}^{H2} \quad \leq \quad C_{i,y}^{H2} * \eta * s \quad \leq \quad \sum_{res,l} C_{res,i,l,y} * c_{res,i,l,t} * \frac{1}{\epsilon} * \eta^{H2,green} * s \qquad \forall\, i, t \in y \tag{4.5}$$

Electricity produced from RE is only used to feed electrolyzers, electricity trading at wholesale markets is not allowed. Electricity generation exceeding the consumption of electrolyzers is discarded. While this approach aims to comply with the *additionality* obligation of the current EU legislation, in order to ensure that RE are built in addition for hydrogen production, it neglects the opportunity of RE to interact with electricity markets. Section 4.5 discusses this simplification in more detail.

[3] Lower heating value of hydrogen: $\epsilon = 3\ \frac{kWh}{cm_{H2}}$

[4] $\gamma = 3.7\ \frac{cm_{H2}}{cm_{ng}}$

Investments in RE capacities are limited by maximum potentials for each technology and cost level (Eq. 4.6).

$$C^{RES}_{i,l} \quad \leq \quad pot^{RES}_{i,l} \qquad \forall\, i, l \tag{4.6}$$

Seaborne hydrogen and natural gas imports I_{gas} are imported as hydrogen derivatives[5] and LNG, respectively, and require import terminals C^{imp}_{gas} (Eq. 4.7).

$$\sum_t I_{i,gas,t} \quad \leq \quad C^{imp}_{i,gas,y} * s \qquad \forall\, i, gas, t \in y \tag{4.7}$$

Production in ammonia and LNG exporting countries are not modeled and are fed into the model as supply curves, defined by potentials and costs per cost level (Eq. 4.8).

$$\sum_{i,t} I_{i,gas,t} \quad \leq \quad \sum_l pot^{imp}_{gas,l,y} \qquad \forall\, gas, t \in y \tag{4.8}$$

Hydrogen cross-border flows are limited by existing pipeline capacities cap^{H2} and pipeline expansions, which can either be built as new pipelines $C^{pipe,H2}$ or through repurposing natural gas pipelines with given capacity cap^{NG}. The following Eq. 4.9 formalizes the conversion process through introducing a binary variable B which ensures repurposing of a whole pipeline only. Repurposing a pipeline from natural gas to hydrogen reduces its transport capacity by the fixed value δ.

$$T^{H2}_{i,j,t} \quad \leq \quad cap^{H2}_{i,j,t} + C^{pipe,H2}_{i,j,t} + B_{i,j,t} * cap^{ng}_{i,j,t} * \delta * \gamma \qquad \forall\, t, i \neq j \tag{4.9}$$

Repurposing an existing natural gas pipeline cap^{ng} removes it from the natural gas transmission system (Eq. 4.10).

$$T^{ng}_{i,j,t} \quad \leq \quad cap^{ng}_{i,j,t} - B_{i,j,t} * cap^{ng}_{i,j,t} \qquad \forall\, t, i \neq j \tag{4.10}$$

[5]As Section 4.3.2 explains, the scenario analysis assumes ammonia is imported as hydrogen derivative. In principle, the model can consider different import fuels when parameterized with according data.

Pipeline investments and repurposing is always symmetrical, which means that capacities are generated in both directions i, j and j, i. Decommissioning of infrastructure is not considered.

Hydrogen storage can only be built as new investments and operational constraints are equivalent to natural gas storage constraints, introduced in Lochner (2011c).

For each capacity investment, a time continuity constraint Eq. 4.11 is added.

$$C_{tech,t-1} \quad \leq \quad C_{tech,t} \qquad \forall\, t, tech \tag{4.11}$$

All variables are non-negative, except for storage flows (S).

4.3.2. Model Parameterization and Calibration

The main purpose of this paper is to present a novel model formulation to allow for integrated assessments of natural gas and hydrogen infrastructure investments and dispatch. In order to demonstrate and validate the model capabilities, a simulation with exogenous data and simplifying assumptions is made. The model is parameterized with numerical assumptions for hydrogen and natural gas demand, supply, and technology costs.[6] The type of model and the large uncertainty about the future development in the energy sector create an unreasonably large solution space. To better represent real-world conditions in the European energy sector, some assumptions and constraints are defined to calibrate the model and reach more realistic results. These assumptions are documented in this section and discussed in Section 4.5. An overview of all numerical assumptions can also be found in the Appendix C.2.

Infrastructure

Specific investment costs of LNG regasification terminals are site-specific and project budgets are often confidential. The model makes no distinction between floating storage and regasification unit (FSRU) or onshore terminals. Capex data for LNG terminals is determined by calculating average specific investment costs of recent regasification terminal projects in Europe, which yields 155 MEUR_{2022}/bcmpa (GEM, 2023). As a comparison, Lochner (2011c)

[6] Currency conversions assume a rate of 0.9 EUR/USD.

calculates with a similar approach average specific costs of 116 $MEUR_{2010}$/bcmpa (corresponding to 146 $MEUR_{2022}$/bcmpa). Lifetime of LNG regasification terminals is estimated with 25 years.[7] Existing and planned LNG terminals in Europe have been updated based on GEM (2023), GIE (2022), and publicly available information. The energy crisis 2022 has led to numerous announcements on LNG terminal expansions. Only projects have been considered, which disclosed information on a final investment decision, capacities, and commissioning dates, thus, LNG regasification capacities are assumed to increase from 240 bcmpa in 2020 to 364 bcmpa in 2040.

Seaborne hydrogen imports are assumed to be transported as liquid ammonia and converted to hydrogen at the port of entry. In general, there are further options for seaborne hydrogen imports, such as liquid hydrogen, methanol, synthetic natural gas, or liquid organic hydrogen carriers. Recent studies consider ammonia one of the most promising import fuels, and the EU targets ammonia to be imported in large quantities (Alsulaiman, 2023, European Commission, 2022, IEA, 2023a, Moritz et al., 2023). While the model can consider different imported hydrogen derivatives, ammonia is an exemplary import fuel for the scenario analysis. Specific investment costs of ammonia import terminals are estimated at 298 EUR/$kcmpa_{H2}$ (IEA, 2021a, Moritz et al., 2023), which include investment costs for the reconversion unit (ammonia cracker) and an ammonia storage tank. Ammonia terminals are only allowed to be built at locations of existing or planned LNG terminals, thus, no greenfield port infrastructure investment is considered. The import cost includes variable costs of converting ammonia to hydrogen.

New hydrogen interconnectors can be built or repurposed along the existing natural gas networks, meaning greenfield investments for entirely new pipeline connections between two countries are not allowed. Capital costs for new hydrogen pipelines show a high variation in the literature, ranging from 41 to 492 EUR_{2022}/mcm_{H2}pa*km (Ball and Wietschel, 2009b, Brändle et al., 2021, van Rossum et al., 2022). As input, a value of 198 EUR/mcm_{H2}pa*km is assumed for new hydrogen pipelines (including compressor stations) and 59 EUR/mcm_{H2}pa*km for repurposed natural gas pipelines. Hydrogen has a lower energy content per cubic meter, however, through increasing the operating pressure in the retrofitted pipeline, around 80% of the energy throughput of natural gas pipelines can be reached for hydrogen (Galyas et al.,

[7]The modeling uses economic lifetimes.

2023, Haeseldonckx and D'haeseleer, 2007). The EU has implemented an Entry-Exit-Regime for pricing natural gas transportation within and across European gas hubs. The tariffs reflect capital costs and variable costs for transportation. For hydrogen, no such tariff scheme has been implemented so far and thus capital and variable transportation costs are explicitly considered in the model. The latter essentially consist of energy costs for compressor stations. Energy consumption of 0.6 Wh/kg_{H2}*km is assumed (Krieg, 2012, Sens et al., 2022) with electricity price projections from Brändle et al. (2021) and Gierkink et al. (2022), which result in variable costs for hydrogen transmission between 1.6 to 6.2 EUR/mcm_{H2}*km.

The EU and the UK already have well-developed underground storage infrastructure for natural gas, capable of storing approximately 30% of annual gas demand (GIE, 2023). The storage capacities are predominantly used to balance seasonal natural gas demand, which is substantially higher in the winter. Hydrogen storage will presumably fulfill two purposes: while it will also balance seasonal demand patterns, hydrogen storage becomes an increasingly important topic in energy systems with high penetration of fluctuating RE since it allows to decouple electricity generation for hydrogen production from hydrogen demand. This second function of hydrogen storage is relatively short-term oriented and will shift the requirements of hydrogen storage in terms of injection and withdrawal capacity. Since the model uses monthly temporal resolution, the storage function focuses more on seasonal balancing than short-term flexibility and provides insights on seasonal storage utilization. Costs are based on van Gessel and Hajibeygi (2023) with investment cost of 1.7 MEUR/mcm_{H2} and operational costs of 6,750 EUR/mcm_{H2}. In reality, specific investment cost may vary and depend on site specific characteristics.

Hydrogen and Natural Gas Production and Import costs

Global hydrogen trade could emerge similar to today's trade in LNG, requiring assets for converting hydrogen to liquid fuel in the exporting country and regasification in the importing country. For seaborne transport, hydrogen must be liquefied or transformed into another energy carrier, such as methanol, ammonia, synthetic natural gas, or liquid organic hydrogen carrier (LOHC) (IEA, 2021a, Moritz et al., 2023). While there is no consensus in the literature about the optimal mode of transportation, recent publications indicate ammonia to be a suitable transportation medium (European Commission, 2022, IEA, 2022a, IRENA, 2023, Salmon and Bañares-Alcántara, 2021). In the model, hydrogen from overseas can be imported as ammonia from Australia, Canada, Chile, Egypt, Namibia, Saudi Arabia, and the United Arab Emirates. The selected countries only represent a sample of possible exporters with high export potentials at comparably low cost. Import costs and potentials are based on the baseline scenario in Moritz et al. (2023) and include all production, transportation, and (re-)conversion costs, except investment cost for import terminals.

Domestic hydrogen production considers investments in RE capacities and electrolyzers in the EU[8], UK, Switzerland, Ukraine, and Norway. Additionally, hydrogen production and exports from Libya and Algeria to Europe are modeled, since both countries are connected to the European gas grid. Maximum installable RE capacities and capacity factors per cost level are determined for each country. Solar PV potentials are categorized in 26 cost levels. Data on production potentials and full load hours per cost level is retrieved from Pietzcker et al. (2014). For wind onshore, average capacity factors and installable wind power capacities are determined for 10 cost levels. Data on production potentials and capacity factors is based on Bosch et al. (2017). Offshore wind generation potentials are ranked in two cost levels. Besides installable capacities and average capacity factors, also water depth is considered for offshore wind (Bosch et al., 2019). For water depths above 25 m, capital costs are assumed to be 40% higher (Brändle et al., 2021). For each country and RE, temporally resolved RE generation profiles are generated, using data from Marinelli et al. (2014).[9] The profile is scaled for mean capacity factors for each RE cost level to obtain temporally resolved capacity factor profiles for each country, RE, and cost level. Due to limited data availability, only solar PV is considered for Libya and Algeria, using monthly generation profiles from ESMAP (2020).

In Figure 4.1 average capacity factor profiles are shown for countries with high capacity factors in each respective RE class. Germany is added as a comparison. Solar PV shows typical seasonal patterns with high generation in summer months and lower generation during winter. Libya has an almost flat

[8]Malta and Cyprus are not connected to the European gas grid and therefore excluded from the analysis.

[9]The dataset provides historical hourly capacity factors for the years 1982–2019. As a representative year, an average capacity factor is calculated.

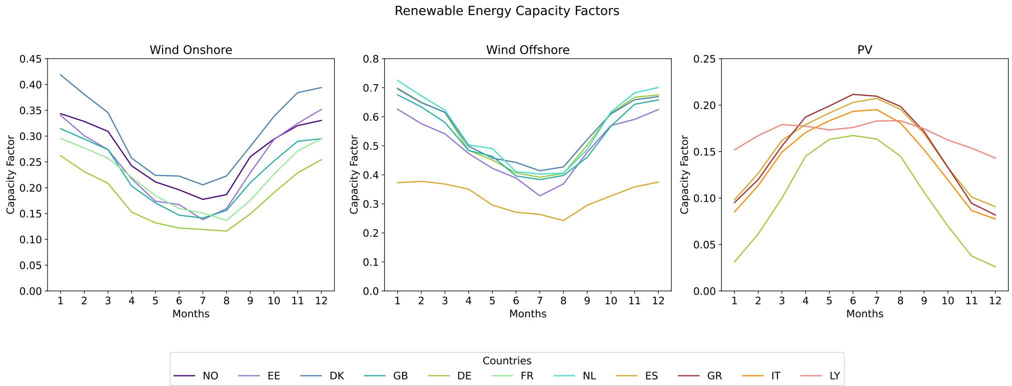


Figure 4.1.: Quantity-weighted capacity factor profiles for exemplary countries (own calculations based on Bosch et al. (2017, 2019), ESMAP (2020), Marinelli et al. (2014), Pietzcker et al. (2014))

capacity factor profile, since the country is located more closely to the equator and solar irradiation has less seasonality. For wind onshore and offshore, months with strong generation are usually winter months. Countries in the North, located close to the sea, exhibit the highest capacity factors in Europe.

Since technical RE capacity potentials tend to be overwhelmingly high and lead to unrealistic expansion of RE in linear optimization models, two different cases are considered: One scenario assumes high RE potentials according to the methodology as described above. The reference case limits total installable RE capacities to the double of projected installed capacities in 2050 from ENTSOE and ENTSOG (2022) for each country and RE technology. Annual capacity expansion is limited by a linear increase until the target year of 2050. This constraint should represent a tighter expansion path for RE in European countries and allows to better understand the interplay of hydrogen network expansion and the availability of RE generation. The techno-economic assumptions for all RE technologies are listed in the Appendix C.2.

Blue hydrogen from natural gas requires SMR plants including CCS units. Investment costs are assumed with 1,300 EUR/kW$_{H2}$ (IEA, 2021a) with a constant efficiency over time of 69% and a CO_2 capture rate of 90%. Uncaptured emissions are priced with an increasing carbon price according to IEA (2022b). Costs for carbon storage are considered as variable costs, which decrease from 50 EUR/t$_{CO2}$ to 30 EUR/t$_{CO2}$ in 2050 (IEA, 2021a), thus aggregated operational costs begin with 15 EUR/MWh$_{H2}$ and decline to 12 EUR/MWh$_{H2}$ in 2050. Variable costs for feed gas is endogenously determined in the integrated model. Investment cost for electrolysis is assumed to start at 1,240 EUR/kW$_{el}$ in 2020 and decrease to 300 EUR/kW$_{el}$ in 2050. Efficiency increases from 64% in 2020 to 74% in 2050 (IEA, 2021a).

While natural gas dominates gas supply today, synthetic methane or biomethane could increasingly substitute fossil gases. The scenarios in ENTSOE and ENTSOG (2022) project a strong uptake of these climate-neutral gases. Fossil and non-fossil gases can be treated as substitutes for network operation and energy consumption. Therefore, the assumed production potentials include natural gas, synthetic methane, and biomethane production. Production potentials within the EU are retrieved from ENTSOE and ENTSOG (2022). Production capacities in Algeria, Libya, Azerbaijan, and other non-EU countries are based on Rystad Energy (2023). For the simulation, a complete cessation of gas supplies from Russia into the EU is assumed. LNG import potentials crucially depend on natural gas production and liquefaction capacities in exporting countries. A modeling of the global gas market is out of the scope of this paper, instead, it is assumed that global natural gas export capacity expansions are sufficient to meet European LNG demand.

Hydrogen and Methane Demand

Methane and hydrogen demand follow the Global Ambition (GA) scenario developed for the TYNDP 2022 (ENTSOE and ENTSOG, 2022).[10] For the year 2030, hydrogen demand is adjusted to the EU commission's target in the REPowerEU plan (European Commission, 2022).[11]

Methane demand in the EU and the UK includes demand for conventional natural gas, synthetic natural gas, and biomethane. In the model, no differentiation is made between different methane sources. For 2030, natural gas demand is reduced according to political goals in the REPowerEU plan (European Commission, 2022). The development of methane demand is shown in Figure 4.2. The strong decline in demand between 2022 and 2030 arises from the ambitious plan of the EU to reduce demand by at least 155 bcm

[10] The publishing institutions stress that the scenarios have been developed and issued before the invasion of Ukraine by Russia with a subsequent change in the European energy policy. In this paper, the supply side assumptions predominantly reflect changing conditions on energy markets.

[11] The REPowerEU plan was launched by the European Commission in May 2022 to react to Russia's invasion in Ukraine and the following energy crisis in the EU in order to improve energy efficiency, energy supply diversification, and reduce GHG emissions.

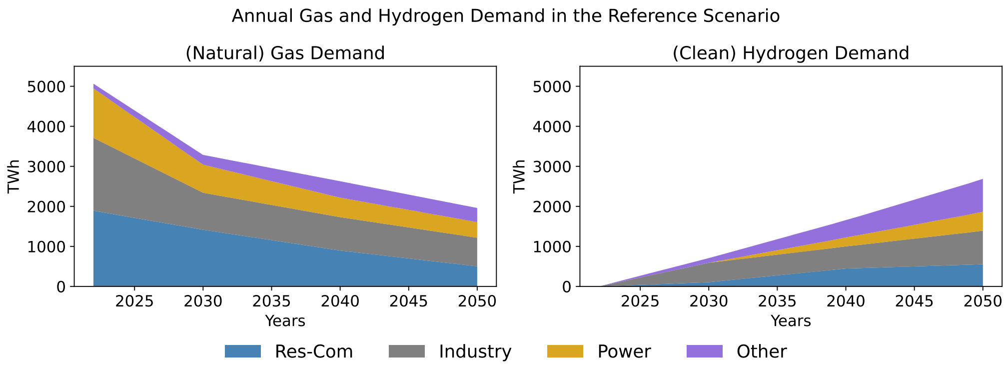


Figure 4.2.: Assumed methane and clean hydrogen demand per sector in the EU and the UK (own figure based on ENTSOE and ENTSOG (2022), European Commission (2022), Eurostat (2023))

(1,722 TWh) from 2021 through energy efficiency measures, fuel switches, reduced consumption, and switching to hydrogen (European Commission, 2022).[12]

Demand for clean hydrogen in EU countries is assumed to rapidly increase until 2030 to meet the European Commission's goals of 20 Mt (equivalent to 667 TWh) in 2030 (European Commission, 2022) (Fig 4.2). After 2030, hydrogen demand in the EU increases to 45 Mt (1,500 TWh) in 2040 and 72 Mt (2,400 TWh) in 2050 (ENTSOE and ENTSOG, 2022). Whereas early hydrogen consumption is dominated by the industry sector in the scenario, demand growth in the electricity and residential and commercial sector take over between 2030 and 2040. Also, demand in the transport sector rapidly increases after 2030, comprising almost one third of European clean hydrogen demand in 2050. For countries outside the EU, only the UK is considered. While smaller non-EU countries will likely have increasing clean hydrogen demand as well, it is assumed that they will not have a decisive impact on the European hydrogen network development. See Figure C.1 in Appendix C.2 for a country-level demand distribution in 2050.

Hydrogen demand is nationally and temporally resolved for the sectors industry, residential and commercial, power, and transport. A flat demand profile is assumed to characterize industrial hydrogen demand, since it will mostly be used by heavy industry with high utilization rates. Residential and commercial demand profiles are scaled according to historical natural gas demand from households, assuming that hydrogen will mostly be used for

[12]For other European countries, demand assumptions are based on Rystad Energy (2023).

heating homes and heating water. Power sector demand profiles are also assumed to follow historical natural gas demand from the power sector. Transport sector demand is assumed to have a flat demand profile. See Figure C.2 in Appendix C.2 for the temporal demand profile in 2050.

The weighted average cost of capital (WACC) for investments is assumed with 8% and to be constant over all countries and technologies. Investment costs are converted to equivalent annual cost, using the annuity factor a:

$$a = \frac{r * (1+r)^n}{(1+r)^n - 1} \tag{4.12}$$

4.3.3. Scenarios

Scenario analyses offer a valuable tool for modeling and evaluating complex and uncertain energy futures. Combinations of essential assumptions are varied to demonstrate the model's capabilities and interdependencies of input parameter choices. Table 4.1 summarizes the simulated scenarios and the varied assumption.

The reference scenario (*REF*) represents the baseline case with numerical assumptions as described in the previous Section 4.3.2. In the high renewable scenario (*High-RES*), capacity constraints for RE expansions are raised so that the technical RE potentials form the upper limit for installed capacities instead of expansion trajectories of the TYNDP (ENTSOE and ENTSOG, 2022). In the low hydrogen demand scenario (*Low-H2*), demand for clean hydrogen is reduced by 40% over all countries and sectors. The reduction rate has been determined based on a comparison of the demand scenarios in TYNDP with other energy system studies (e.g. Deloitte (2023), IEA (2022b), van Rossum et al. (2022)). In the fourth scenario, hydrogen imports from North African countries and from overseas are deactivated (*No-imports*) to assess a case, where Europe is self-sufficient in hydrogen supplies. Another scenario analyses the effect on hydrogen supply and infrastructure, if no hydrogen storage is allowed to be built (*No-storage)*. While this scenario is most unlikely, it should show the economic benefits of hydrogen storage on the system. In the long-term, most countries strive for green hydrogen production, using electrolysis and RE, but blue hydrogen from SMR with CCS is another option to fill supply gaps. The scenario *Blue-H2* allows for hydrogen production from natural gas. The last scenario assumes less hydrogen is used in the residential and commercial sector, where it is mostly used to heat homes (*Low-H2-heating*). This case is of interest, since heating demand has a high seasonality and using less hydrogen with seasonal demand patterns could have an impact on the supply and infrastructure. It is assumed that the residential and commercial sector's hydrogen demand is 80% lower compared to *REF*.

Table 4.1.: Scenario outline

Scenario	RES potentials	H2 demand	Imports	H2 storage	Blue H2
REF	2 * TYNDP capacity	TYNDP GA	Allowed	Allowed	Not allowed
High-RES	Technical potentials	TYNDP GA	Allowed	Allowed	Not allowed
Low-H2	2 * TYNDP capacity	TYNDP GA - 40%	Allowed	Allowed	Not allowed
No-imports	2 * TYNDP capacity	TYNDP GA	Not allowed	Allowed	Not allowed
No-storage	2 * TYNDP capacity	TYNDP GA	Allowed	Not allowed	Not allowed
Blue-H2	2 * TYNDP capacity	TYNDP GA	Allowed	Allowed	Allowed
Low-H2-heating	2 * TYNDP capacity	TYNDP GA - 80% Res-Com	Allowed	Allowed	Not allowed

For each scenario the model is simulated for 2030, 2040, and 2050. The model is implemented with the mathematical programming language GAMS[13] and solved using the IBM CPLEX Optimizer.

4.4. Results

The following section presents the results of the scenario simulations along the dimensions (i) investments and capacity expansion, (ii) dispatch decision, and (iii) costs. The focus of all three sections will be on hydrogen-related outcomes. The last section will provide more general insights into natural gas supply.

4.4.1. Investments and Capacity Expansion

The country coloring in Figure 4.3 indicates installed electrolyzer capacities per country in *REF* for the year 2050. Green hydrogen production is mainly located in North Africa (Libya, Algeria), Southern Europe (Greece, Italy, Spain), and North(west) Europe (Norway, Denmark, UK, Ireland). High-demand countries in Central and Western Europe have also significant hydrogen production to satisfy domestic demand and to avoid long-distance transportation. In total, 512 GW_{el} of electrolyzer capacities are installed in *REF* in 2050, with 427 GW_{el} being located in Europe.

[13]Generic Algebraic Modeling System

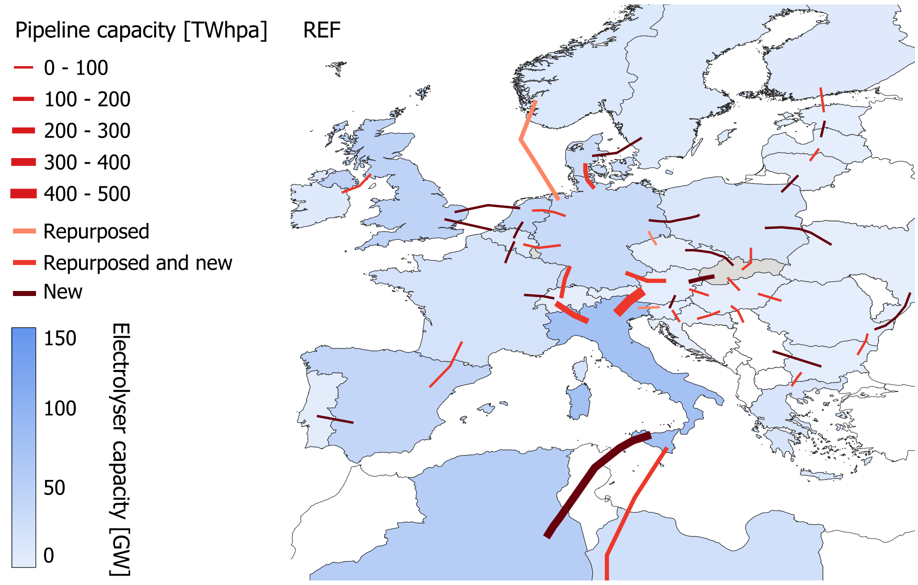


Figure 4.3.: Hydrogen production and cross-border transportation capacities in 2050 in the reference scenario

Unsurprisingly, RE capacities are mostly built in countries with high RE capacity factors, with solar PV focused in the South and wind turbines mostly located in the North and Central European countries. In some countries the assumed RE potentials are fully utilized and become a binding constraint in the model.[14] Already in the year 2030 all EU countries[15], the UK, Switzerland, and Norway are connected to a pan-European hydrogen grid in each scenario. Hydrogen pipeline infrastructures develop primarily along import corridors from production towards consumption centers. Supply corridors from North Eastern Europe (Baltic States, Finland) and Spain are surprisingly low. In the Baltic States, this is because, although RE generation potentials are high, the existing pipeline infrastructure is needed to ensure sufficient natural gas supply in those countries, and consequently, hydrogen pipelines have to be newly built at higher cost. Spain, on the other hand, has significant RE production potentials, which is used to supply domestic demand and provide some exports to France and Portugal. However, the existing natural gas cross-border capacities between Switzerland, Austria, and Germany are substantially larger compared to the interconnection capacity between the

[14]Note that RE potentials are restricted based on an exogenous scenario and do only reflect technical potentials in *High-RES*, see Section 4.3 for details.
[15]Excluding Malta and Cyprus due to their missing connection with the continental natural gas infrastructure today.

Iberian peninsula and France. As a consequence, hydrogen exports from Spain require cost-intensive investments for new hydrogen pipelines, while the import corridor from Libya and Italy can make use of large repurposed pipelines, making the route more cost-competitive. As a result, Italy, Austria, and Switzerland emerge as hydrogen hubs with several interconnections to neighboring countries and significant pipeline capacities of up to 50 GW.

An increase of the RE potentials is assumed in *High-RES*. Wind and solar capacities considerably shift and hydrogen production becomes more concentrated in RE rich countries in Europe, such as Norway, Denmark, Italy, and Greece (see Figure 4.4). The total installed electrolyzer capacity roughly stays the same, but European capacities increase by 18% and decrease in North Africa to reduce transportation cost. The allocation of electrolyzer (and accompanying RE) capacities within and across the scenarios emphasize the overwhelming dominance of RE availability for the distribution of hydrogen production capacities in Europe. With restricted imports from overseas and North African countries (*No-imports*), electrolyzer capacities increase in European countries, and RE potentials are exploited to a high degree. Greece, the British Isles and Denmark become production centers with high export shares. Italy, Spain, the Netherlands, and Germany also have substantial hydrogen production capacities in *No-imports*, but largely use their production to satisfy domestic demand. Hydrogen production capacities in Europe increase by 23%. Adding blue hydrogen (*Blue-H2*) to the supply mix has a very little effect on electrolyzers, in-fact, the aggregated installed capacity roughly stays the same and only the spatial distribution is affected. The share of blue hydrogen in the supply mix is 3% in 2040 and 2050, and below 1% in 2030. Blue hydrogen is only used to supply demand during high demand periods (see Section 4.4.2). Hydrogen storage balances seasonal hydrogen production and demand (see Section 4.4.2 for details). Eliminating the possibility of building hydrogen storage increases the installed electrolyzer capacity in 2050 by 6% (equal to 30 GW_{el}, roughly the combined capacity of Norway and Spain in this scenario). Lastly, a decline in the seasonality and aggregated level of demand (*Low-H2* and *Low-H2-Heating*) has a limited impact on the allocation of electrolyzers in Europe. The reduction of electrolyzer capacities in comparison to *REF* is proportional to the reduced demand of approximately -40% and -14% respectively.

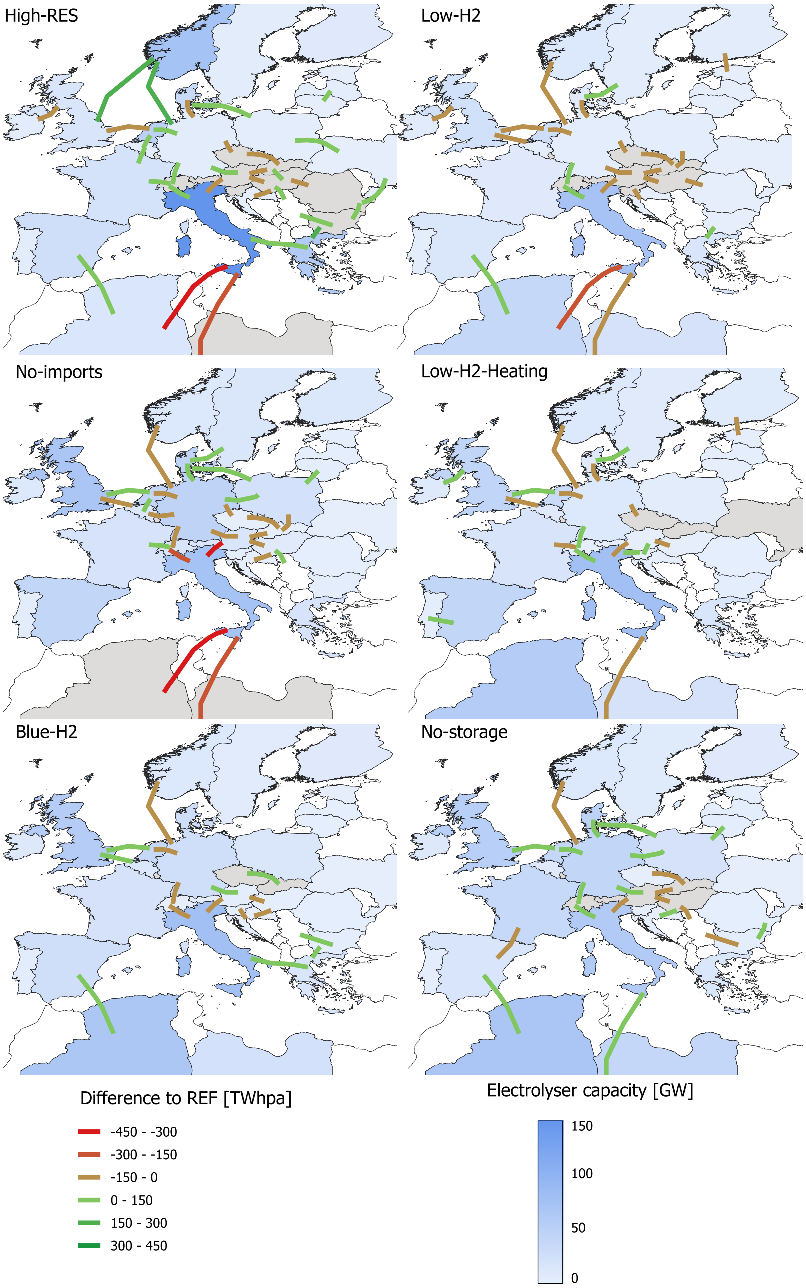


Figure 4.4.: Hydrogen production capacities in 2050 and cross-border capacity differences compared to the reference scenario

In *High-RES*, pipeline connections between RE rich countries in Europe are enforced (see Figure 4.4 and Figure C.4 in the Appendix C.3). In particular, export pipelines from Norway, Denmark, and Greece are added, with Germany becoming another important hydrogen hub. Lower hydrogen demand in *Low-H2-Heating* and *Low-H2* leads to an overall reduced expansion of hydrogen cross-border pipelines. Without hydrogen storage, more capacity is built for hydrogen imports from North African countries, and cross-border pipeline capacities between high-demand countries in Europe are expanded. The lowest grid expansion can be found in *No-imports* since each country has a higher self-supply rate. Over all scenarios, the hydrogen interconnectors between EU countries do not change too much. In particular, in Eastern and South Eastern Europe, the differences in the pipeline cross-border capacities are only minor. Hydrogen demand and production in the region are relatively low, and the development of hydrogen interconnectors is driven mainly by the origin of imports (e.g., Greece, Italy, Central Europe). However, import pipelines (e.g., from Norway and North Africa) are more sensitive to changes in economic and technical conditions. The distribution within Europe, e.g., from Italy and Germany to neighboring countries, is mainly affected by changing import routes (North Africa and Norway, respectively).

Most pipeline retrofits take place after 2030, in most scenarios the share of repurposed pipelines in the hydrogen grid varies between 53% and 68%, referring to Table 4.2. Least repurposing occurs in *No-storage*. Repurposed pipelines have lower cost than building new ones, but hydrogen flows need to be higher than the break-even quantity in order for repurposed pipelines to become cost-competitive. Large import pipelines from Norway, which are reasonable import routes for green hydrogen to Central Europe, are only repurposed between Norway and Germany. The large pipeline capacity requires significant production volumes to fill the pipeline over the year and production volumes in Norway are restricted by the available RE potentials. Apart from that, routes with high shares of pipeline repurposing are mostly where alternative natural gas import routes are present, e.g., in Southeast Europe, where natural gas can be imported from the Southern Gas Corridor (Turkey, Caspian region, Middle East), from Central and Southwest Europe, or as LNG. Also, in Central and Northwestern Europe (e.g., Germany/Austria, Germany/Netherlands, Poland/Slovakia), redundant natural gas pipelines exist, thus, pipelines can be retrofitted without risking a shortage in gas supply. Note that the model does not simulate gas and hydrogen flows within a country.

Table 4.2.: Share of repurposed and newly built cross-border hydrogen pipelines in 2050

Scenario	REF	High-RES	Low-H2	No-imports	No-storage	Blue-H2	Low-H2-Heating
Repurp.	56%	59%	68%	63%	53%	59%	61%
New	44%	41%	32%	37%	47%	41%	39%

Currently, the EU has a well developed natural gas storage infrastructure with an aggregated storage capacity of 30% of annual demand (GIE, 2023). Storage capacities for hydrogen are comparably lower and are mostly developed until 2040, as shown in Figure 4.5. The total storage capacity relative to demand is between 6% and 12% in 2040 and between 4% and 7% in 2050. Least capacities are built in *Low-H2-heating* (87 TWh or 29 bcm_{H2} aggregated capacity), most storage capacity is added in *No-imports* (197 TWh or 66 bcm_{H2}). Also, low hydrogen storage capacities are built in *Blue-H2*. Hydrogen storage caverns can be newly built or developed by repurposing natural gas caverns (in the model, only newly built storage are considered). However, when repurposing natural gas storage caverns to hydrogen, the (energetic) storage capacity decreases by approximately 80% (DBI, 2022, NWR, 2021). In 2021, the EU and the UK had an aggregated natural gas storage capacity in salt and rock caverns of 244 TWh (GIE, 2021). Converting all natural gas caverns to hydrogen would result in a storage potential of approximately 50 TWh for hydrogen, substantially below the required storage capacities in the scenarios, ranging from 88 to 197 TWh. Thus, introducing hydrogen as an energy carrier might need additional investments in new hydrogen storage caverns or technological improvements in using other types of underground storage (aquifers, depleted fields) for hydrogen.

Capacities for seaborne hydrogen imports are highest in *No storage* with an annual capacity of 561 TWhpa in 2050 and lowest in *Blue-H2* (58 TWhpa) and *Low-H2-heating* (8 TWhpa). Across all scenarios the relevance of seaborne imports is very low, since pipeline imports from adjacent regions are available at lower cost. Most import capacities are added in Northwest Europe, where most hydrogen demand is located, and in peripheral regions, like the Baltic States, where the interconnectivity with other countries is weak. In the model, hydrogen storage, import capacities, and blue hydrogen production are interchangeably used to provide flexibility to the system (see Section 4.4.2 for more details).

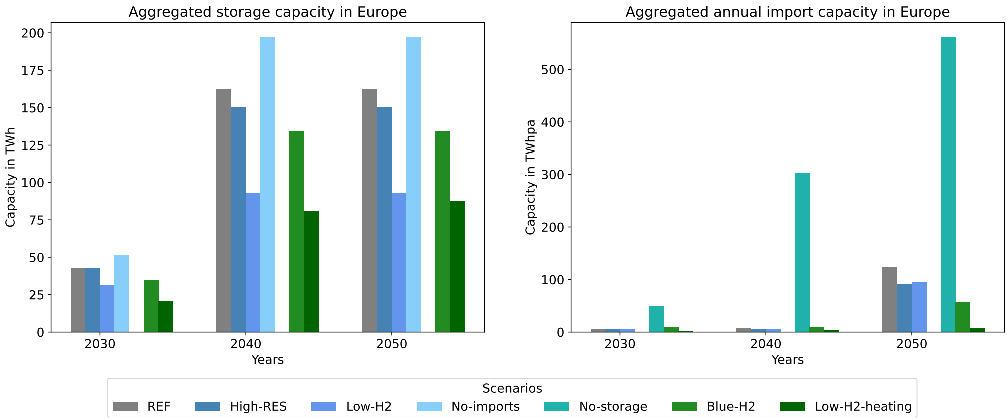


Figure 4.5.: Hydrogen storage and import capacities for different scenarios

4.4.2. Dispatch and Infrastructure Utilization

The arithmetic mean of cross-border capacity utilization is between 76% and 81% in 2050. The highest utilization rates occur in the scenario *Blue-H2* and lowest in *No-storage*. The interconnectors from North Africa to Europe have a high capacity factor of more than 90%. In contrast, the retrofitted hydrogen pipeline from Norway to Germany is only used at a rate of 63 to 80%. Transit routes between large distribution hubs tend to have a higher capacity factor than interconnectors between countries with lower demand.

The mean utilization mostly follows the demand seasonality with increased flows in the winter months and reduced utilization during the summer, as illustrated on the left in Figure 4.6 for 2040. Without hydrogen storage (*No-storage*), the mean utilization has a much stronger seasonal profile with 65% utilization in summer months and 88% during the winter.

Hydrogen storage is mostly filled during summer months and emptied in winter to supply seasonal demand, thus, storage is similarly used to natural gas storage today. The utilization of storage assets is almost equal across different scenarios, as shown on the right in Figure 4.6. Only the scenario *Low-H2-heating* shows a slightly different storage profile, with a temporal shift to the left. However, these results only hold for this study's defined system scope. In future energy systems, hydrogen storage could play an essential role

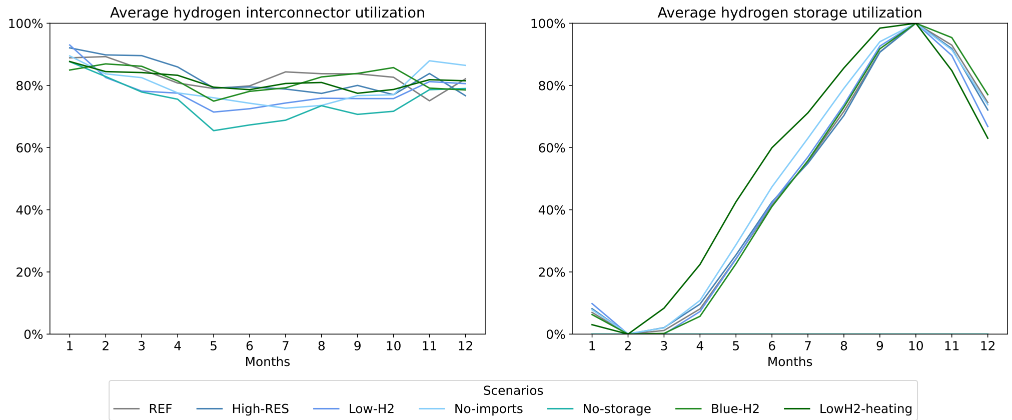


Figure 4.6.: Average cross-border pipeline utilization and hydrogen storage levels in 2040 for different scenarios

to provide backup energy for the electricity system during periods with low RE generation and storage profiles could be more dependent on electricity generation and demand.

As found in the previous section, ammonia import, blue hydrogen production, and storage capacities fulfill a similar purpose of providing supply flexibility to the system. Ammonia import terminals have an average utilization rate of 25%, with little variation between the scenarios, however, with a strong temporal profile. Seaborne imports are particularly high during months with high demand and become zero during summer. The same effect applies to blue hydrogen production, with an average capacity factor of 40%. While storage, seaborne imports, and blue hydrogen could provide valuable flexibility to the hydrogen system, it is unclear whether price-based incentives are sufficient to motivate investments in these assets.

4.4.3. Costs

In Figure 4.7, normalized cost differences are shown relative to *REF* for the simulated scenarios, years, and each system component's contribution. In all scenarios, the predominant cost component is energy supply from RE to produce electricity for hydrogen electrolysis. The second largest costs are capital costs for hydrogen production equipment with relatively constant shares of 11% to 13% over all years and scenarios. Transportation costs are also almost stable over all scenarios and years and account for 8% of hydrogen supply costs on average. Storage contributes between 3% and 10% to hydrogen supply costs. The benefit of hydrogen storage materializes in the long term. In 2030, the unit costs in *No storage* are still lower, while they increase significantly in 2040 and 2050 without the ability to invest in storage capacities. The lowest storage cost share is found in *Blue-H2* and *Low-H2-heating*. In the former, blue hydrogen production provides additional flexibility and can thus reduce the need for hydrogen storage. In contrast, in the latter, the need for hydrogen storage is reduced through less seasonal hydrogen demand. In comparison with *REF*, unit supply costs increase between 3% and 13% in 2050, when hydrogen imports (*No-imports*) or hydrogen storage (*No-storage*) is restricted. Higher RE potentials (*High-RES*) decrease the costs by 3%. With blue hydrogen production, total hydrogen supply costs roughly stay the same (*Blue-H2*), however, this only holds for hydrogen supply and does not include higher costs for methane supply, since natural gas prices increase with higher demand for SMR.

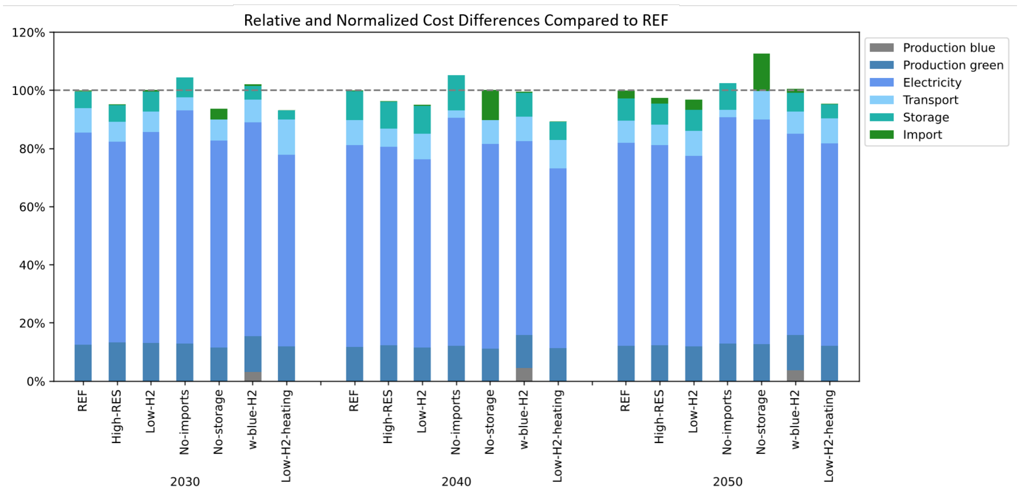


Figure 4.7.: Relative and normalized cost differences compared to *REF*

The total LCOH[16] of clean hydrogen supply in Europe (including production, imports, transportation, and storage) decrease from 2.6 EUR/kg in REF_{2030} to 2 EUR/kg in 2050. The supply cost are highest in the scenarios *No imports* and *No storage*. Average import costs are comparably higher and thus production within Europe and neighboring regions is more cost competitive. Imports are economically only reasonable to fill supply gaps during high demand periods.

[16]Levelized Cost of Hydrogen (LCOH) refer to the average net present cost of hydrogen production. In Figure 4.7, costs in each scenario are shown relative to the total costs in REF.

4.4.4. Impact on Natural Gas Supply

Converting natural gas pipelines to hydrogen instead of building an entirely new infrastructure saves costs and time. However, it is crucial to secure natural gas supply in the transition period toward a European hydrogen infrastructure. The presented model can optimize both the development of a hydrogen infrastructure and the dispatch of the existing natural gas network.

The European gas supply has been under pressure after supplies from Russia have been halted over the Nord Stream and Yamal corridor in 2022. European countries reacted with expansion of LNG import capacities and demand reduction. The scenario simulations show that in the event of a full cessation of Russian gas supplies to Europe, supply would still be sufficient and no additional LNG capacities would need to be built (apart from the announced expansion projects). Aggregated LNG imports are 1,200 TWh (108 bcm) in 2030 and increase over time, since domestic production and import volumes from North African countries and Norway decline.[17]

Norway becomes the most important supplier of natural gas for the European market until 2030, however, due to decreasing production, export volumes decline onward. Pipeline imports from Norway are at the same level over all scenarios. Repurposing pipelines of this import corridor does not impact gas supplies, since sufficient spare capacities exist. Declining pipeline imports and domestic production are mostly replaced with LNG imports, contributing up to 77% of European natural gas supply in 2050. LNG import terminals have an average utilization rate between 6% and 100% in 2050, with highest utilization rates in Northwestern Europe and the Baltic States, as shown in Figure 4.8. Algeria continues to export significant amounts of natural gas to Europe at a relatively constant rate. In some scenarios, imports from Libya fall to zero, since natural gas pipelines are repurposed and no redundant gas pipelines exist. However, at least one interconnection from Algeria to either Italy or Spain remains operational to maintain natural gas flows in every scenario.

Previous analysis has shown that natural gas pipeline imports into Europe are unlikely to increase, and more LNG is imported from the global market instead (Schlund et al., 2023). Spare capacities in LNG regasification terminals

[17] The results should be carefully interpreted since they only consider one demand and supply scenario and are determined in a simulation with monthly time resolution.

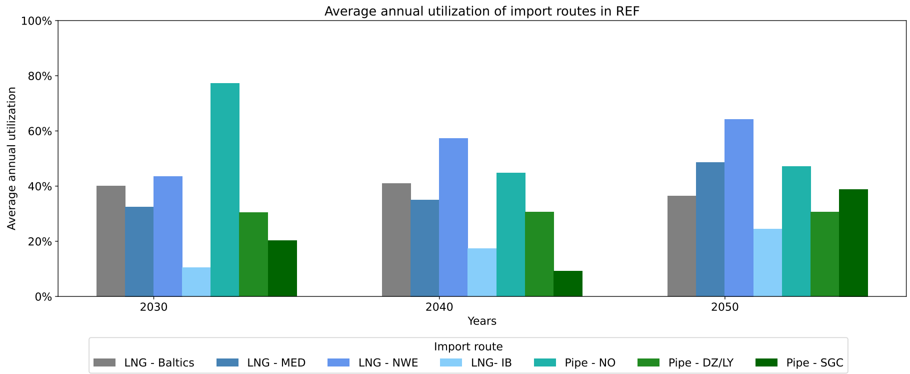


Figure 4.8.: Average annual utilization of natural gas import routes in *REF*[18]

enable increased natural gas imports in the case of a supply shortage or increased demand. Thus, repurposed import pipelines have a limited effect on the security of supply for natural gas. The distribution and cost-efficient allocation of natural gas within Europe requires transportation capacities between and within the European countries. In the scenario simulations, there are no supply shortages, and security of supply is guaranteed in every European country. However, some natural gas interconnection pipelines appear to be wholly or almost entirely utilized,[19] which can be a potential risk for security of supply unless alternative pipeline connections to neighboring countries or sufficient storage inventories exist. In particular, some countries or regions, such as Finland, Greece, and Denmark, become largely disconnected from the European natural gas grid. Methane supply in these countries is ensured either by domestic biomethane production or by LNG imports. This could put the countries in a risky situation of dependence on a single supply source. Consequently, the decision to repurpose interconnection pipelines between European countries involves individual and in-depth assessments of country-specific infrastructures, alternative supply sources, and desired resilience levels.

[18]Route definition: Baltics - Baltic states: Finland, Estonia, Lithuania; MED - Mediterranean: Italy, Croatia, Greece; NWE - Northwest Europe: Great Britain, France, Belgium, the Netherlands, Germany, Poland; IB - Iberian peninsula: Spain, Portugal; NO: Norway; DZ/LY: Algeria, Libya; SGC - Southern Gas Corridor: Azerbaijan, Turkey.

[19]For instance, interconnectors between the following countries: Spain-France, France-Germany, France-Switzerland, Belgium-Germany, Hungary-Austria, or Hungary-Slovakia.

4.5. Discussion

The following section summarizes structural findings from the scenario simulation and compares the results on a high level with other publications on the development of a European hydrogen infrastructure. Also, the assumptions and results are critically discussed, and further ideas for future research are suggested.

4.5.1. Comparison of Results with Other Studies

In Section 4.2, studies and research papers with similar objectives have been introduced. The different numerical and methodological assumptions make it difficult to draw a clear comparison between the results of earlier work and the present study. Still, some findings from different studies can be compared at a high level.

The European Hydrogen Backbone (EHB) initiative (van Rossum et al., 2022) regularly updates its report on a European hydrogen grid for the years 2030 and 2040. A detailed methodology report is unavailable, but the results allow for some comparisons. The EHB consists of 69% repurposed pipelines for a European hydrogen grid in 2040, which is at the same level of maximum repurposed pipelines in this work, however, the EHB also covers domestic pipelines. The load factor of the pipeline grid is an exogenous assumption in the report and is estimated at 5,000 hours per year in 2040 (57% utilization rate) for large pipelines with a maximum capacity of 13 GW. The endogenously determined capacity factor from the simulation in the present study varies between the scenarios, resulting in 76 to 81% over the entire pipeline grid in 2050. The largest pipelines in the model have a total capacity of up to 47 GW between Italy and Austria. This significant difference is also the result of varying import corridors. While some of the supply corridors from the report are similar to this work's results (e.g., Northwest Europe, North Africa, Southeast Europe), supply from Spain and the Baltic States to Central Europe has yet to be found as major corridors in the analysis.

Another work from Neumann et al. (2023) results in a similar pipeline utilization rate of 78% with storage capacities between 26 and 43 TWh (compared to 87 and 197 TWh in this work). One reason for the comparably lower storage capacities is lower hydrogen demand for heating and power generation. The present work assumes a strong seasonality of hydrogen demand in the heating and power sector, pushing for a higher capacity expansion of hydrogen storage. Similarly, the authors find primary import corridors from the British Isles and Southern Europe (North African countries are excluded in the analysis) and the most extensive hydrogen network expansion in Northwestern Europe. The share of repurposed gas pipelines is between 64 and 69% and the largest hydrogen pipelines have capacities of up to 30 GW (compared to 47 GW in this study).

While the studies differ in many detailed results, some key findings are similar and could indicate robust results for planning a hydrogen grid, such as import corridors from the South and North, the relevance of hydrogen storage, and the high shares of repurposed natural gas pipelines. For operational and technical grid planning, the economic simulations would need to incorporate more engineering aspects to correctly reflect the pipeline flows of natural gas and hydrogen and determine the actual costs of each pipeline project.

4.5.2. Key Findings from the Scenario Analysis

The model simulation provides some strategic insights for the development of a European cross-border infrastructure. First, it shows the dominance of RE potentials in shaping the hydrogen supply side and determining the supply corridors for hydrogen trade and imports. While technical potentials are widespread across the continent, acquiring knowledge on the realistically exploitable RE potentials becomes crucial, e.g., due to land eligibility, acceptance issues among the local population, or economically unreasonable greenfield investments. The scenario comparison has shown that high utilization of RE potentials can decrease the total supply cost for hydrogen. However, this could lead to a high concentration of hydrogen production in a few countries with adverse effects on the security of supply and risk exposure due to one-sided dependencies. This result implies the importance of an accelerated expansion of RE capacities since electricity for hydrogen production will compete with other electricity consumers from the household, industry, and mobility sectors. The model results imply a cost-optimal allocation of RE sources across European countries according to country-specific generation and capacity potentials. This leads to a concentration of RE for hydrogen generation in Italy, Greece, Spain, and Portugal for Solar PV, and in Nordic countries, Denmark, France, the

Netherlands, the British Isles, and Germany for wind resources. However, the trajectory of RE capacities in reality partially differs from the cost-optimal distribution, as shown by a comparison of the model results' capacity shares with the capacity expansion in the TYNDP National Trends scenario[20] (see Appendix C.3). The diverging allocation of RE resources from the cost-optimal pathway could increase the need for infrastructure and generation assets, potentially leading to higher supply costs. However, quantifying the loss in welfare requires an integrated simulation of hydrogen and electricity markets and is out of the scope of this paper. Also, the availability of RE generation crucially impacts the output of hydrogen producers. In the scenario simulations, average RE capacity factors over the past 37 years have been used as a representative generation profile (see Section 4.3.2). However, RE supply is much more volatile with extreme weather events at both ends; hence, for the reason of hydrogen security of supply, it can be reasonable to design the supply chain along a year with below-average RE feed-in in order to reflect different climatic conditions.

Second, the simulation results indicate the relevance of flexibility in the hydrogen supply system. While hydrogen is commonly considered an enabler to provide flexibility and backup energy for a RE dominated electricity system, the flexibility of hydrogen is not inherent. It must instead be provided by an accordingly designed infrastructure and supply system. Unlike natural gas, where production is mostly constant throughout the year and demand is characterized by a strong seasonality, hydrogen will have both unsteady demand and supply. Production will primarily dependent on volatile RE and demand will depend on both seasonality and short-term fluctuations in demand from the power sector. In the simulation, hydrogen storage, imports, and blue hydrogen from SMR provide (seasonal) flexibility to the system. The load factor of these assets could be comparably low, making them potentially unprofitable business cases, and it is thus unclear whether market prices (and, in particular, price spreads) will set sufficient incentives for the investments.

Third, the results show that repurposing natural gas pipelines has a cost advantage over greenfield pipeline investments in every scenario. Repurposing of cross-border pipelines was found to take place between 2030

[20]The national trends scenario describes a development of the European energy system until 2040, which aligns with the current national policies (ENTSOE and ENTSOG, 2022). Note that the scenario was published in early 2022, and some national targets have since been adjusted.

and 2040 primarily, but this will require substantial coordination between transmission system operators in order to guarantee security of supply for natural gas during the transition period. Recent publications have suggested different import corridors for hydrogen; however, the identified import routes and exporting countries differ. The capacity and direction of import routes highly depend on the economic and technical parameter choices. Thus, they are less robust against varying assumptions and would need more in-depth analysis of whether they are cost-efficient import corridors. On the other hand, cross-border hydrogen pipelines within Europe have appeared in every scenario, showing the potential benefits of trade within the continent and neighboring regions. Many stakeholders consider seaborne imports an essential contribution to hydrogen supply in Europe, but the simulation results could not prove a high cost efficiency for imports of hydrogen derivatives. While the hydrogen production costs in exporting countries are substantially lower in some cases, the costs for ammonia synthesis, shipping, and reconversion to hydrogen almost double the total import costs. However, these results should be carefully interpreted against the chosen input parameters and the high uncertainty of technology cost development, particularly for hydrogen (derivatives) shipping. This great uncertainty challenges today's planning of trade partnerships with overseas countries. It bears the risk of stranded assets if the technology costs are not decreasing as often projected.

4.5.3. Limitations and Future Research

The model and the analysis presented in this work contribute to the ongoing discussion on introducing hydrogen as a climate-neutral energy commodity, which could be traded across borders in the future. While proposing new methods to allow integrated assessments of natural gas and hydrogen supplies and showing new insights into drivers of a European hydrogen infrastructure, the results should be interpreted against important limitations and shortcomings of the model.

A central assumption of the model and the scenario analysis is dedicated electricity supply for electrolyzers from RE without using electricity markets and transmission. While direct coupling of RE and hydrogen production might be applied in some remote areas, e.g., for offshore wind parks or large-scale solar PV in sparsely populated areas, the majority of electrolyzers in Europe will most probably be connected to the public electricity grid and thus use electricity markets to optimize dispatch. Trading electricity instead of hydrogen would become relevant opportunity costs when electricity transmission and markets are included in the model. This missing link in the model raises significant changes in electrolyzers' investment and dispatch decisions. First, operating hours would be less dependent on the sole availability of RE and rather on supply and demand and, consequently, on the electricity price in the equilibrium. The presented model overestimates the operating hours because hours with low RE generation might have uneconomically high electricity prices. Second, the oversupply of RE is currently discarded in the model and cannot be used to supply electricity demand for other purposes. As stated in the results (Section 4.4), costs for RE represent the highest single cost component, and thus, the model keeps the oversupply of RE small. Adding opportunities for RE generators to the model could lead to a decrease in costs for electricity supply and a varying capacity ratio of RE generators and electrolyzers. Moreover, hydrogen demand is entirely exogenous to the model. Many energy consumers have different options to decarbonize, with hydrogen being one option. The cost-efficient use of hydrogen in integrated energy systems becomes a function of relative price differences between hydrogen imports, domestic hydrogen production, and electricity prices, which is out of the scope of this paper. These limitations could be partially solved through integrated optimization of electricity markets and networks for gaseous energy carriers, e.g., similar to Frischmuth et al. (2022) and Neumann et al. (2023). The limitations of these integrated models often lie either in the temporal or spatial resolution or in covering electricity, hydrogen, and natural gas supply. An alternative to this could be a coupling of the integrated hydrogen and natural gas infrastructure model with an electricity market model, e.g., as suggested in Schlund and Schönfisch (2021), and iteratively simulating the development of natural gas, hydrogen, and electricity supply.

The current model setup allows for integrated assessments of hydrogen and natural gas investments and dispatch of cross-border energy exchange but neglects domestic distribution of hydrogen. The focus on cross-border pipelines in the model is chosen to keep computational burden, temporal, and spatial resolution in balance. Hence, the model provides information on European import corridors and developments of a pan-European hydrogen grid but fails to explain the detailed spatial distribution of hydrogen demand, supply, and infrastructures. While this limitation is not expected to impact the described effects substantially, it could lead to different pipeline investments and cost structures between certain countries. Since the presented model is an extension of the original TIGER model, introduced by Lochner (2011c), it can improve spatial resolution, which could be the subject of future research.

As a partial equilibrium model, assuming perfect competition in the evolving hydrogen market, the applied method neglects some endogenous effects and imperfections during the hydrogen market development. For instance, increasing energy costs due to a more complex energy system could lead to higher investment costs for technologies, particularly those with energy-intensive production, e.g., solar PV or steel pipes. Also, an emerging hydrogen market might suffer from imperfections, like reduced liquidity, oligopolistic market structures, or high transaction costs. Furthermore, emerging trade in hydrogen could also be based on long-term contracts in the early years of the market (see, e.g., Antweiler and Schlund (2023)) before a liquid spot market arises.

4.6. Conclusions

Developing a European cross-border hydrogen infrastructure is considered an essential contribution to transforming the energy system towards climate neutrality while maintaining security of supply and ensuring efficient energy markets. Different initiatives and researchers have published drafts and potential designs of a hydrogen transmission network for Europe. This paper introduces a novel model to simulate a cost-efficient pathway of integrating a European hydrogen network in the existing natural gas infrastructure through repurposing natural gas and building new dedicated hydrogen pipelines. The model extends an existing natural gas dispatch model through investment decisions for hydrogen import terminals, pipelines, storage, and production assets, as well as dedicated RE generation from solar PV, wind onshore, and wind offshore. The original LP model is formulated as a MILP to correctly reflect the binary decision of repurposing cross-border gas pipelines. It is parameterized, applied to seven scenarios, and simulated with monthly resolution for 2030, 2040, and 2050.

The purpose of the case study is not to forecast a future European hydrogen grid because this would need additional information on the development of electricity markets and more detailed technical modeling of the grid. Instead, the simulation shows critical dependencies between different system elements and provides insights for strategic planning of a hydrogen infrastructure. The results have shown the dominance of RE potentials for developing a European hydrogen infrastructure. The availability and location of installed RE capacities for hydrogen production strongly shape investments in and utilization of cross-border pipelines. Highly concentrated hydrogen production in exporting regions, such as North African countries, Norway, and Denmark, can significantly expand import corridors to Central and Northwest Europe, where most hydrogen demand could be located. The share of repurposed pipelines in a hydrogen network could be between 53% and 68% and is relatively constant over all scenarios. While investment in import routes is somewhat sensitive to varying technical and economic assumptions, developing within-Europe cross-border pipelines is robust against different assumptions. Furthermore, the supply system appeared to need flexible assets. In the simulation, flexibility could be provided by either hydrogen storage, seaborne imports, or blue hydrogen production from SMR with CCS. While it will be crucial for the hydrogen system to provide flexibility and pass this value proposition on to the power sector, it is not inherent to hydrogen. It must be enabled by corresponding infrastructure planning. From an economic perspective, it has yet to be found whether price signals (and price spreads) will sufficiently incentivize investments and provide flexibility.

The presented model is one of the first of its kind, allowing for integrated analyses of natural gas and hydrogen infrastructure development. However, it exhibits important limitations with options for future research. The model assumes direct coupling of RE with electrolyzers without allowing outside options to sell electricity at wholesale markets. For most of the hydrogen production plants, this will most likely not be the case; instead, electrolyzers will be dispatched according to price signals from the electricity market. This limitation could be solved by, e.g., coupling the model with an electricity market model. Further, improving the temporal and spatial resolution of the simulation could allow for more detailed insights into the security of supply for hydrogen and natural gas as well as more detailed dispatch strategies of infrastructure assets. Overall, the model uses many numerical and conceptual assumptions characterized by high uncertainty by nature; thus, updated analyses using state-of-the-art data in the future could provide more insights and implications of changing market conditions.

5. The Emerging International Trade in Hydrogen and the Role of Environmental, Innovation, and Trade Policies

5.1. Introduction

Hydrogen (H_2) has been heralded as a clean energy carrier of the future. Its versatility is similar to fossil fuels because it can be transported in gaseous and liquefied form similar to natural gas. It can be transported as ammonia (NH_3), which requires less refrigeration (–33°C) than liquefied hydrogen (–252°C). Hydrogen can be mixed with natural gas, it can be burned in gas turbines to provide mechanical power, and it can be used in fuel cells to generate electrical power. Unlike conventional electric batteries, hydrogen can store energy for a long duration with little decay. These prospects of hydrogen have prompted numerous countries to adopt explicit 'hydrogen strategies' for production, use, storage, and transportation.[1]

Today, hydrogen is overwhelmingly produced from natural gas (CH_4) through steam methane reforming with significant carbon dioxide (CO_2) emissions. This is described as "grey" hydrogen. If coal is used instead of natural gas, hydrogen production is considered "black" or "brown" (depending on the type of coal). However, when CO_2 emissions are captured and stored, such hydrogen is described as "blue." The "turquoise" variant separates carbon black from methane through methane decomposition (MD), generating an additional useful raw material for making graphite, graphene, and other carbon-based products. If hydrogen is produced from renewable energy sources (RES) through electrolysis, it is described as "green." If electrolysis involves nuclear power instead, hydrogen is described as "pink". Green hydrogen is the most costly form of production today, but its cost is decreasing through rapid innovation and learning-curve effects.

[1] Examples include Germany's National Hydrogen Strategy, the US Department of Energy Hydrogen Strategy, and the Hydrogen Strategy for Canada. Australia, Japan, Norway, and South Korea have adopted similar frameworks, and this list is growing.

With the emergence of hydrogen as an energy carrier, we can expect a significant increase of international trade in hydrogen as countries benefit from their respective comparative advantages in hydrogen production. This paper is concerned about the evolution of this new international trade both theoretically and empirically, with a special focus on long-term contracts (LTCs) as the likely dominant form of trade during the early decades of developing hydrogen markets.[2] Because this new market will evolve with multiple firms entering the market simultaneously in each period (with a significant level of heterogeneity and randomness), the resulting complexity does not lend itself to closed-form analytic solutions. Instead, we develop a theoretical model which we employ to conduct empirical simulations.

International trade creates opportunities for gaining from comparative advantages, making hydrogen more available, and cheaper, than without trade. As hydrogen is a pathway to decarbonizing emission-intensive industries, international trade has a potentially beneficial effect on the environment. Our paper quantifies the likely scope of international trade in hydrogen under a variety of policy scenarios. The policy implications are readily apparent: rapidly growing trade in hydrogen needs trade policies to facilitate access and infrastructure policies to facilitate imports and exports.

International trade in hydrogen is attracting attention from different directions. Nuñez-Jimenez and De Blasio (2022) have developed a model specifically for green hydrogen using mixed linear programming optimization, focusing on supply costs. Our approach is rather different and focuses on an oligopolistic market mechanism with LTCs at its core, and we explore multiple policy scenarios. In part it shares the foundation with the Brander and Krugman (1983) notion of single-period two-way trade in homogeneous products, but expands to include the dynamic effect of LTCs. Similar to Antweiler (2016), who studies dynamic comparative advantage in electricity trade, we find two-way trade with a dynamic dimension facilitated by overlapping generations of LTCs with shifting comparative advantage that locks in trade patterns alongside the conventional static effects from 'reciprocal dumping'. Along the lines of strategic interactions, our paper also shares traits of Bernhofen (1999), who finds patterns of intra-industry trade that prompts us

[2] One example for this it the *H2Global Mechanism* of the Germany based H2 Global Foundation, which developed a two-sided auction model to lock in prices for producers and thus to create incentives for international trade in hydrogen and its derivatives, see `https://www.h2global-stiftung.com/project/h2g-mechanism` for more details.

to employ the Grubel-Lloyd index to capture the volume of two-way trade and compare it across industries. Our paper also has an antecedent in Balistreri et al. (2017), who investigate the effect of carbon policy on global trade from the perspective of different trade models. Our focus on the extensive margin of international trade raises questions about market entry and linkages between micro and macro behavior, as discussed in Eaton et al. (2013). Our trade model rests almost exclusively on the extensive margin of entry, which distinguishes our approach from homogeneous trade models that are focused primarily on the intensive margin.

Carbon policies play a crucial role in determining the evolution of hydrogen trade because they boost both demand and innovation. While our model operates in a partial equilibrium context, it has wider implications in a general equilibrium context as specialization in hydrogen production can reinforce other mechanisms that drive local sectoral specialization in a warming world, as discussed in Conte et al. (2021). Regions with comparative advantages in hydrogen production may see increased economic growth. This in turn also connects to questions about trade and the environment. As Cherniwchan and Taylor (2022) point out, one of the key remaining questions in this literature is about the trade-induced technique effect. We contribute to this question by focusing on a policy-induced endogenous innovation channel that contributes to trade and economic growth.

Our paper makes several important contributions. First, we develop a model where LTCs lead to a pattern of "sequential trade" that is particularly susceptible to initial conditions and subsequent global technology innovation and policy interventions. Trade with overlapping vintages of LTCs emerge as two-way trade as comparative advantages shift. Second, we develop an empirical model of international trade in hydrogen that we can simulate with suitable demand forecasts, supply costs, and transportation costs. This model we use to explore different policy scenarios. We are not trying to forecast future trade in hydrogen because this would require a level of foresight that is simply unrealistic. However, we are interested in understanding the *patterns of trade* that will emerge—answering questions such as whether there will be an "early-adopter curse" where early adopters lock in high prices through LTCs, whether there will be significant price dispersion across markets and within markets, and whether there will be "hydrogen trading blocs" due to transportation costs or carbon policies. Because of the significant level of uncertainty about technological developments and policy approaches, our empirical analysis necessarily explores a wide variety of different plausible scenarios.

While our simulations are not meant to forecast the emerging trade in hydrogen, our simulation scenarios are highly suggestive. We see an early dominance by blue and turquoise hydrogen, as related technologies are initially cheaper than green hydrogen. We see uptake of green hydrogen propelled by endogenous innovation, which ultimately will lead to stagnating growth of blue and turquoise hydrogen. Yet, the most important factor in all of our scenarios is the trade cost, driven by the cost of hydrogen infrastructure. Significantly lower trade costs will naturally boost hydrogen production, but as our results reveal, with non-trivial effects on the technology path and market concentration.

Energy trade takes place in a world imperiled by political frictions. Recent events have underscored the need for energy security—i.e., the ability to maintain stable levels of supplies in the event of political, economic, or environmental adversity. We explore the political context of hydrogen production and distribution in a separate section. Hydrogen trade comes with unique new benefits and risks. It is not a panacea for the world's long-term energy needs, but instead will fill an important gap in the transition away from fossil fuels that allows the world to achieve the climate goals adopted by the 2015 *Paris Agreement* of the UNFCCC.

In what follows, we organize our paper in several steps. Section 5.2 summarizes the most pertinent logistical and technological considerations. Section 5.3 introduces our theoretical model, introduces the rationale for LTCs, the conditions for co-existence with spot markets, the role of uncertainty about future prices, and a model of dynamic sequential trade with LTCs. Section 5.4 previews our data and calibrations. Section 5.5 discusses our simulation of 19 different scenarios, and section 5.6 acknowledges important caveats of our analysis. Section 5.7 puts our analysis into the policy context, and section 5.8 concludes.

5.2. Technological and Logistical Considerations

Hydrogen is the lightest and most abundant element on earth (Møller et al., 2017). When used as an energy carrier or feedstock in pure form, it does not generate CO_2 emissions. Hydrogen's carbon intensity is defined upstream by production technologies. While unabated hydrogen production from fossil fuels emits significant CO_2 emissions, technology options exist to reduce or avoid direct CO_2 emissions.[3] The fugitive characteristics of hydrogen gas lead to high cost of transportation in comparison to other energy carriers (Ball and Wietschel, 2009a). As a consequence, global hydrogen trade is very limited today. In order to facilitate global trade of hydrogen, the gas needs to be converted into a state which allows for cost-effective long distance transportation. Below we outline the most important technical and economic considerations in the context of producing, transporting, and consuming hydrogen.

5.2.1. Hydrogen production

The most common way to produce hydrogen today involves using natural gas or coal as a feedstock, with steam methane reforming (SMR) being the dominant technology (IEA, 2019). In this process, natural gas is used to provide both the necessary heat and the feedstock to generate pure hydrogen. The major drawback of SMR are CO_2 emissions of 9–11 tonnes of CO_2 per produced tonne of pure hydrogen (Molburg and Doctor, 2003). Carbon capture can significantly reduce emissions as CO_2 is separated from the exhaust stream and is either utilized (e.g., in enhanced oil recovery) or stored underground. Carbon capture, utilization and storage (CCUS) increases total costs of production significantly (Leung et al., 2014). The costs of hydrogen from natural gas is predominantly driven by variable costs: natural gas prices and carbon prices (Ball and Wietschel, 2009b).

Hydrogen can be produced cleanly through water electrolysis with electricity from renewable energy sources (RES) such as wind, solar photovoltaics (PV), hydro, or geothermal. Electrolysis splits water into molecular hydrogen and oxygen. Hydrogen electrolysis has mostly remained limited to pilot projects (Proost, 2019), with costs mostly driven by electricity

[3] While this includes immediate emissions from the production process itself, upstream emissions for manufacturing of equipment, buildings, or transportation is not included.

supply (Ball and Wietschel, 2009b) and thus in turn primarily the capital cost of RES. In the case of electrolyzers with own RES (in contrast to grid-connected systems), the cost of hydrogen production is almost entirely determined by the investment cost for RES, the investment cost of the electrolyzer, and the capacity factor of the integrated system (Brändle et al., 2021, Dincer and Acar, 2017). Variable costs such as water supply and labor costs are comparably low. As a result, hydrogen from RES is economically attractive at locations with beneficial conditions for renewable energy with high capacity factors. electrolyzer technologies are at the frontier of commercialization, and with expanding production capacities the costs are expected to decrease significantly (Proost, 2019) due to learning-curve effects.

Methane decomposition (also known as methane cracking or pyrolysis) is another viable avenue and is referred to as turquoise hydrogen. The technology is still undergoing development. More innovation is needed to lift the technology to full commercialization (Schneider et al., 2020). Methane decomposition has a clear advantage over blue hydrogen because solid carbon is produced instead of gaseous CO_2. 'Carbon black' is a valuable by-product and can be used in industrial applications. Similar to blue hydrogen, production costs are predominantly driven by fuel costs for natural gas. There are also numerous alternative production technologies for low-carbon hydrogen, which are not outlined here in detail; for further information we refer to the recent literature (IEA, 2019, Nikolaidis and Poullikkas, 2017, Ruth et al., 2020).

5.2.2. Hydrogen transportation and storage

The cost of hydrogen transportation will considerably shape its potential as a globally-traded energy commodity. Today's absence of long-distance hydrogen transportation causes uncertainty for technology choices and trade routes. The cost of transportation is a function of technology, distance, and volume (Yang and Ogden, 2007). While shipping hydrogen through repurposed natural gas pipelines appears as a promising and cost-effective solution for medium distances (IEA, 2019, Schönfisch, 2022), it requires existing pipeline networks with spare capacities. For long-distance hydrogen trade different forms of transportation are needed (IEA, 2019). Seaborne hydrogen transportation can evolve similar to today's global LNG trade. Suitable technologies include compression, liquefaction, conversion to ammonia, or chemically attaching hydrogen to liquid organic hydrogen carriers (LOHC) or metal hydrides (Faye et al., 2022, Teichmann et al., 2011).

Hydrogen storage will fulfill different purposes, e.g., flattening seasonal demand and supply patterns, short-term storage at export or import terminals, on-site storage at the place of consumption, or on-board storage in mobility applications (IEA, 2019). Similar to hydrogen transportation, different forms of hydrogen storage are being explored (Andersson and Grönkvist, 2019, Graetz, 2009, Hwang and Varma, 2014). Large-scale hydrogen storage in salt caverns has already been applied in some storage facilities in the US and the UK (Tarkowski, 2019) with more pilot projects being announced to explore and deploy underground storage (Bauer, 2017, Hychico, 2018, Hystock, 2022, IEA, 2021c).

5.2.3. The Demand for Hydrogen

Today hydrogen is used mostly as a feedstock in ammonia and fertilizer production, mineral oil refining, and in the chemical industry (IEA, 2019). Further applications of low-carbon hydrogen are anticipated in all sectors, though the gas is in competition with other options of carbon-mitigation, such as direct electrification or CCUS (Abdin et al., 2020). Future fields of applications are mostly those with limited capabilities for direct electrification due to technical or economic limitations. Examples include primary steel production, long-distance and heavy-duty transportation, aviation (either as pure hydrogen or as synthetic kerosene), maritime transportation, and long-term energy storage. Hydrogen can also be used as a close substitute for natural gas, and therefore can be consumed in a variety of applications including the provision of heat for industrial, commercial, and private consumers, as well as power generation. Because hydrogen is one of the prime options for storing intermittent renewable energy, hydrogen and ammonia can be used in gas turbines to improve power system flexibility, while ammonia can also be used in coal-fired power plants to reduce emissions.

5.3. Theoretical Foundations and Model Formulation

5.3.1. Emergence of Long-Term Contracts

Long-term contracts (LTCs) are a common feature of global energy markets. They are particularly prevalent in natural gas markets, although they are found in numerous other circumstances as well. The literature (Abada et al., 2014, Creti and Villeneuve, 2004, Hubbard and Weiner, 1986, Neuhoff and von Hirschhausen, 2006) points to several elements that are necessary or conducive to the formation of LTCs.

LTCs emerge when production facilities have large project size (due to indivisibilities or economies of scale) and high fixed costs relative to variable cost, which requires a predictable long-term income stream to amortize the fixed cost. High fixed costs are associated with long amortization periods. Variable costs for upstream resources are often also locked in through LTCs. Another key feature for the emergence of LTCs is a significant degree of uncertainty about the future path of prices, which could be driven by demand fluctuations as well as the potential of unexpected innovation that lowers the cost of competitors. The presence of specificity is also conducive for LTCs. Relationship-specific investments (RSIs) have great significance in international trade relationships (Nunn, 2007). Here, infrastructure that is specific to particular trade partnerships enhances the likelihood that such an investment is secured through LTCs. Another concern is stability on the purchaser's side, where reliability of intermediate goods supply mitigates uncertainty about the availability, quantity, and price of these goods. Lastly, LTCs manage and allocate risk that in other markets would be mitigated through hedging or insurance. LTCs can also act as a hedge when long-term insurance or futures markets remain immature.

5.3.2. Dynamic-Sequential Trade based on Long-Term Contracts

In the presence of LTCs, international trade emerges rather differently than in conventional trade models that are typically single-period allocation problems. With LTCs, demand and supply arrive sequentially and in each period there is a market-based process of matching buyers and sellers. There are thus distinct 'vintages' of LTCs, giving rise to different prices locked in at different periods. Importantly, LTCs can also give rise to two-way trade as comparative advantages shift and evolve. We examine the evolution of such a market in this section, assuming that LTCs dominate the hydrogen market during the early decades of scaling up of this technology. A parallel spot market will emerge as well, but we assert that our emphasis on LTCs is justified given the key characteristics of hydrogen infrastructure: large size, long amortization periods, high fixed costs, and low marginal costs (at least for green hydrogen).

We allow for exogenous sources that drive the sequencing of contracts. Each jurisdiction follows a path of environmental taxation $\sigma_{j,t}$ that shifts demand towards hydrogen and away from fossil fuels. We allow this path to differ by country. We also allow technological innovation at a rate ϕ to influence the supply of hydrogen, and for subsidies that promote domestic production over imports in a WTO-compatible manner. We also allow for global cost spillovers.

Sequential Demand

Exogenous demand in market j is composed of multiple linear segments that characterize particular industries. Let there be K such industries $k \in \{1, .., K\}$, each with a maximum demand $\bar{q}_{jk}$ and a willingness to pay between $[p^L_{jk}, p^H_{jk}]$. Total (or cumulative) demand in this economy is then given by

$$Q_j(p_j) = \sum_k \mathcal{U}\left(\frac{p^H_{jk} - p_j}{p^H_{jk} - p^L_{jk}}\right) \bar{q}_{jk} \tag{5.1}$$

where $\mathcal{U}(x) \equiv \max(0, \min(x, 1))$ is a truncation function that limits the range of its argument to $[0, 1]$. The expression in round parentheses in (5.1) is the share of demand that is seeking matching supplies when the price is p_j. In each period t, there is new demand emerging as $p_{j,t}$ changes from period to period so that each LTC locks in supply at price $p_{j,t}$, and thus cumulative demand evolves as

$$Q_{j,t} = Q_{j,t-1} + \sum_i x_{ij} = Q_{j,t-1} + q_{j,t} \tag{5.2}$$

with supplies x_{ij} arriving from (possibly more than one) producer-plant i, and $Q_{j,0} = 0$. If no new supplies are secured in a given period, $Q_{j,t}$ remains unchanged from the previous period. In practice, we only focus on q_j in each period and "retire" the satisfied demand portion in each country and industry.

We then recalculate the remaining demand in each period but lowering the p_{jk}^H to reflect demand that has been satisfied.[4]

We also allow p_{jk}^H and p_{jk}^L to increase along with a policy variable σ_{jkt} that reflects an implicit subsidy that we consider as being composed of a carbon price ω_{jt} and an industry-specific adjustment factor ξ_{jk}:

$$\sigma_{jkt} = \omega_{jt}\xi_{jk} \tag{5.3}$$

We discuss below how we see ω_{jt} evolve over time in each country. We call σ_{jkt} the hydrogen-equivalency carbon price, or simply the hydrogen subsidy.

In order to make this demand system tractable numerically, we also introduce the inverse demand function that relates quantity to price. Inverting (5.1) requires sorting the (at most) $2K+1$ prices $\{0, p_{j1}^L, p_{j1}^H, ..., p_{jK}^L, p_{jK}^H\}$ in ascending order so that a sequence $\{p_j^0, ..., p_j^{2K}\}$ emerges with $p_j^{l-1} < p_j^l$ for $l \in \{1, .., 2K\}$.[5] Using (5.1), there is a corresponding $q_j^l(p_j^l)$ for each segment point so that

$$p_j(Q_j) = p_j^l + (p_j^{l+1} - p_j^l)\frac{q_j^l - Q_j}{q_j^l - q_j^{l+1}} \quad \text{s.t.} \quad q_j^{l+1} \leq Q_j \leq q_j^l \tag{5.4}$$

Due to the hydrogen subsidy, the demand system evolves from one period to the next as the price tuple $\{p_{jk}^H, p_{jk}^L\}$. As previously mentioned, we keep track of satisfied demand in each period and subtract it for each country and industry. When price $p_{j,t}$ is realized in a period, we know that the corresponding demand segment $p_{jk}^H - p_{jt}$ is satisfied. This leaves us with still-unsatisfied demand for the current period. Thus there is a different demand curve for each country in each period.

When suppliers vie to ship hydrogen to destination j, the price that they will achieve is $p_{jt}(q_{jt})$. For notational convenience, we drop the time subscript when we discuss what happens in period t. The function $p_j(q_j)$ can of course be evaluated in reverse to yield $q_j(p_j)$ as well. Importantly, the marginal revenue function takes on a particularly simple form in the case of piecewise linear demand:

$$p_j'(q_j)q_j + p_j(q_j) = 2p_j - p_j^\circ \tag{5.5}$$

[4]This process looks like an inter-temporal form of first-degree Pigouvian price discrimination as demand emerges only gradually, and we are moving down step by step on the demand curve.

[5]There may be fewer than $2K+1$ unique price points if there are duplicates.

where p_j° is the maximum price at which demand is zero.

Supply and Trade Costs

Supply comes in discrete projects i, which we consider as separate locations. Each new plant has a new fixed cost f_i, expressed as capex per unit of production. Shipping goods to location j incurs a trade cost τ_{ij} that does not change over time. A project that comes to life in period t has fixed cost that can be composed of one or more technological components, each of which can be subject to endogenous and exogenous technological progress

$$f_{i,t} = \sum_k \frac{f_{ik}^\circ}{(1+\phi_1^k)^t (1+X_t/X^\circ)^{\phi_2^k}} + g_{h,t} \tag{5.6}$$

where f_{ik}° identifies the location-specific comparative advantage for (annuitized) cost component k. For green hydrogen, the two components are electrolyzers and renewable energy. For blue and turquoise hydrogen, we assume only a single technology. We assume that there is an efficient size for each project $\bar{x}_i$, determined exogenously. Firm i will enter into contracts with markets j and supply x_{ij}. Let s denote the time period the project is implemented, thus fixating $f_{i,s}$ when the firm enters.

We also add a cost factor $g_{h,t}$ that captures the global cost of constructing new plants. There is a globally limited supply of equipment and workers to build new plants, and thus there is increasing cost to building more plants in the same time period t. For each hydrogen class $h \in \{\mathrm{green}, \mathrm{blue}, \mathrm{turquoise}\}$ we calculate the capacity $x_{h,t}^\Delta$ of plants (the sum of their capacities $\bar{x}_i$) proposing to be built and calculate the two-parameter function

$$g_{h,t} = (x_{h,t}^\Delta)^{\xi_1}/\xi_2 \tag{5.7}$$

with $\xi_1 \geq 2$ and $\xi_2 \gg 0$. The existence of global capacity costs limits the number of plants that can be realized in each period. It is a natural limit to entry—a global throttle that requires firms to queue up for entry.[6]

We allow for two sources of technological progress in (5.6). Parameter $\phi_1^k > 0$ captures exogenous technological progress. For endogenous progress,

[6] Practically, it also prevents the entry set from becoming excessively large so that too many firms enter at the same time during the initial periods when there is an overhang of excess demand.

we let $X_t \equiv \sum_i \delta_{i,t}\bar{x}_i$ denote the cumulative installed capacity of a particular type of hydrogen production (green, blue, turquoise) at time t, where $\delta_{i,t} \in \{0,1\}$ is an indicator variable that reveals if plant i is active or not in period t. Cumulative installed capacity reflects learning-by-doing and other dynamic scale economies, including agglomeration benefits from shared infrastructure. We assume that technological diffusion is global in nature, but acknowledge that some of the dynamic scale economies may potentially be location-specific (e.g., import and export terminals, distribution networks). We assume that the endogenous technological learning parameters is positive $\phi_2^k > 0$.[7] The parameter X° is the 'knowledge base' so that in period zero the denominator in (5.6) equals one. The parameters can vary for different technologies and are explained in detail in our simulation set-up.

When will a new project of size $\bar{x}_i$ emerge in period t? It requires that project i finds customers to buy all of its output and enter into a long-term contract so that the project is profitable. Firm i's profits are

$$\pi_i = \sum_j (\bar{p}_{ij} - c_i - \tau_{i,j})x_{i,j} - f_{i,t}\bar{x}_i \overset{!}{>} 0 \quad \text{s.t.} \quad \sum_j x_{ij} \leq \bar{x}_i \tag{5.8}$$

and $\bar{p}_{ij}$ is fixed at contracting time t so that $\bar{p}_{ij} = p_{j,t}$. Thus the objective is to maximize the Lagrangean $\mathcal{L}_i = \pi_i + \lambda_i(\bar{x}_i - \sum_i x_{ij})$ by finding the optimal x_{ij} and λ_i. We have dropped the time subscript here for notational expediency.

If in a given period there is only one producer ready to launch a plant, the maximization problem essentially amounts to finding the most profitable destination(s) with which to contract. In our model (5.8) we allow for incomplete capacity utilization, and only require that a project is marginally profitable. Some projects may end up with slack capacity, although in practice we find that this is rare. Virtually all of the entries we observe empirically are all-or-nothing entries. The profit maximization problem (5.8) has M decision variables, a capacity constraint, and a positive-profitability constraint.

Our model allows for bilateral shipment costs $\tau_{ij} > 0$ between producer i and market j. We also allow for the possibility that some but not all hydrogen production technologies have marginal costs $c_i \geq 0$. Blue and turquoise hydrogen tends to have upstream cost for natural gas extraction, whereas green hydrogen has mostly fixed cost.

[7] Swanson's law for photovoltaics implies a $\phi_2 \approx 0.4$.

Each producer will want to ship an unconstrained quantity $\tilde{x}_{ij}$ as determined by the first-order condition (FOC) for a profit maximum, $p'_j(q_j)x_{ij} + p_j(q_j) = c_i + \tau_{ij} + \lambda_i \equiv b_{ij}$. If the capacity constraint is binding, then a shadow price $\lambda_i > 0$ expresses the implicit cost of this constraint to the business. The extensive margins are crucially important in our model. Therefore, let $\delta_{ij} \in \{0, 1\}$ denote whether firm i is active in market j or not:

$$\delta_{ij} = 1\left(p_j > b_{ij}\right) \cdot 1\left(\pi_i > 0\right) \tag{5.9}$$

To be active in the market, each export market must be profitable at the margin, and the firm must be profitable overall. Summing up a market's suppliers yields

$$p'_j(q_j)q_j + n_j p_j = \sum_i \delta_{ij}(c_i + \tau_{ij} + \lambda_i) \equiv B_j \tag{5.10}$$

where $n_j \equiv \sum_i \delta_i$ is the number of firms supplying market j and $q_j = \sum_i x_{ij}$. Together with the relationship for marginal revenue (5.5) we find from the FOC that the price in market j follows as

$$p_j = \frac{p_j^\circ + B_j}{1 + n_j} \tag{5.11}$$

and shipments are

$$x_{ij} = \left[\frac{p_j - b_{ij}}{p_j^\circ - p_j}\right] q_j(p_j) \tag{5.12}$$

The Lagrange multiplier $\lambda_i \geq 0$ is derived by adding up over all markets j served by firm i and solving for λ_i:

$$\lambda_i = \frac{\tilde{x}_i - \bar{x}_i}{w_i} \tag{5.13}$$

where

$$\tilde{x}_i \equiv \sum_j \frac{\delta_{ij} q_j}{p_j^\circ - p_j} \left[p_j - c_i - \tau_{ij}\right] \quad \text{and} \quad w_i \equiv \sum_j \frac{\delta_{ij} q_j}{p_j^\circ - p_j} \tag{5.14}$$

The numerator in (5.13) can be thought of as the difference between unconstrained and constrained output. Increasing the shadow price λ_i throttles potential output until the firm stays within its capacity limit. The side effect is that as λ_i increases, it turns off some markets so that some δ_{ij} become zero. Eventually, a firm may operate with LTCs only in the one or two most profitable markets.

Our model with N producers and M markets has rather complex extensive margins. In fact, it is all about extensive margins. The reader may find it helpful to work through a simple version of this model with only two producers and two producers that offers closed-form solutions. Our Appendix D.1 offers a quick tutorial on how our model works out in this simplified form.

Equilibrium

In each period we have one or more potential suppliers facing growing demand from M markets. Each market presents a demand curve $q_{j,t}(p_{j,t})$, and each supplier offers x_{ij}. Which equilibrium will emerge in period t? Our model finds that the set of *concurrent* entrants in each period tends to be relatively small. With multiple entrants a Cournot-Nash equilibrium emerges that determines prices $p_{j,t}$ in each market and shipments in equation (5.12). Unlike conventional Cournot models, our model has one distinct feature: the spillovers across markets from the capacity constraint, where the shadow price λ_i of the capacity constraint takes on a role similar to that of variable cost.

We can find the emerging equilibrium by solving numerically for the M prices p_j and the $N_t^{\mathcal{E}}$ capacity-constraint shadow prices λ_i, for any producer i that is part of the proposed entrant set $\mathcal{E}_t$. Numerically, we solve $M + N_t^{\mathcal{E}}$ non-linear equations in $M + N_t^{\mathcal{E}}$ unknowns using a multi-dimensional unit root finder. Starting values are zero for the shadow price, and 98% of last period's prices. Procedurally, we compute B_j and new p_j via (5.10) and (5.11), as well as new λ_i through (5.13). This process continues until the solution is found, at which point we calculate x_{ij} via (5.12). A feasible equilibrium is one in which all entrants in the set $\mathcal{E}_t$ make positive profits, and consequently an infeasible equilibrium is one in which at least one of the entrants makes losses.

A major challenge lies in finding the suitable set of candidates $\mathcal{E}_t$. As is common in the firm-entry literature in industrial organization, there is the possibility of multiple equilibria. Even if we evaluated all feasible $2^{||\mathcal{E}_t||}$ combinations, which is computationally infeasible, we would still need to pick a particular solution. We tackle this challenging problem through two mechanisms. First, we choose a heuristic to pick a solution that we believe is plausible. We rank firms by their profit based on entering the market alone, and then enter one firm at a time to find the largest entry set where all entrants are still profitable. This heuristic favors projects that are larger and more profitable. The existence of global costs in equation (5.7) ensures that the entrant set cannot become arbitrarily large. As more firms attempt to enter simultaneously, global construction costs increase. Second, we base our results on repetitions of the equilibrium so that randomization reflects the stochastic nature of the entrant set. It is important to understand that our method of choosing the entrant set does not have much influence on the overall results due to the randomization of repetitions. The only bias that remains is with respect to the initial profitability of projects, a bias that can be justified by the implicit reduction in investor risk while also acknowledging potential economies of scale.

The Nature of Trade Costs

For merchandise trade, the bilateral trade cost τ_{ij} between supplier and market often entail tariffs and non-tariff barriers. Tariffs are virtually absent in global energy markets. However, the size of investments often entails political calculations. Large infrastructure carries dependency risk, and some countries may put a risk premium on undesirable dependencies. Thus some countries may prefer domestic production and consumption by directing subsidies in this direction, effectively diminishing opportunities from international trade.

In the scenarios we introduce a hybrid approach. As is common, we allow for trade costs so that τ_{ij} is a function of distance and transportation mode. We allow for countries to subsidize linking domestic production and consumption, which amounts to reducing the internal trade cost τ_{ii}. Denoting this subsidy $h_i \geq 0$, the effective internal transportation cost will thus become $\tau_{ii} - h_i$. If h_i is large enough, the effective trade cost can even turn negative. This is the most direct way to model a home-centric hydrogen policy. Subsidizing domestic consumption instead would also induce imports, while subsidizing domestic production would also induce exports. The home-centric policy is best captured by effectively reducing internal trade costs per unit of domestic shipments.

5.3.3. The long term: from LTCs to Spot Markets

The model laid out above characterizes sequential trade rather than parallel trade, as LTCs enter into force one by one and competition is limited to concurrent proposals. However, plants often outlive their amortization horizon, which may have been chosen cautiously. Eventually, plants may become "free agents" and will tend to prefer participating in spot markets with higher prices than they may achieve through LTCs. However, if there is again significant innovation risk, firms may prefer to ensure their long-term viability through renewing existing LTCs.

As technology matures, we may also see the deployment of smaller plants, which has two effects. First, smaller plants make production more divisible, allowing firms to hedge efforts internally and allow some projects to fail, or be mothballed, if and when market conditions change. Second, smaller plants also change the bargaining power between buyers and sellers, giving greater bargaining power to buyers. Thus LTCs become less attractive when sellers are strategically disadvantaged. These conditions are all conducive for the share of the spot market to grow. Whether LTCs remain the dominant mode of market arrangement depends very much on how technology changes the key conditions that underpin LTCs: high fixed costs, price uncertainty, and indivisibilities.

5.4. Data Preview and Calibration

As we are exploring future states of international trade, a significant part of our analysis is concerned with calibrating model parameters. In the absence of a global hydrogen market and its accompanying empirical data today, we need to develop our own data to research the nature of future trade in hydrogen. This section discusses the major assumptions that have gone into our empirical model.

5.4.1. Supply

We consider three pathways for low-carbon hydrogen production. First, blue hydrogen. Natural gas is converted to hydrogen with emitted CO_2 being sequestered and stored underground (CCS). The predominant cost parameters of this process are the capex and opex of the reforming plant and of the CCS facility as well as costs for natural gas. Second, turquoise hydrogen. Natural gas is converted to hydrogen using methane decomposition. The essential costs are determined by the capex of the plant and the cost of the feedstock. The process requires a large amount of heat, which can either be supplied by the feedstock, or through (clean) electricity. And third, green hydrogen involving electrolysis with electricity from RES. The costs for electrolytic hydrogen consist of the capex and opex of the renewable energy technology (typically wind or solar), and the capex of the electrolyzer. Other variable cost are negligible.[8] Other hydrogen production technologies are not considered in the empirical analysis. In the absence of a global hydrogen market and its accompanying empirical data today, we need to develop our own data to research the nature of future trade in hydrogen. We split the total costs of a facility into fixed costs $f_{i,t}$ and variable costs $c_{i,t}$, which vary temporally and spatially.

There are different driving factors for the cost of green, blue, and turquoise hydrogen. In our model, costs for green hydrogen occur as fixed costs, which are determined by capex of the RES and the electrolyzer, and the utilization factor of the system.[9] Blue hydrogen comprises a variable and a fixed cost component. We consider capex for the SMR plant with carbon capture, variable cost for natural gas, and cost for CO_2 transport and storage. For turquoise hydrogen, we include the capex of the methane decomposition plant and the variable cost for natural gas as feedstock. We assume that produced hydrogen is used to produce the required heat for the process, instead of using unabated natural gas or other sources of heat. While the produced carbon black has a commercial value, we do not include a price for carbon black because of two reasons. First, it is uncertain in which direction the market for carbon black will develop and whether there will be sufficient demand to support a positive price. Second, the yield of carbon black per produced kilogram of hydrogen is comparably high (3 kg of carbon black per produced kilogram of hydrogen). In a scenario where turquoise hydrogen is deployed on

[8]We do not consider outside options such as selling of electricity at wholesale market prices as an alternative option for RE generators.

[9]Here we assume electrolyzers being connected to renewable energy generators only, instead of withdrawing electricity from the grid. In the latter case, electricity costs would occur as variable costs. Other variable costs such as water supply are negligibly small.

a large scale, the carbon black market would be oversupplied very quickly, leading to a drop in prices.[10]

Electrolyzers for green hydrogen are assumed to draw all their power from dedicated RE generators. Costs for green hydrogen are predominantly driven by capex for the RE generator and the electrolyzer. For blue and turquoise hydrogen, the capital costs for the RES become zero since energy is sourced from natural gas and occur as variable costs. The annual fixed costs for hydrogen are calculated using the following equation:

$$f_{i,t} = \frac{\mathrm{lhv}}{\eta} \left[\frac{F_t^{\mathrm{RE}}(\mathrm{a}+\mathrm{o})}{8760 \cdot u_i} \cdot v + \frac{F_t^{\mathrm{H2}}(\mathrm{a}+\mathrm{o})}{8760 \cdot u_i} \right] \tag{5.15}$$

Fixed cost F_t is a technology specific parameter, which is annualized using a capital recovery factor (a). Periodical fixed operative and maintenance costs (o) are added as a percentage share of the fixed cost. The capex of RE generator (F_t^{RE}), electrolyzer, SMR, or methane decomposition (MD) plant (F_t^{H2}) change over time due to technological progress and learning; see equation (5.6).[11] The utilization rate u_i of the RE generator varies spatially and therefore represents the comparative advantage of different locations. The utilization rate of the electrolyzer can be increased by choosing a higher capacity ratio v of electrolyzer and RE generator. With an increasing capacity ratio, the fixed costs of the RE generator will rise, while the cost per unit of hydrogen decreases with higher output. The total effect varies with the parameter choice and reveals a trade-off when sizing RE generators and electrolyzers. In most cases it will be more cost efficient to choose a value for v greater than one, which means that the installed capacity of the RE generator is larger than the electrolyzer. This means that in some hours there is excessive electricity generation, if the electrolyzer is operating at full capacity, but generally oversizing will lead to a better utilization rate of the electrolyzer. The optimal choice of the capacity ratio changes with technological progress of renewable energies and electrolyzers. For blue and turquoise hydrogen, the utilization

[10] According to IEA (2021a), 16 Mt of carbon black were consumed in 2020, which equals around 5 Mt of hydrogen from methane decomposition.

[11] We do not assume technological progress for SMR with CCS, since we see costs for CCS being influenced by two effects pushing in opposite directions: process-relevant cost for CCS might decrease over time due to technological progress, while site specific CCS cost tend to increase with the locations with lowest cost being developed first and increasing the costs for further projects. To avoid influencing our results in one direction, we keep costs for SMR and CCS constant over time.

rate is fixed at a value of 0.95 for all locations. The constant parameters for efficiency η and the lower heating value (lhv) scale the value to USD per kilogram of hydrogen. An overview of our assumptions for fixed costs is given in Table 5.1. In our simulations, heterogeneity for locations within a country and within the same technology class is introduced by drawing u_i from a Beta distribution with mean $\bar{u}$ and a coefficient of variation ρ_u; see Appendix D.2 for details.

Table 5.1.: Assumptions about Supply-Side Parameters

Parameter	Unit	Value
$F_0^{\text{Wind Onshore}}$	USD/kW$_{\text{el}}$	977–1630 (country-specific)
$F_0^{\text{Wind Offshore}}$	USD/kW$_{\text{el}}$	2238–2960 (country-specific)
F_0^{PV}	USD/kW$_{\text{el}}$	524–855 (country-specific)
F_0^{EL}	USD/kW$_{\text{el}}$	950
F_0^{SMR}	USD/kW$_{\text{H2}}$	1470
F_0^{MD}	USD/kW$_{\text{H2}}$	950
o^{RE}	% of capex	0.02
o^{EL}	% of capex	0.02
o^{SMR}	% of capex	0.03
v_i	-	location-specific
$\bar{u}_i$	-	location-specific
η^{EL}	kWh$_{\text{H2}}$/kWh$_{\text{el}}$	0.67
η^{SMR}	kWh$_{\text{H2}}$/kWh$_{\text{el}}$	0.69
lhv	kWh$_{\text{H2}}$/kg$_{\text{H2}}$	33.3
r	-	0.07

Note: derived from Brändle et al. (2021), IEA (2021a), Lazard (2021a,b), own assumptions

Blue and turquoise hydrogen have variable costs. Both have a cost of natural gas supply, and blue hydrogen also has a cost for transportation and storage of CO_2. Producing hydrogen from natural gas constitutes a link between natural gas and hydrogen markets. We simplify this connection by allowing hydrogen production only with slack natural gas production capacities. We also assume that natural gas is obtained at production cost rather than purchased at market prices. For each country we determine slack gas production capacities based on data from IEA (2021e) and Rystad Energy (2022). Natural gas production costs typically increase over the available capacity. We can approximate the variable cost structure using a Pareto distribution, which is commonly used in the international trade literature to capture productivity effects, and which fits our reference data very well for most of the countries. Specifically, we observe the lower bound of variable costs $\underline{c}_j$ for country j, and then proceed to estimate the Pareto parameter α_i by splitting our capacity range Z_i into K bins of equal size and observing corresponding variable cost $c_{j,k}$. Then our estimate of α_j is given by

$$\hat{\alpha}_j = \frac{K}{\sum_{k=1}^{K} \ln(c_{j,k}/\underline{c}_j)} \tag{5.16}$$

Armed with parameters $\{\underline{c}_j, \alpha_j\}$ for each country, we can draw random variable costs for each plant from this Pareto distribution. For two countries we do not observe gradually increasing marginal costs, but instead we see a step function for two major gas fields. In this case we draw variable costs from either level at a probability proportional to the size of the gas fields.

Variable costs for CO_2 transportation and storage strongly depend on the specific conditions of each location and project parameters such as plant sizes, distance between plant and storage site, or the volume of CO_2 to be stored. We simplify this complexity by using country-specific variable costs for CCS based on Brändle et al. (2021) and Hendriks et al. (2004).

Each country has production potential for hydrogen from RES and natural gas. For the latter, we set the capacity limit at the slack capacity of natural gas production. This implies that countries with no or full utilization of their domestic natural gas production have zero capacity to produce blue or turquoise hydrogen. For green hydrogen, production potentials are based on RE capacity potentials from Brändle et al. (2021). The comparative advantage of renewable energy potentials are reflected in the country-specific utilization u_i, i.e. full load hours, per renewable energy resource (solar PV, wind offshore, and wind onshore). The utilization rates and the production potentials are based on Brändle et al. (2021), which uses primary data on global assessments for renewable energy potentials and full load hours from Bosch et al. (2017, 2019), Pietzcker et al. (2014).

Project size can be subject to economies of scale as well as technical limitations. Today only few Megawatt-scale electrolyzers are in operation, with many new proposed projects in the Megawatt to Gigawatt range (IEA, 2021b).[12] We assume an efficient project size of 500,000 metric tonnes of

[12]Economies of scale in hydrogen supply can have multiple reasons along the supply chain, starting with the primary energy supply (natural gas or renewable energy sources), over hydrogen production (electrolyzers or SMR+CCS), and ending with conversion facilities and transportation infrastructure (pipelines, ammonia synthesis plants, ships, and reconversion facilities). New projects need to optimally choose all sizing parameters along the value chain to benefit from economies of scale and achieve the highest profitability. In practice the project size is thus dependent on multiple local conditions.

hydrogen per year as the base case. This value should take into account cost advantages due to economies of scale for transporting gaseous hydrogen through pipelines or for converting hydrogen to ammonia. For the latter, IRENA (2022a) assumes an efficient project size for ammonia exporting projects in the range of 0.5–1.5 MMt per year. For transporting gaseous hydrogen, our assumed project size of 0.5 MMt equals a pipeline with an annual transportation capacity of around 2.5 GW[13], which corresponds to a medium pipeline (van Rossum et al., 2022).

Green hydrogen production can be scaled by stacking up multiple electrolyzers, and thus economies of scale are likely weak. However, there are significant economies of scale for hydrogen conversion to ammonia and transportation. It seems very unlikely that each single hydrogen producer will invest in an exporting infrastructure, and instead producers will access joint infrastructure for the conversion to ammonia, which in turn will be shipped to the destination with large-scale tankers. We acknowledge the uncertainty from this assumption by calculating sensitivities on the project size and evaluating the impact on the results.

5.4.2. Demand

We derive simplified demand functions from empirical data on energy consumption and assumptions on commodity prices. While our demand estimates do not represent forecasts of future demand for hydrogen, they ought to cover the underlying structure of demand in different countries. We are focusing on seven types of consumers across all sectors: (i) primary steel production, (ii) mineral oil refining, (iii) ammonia production, (iv) private passenger vehicles (PPV), (v) heavy duty vehicles (HDV), (vi) aviation, and (vii) hydrogen as a substitute for natural gas. For each type of consumer we estimate average break-even prices for low-carbon hydrogen and maximum hydrogen demand quantities if the entire energy consumption would switch to low-carbon hydrogen. Assumed commodity prices for different regions in the base case are listed in Table 5.2. We introduce heterogeneity in demand by allowing demand to vary between and upper and lower price point defined by scaling our break-even price up and down by 10% relative to the baseline case.

[13] Assuming an annual utilization rate of 75%.

In 2021 more than 1,952 Mt of steel were produced globally causing substantial CO_2 emissions (World Steel Association, 2022). The majority of steel is produced using blast furnace and coke oven technology, which emits approximately 1.7 tonnes of CO_2 per produced tonne of steel (Chevrier, 2018, Pinegar et al., 2011). While a share of future demand for steel will be produced by increasing the rate of recycling (secondary steel production), conventional primary steel production will either require CCUS to prevent emissions to escape into the atmosphere or a shift toward an alternative production route using hydrogen or natural gas as reduction agent (direct reduced iron, DRI). The latter can either be supplied by a mixture of hydrogen and methane or by pure hydrogen (Chevrier, 2018). For using hydrogen in steel production, we assume a specific hydrogen demand of 57.5 kg_{H2} per tonne of steel in the DRI process (IEA, 2019). Associated CO_2 emissions can be reduced to 0.03 tonnes of CO_2 per produced tonne of steel (Hölling et al., 2017). Steel production quantities are retrieved from the world steel association assuming that basic oxygen furnaces (BOF) are converted to the DRI production route (World Steel Association, 2021, 2022). To become cost competitive with the mixed gases process route, hydrogen must compete with the price for natural gas at the higher heating value (Elgowainy et al., 2020). The carbon credit for abated emissions is added using the specific emission factors and the carbon price of each respective jurisdiction.

In mineral oil refining hydrogen is used for hydrotreating and hydrocracking (Elgowainy et al., 2020). While a share of the required hydrogen is produced within the refining process as a by-product, dedicated hydrogen production fills the gap between by-product and total hydrogen demand for mineral oil refining. Dedicated hydrogen production is mostly supplied from natural gas reforming (IEA, 2019). We assume a specific hydrogen demand of 4.8 kg_{H2} per processed tonne of crude oil (European Commission and Joint Research Centre and Dolci, F, 2018, IEA, 2019). Since hydrogen from fossil fuels is already used today, the break-even price for low-carbon hydrogen is essentially determined by the cost of conventional hydrogen from natural gas.[14] Prices for natural gas and CO_2 emissions are a key driver for the variable costs of conventional hydrogen and are considered accordingly. Data on processed crude oil in refineries is used from IEA (2021e) for the year 2019.

[14] Assumptions for conventional hydrogen: USD 910 kW_{H2}^{-1} capex, 5 % share of capex annual fixed operative costs, 76 % efficiency, 25 years lifetime, 8.9 kg_{CO2}/kg_{H2} emission factor.

Hydrogen is as an essential feedstock for producing ammonia, which in turn is used to produce fertilizer, explosives, plastics, and other chemicals (IEA, 2019). Hydrogen demand for ammonia production is mostly supplied by natural gas reforming. Approximately 8.9 kg_{CO2} are emitted per kilogram of hydrogen and 0.176 kg_{H2} are required per produced kilogram of ammonia. Substituting grey with low-carbon hydrogen leads to immediate emission reductions without modifications of the ammonia synthesis plant. The break-even price of low-carbon hydrogen is determined analogously to mineral oil refining, since SMR is the dominant technology to supply ammonia facilities with hydrogen today. Global ammonia production in 2021 was around 182 MMt (USGS, 2022). For country-level data we use production data for the time period 2018 to 2021 (USGS, 2018, 2022).

Passenger and freight transportation consume substantial amounts of refined products every year. While battery technology will likely dominate the decarbonization of personal passenger (light-duty) vehicles (PPV), hydrogen offers a promising solution for replacing fossil fuels for trucks and heavy-duty vehicles (HDV), aviation, freight rail, and maritime transportation. Hydrogen may also replace internal combustion engines in part of the PPV market. For PPVs, HDVs, and aviation we estimate the break-even price for hydrogen based on crude oil prices and refining costs. For simplification, we assume that PPVs consume gasoline only, with 0.14 kg_{H2} replacing one liter of gasoline (Helgeson and Peter, 2020). HDVs are assumed to be dominated by diesel fuel with a factor of 0.18 kg_{H2} per liter (Helgeson and Peter, 2020). In aviation, research is still at an early stage to replace conventional kerosene. The size and weight of batteries are considered as a major hurdle for direct electrification. Alternatives are direct use of liquid or gaseous hydrogen, or converting hydrogen with captured CO_2 into synthetic kerosene. While increasing the fuel costs, the latter benefits from lower system integration costs and can be used with the existing infrastructure and turbines. We assume a hydrogen demand of 0.4 kg_{H2} per liter of synthetic kerosene (Engie, 2021, Fasihi et al., 2016). Costs of hydrogen to kerosene conversion are estimated at USD 0.75 per liter including the costs of CO_2 capture (Fasihi et al., 2016, Siegemund et al., 2017). Demand for gasoline, diesel, and kerosene were obtained from IEA (2021e) for the year 2019. We assume a penetration rate of hydrogen in transportation of 18% for PPV, 22% for HDV (Elgowainy et al., 2020), and 30% as hydrogen-based fuels in aviation (IEA, 2021d).

As a gaseous energy carrier with similar physical properties, hydrogen is a close substitute to natural gas. While a full conversion of today's natural gas consumers to hydrogen appears to be rather challenging for economic reasons (end use appliances, transportation, and distribution infrastructure must be modified or replaced), natural gas could be mixed with hydrogen to lower its emissions (Schlund and Schönfisch, 2021). At the consumer level, hydrogen needs to compete with natural gas while avoiding costs for carbon emissions. We derive a break-even price using natural gas prices and the carbon price as alternative technology. We do not further distinguish between natural gas consumers and assume that all customers are able to switch from natural gas to hydrogen. Total natural gas demand is based on IEA (2021e).

Commodity prices are volatile over time as the recent energy crisis and price spike during 2021/22 have demonstrated. We include the uncertainty of commodity prices in our analysis by varying the fuel prices in two scenarios. Table 5.2 summarizes our assumptions about the price of natural gas and crude oil, as well as the refinery margins for gasoline and diesel, across different regions. Our commodity prices are meant to represent a 'floor' in order to err on the side of caution in determining hydrogen demand.

Table 5.2.: Commodity prices and refinery spreads in the base case (own assumptions)

Region	Unit Price		Refining margin	
	natural gas	crude oil	diesel	gasoline
	USD/MMBtU	USD/bbl	USD/bbl	USD/bbl
Europe	10	50	28	21
North America	5	40	28	21
South and Central America	6	45	28	21
MENA	4	20	28	21
China	7	25	28	21
Oceania	6	45	28	21
Rest of Asia	10	30	28	21

In order to visualize our assumptions and modeling of hydrogen demand, Figure 5.1 stacks together the demand originating in different countries and industries. There is significant demand up to about 100 MT of hydrogen in the price range between \$1.5/kg and \$3.5/kg. The demand curve flattens considerably after reaching this point.

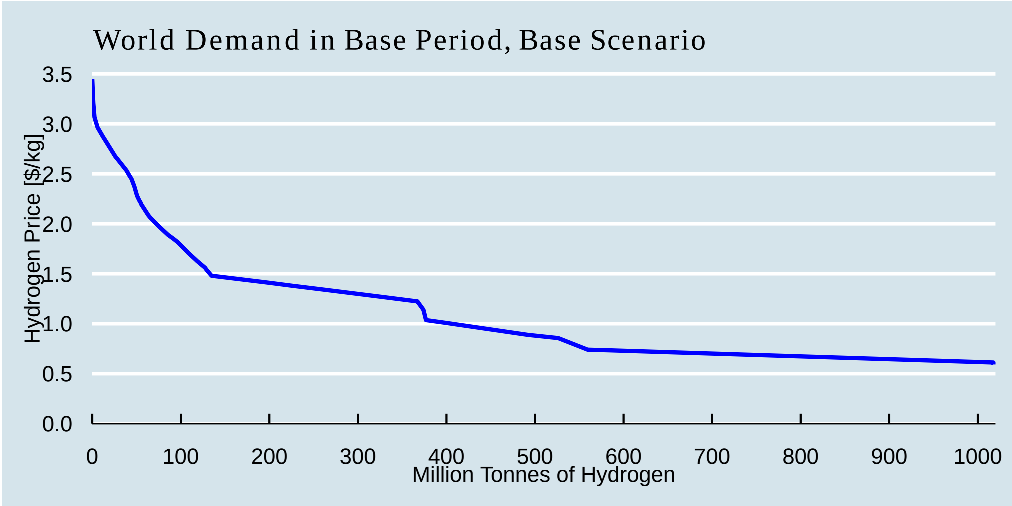
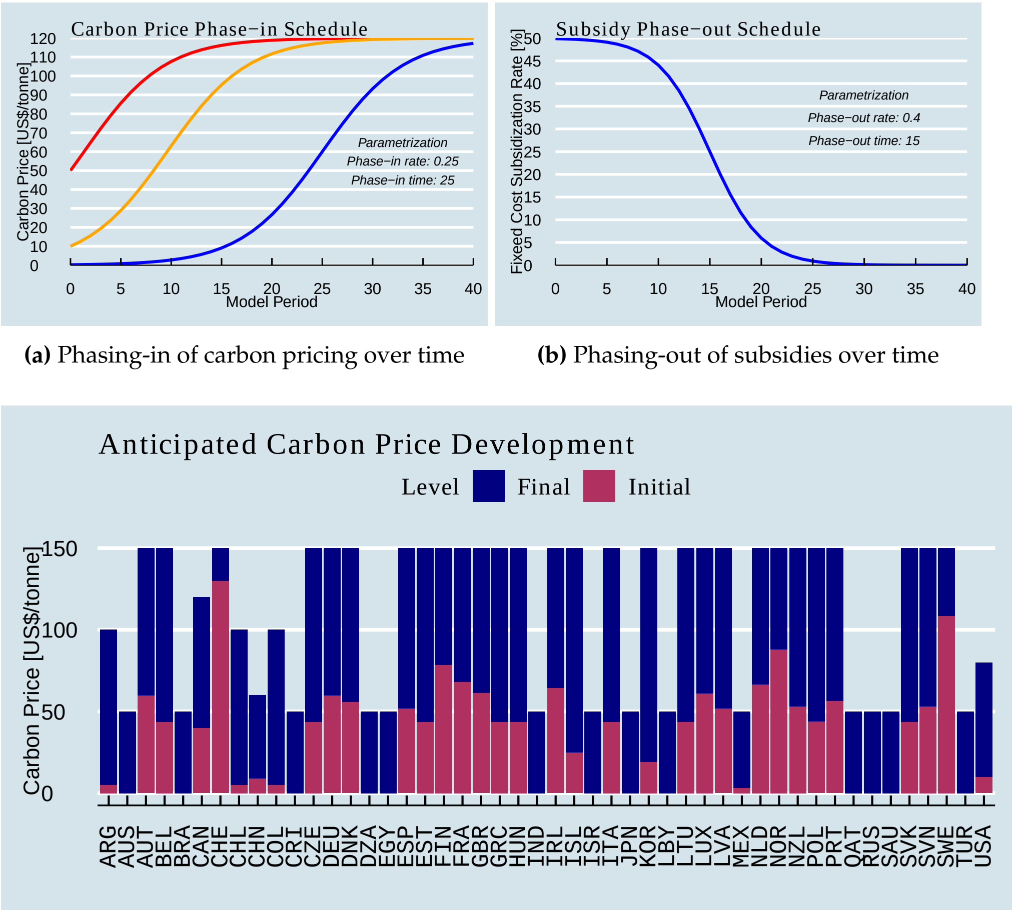


Figure 5.1.: Initial World Demand for Hydrogen

5.4.3. Policies

For our simulations we rely on information about national hydrogen policies, especially on subsidies and on the type of hydrogen being supported. Few governments have published concrete subsidy schemes so far. To quantify the extent of public support for hydrogen, we have scanned the national hydrogen strategies for information about policies and priorities to support hydrogen supply. Each country was given a rating for green and blue hydrogen support policies. The ratings range between 0.5 (substantial support for hydrogen production, equivalent to a subsidy rate), to zero, which implies that either no information was available on hydrogen policies or that the government does not plan to grant financial support for the production of hydrogen. The specific instrument applied by each national government—e.g., tax subsidies, feed-in tariffs, contracts for difference—is not further evaluated. For simplification, all subsidies will take the form of a discount on fixed costs. We phase out subsidies over time along a logistic curve as visualized in Figure 5.2b, with a half-life of 15 years.

We also consider carbon policies, utilizing information compiled by The World Bank (2022) about which countries have carbon prices in place. For countries with different carbon policies on a sub-national level, we use our own assumptions on the carbon price level. Different carbon price projections for the year 2050 were reviewed to set an upper bound for future carbon



(a) Phasing-in of carbon pricing over time

(b) Phasing-out of subsidies over time

(c) Initial and final levels of carbon prices by country

Figure 5.2.: Carbon Pricing and Hydrogen Subsidies

prices. We use a long-term carbon price ceiling of \$150/tonne.[15] For some of the large countries that rely heavily on fossil fuels today or have shown mixed attitude towards carbon pricing (Australia, China, United States), we assume lower final carbon prices than for the carbon pricing leaders; see Figure 5.2c. Our alternative scenarios consider weaker carbon policies, including holding current carbon prices constant. Carbon prices are phased-in over time along a logistic curve described in Figure 5.2a. Carbon prices that start at zero ramp up relatively slowly, while countries with significant initial carbon prices (e.g., many European countries, and Canada) would reach their carbon prices target by 2030-2035.

[15]Own estimation based on Bhat (2021), IEA (2021d), IETA (2022).

It is also useful to identify how carbon prices translate into quasi-subsidies for hydrogen. Table 5.3 shows the implicit hydrogen subsidies for different industries for four levels of carbon prices. Different industries have different emission intensities, which would be displaced by clean hydrogen. We have calculated an equivalency factor expressed in kilograms of carbon dioxide per kilogram of hydrogen. For a carbon price of $50/tonne, we see implicit hydrogen subsidies that range between $0.52 and $1.45 per kilogram. These are significant magnitudes, and thus the path and ultimate level of carbon pricing have a significant impact on the development of the global hydrogen market.

Table 5.3.: Hydrogen-Equivalent of Carbon Prices

Industry	Emission Intensity [kg-CO_2/H_2]	Carbon Price [$/tonne] 20	50	80	150
		Hydrogen Price [$/kg]			
Ammonia	8.90	0.18	0.45	0.71	1.33
Natural Gas Substitution	7.92	0.16	0.40	0.63	1.19
Oil Refining	8.90	0.18	0.45	0.71	1.33
Steel, direct-reduced iron	29.04	0.58	1.45	2.32	4.36
Aviation	6.54	0.13	0.33	0.52	0.98
Heavy Duty Vehicles	15.26	0.31	0.76	1.22	2.29
Light Duty Vehicles	15.03	0.30	0.75	1.20	2.25

5.4.4. Transportation

The main driver of trade costs is the transportation between markets and within each market. We consider two modes of transportation: (i) transportation of compressed hydrogen in pipelines, and (ii) conversion and shipping of hydrogen as liquefied ammonia. The latter is considered to have the lowest cost at long distances (IEA, 2021a).

For hydrogen transportation via pipeline either new hydrogen pipelines can be built or existing natural gas grids can be repurposed and retrofitted. Several studies expect the costs of repurposed pipelines to be significantly below the costs of a new hydrogen grid (Cerniauskas et al., 2020, IEA, 2021a, IRENA, 2022b). The prerequisite is an existing natural gas infrastructure with decreasing utilization over time. We assume that hydrogen trade via pipelines is only possible between countries with existing cross-border pipeline infrastructure. We assume variable cost for pipeline transportation of hydrogen of USD 0.5 per 1,000 km and per kilogram of hydrogen (Brändle et al., 2021, IEA, 2021a).

Converting hydrogen to ammonia requires additional facilities: a conversion and liquefaction terminal at the origin (ammonia is transported in tankers at –33°C), a regasification/reconversion terminal at the destination, storage facilities at both export and import terminals, tankers for moving the liquefied ammonia, and port infrastructure. The additional costs for these facilities depend on various location-specific parameters such as infrastructure, labor, financing and energy cost. Without specific information on this heterogeneity in cost, we assume a fixed rate for converting hydrogen and shipping overseas of USD 2 $kg^{-1}{}_{H2}$ for converting hydrogen to ammonia and USD 0.03 $kg^{-1}{}_{H2}$ to move liquid ammonia over a distance of 1000 km.[16]

The trade costs τ_{ij} between two markets is determined by the minimal transportation costs of either shipping ammonia with fixed cost f^{NH3} and variable cost c^{NH3}, or pipeline transportation with variable cost c^{pipe}. Distances d_{ij} are either the shortest shipping distance between two markets or the pipeline distance where pipeline infrastructure exists.

$$\tau_{ij} = \min\left\{d_{ij} \cdot c^{\mathrm{pipe}}, f^{\mathrm{NH3}} + d_{ij} \cdot c^{\mathrm{NH3}}\right\} \tag{5.17}$$

For internal trade ($i = j$) we use average internal distances within a market. Trade distances were obtained from the CEPII data as described in Head and Mayer (2014).

5.5. Empirical Analysis and Simulation

We have implemented our simulation in the C++ and R languages so that our results can be easily replicated.[17] Each of our scenarios was replicated 500 times in order to determine average performances across different random draws of our key variables.[18]

[16] The assumptions are based on IEA (2021a), IRENA (2022a) and Salmon and Bañares-Alcántara (2021) and represent simplified estimates.

[17] The model source code and all underlying assumptions and data input are published as Antweiler, W and Schlund, D (2024).

[18] Running these simulations is computationally expensive because of the iterative nature of determining the Cournot-Nash equilibrium. Running all simulation replications takes about a week of CPU time on a dedicated server.

The main purpose of our simulation is not to forecast the future. Instead, our simulations are meant to uncover how significant changes in the assumptions lead to changes in the outcome. We are interested in identifying the important drivers of the emerging international trade in hydrogen, determining the sensitivity of trade patterns to different starting conditions, dynamic forces, and public policies. For example, we are interested in how more or less demand heterogeneity, or more or less supply heterogeneity, changes the overall outcome relative to our base case. We can thus determine how robust or how vulnerable the eventual outcome is to variations in key parameters. Once we know the sensitivity of our simulation model to key parameters, we can shed light on the relative merit of public policies such as subsidies and carbon pricing.

5.5.1. Scenarios

We simulate the market evolution and evaluate our results for a range of scenarios. In each case a parameter is varied to better understand how it affects the trade mechanisms. Our 18 different scenarios are summarized in Table 5.4. Broadly speaking they explore demand and supply heterogeneity, innovation speed, carbon policies, hydrogen plant subsidies, trade costs, and internal trade subsidies. We also allow for the possibility of drastic natural gas price changes and have constructed corresponding demand scenarios.

Table 5.4.: Overview of simulated scenarios

Scenario	Description	Parameter	Base Case	Variation
00	Base Case	—	—	—
DL, DH	Demand heterogeneity	p_{jk}^L, p_{jk}^H	Table	half, double
SL, SH	Supply heterogeneity	ν_x, ν_f	0.25, 1.0	half, double
AL, AH	Average Plant Size	$\bar{\bar{x}}$	0.5 MTPA	half, double
IL, IH	EL Innovation Speed	X°, ϕ	4, 0.20	half, double
IS	RE Innovation slowing	(formula)	0.03	linear growth
CH	Carbon Policy: slow	ω_{jt}	Table	half target
CN	Carbon policy: frozen	ω_{jt}	Table	initial level
UF	Subsidies fast phase-out	g_σ, t_σ	0.4, 15	half
UL	Subsidies: reduced	σ_j^*	Table	half
TL, TH	Trade Costs	τ_{ij}	Trade Costs	half, double
UD	Domestic Subsidy	h_j	Table	linear decrease
NL, NH	Natural Gas Price	p_{jk}^L, p_{jk}^H	Table	low, high

5.5.2. Policy Parameterization

For the progression of carbon pricing we observe the current price $\omega_j^{\circ} \geq 0$ and an ultimate tax rate $\omega_j^{\bullet} \geq \omega_j^{\circ}$. The speed at which carbon prices are ramped up are determined by the rate g_ω and the half-level time t_ω.

$$\omega_{jt} = \begin{cases} \dfrac{\omega_j^{\bullet}}{1+\exp(-g_\omega t)(\omega_j^{\bullet}/\omega_j^{\circ}-1)} & \text{if } \omega_j^{\circ}>0 \\ \dfrac{\omega_j^{\bullet}}{1+\exp(-g_\omega(t-t_\omega))} & \text{if } \omega_j^{\circ}=0 \end{cases} \tag{5.18}$$

The carbon price is then applied to individual industries using the average emission intensity. Higher carbon pricing change the break-even price for using hydrogen, and thus shift hydrogen demand upward.

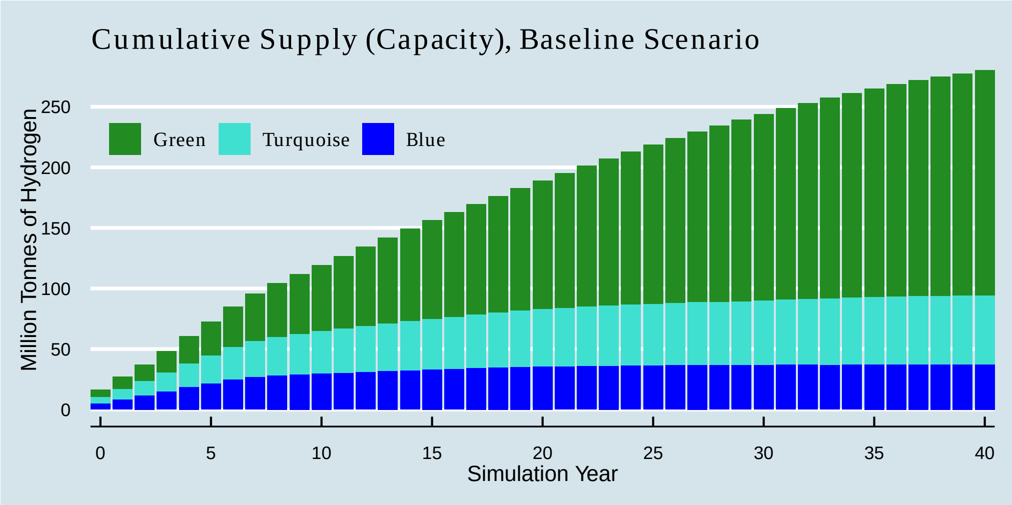
For the phase-out of subsidies we proceed in a similar fashion. Given an initial rate of subsidization (a share of total cost) $\sigma_j^{\bullet}$, a phase-out rate g_σ, and a phase-out half-time t_σ, we calculate the prevailing subsidy for country j in period t as

$$\sigma_{jt} = \frac{\sigma_j^{\bullet}}{1+\exp(g_\sigma(t-t_\sigma))} \tag{5.19}$$

5.5.3. Scenario Results

Starting with our baseline scenario, the cumulative supply is shown in Figure 5.3. We see rapid entry during the first stages. Early demand is satisfied by turquoise and blue hydrogen, allowing for an early lead because of cost advantages. Green hydrogen scales up at a later stage when innovation makes it increasingly cost competitive, making it eventually dominant as rapid innovation gains the upper hand.

Table 5.5 presents an overview of the simulation results of our different scenarios, averaged across 500 replications. We show the number of firms that have entered by the end of the simulations, along with the total number of markets served. To track the evolution of overall supply, we show the cumulative output by 2040 (20 years forward) and by 2060 (40 years forward, the end of our simulation run). We show the share of green hydrogen relative to total output in 2060. The next two columns show the innovation rates for electrolyzers (a mixture of endogenous and exogenous progress), for renewable energy (exogenous progress only), and for methane decomposition



Note: diagram summarizes 500 simulation replications.

Figure 5.3.: Cumulative Supplies of Hydrogen (Baseline Scenario)

(again a mixture of endogenous and exogenous progress). The last two columns show two measures of price dispersion, captured as the coefficient of variation (i.e., standard deviation divided by mean) across markets (countries) and the coefficient of variation within markets.

The basis for the across-country variation is the average price $p_{\bullet jt}$ (averaged across firms serving market j in period t), and the basis for the within-country variation is the country-level mean-adjusted price $p_{ijt} - p_{\bullet jt}$. We expect to find price variation across markets primarily because of the "vintage effect" of LTCs, as prices decrease over time due to innovation, and countries cluster around earlier or later participation. We expect to find price variation within markets when countries participate over a longer duration and accumulate contracts of different vintages.

Our baseline scenario predicts the entry of about 190 projects, generating a total supply of nearly 300 million metric tonnes (MMT) by 2060, and about two-thirds of that by 2040. This is roughly equal to 10,000 TWh and thus more than double today's electricity generation in the United States. Green hydrogen eventually captures a two-thirds market share, and we see about 17% price dispersion across markets.

Our scenarios typically do not show much variation in final output. A significant constraining factor in our modeling is the global cost spillover, which limits the construction activity in each period. There is a limited set of

Table 5.5.: Simulation Results for Hydrogen Trade Scenarios

Scenario	Firms	Markets	Supply [2040]	Supply [2060]	Green H_2 share	Export share	NH_3 share	Innovation: EL	Innovation: RE	Innovation: MP	Pr.Disp. Across	Pr.Disp. Within
			MT	MT	%	%	%					
Base Case	190.2	47.8	189.2	280.4	66.4	41.8	7.4	2.99	3.26	1.95	0.167	0.101
	(13.0)	(0.4)	(11.5)	(12.7)	(2.2)	(2.2)	(1.2)	(0.04)		(0.03)	(0.009)	(0.007)
Demand Het.: double	197.5	48.0	189.1	302.2	67.9	42.1	7.5	3.05	3.26	1.96	0.156	0.094
	(17.5)	(0.0)	(12.1)	(16.3)	(1.7)	(2.0)	(1.1)	(0.04)		(0.03)	(0.009)	(0.007)
Demand Het.: half	158.1	47.4	172.9	233.4	62.7	42.0	8.9	2.83	3.26	1.92	0.176	0.110
	(12.5)	(0.8)	(14.8)	(14.8)	(3.1)	(2.8)	(1.8)	(0.07)		(0.03)	(0.010)	(0.008)
Supply Het.: double	150.2	47.9	220.2	316.8	64.3	46.4	11.0	3.05	3.26	2.01	0.174	0.113
	(13.0)	(0.3)	(10.9)	(15.9)	(2.9)	(2.8)	(2.0)	(0.05)		(0.05)	(0.009)	(0.008)
Supply Het.: half	289.5	47.7	159.2	247.3	67.1	37.8	5.5	2.91	3.26	1.90	0.167	0.102
	(23.4)	(0.5)	(13.4)	(16.6)	(2.0)	(1.7)	(1.1)	(0.07)		(0.02)	(0.008)	(0.007)
No subsidies	222.6	47.8	153.5	263.7	51.7	44.1	14.2	2.77	3.26	2.03	0.186	0.130
	(16.5)	(0.4)	(9.6)	(11.8)	(2.4)	(2.4)	(1.4)	(0.05)		(0.02)	(0.007)	(0.006)
Domestic subsidies	211.0	47.8	172.2	279.4	58.1	31.3	8.7	2.89	3.26	1.98	0.185	0.135
	(16.3)	(0.5)	(12.0)	(16.1)	(3.0)	(2.6)	(1.2)	(0.06)		(0.03)	(0.008)	(0.008)
Carbon pricing: half	226.3	47.5	168.9	259.8	63.5	41.2	5.9	2.90	3.26	1.95	0.190	0.130
	(18.7)	(0.5)	(10.0)	(14.3)	(2.0)	(2.5)	(1.1)	(0.05)		(0.02)	(0.009)	(0.008)
Carbon pricing: fixed	297.1	48.0	151.2	218.1	58.6	42.0	4.3	2.73	3.26	1.94	0.220	0.160
	(19.3)	(0.1)	(8.5)	(6.7)	(1.6)	(2.1)	(1.1)	(0.03)		(0.02)	(0.009)	(0.009)
Innovation: EL double	165.1	47.9	188.6	301.2	76.4	46.4	7.0	9.23	3.26	1.86	0.156	0.093
	(10.7)	(0.3)	(10.1)	(12.0)	(2.0)	(2.4)	(1.2)	(0.23)		(0.04)	(0.011)	(0.006)
Innovation: EL half	225.1	47.9	188.9	278.9	59.5	41.2	9.0	1.93	3.26	2.01	0.176	0.114
	(15.2)	(0.3)	(12.3)	(10.2)	(2.0)	(2.0)	(1.1)	(0.01)		(0.03)	(0.008)	(0.006)
Innov.: RE slowing	206.7	47.8	189.7	275.5	61.2	40.8	8.2	2.93	2.20	1.99	0.172	0.110
	(13.8)	(0.4)	(12.1)	(10.7)	(2.0)	(2.1)	(1.2)	(0.04)		(0.03)	(0.008)	(0.007)
Trade costs: high	223.3	45.4	157.2	265.3	75.0	31.7	1.1	3.03	3.26	1.87	0.233	0.163
	(9.8)	(0.6)	(5.0)	(5.9)	(1.4)	(2.2)	(0.4)	(0.02)		(0.03)	(0.009)	(0.012)
Trade costs: low	205.6	48.0	240.7	334.6	58.7	60.5	30.6	3.03	3.26	2.03	0.117	0.072
	(13.8)		(12.9)	(11.9)	(2.6)	(2.1)	(2.8)	(0.04)		(0.03)	(0.007)	(0.005)
Capacity: double	140.6	47.8	213.1	291.8	63.4	43.4	9.2	2.99	3.26	2.00	0.168	0.101
	(9.8)	(0.5)	(9.8)	(14.8)	(2.6)	(2.3)	(1.5)	(0.05)		(0.03)	(0.009)	(0.007)
Capacity: half	259.2	48.0	160.7	257.4	69.3	40.7	6.3	2.96	3.26	1.89	0.168	0.105
	(20.7)	(0.2)	(12.9)	(12.1)	(1.9)	(1.9)	(1.1)	(0.04)		(0.03)	(0.007)	(0.006)
Nat.Gas price: high	176.1	47.9	226.3	334.2	68.9	49.4	15.1	3.14	3.26	1.95	0.162	0.099
	(11.4)	(0.3)	(12.4)	(13.2)	(2.5)	(2.1)	(1.9)	(0.04)		(0.03)	(0.009)	(0.007)
Nat.Gas price: low	204.3	45.0	157.2	208.0	59.7	37.1	5.3	2.73	3.26	1.93	0.189	0.117
	(13.6)	(1.0)	(8.4)	(9.0)	(2.3)	(2.1)	(1.1)	(0.04)		(0.03)	(0.006)	(0.007)

Note: Output volumes are in million metric tonnes (per year). Innovation rates are relative to the base year. The green H_2, export share, and NH_3 share are relative to total supply in the final year. Based on 500 replications of each scenario. Standard errors are shown in parenthesis.

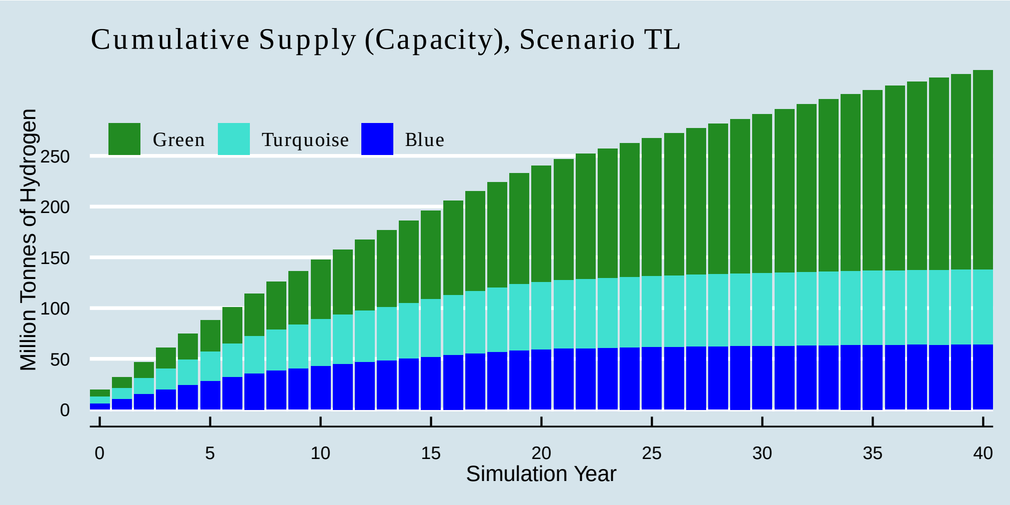
resources to expand the industry, although this constraint is likely going to relax over time. Yet, it is an essential element during the early stages of hydrogen adoption.

In terms of market entry we see significant deviations in some of our scenarios. When supply heterogeneity is high, we see fewer but larger firms entering, and elevated overall hydrogen supply. There is significantly less hydrogen production when supply heterogeneity is low. We also see fewer entries when facilities are larger on average, and more entries when facilities are smaller, as can be expected.

Our most surprising result occurs in the 'no subsidies' scenario. We expected this to result in significantly less hydrogen production. Nevertheless, after a slow start, innovation is still driving rapid hydrogen adoption later, almost catching up to the production level in our baseline. Without subsidies the share of green hydrogen is lower, but exports are somewhat larger (as is the share of long-distance ammonia transportation). Our empirical model suggests that direct subsidies are not a key driver of hydrogen adoption.

The two trade-cost scenarios also stand out. With high trade costs there is not much less hydrogen production than in the base case, but export volume is rather low (32% compared to 42%). With low trade costs, export volume is significantly elevated (61%). Similarly, the share of long-distance ammonia transportation is the highest in our low trade-cost world (around 31% compared to 7% in the base case). Ammonia transportation is virtually non-existent in our high trade-cost scenario. Interestingly, the share of green hydrogen is also the highest when trade costs are high. Concentrated trade is less advantageous for blue and turquoise hydrogen because green hydrogen is easier to produce domestically. Figure 5.4 shows our results for the low trade cost scenario. There is quicker growth in early stages of hydrogen adoption, but it does not boost the share of green hydrogen significantly.

Carbon pricing has a predictable effect when we consider half-rate carbon prices, or hold carbon prices at their current levels. In both instances we see less hydrogen production. Because of the country differences in carbon pricing, we see trade patterns shift. Overall, trade intensity decreases when carbon prices stagnate, and the share of green hydrogen is somewhat reduced. Stagnant carbon pricing does boost price dispersion, as trade patterns shift and LTC prices are locked in. The scenario with fixed carbon prices has the highest level of across and within price dispersion.



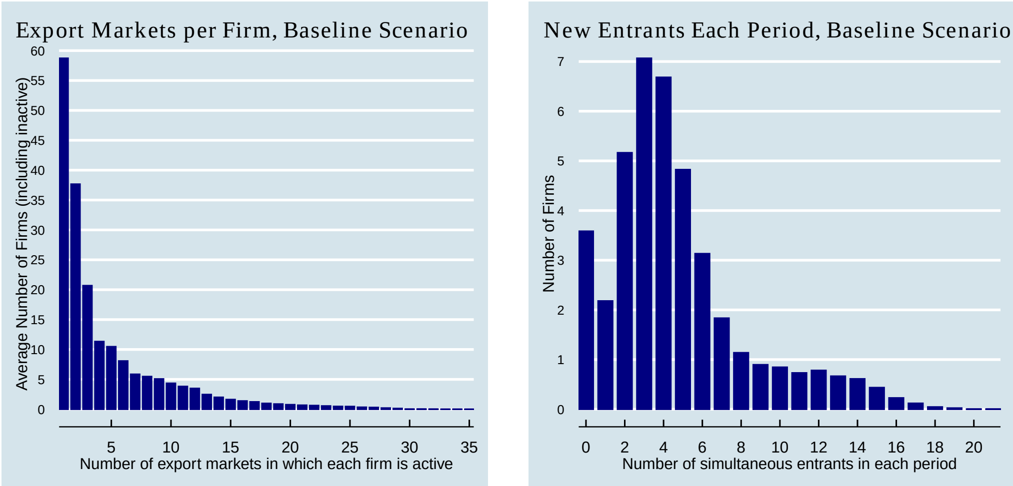
Note: diagram summarizes 500 simulation replications.

Figure 5.4.: Cumulative Supplies of Hydrogen (Low Trade Cost Scenario)

Faster innovation for electrolyzers (holding innovation rates constant for RE) naturally boosts the share of green hydrogen, but it is not the only avenue through which there is more uptake of green hydrogen. Our scenario generates a rather unrealistic terminal innovation rate, but this result assures us that super-charged innovation simply cannot overcome the constraint imposed by global cost spillovers in facility construction.

Turning to our results for overall price dispersion, we see diminished across-country price dispersion only when high trade costs are sufficiently low to boost international trade significantly. We see elevated price dispersion when carbon pricing is stagnating, and when trade costs are very high.

Figures 5.5a and 5.5b show the complexity and thickness of market entry. Complexity captures how many markets a firm is active in, and the Figure shows that a significant number of firms is only active in a few markets, while only larger plants tend to have a more diversified set of markets. Thickness captures the notion of competition during each period when firms enter simultaneously. Most firms enter with just a few others competing. We see entrant sets of 1-6 most often. The stylized results of our analysis is that in LTC markets, competition is limited in each period, as entry is stretched out over time as new project become economically viable for the first time. We also have a global cost effect that works against overly large concurrent entry.



(a) LTC Complexity

(b) LTC Thickness

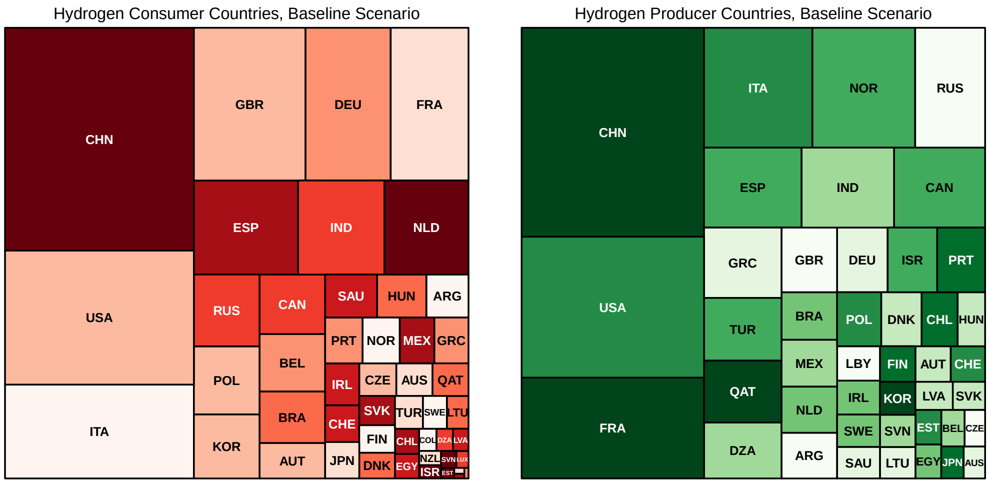
Note: diagrams summarizes 500 simulation replications.

Figure 5.5.: Long-Term Contracts (Baseline Scenario)

Figures 5.6a and 5.6b contain tile charts of the market sizes for consumption and production, respectively. (These results are the average of 500 replications.) Consumption mostly follows the economic size of markets, with China and the United States as the largest hydrogen markets, followed by markets in the European Union. Some of the large countries are also large producers (US, China), but there are also less obvious producer countries such as France and Norway. To the extent that green hydrogen takes on a significant share of output at later stages, countries with relatively low electricity costs and renewable-energy potential become significant players. Countries with low cost of natural gas, including Qatar, Saudi Arabia, and Canada, are early adopters of blue and turquoise hydrogen, while Australia suffers a transport cost disadvantage.

5.5.4. Price Evolution, Price Heterogeneity and the 'Early Adopters Curse'

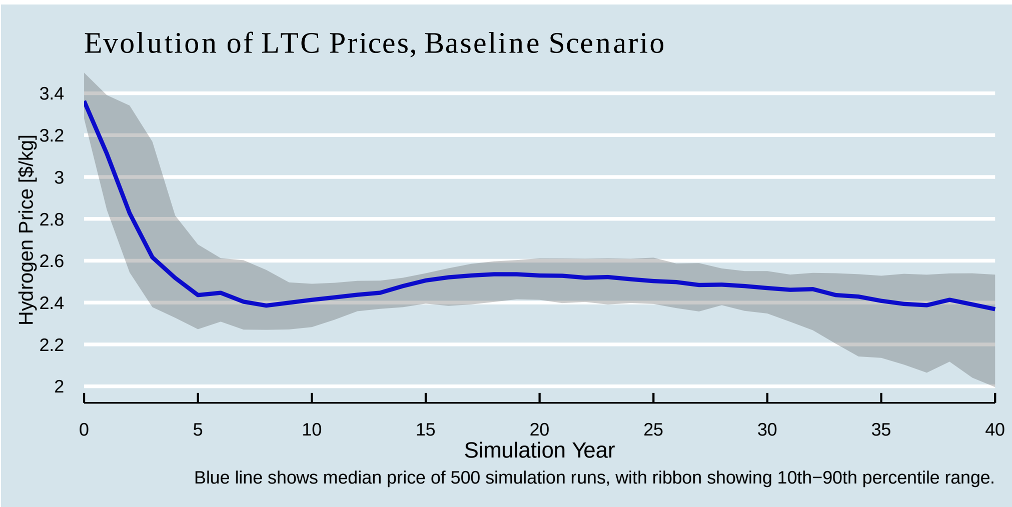
Figure 5.7 shows that prices tend to remain low during the initial phase of rapid expansion of hydrogen production, and stagnate while the market does not expand significantly. Prices can even vary during particular rounds of new plant entry as they may serve separate (and possibly few) markets.



(a) Hydrogen Consumption **(b)** Hydrogen Production

Note: diagrams summarizes 500 simulation replications.

Figure 5.6.: Market Shares (Baseline Scenario)

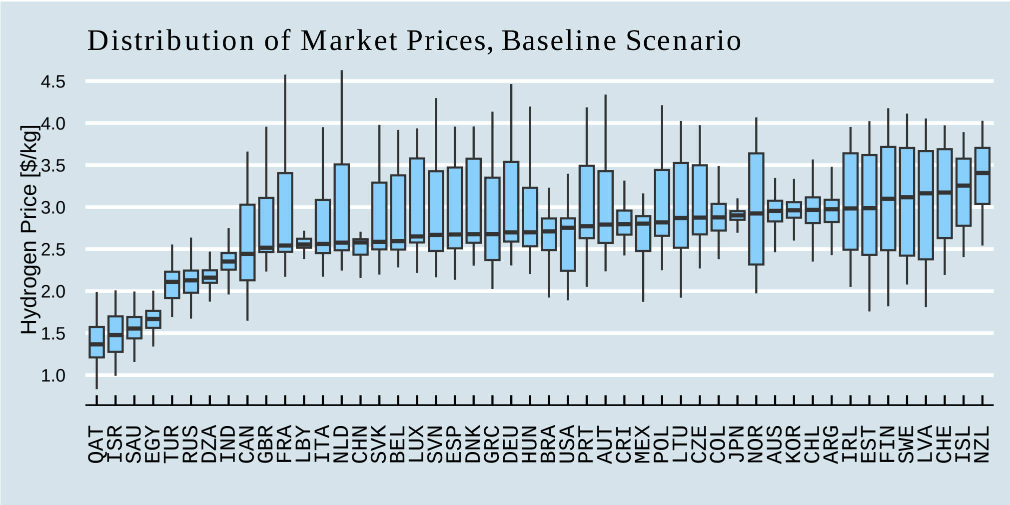


Note: diagram summarizes 500 simulation replications.

Figure 5.7.: Evolution of mean LTC prices each period

Figure 5.8 shows the price dispersion by country as a box chart, identifying which countries pay a higher price as a result of being early hydrogen adopters. Generally, exporter countries have lower prices than importer countries, with median prices for the major exporters below the $2/kg mark. Major producer countries also appear to have lower price dispersion. Importer countries satisfy growing demand by lining up import LTCs over time, leading to higher price dispersion. There is only a slight hint of an early adopter's curse, while Middle East countries wind up with some of the lowest market prices.

In order to capture the price formation in our simulation model, we have also investigated how the simulated price p_{ijt} of LTCs of firm i delivering to market j in period t depends on three variables: the elapsed time, the size of the importer market, and the distance between producer and consumer. We have estimated a simple log-linear relationship. The time effect simply captures what is visible in Figure 5.7.



Note: diagram summarizes 500 simulation replications.

Figure 5.8.: LTC Price Dispersion (Baseline Scenario)

The size of the importer market can have an ambiguous effect. On one hand, larger markets attract more competition in periods with multiple entrants. More competition should depress prices. On the other hand, market size may be correlated with policy variables and demand characteristics that boost prices, and in particular large markets may be early adopters of hydrogen. Indeed we find an effect that is both small and ambiguous, insufficient to conclude that importer size matters.

The distance effect is expected to be positive, as trade costs increase with distance. We find an distance-elasticity of price that is between about 0.04 and 0.10. It is highest in the high trade-cost and domestic subsidies scenario, and lowest in the low trade-cost scenario. We conclude from this that domestic subsidies and high trade costs amplify the effect of distance on hydrogen equilibrium prices.

Overall, we find little evidence of a persistent early adopter's curse. As most countries have staggered contracts over a longer time horizon, we do see significant within-market and across-market price dispersion.

5.5.5. Trade Patterns

Our simulations entail numerous scenarios that we wish to compare in terms of the emerging patterns of international trade. Concentration and diversification are key considerations in trade. We use Shannon Entropy measures that provide useful characterizations of trade flows at a summary level (Tezi et al., 2021). The starting points are the export and import shares (θ_i^x and θ_i^m) for each country, which can be compared to the economic size (θ_i^*) of each country, so that $\sum_i \theta_i = 1$. Our Entropy Diversification Index (EDI) for exports and imports are defined as

$$\mathrm{EDI}^x \equiv \exp\left(-\sum_i \theta_i^x \ln(\theta_i^x)\right) \quad \text{and} \quad \mathrm{EDI}^m \equiv \exp\left(-\sum_i \theta_i^m \ln(\theta_i^m)\right) \tag{5.20}$$

and can be viewed as the effective number of exporting (or importing) countries. If all countries had the same trade share ($1/N$), then $\mathrm{EDI} = N$ (the trade pattern with maximum entropy). This means our EDI measures is bounded between zero and N. A more familiar measure of concentration is the Herfindahl-Hirschman Index (HHI), bounded between $100/N$ and 100, which we report as an alternative to our EDI measure:

$$\mathrm{HHI}^x \equiv 100\sum_i (\theta_i^x)^2 \quad \text{and} \quad \mathrm{HHI}^m \equiv 100\sum_i (\theta_i^m)^2 \tag{5.21}$$

We are also interested in the effect of distance on trade, and for this purpose we estimate the simple gravity model with importer fixed effects β_i^m and exporter fixed effects β_i^x, and distance D_{ij}:

$$\ln(X_{ij}) = \beta_i^x + \beta_j^m + \phi \ln(D_{ij}) \tag{5.22}$$

The estimate of ϕ, conditional on observing positive trade, gives an indication of how quickly trade diminishes over distances (in comparison to trade of other commodities).

A further measure we find helpful in comparing scenario outcomes is the export intensity (XI), which is simply total exports divided by total production (as of the last simulation period when all long-term contracts are active).

Lastly, we also employ the Grubel-Lloyd Index (GLI) of intra-industry trade to characterize the average of two-way trade that emerges due to the overlapping nature of LTCs. Let $x_{i\bullet}$ denote total exports and $x_{\bullet i}$ denote total imports of country i. Then:

$$\mathrm{GLI} = \frac{100}{N} \sum_{i} \left[1 - \frac{|x_{i\bullet} - x_{\bullet i}|}{x_{i\bullet} + x_{\bullet i}} \right] \tag{5.23}$$

Two-way trade is an interesting feature of LTC trade. Whereas simple comparative advantage would point to trade in a commodity being mostly one-way, shifting comparative advantage over time combined with the lock-in effect of LTC generates patterns of two-way trade. Of course, two-way trade can also arise through re-exporting and differences in quality, and this is in part what we observe for conventional commodity trade.[19]

Results of our simulations are shown in Table 5.6, along with comparison values for nine major commodities based on COMTRADE data for 2019.[20] The results are the averages across 500 simulation runs, with standard errors in parenthesis. For exports and imports we report the number of active trading countries n, the Entropy Diversification Index, and the Herfindahl-Hirschman Index. We also report the estimated distance effect from the simple gravity model, the export intensity, and the Grubel-Lloyd Index.

Our model suggests that there will be between 24 and 29 hydrogen producer countries, a little more than half of the 48 countries we consider. Comparing export concentration and diversification measures, we find that hydrogen trade is most similar to crude oil. Perhaps this is not surprising because hydrogen, like oil, can be transported over long distances and shipped to many locations. Among metals, our EDI measure suggests that the effective number of exporters is between 3 and 11, and for fossil fuels it is between 6 and 15. Our export EDI for hydrogen varies between 13 and 17, similar to the level of crude oil. Our model suggests that hydrogen could rival crude oil for trade versatility.

[19] We use the average GLI instead of the gross GLI because the latter would give large weight to the big countries. Instead, we are interested in characterizing two-way trade across large and small countries.

[20] This pre-pandemic year appears to be a more suitable choice than more recent years.

Table 5.6.: Metrics of International Trade for Key Commodities (2019) in Comparison with Hydrogen Trade Simulations Scenarios

		Exports			Imports			Dist.		
HS6	Commodity	n	EDI	HHI	n	EDI	HHI	Effect	XI	GLI
260100	Iron Ores	80	5.2	35.2	112	4.3	50.2	-1.001		9.4
260200	Manganese	60	3.2	52.8	98	4.3	47.7	-0.609		15.7
260300	Copper Ores	75	11.2	16.2	81	5.8	34.8	-0.710		20.9
260400	Nickel Ores	42	6.5	19.6	56	2.3	66.6	-0.676		11.2
260500	Cobalt Ores	28	2.9	58.9	44	2.4	61.5	-0.503		14.8
270900	Crude Oil	94	15.0	9.4	126	20.5	9.0	-1.379		14.6
270100	Coal	98	7.0	21.8	148	18.0	9.9	-1.131		12.8
271111	LNG	57	6.4	26.8	104	10.5	15.5	-0.229		11.3
271121	Natural Gas	58	10.9	13.7	88	18.3	9.6	-2.328		19.6
Base Case		26.5	15.5	9.2	47.8	18.9	8.5	-1.118	41.8	34.1
		(1.7)	(0.8)	(0.5)	(0.4)	(0.5)	(0.3)	(0.134)	(2.2)	(2.7)
Demand Het.: double		26.7	15.5	9.5	48.0	18.5	8.9	-1.123	42.1	34.3
		(1.7)	(0.8)	(0.6)	(0.0)	(0.6)	(0.5)	(0.123)	(2.0)	(2.6)
Demand Het.: half		24.8	14.8	9.2	47.4	19.5	7.9	-1.033	42.0	31.9
		(1.8)	(1.1)	(0.7)	(0.8)	(0.7)	(0.5)	(0.186)	(2.8)	(2.7)
Supply Het.: double		28.2	16.9	8.2	47.9	20.0	7.7	-1.087	46.4	34.4
		(2.0)	(1.2)	(0.7)	(0.3)	(0.7)	(0.4)	(0.149)	(2.8)	(3.2)
Supply Het.: half		26.0	14.7	10.0	47.7	18.0	9.3	-1.204	37.8	35.5
		(1.4)	(0.6)	(0.4)	(0.5)	(0.5)	(0.4)	(0.167)	(1.7)	(2.3)
No subsidies		25.6	15.4	9.3	47.8	18.5	8.8	-1.097	44.1	31.2
		(1.5)	(0.8)	(0.6)	(0.4)	(0.6)	(0.5)	(0.189)	(2.4)	(2.3)
Domestic subsidies		26.4	15.5	9.4	47.8	17.9	9.1	-1.109	31.3	34.9
		(1.7)	(0.8)	(0.6)	(0.5)	(0.7)	(0.5)	(0.198)	(2.6)	(2.7)
Carbon pricing: half		26.8	16.0	8.7	47.5	19.3	7.9	-1.195	41.2	36.0
		(1.6)	(1.0)	(0.7)	(0.5)	(0.7)	(0.6)	(0.158)	(2.5)	(2.5)
Carbon pricing: fixed		29.3	17.2	7.7	48.0	21.1	6.9	-1.236	42.0	40.6
		(1.6)	(0.7)	(0.4)	(0.1)	(0.4)	(0.2)	(0.157)	(2.1)	(2.5)
Innovation: EL double		28.4	16.5	8.6	47.9	19.3	8.1	-0.976	46.4	35.8
		(2.0)	(1.0)	(0.6)	(0.3)	(0.7)	(0.4)	(0.136)	(2.4)	(3.1)
Innovation: EL half		25.9	15.3	9.3	47.9	18.9	8.5	-1.233	41.2	33.1
		(1.4)	(0.7)	(0.5)	(0.3)	(0.5)	(0.3)	(0.162)	(2.0)	(2.4)
Innov.: RE slowing		25.7	14.9	9.5	47.8	18.8	8.6	-1.187	40.8	33.2
		(1.5)	(0.7)	(0.5)	(0.4)	(0.5)	(0.3)	(0.148)	(2.1)	(2.5)
Trade costs: high		31.6	15.9	9.3	45.4	18.8	8.3	-1.165	31.7	50.6
		(1.9)	(0.7)	(0.5)	(0.6)	(0.6)	(0.4)	(0.192)	(2.2)	(3.2)
Trade costs: low		25.2	15.4	9.0	48.0	18.3	8.8	-0.931	60.5	25.6
		(1.7)	(1.0)	(0.6)		(0.3)	(0.2)	(0.115)	(2.1)	(2.5)
Capacity: double		24.7	14.8	9.4	47.8	18.9	8.4	-1.117	43.4	30.9
		(1.8)	(0.9)	(0.6)	(0.5)	(0.5)	(0.4)	(0.166)	(2.3)	(2.8)
Capacity: half		27.8	15.9	9.2	48.0	18.9	8.7	-1.073	40.7	36.3
		(1.7)	(0.7)	(0.4)	(0.2)	(0.5)	(0.4)	(0.145)	(1.9)	(2.6)
Nat.Gas price: high		26.8	16.4	8.5	47.9	19.7	7.8	-0.969	49.4	31.1
		(2.0)	(1.0)	(0.6)	(0.3)	(0.6)	(0.5)	(0.130)	(2.1)	(3.1)
Nat.Gas price: low		24.3	13.3	10.6	45.0	17.8	9.1	-1.236	37.1	34.8
		(1.6)	(0.8)	(0.6)	(1.0)	(0.6)	(0.4)	(0.241)	(2.1)	(2.6)

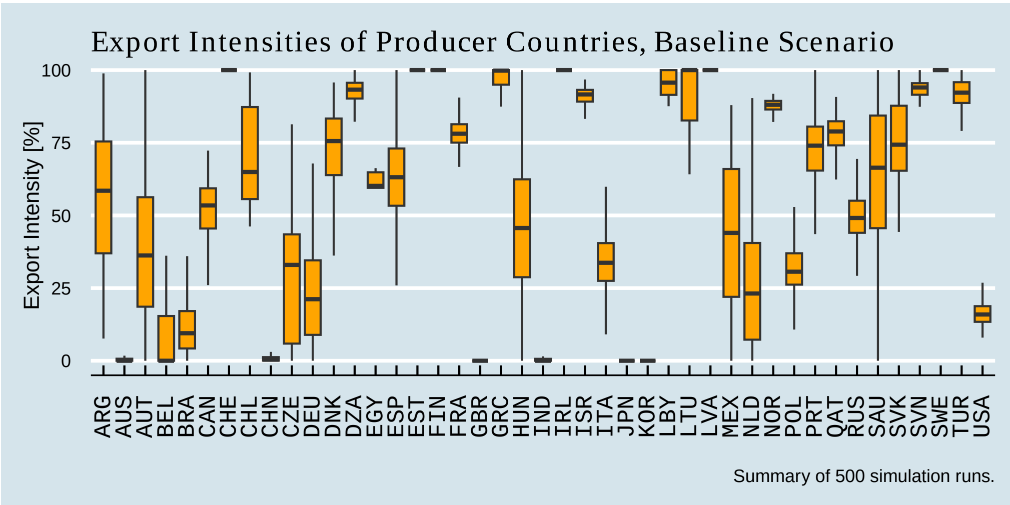
Note: results based on 500 replications of each scenario. Standard errors shown in parentheses. Abbreviations are EDI: Entropy Diversification Index; HHI: Herfindahl-Hirschman Index; XI: Export Intensity; and GLI: Grubel-Lloyd Index. Distance Effect: estimated distance elasticity of trade from a simple gravity model.

On the demand side we end up with all countries importing hydrogen in almost all scenarios. Import concentration is roughly similar to fossil fuels. Our EDI is hovering about 18–21 countries, while for fossil fuels it lies between 11 and 21. Again, our EDI measure for hydrogen is most similar to crude oil.

The distance effect estimated by our simple gravity model sheds further light on the patterns of trade. For coal and oil, the distance effect is quite similar to typical estimates for merchandise trade, while for liquid and gaseous natural gas, the coefficients are much smaller or larger in magnitude, respectively. Gaseous natural gas is shipped via pipeline, and thus there is a very strong distance effect. Liquid natural gas is shipped by LNG tanker, and thus the distance effect is weak. For hydrogen, our base case produces a distance effect of about –1.1, similar to coal and oil, but larger than for LNG and smaller than for piped natural gas. Across the different scenarios we find distance effects that are consistently between –0.9 and –1.2. We see weak distance effects (i.e., low-magnitude distance elasticities) only in the presence of low trade costs, and stronger distance effects (i.e., high-magnitude distance elasticities) with stagnant carbon pricing, slow innovation, and low natural gas prices.

Our export intensity (XI) measure hovers around the 40%-mark throughout most scenarios. It is only elevated in the low trade cost scenario, and depressed in the high trade cost scenario. Our GLI measure captures the significance of two-way trade. Many countries will export and import hydrogen, in part driven by different vintages of LTCs. We see significantly more two-way trade in our data than for conventional fossil fuels. Whereas the GLI for fossil fuels falls between 11 and 20, it tends to fall between 25 and 51 for hydrogen. The highest GLI (and thus two-way trade) we find when trade costs are high, and the lowest GLI we find when trade costs are low. Vintage effect of LTCs appear to be at work in both cases. Trade directions change over time as comparative advantages change, and LTCs lock in export and import directions that lead to two-way trade from different LTC vintages. Our findings about the importance of two-way trade in hydrogen is perhaps one of the most significant results of our paper.

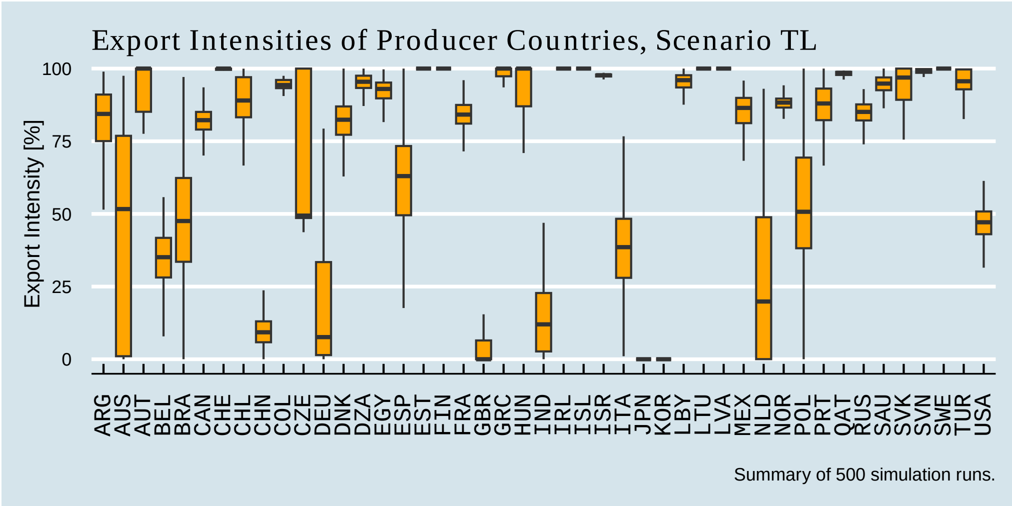
While Table 5.6 provides summary statistics for our scenarios, it is also useful to look at which countries are specializing as exporters and which countries are mostly serving their domestic market. Figure 5.9 shows the median export intensities of producer countries in our baseline scenario along with their inter-quartile range (IQR) and 1.5-IQR whiskers, while Figure 5.10 shows the export intensities in our low trade-cost scenario. In the baseline scenario we see large producer countries (China, US) largely serving domestic markets, and some countries (Korea, Japan, Australia) relying exclusively on domestic production. In the low trade cost model we see major producer countries increasing exports, e.g., Australia, the United States, Canada, and Middle East countries. Cheaper imported hydrogen can make domestic production less attractive—note the drop in export intensity in Germany. Our model shows a strong sensitivity to trade costs, so that countries such as Australia or Argentina, which are often seen as future exporters, are at a disadvantage due to their great distance from consumption centers such as Europe, North America or China.



Note: diagram summarizes 500 simulation replications.

Figure 5.9.: Export Intensities of Producer Countries (Baseline Scenario)

The analysis of the different scenarios leads us to conclude that international trade in hydrogen will resemble existing trade in energy in many ways, and will depend crucially on trade costs and transportation infrastructure—whether hydrogen is shipped via pipeline or in liquefied form (as ammonia). Hydrogen trade will be quite sensitive to trade costs, as these costs will be a significant share of overall costs of the hydrogen economy. Furthermore, LTCs are a mechanism through which strong two-way trade arises even when the traded good (hydrogen) is essentially homogeneous.



Note: diagram summarizes 500 simulation replications.

Figure 5.10.: Export Intensities of Producer Countries (Low Trade Cost Scenario)

5.6. Caveats of the model

Simulations of future states of the world depend crucially on underlying assumptions, and history has a tendency to defy predictions. We readily concede that many of the assumptions we have made above may stray from the reality that will emerge. But our goal is not to predict the future. What we aim to achieve with our scenario analyses is to identify how international trade in hydrogen can emerge, at first mostly in the form of LTCs. We can thus identify what matters more, and what matters less, in the development of this nascent industry. Nevertheless, it is important to point out significant caveats and limitations in our modeling.

Our piece-wise linear demand model is based on break-even points for hydrogen technologies across different countries and industries, along with the demand potential from converting existing industries and applications. We assume a scope for heterogeneity as we are not able to estimate demand heterogeneity directly, as we cannot rely on historic data. What we find in our simulations is that more demand heterogeneity is conducive to developing global hydrogen markets. Therefore, quantifying demand heterogeneity will be an important task for further research.

We do not model inter-dependencies between hydrogen and other commodity markets. For green hydrogen, we do not consider the opportunity cost of selling electricity at wholesale markets instead of feeding electrolyzers, or the cost development of other forms of grid-scale long-term electricity storage. For blue and turquoise hydrogen, we do not consider the development of natural gas markets and how this affects the availability of natural gas for hydrogen production.

Hydrogen markets also depend on complementary technologies, including infrastructure investments for storage and transportation. These are not modeled explicitly, but are captured in our simulations through subsidies and heterogeneity of supply costs.

There are also general-equilibrium repercussions that go well beyond our partial-equilibrium model. For example, government subsidies for hydrogen that are financed through taxation have repercussions in other markets. We implicitly assume that the hydrogen market will not change relative prices significantly elsewhere in the economy.

We also make specific assumptions about the size of proposed projects, ending on the high side of projections, which are closer to LNG projects than to smaller-scale electrolyzer projects. The efficient project size is likely to remain rather uncertain and is likely also site-specific. As the industry is in its infancy, the role of economies of scale is still emerging, but is very likely to be of great importance for the conversion to ammonia and shipping. This is a key argument in our heuristic for choosing feasible entrant sets.

Lastly, our focus on LTCs ignores the possibility that a spot market for hydrogen may evolve faster than we anticipate. In our model, LTCs persist indefinitely. Alternatively, one could limit the duration of LTCs. As previously discussed, we fully foresee the emergence of a spot market as plants increasingly amortize their fixed costs.

5.7. Policy Considerations

5.7.1. Climate Policy and Carbon Pricing

The first-best policy to address climate change is to put a price on the negative externality that is equal to marginal damage. Governments around the world have been adopting a variety of carbon policies including emission trading systems and direct carbon taxes. The World Bank is tracking the evolution of these policies on its Carbon Pricing Dashboard. As of mid-2022, there were 46 national jurisdictions with carbon policies that covered 23% of global GHG emissions. The stringency of theses policies varies significantly. In our simulations, we have assumed as a baseline an aggressive carbon pricing path that ramps up pricing to levels near 150 USD/tonne of carbon dioxide. We found that carbon pricing alone will not be a major driver of hydrogen adoption in this scenario. Instead, the main driver of hydrogen adoption is technological innovation, accompanied by a reduction in hydrogen transportation costs. Learning-curve effects for electrolyzers will play a major role. The innovation gap for green hydrogen remains quite large and will require continued cost reductions for renewable energy sources and electrolyzers to make headway. Thus the initial phase of hydrogen trade will be driven mostly by blue and turquoise hydrogen.

Blue hydrogen faces several challenges. There are some upstream emissions, in particular related to wellhead methane leakage. Carbon capture is incomplete, and thus there are fugitive emissions. Sequestration or utilization of carbon dioxide may also face limitations due to availability of suitable reservoirs or utilization applications. Development of blue hydrogen thus requires solutions to these challenges and a full accounting of the net emissions, a topic under active investigation and conflicting views (Bauer et al., 2022, Howarth and Jacobsen, 2021).

For green hydrogen it is crucial that electrolyzers need to draw power from clean electricity sources. We thus assume that electrolyzers are connected directly to renewable energy sources. However, in many countries electrolyzers will presumably be connected to the public grid. This bears a risk that hydrogen production is not truly zero emission if the electricity grid contains fossil fuel generators. Policy frameworks will be needed to ensure that green hydrogen production does not lead to a “reshuffling” effect that designates hydrogen as green by shifting emissions to other electricity users.[21]

5.7.2. International Trade Law

Blue and turquoise hydrogen will play an important bridge role until green hydrogen becomes more economically attractive. Thus there will be some

[21] The European Union has, for instance, issued a definition for green hydrogen, which contains elements of RES additionality as well as geographical and temporal correlation to ensure that hydrogen is predominantly produced from RES, see, e.g., Schlund and Theile (2022).

emissions associated with production even if the majority of CO_2 emissions are captured. In December 2022, the European Union has finalized a Carbon Border Adjustment Mechanism (CBAM) that covers a number of industries, including electricity and hydrogen. Such mechanisms are designed to prevent carbon leakage and restore competitiveness in the presence of international carbon pricing differentials (Böhringer et al., 2022, 2021).

The EU-CBAM raises questions about measuring the carbon content of hydrogen imports that arrive from blue hydrogen sites (and to a lesser extent turquoise hydrogen), and about the need for certification of the CO_2-content of hydrogen. Certification may lead to different shades of blue hydrogen, with darker shades of blue (linked to uncaptured upstream emissions) likely subject to higher carbon prices. Countries that import blue hydrogen may well impose carbon tariffs on hydrogen imports that are not fully carbon-neutral in order to level the playing field for domestic green hydrogen facilities.

5.7.3. Energy Security

Recent geopolitical events have led to an increased interest in energy security and energy independence. High reliance on imported energy, especially if it is geographically concentrated, poses risks in case of geopolitical conflict or natural disaster. Comparative advantages that favor high-risk production locations may expose importer countries to strategic vulnerabilities, or even jeopardize national security. Renewable energy sources (wind, sun) are often readily available domestically. Reliance on renewable energy is therefore tantamount to increasing energy security. As De Blasio and Pflugmann (2020) discuss, geopolitical tensions are often related to energy, with resource abundance and resource scarcity translating into geopolitical influence or vulnerability, respectively.

Many countries are naturally unable to achieve energy independence because they will continue to rely on energy imports because of geographic factors such as small country size, topography that is not conducive to hydro electricity, latitudes that are not conducive to solar power, or lack of suitable geothermal resources. Where energy independence is not feasible, energy diversification can enhance energy security. Hydrogen is a particularly useful way of achieving diversification because hydrogen production will grow beyond traditional suppliers of natural gas that pivot towards blue hydrogen production, and increasingly include a variety of new providers that can provide green hydrogen from renewable energy sources. Yet, our simulations suggest that blue and turquoise hydrogen will play an important role at least initially, suggesting that the evolving trade in hydrogen may not provide a quick route to improving energy security. Diversification will only arrive along with dominance of green hydrogen production.

5.8. Conclusions

Our paper develops a model of international trade in hydrogen that is characterized by long-term contracts (LTCs), which leads to sequential trade with overlapping vintages of contracts. LTCs lock in quantities and prices, and thus trade patterns follow a different logic and at times can appear suboptimal compared to spot markets. Importantly, LTCs give rise to two-way trade as comparative advantages shift over time. This effect is very pronounced in the case of hydrogen because different production types (blue, turquoise, green) are subject to separate innovation processes and policy interventions.

Our LTC trade in hydrogen is based on projects that can enter in each period and compete for entry in a Nash-Cournot equilibrium, but with quantity competition replaced by market access competition as capacity is always fully utilized. Thus the place of variable costs that determine market share in Cournot models is replaced by the shadow price of capacity utilization, along with trade costs. Entry decisions are at the extensive margin only. We employ our model to simulate the emergence of hydrogen trade using carefully calibrated supply, demand, and trade cost data. We investigate 19 different scenarios in order to determine which factors influence the emerging market the most.

Our scenarios investigate demand and supply heterogeneity, different speeds of exogenous and endogenous innovation, different hydrogen subsidy schemes, different carbon tax trajectories, different levels of trade costs, and different states of the natural gas market. Overall, the early stages of hydrogen production are dominated by blue and turquoise hydrogen. Eventually, endogenous experience curve effects will lower the cost of green hydrogen, and eventually new capacity will be dominated by this technology. Our models highlight the importance of innovation and transportation costs.

Lower transportation costs than our baseline would significantly boost the trade potential, especially for green hydrogen.

We also investigate price formation and trade complexity. Locked-in LTCs prices could penalize early adopters as prices decline with innovation. As hydrogen trade emerges gradually, we see a significant volume of two-way trade, but little evidence of an "early-adopter curse". Instead, we see significant price heterogeneity in most markets. Naturally, some countries end up with lower average prices than others, but this is primarily due to domestic production advantages and fortuitous geographic locations.

Many countries have adopted explicit hydrogen policies in order to accelerate the innovation for electrolyzers, as well as other technologies beneficial to blue hydrogen (carbon capture and sequestration) and turquoise hydrogen (methane decomposition). Our simulations reveal that the path of innovation is critical, and that domestic-oriented subsidies are ultimately less beneficial than those that generate global spillovers. Because trade costs especially for long-distance shipping are critically important, subsidies that target infrastructure development that lower trade costs will be more beneficial than simple production subsidies. Government policies are best focused on boosting innovation and infrastructure, not promoting domestic production.

While hydrogen may be able to (re-)utilize existing natural gas pipeline networks over short distances, trade over large distances depends crucially on making ammonia conversion economical. This complementary technology is essential for tapping into the full global potential for green hydrogen production.

A. Supplementary Material for Chapter 2

A.1. Model, data and assumptions

A.1.1. 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 2.1.

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.1 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% (CRE, 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% (BNetzA and BKartA, 2020) compared to 74% in the modeled projection.

Table A.1.: 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%

A.1.2. Model indices, parameters and variables

Table A.2.: 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)
$l \in L$		Sectors (Electricity, industry, households, transport)
$z \in Z \subset N$		Gas storage
$g \in G \subset N$		Natural gas production locations
$r \in R \subset N$		LNG import terminals (regasifiers)
$v \in V$		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
P	MWh	Production or regasification
F	MWh	Energy flows
S	MWh	Storage flows
D	MWh	Demand
VC	EUR	Variable cost
TSC	EUR	Total system cost

A.1.3. Data assumptions

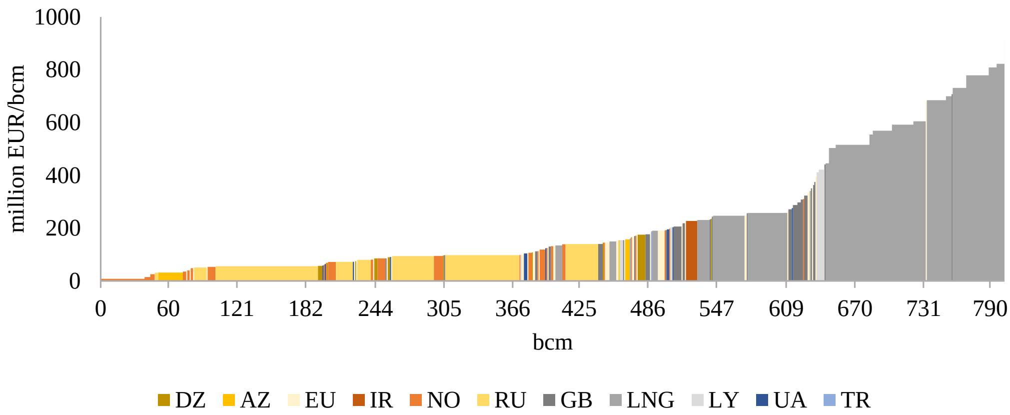


Figure A.1.: European natural gas supply curve and major exporting countries in 2030 (based on Rystad Energy (2020) with own assumptions)

Table A.3.: Assumed conversion factors for fuels referred to net calorific value and gross calorific value

Fuel	Unit	NCV	GCV
Hydrogen	kWh/m³	3.00	3.54
Methane	kWh/m³	9.97	11.05
Natural gas	kWh/m³	10.00	11.11

Table A.4.: 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. (2021) (baseline assumptions) and IEA (2019) for methanation.

Table A.5.: 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. (2021) (baseline assumptions) and IEA (2019) 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.

A.2. Supplementary Results

Table A.6.: 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	3644	3290	3360	3353
EU gas production	TWh	340	355	342	303
PtG capacity	GW	0	0	0	0
PtG production	TWh	0	0	0	0

Table A.7.: 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	3825	3479	3576	3508
EU gas production	TWh	340	356	339	296
PtG capacity	GW	26	54	84	117
PtG production	TWh	103	220	338	452

Table A.8.: EU ETS and non EU ETS gas demand in the EUQ and REF scenario (in TWh)

	REF		EUQ	
	non EU ETS	EU ETS	non EU ETS	EU ETS
2025	2068	1576	2068	1757
2030	2200	1090	2200	1279
2035	2251	1108	2251	1325
2040	2262	1091	2262	1245

Table A.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	181	189	216	154
Natural gas production (imports and EU)	TWh	78	-31	-122	-298
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

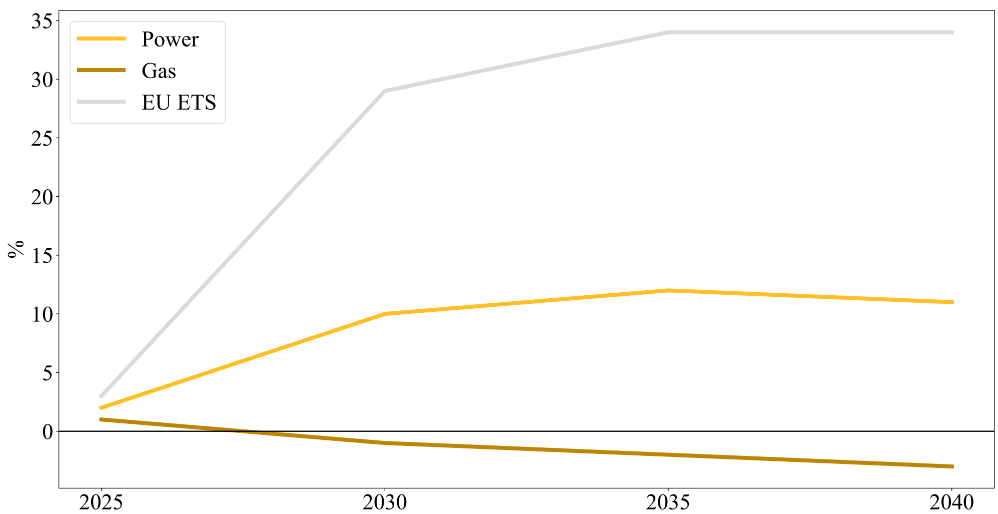


Figure A.2.: Difference in power, gas and EU ETS allowance price between the EUQ and the REF scenario

B. Supplementary Material for Chapter 3

B.1. Regression Results

The regression results for the day-ahead market are illustrated in Figure B.1. Based on the data for the years 2015-2019, a function is fitted to each month of the year.

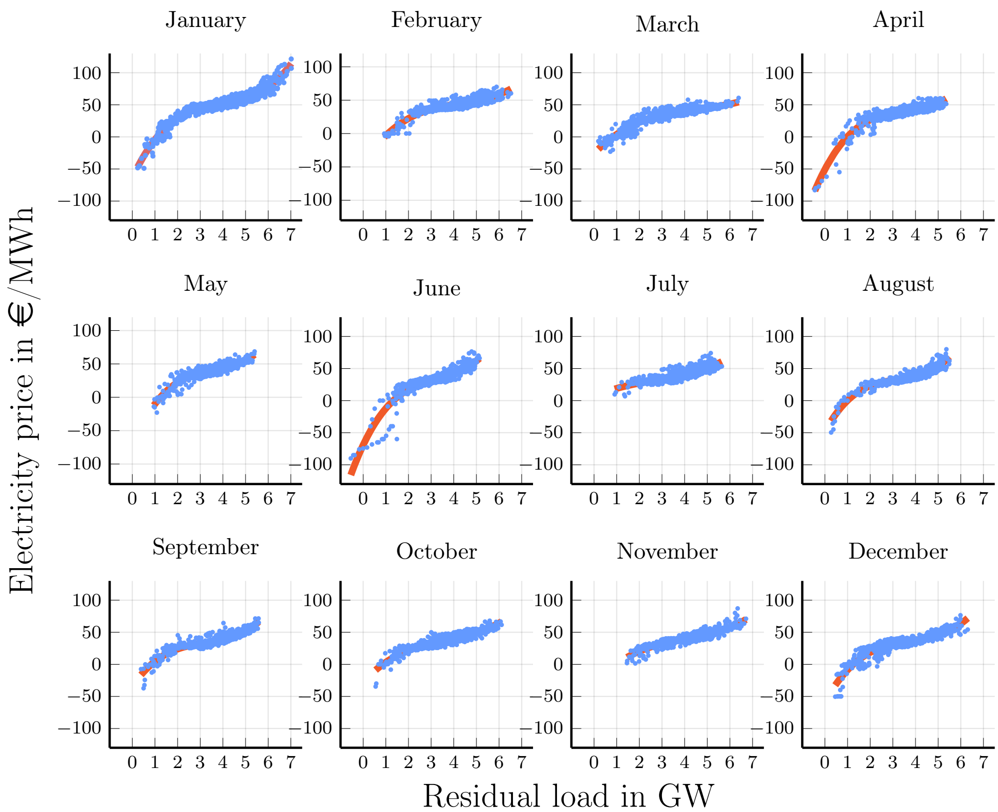


Figure B.1.: Regression results for the day-ahead market.

Analogously, the intraday market prices are regressed on the day-ahead market prices and the wind generation forecast error. Table B.1 shows the regression results indicating that the applied independent variables are significant within this model.

Table B.1.: Regression results for the intraday market.

	Coef.	Std. Error	t	Pr(>|t|)	Lower 95%	Upper 95%
(Intercept)	1.80256	0.192212	9.38	<1e-20	1.42582	2.1793
DA prices	0.971656	0.00459027	211.68	<1e-99	0.962659	0.980653
Forecast error	-0.976845	0.0194165	-50.31	<1e-99	-1.0149	-0.938789
(Forecast error)^2	-0.0220511	0.0023063	-9.56	<1e-20	-0.0265715	-0.0175307

B.2. Monte Carlo simulation

To obtain synthetic electricity market price time series for both the day-ahead and the intraday market, we generate synthetic time series of the independent variables used in the parametric models of the electricity market, i.e. wind generation forecast and wind generation forecast errors. We follow Papaefthymiou and Klockl (2008) by parameterizing the transition probabilities of a Markov chain with 15 states on both parameters separately. Note that we do not take into account the correlation between the parameters. However, we use the relative forecast errors instead of the absolute ones so that the absolute errors still scale with the wind generation forecast. The transition probability matrix includes the probabilities to change from one state to another to the next period. We obtain a cumulative distribution function of possible following states for every state.

For each time step of the simulation horizon, we draw random numbers from a uniform distribution $\mathcal{U}(0,1)$. Plugging the random number into the inverse of the cumulative distribution function obtains the next state within the Markov chain (Amelin, 2004). We continue the process for the entire simulation horizon and repeat it for the number of samples we generate. The day-ahead prices are then calculated based on Equation (3.7). Figure 3.3 shows the range of resulting price duration curves. The intraday price are computed based on Equation (3.8), also using the synthetic day-ahead prices. The results are shown in Figure 3.3.

B.3. Annuity

The annuity of the electrolyzer investment is computed based on equation (B.1). Multiplying the CAPEX with the capital recovery factor obtains the annuity.

$$\text{annuity} = CAPEX * \frac{(1+i)^n * i}{(1+i)^n - 1} \tag{B.1}$$

B.4. Annotation

Table B.2.: Model indices, parameters and variables.

Name	Unit	Definition
Sets		
$t, j \in T$		Time periods
$m \in M$		Electricity markets (intraday, day-ahead)
Parameters		
p^{H2}	EUR/kg	Green hydrogen selling price
p^{DA}	EUR/MWh_{el}	Day-ahead price
p^{ID}	EUR/MWh_{el}	Intraday price
p	EUR/MWh_{el}	Electricity price
δ	-	Time scaling
cap	MW_{el}	Electrolyzer capacity
α	EUR/MWh_{el}	Electricity price surcharges
β	-	Minimal load as fraction of the capacity
γ	-	Simultaneity of electricity production and consumption
σ	-	Capacity ratio of electrolyzer and RE plant
re	-	(current) RE capacity factor
q^{res}	MW_{el}	Residual load
n	a	Years
Variables		
$Contribution\ margin$	EUR	Total contribution margin
R	EUR	Revenue
C	EUR	Cost
C^{FOM}	EUR	Fixed operation and maintenance cost
C_t	EUR	Variable cost
Q	kg	Hydrogen production
L	MW_{el}	Load
B	-	Binary variable to determine whether plant is switched on/off
FE	-	Forecast error

C. Supplementary Material for Chapter 4

C.1. Model formulation

Table C.1.: Model indices, parameters, and variables.

Name	Unit	Definition
Sets		
$t \in Time$		Time
$y \in Years$		Years
$i, j \in Nodes$		Nodes
$tech \in Tech$		Investment technologies: solar PV, onshore wind, offshore wind, electrolyzer, hydrogen interconnector, hydrogen storage, ammonia import terminal, SMR with CCS, LNG import terminal
$gas \in Gas$		Type of gas: hydrogen, methane
$res \in RES$		Renewable energy technologies: solar PV, onshore wind, offshore wind
$l \in L$		Costlevels
Parameters		
a	-	Capital recovery factor
f	% of $capex$	Fixed operative and maintenance costs
$capex$	EUR/mcm_{gas}pa or EUR/MW_{el}	Capital expenditures
$opex$	EUR/mcm_{gas} or EUR/MWh_{el}	Operational expenditures
d	mcm_{gas}	Gas demand (hydrogen or methane)
c_{res}	-	Capacity factor of renewable energy technologies
pot_{tech}	MW_{el}	RE capacity and ammonia import potentials
cap	mcm_{gas}pa	Existing annual hydrogen or natural gas pipeline capacity
Variables		
TC	EUR	Total system costs
P	mcm_{H2} or MWh_{el}	Production quantity
C	mcm_{gas}pa or MW_{el}	Capacity expansion
I	mcm_{gas}	Import quantity
S	mcm_{gas}	Storage flows
T	mcm_{gas}	Transported quantity of gas
$B \in \{0, 1\}$	-	Binary variable to indicate repurposed natural gas pipelines

C.2. Model assumption

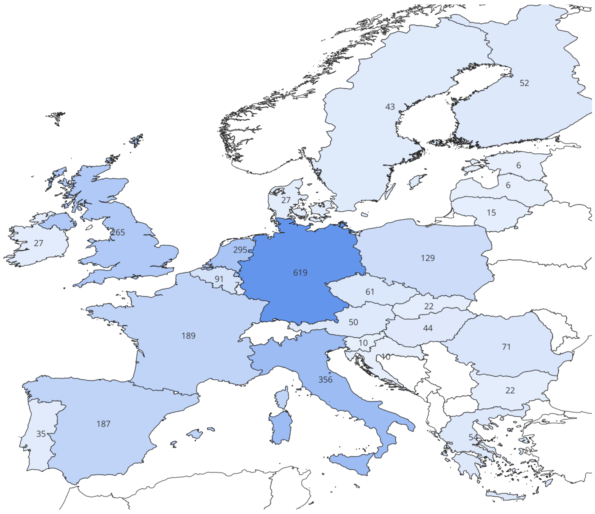


Figure C.1.: Country-level hydrogen demand in 2050 in the reference scenario in TWh (own figure based on the Global Ambition scenario in ENTSOE and ENTSOG (2022))

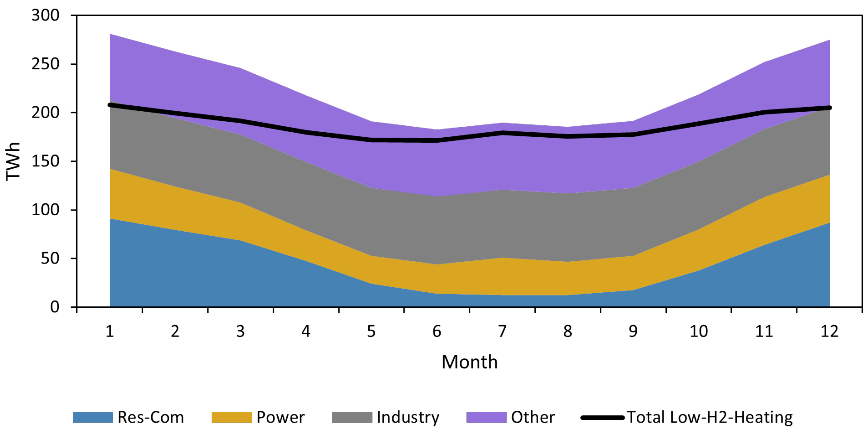


Figure C.2.: Temporal hydrogen demand profile per sector in 2050 in the reference scenario and aggregated demand in the low-H2-heating scenario (based on the Global Ambition scenario in ENTSOE and ENTSOG (2022))

Table C.2.: Capex data for investment technologies.

Technology	Unit	Capex 2020	2030	2040	2050
LNG regasification terminal	MEUR/bcm$_{ng}$pa	155	155	155	155
Ammonia import terminal	MEUR/bcm$_{H2}$pa	298	231	202	184
Hydrogen pipeline new	EUR/mcm$_{H2}$pa*km	198	198	198	198
Hydrogen pipeline repurposed	EUR/mcm$_{H2}$pa*km	59	59	59	59
Hydrogen cavern storage	MEUR/mcm$_{H2}$	1.71	1.71	1.71	1.71
Electrolysis	EUR/kW$_{el}$	1240	378	338	300
Solar PV utility-scale	EUR/kW$_{el}$	560	380	320	290
Wind onshore	EUR/kW$_{el}$	1120	1040	980	960
Wind offshore	EUR/kW$_{el}$	2120	1800	1680	1640
SMR with CCS	EUR/kW$_{H2}$	1300	1300	1300	1300

Source: Adapted from Brändle et al. (2021), DEA (2022), ENTSOG (2018), ENTSOG and ENTSOE (2023), van Gessel and Hajibeygi (2023), IEA (2021a), Moritz et al. (2023). Detailed references in Section 4.3.2.

Table C.3.: Fixed O&M, opex, and lifetime data for investment technologies.

Technology	Fixed O&M costs (% of Capex)	Opex (EUR/mcm$_{gas}$)	Lifetime (years)
LNG regasification terminal	1.5	*included in import cost*	25
Ammonia import terminal	4.0	*included in import cost*	25
Hydrogen pipeline	-	1.57 - 6.2 *(depending on electricity price)*	30
Hydrogen cavern storage	3.6	6,750	33
Electrolysis	2.0	-	25
Solar PV	2	-	25
Wind onshore	2	-	25
Wind offshore	2	-	25
SMR with CCS	4	31,035 - 45,060	25

Source: Adapted from van Gessel and Hajibeygi (2023), IEA (2021a), Krieg (2012), Moritz et al. (2023), Sens et al. (2022).

Table C.4.: Efficiency data for electrolyzers and SMR with CCS (lower heating value).

Technology	2020	2030	2040	2050
Electrolysis (kWh$_{H2}$/kWh$_{el}$)	0.64	0.69	0.72	0.74
SMR with CCS (kWh$_{H2}$/kWh$_{th}$)	0.69	0.69	0.69	0.69

Source: Adapted from IEA (2021a), Moritz et al. (2023).

C.3. Supplementary Results

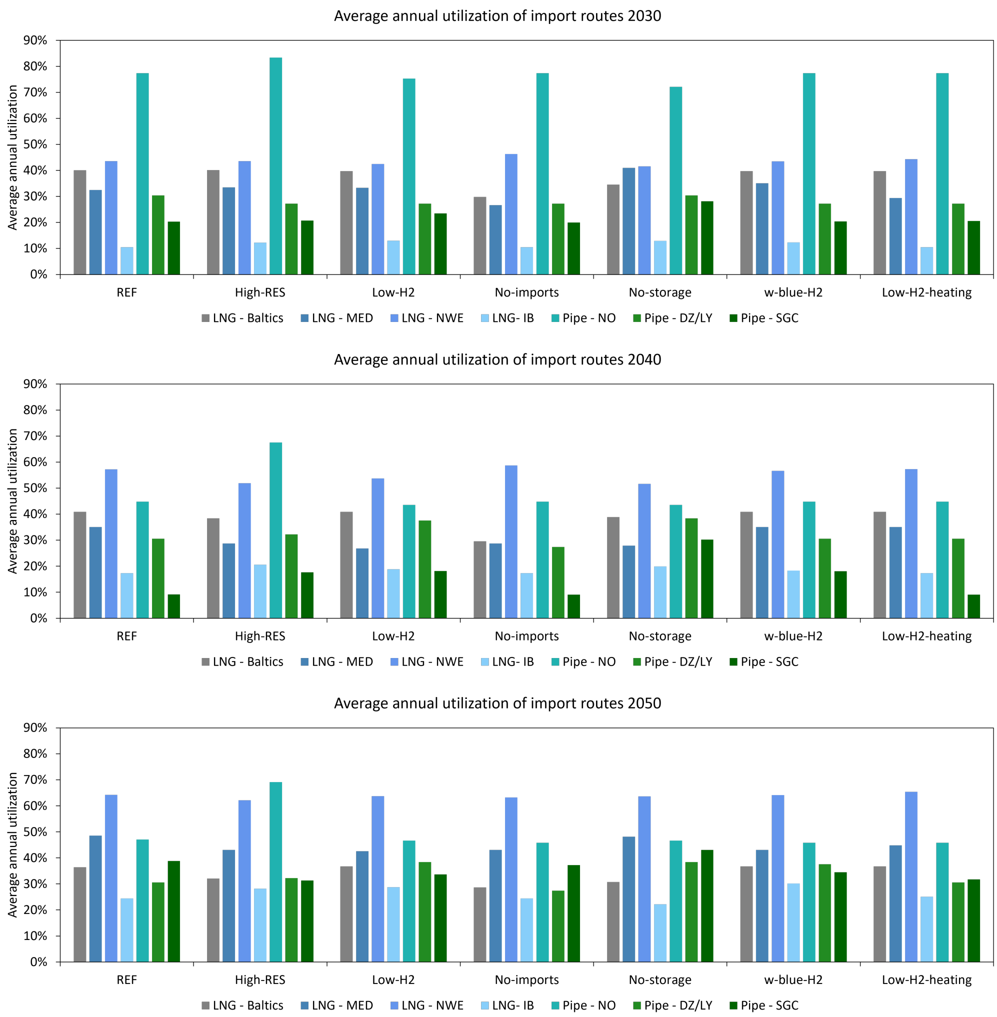


Figure C.3.: Average annual utilization of natural gas import routes in different years[1]

[1] Route definition: Baltics - Baltic states: Finland, Estonia, Lithuania; MED - Mediterranean: Italy, Croatia, Greece; NWE - Northwest Europe: Great Britain, France, Belgium, the Netherlands, Germany, Poland; IB - Iberian peninsula: Spain, Portugal; NO: Norway; DZ/LY: Algeria, Libya; SGC - Southern Gas Corridor: Azerbaijan, Turkey.

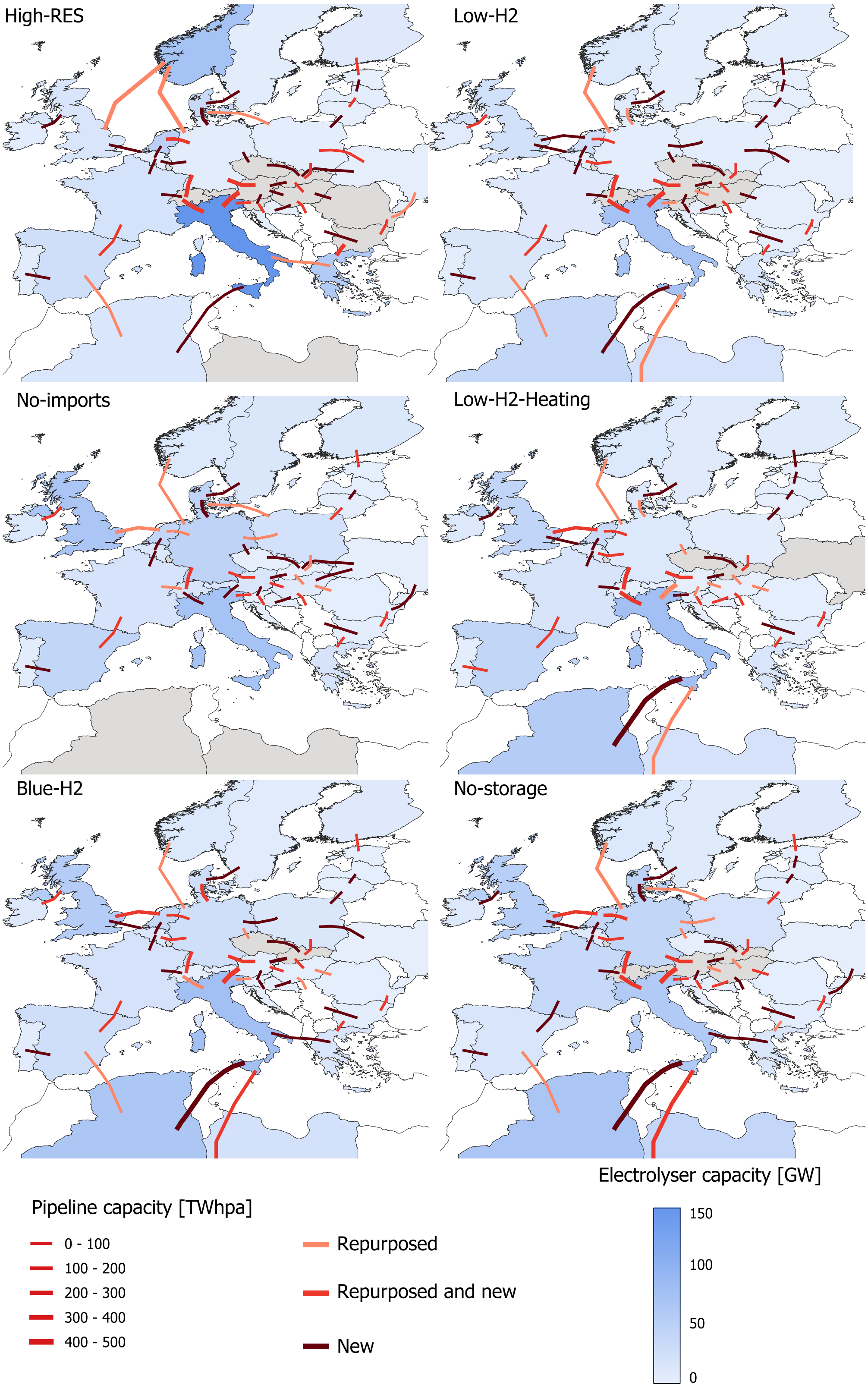


Figure C.4.: Hydrogen production and cross-border transportation capacities in 2050 in all scenarios

Table C.5.: Relative RE capacity shares per EU country in the year 2030 in the scenarios *REF* and *High-RES* compared to the National Trends scenario in ENTSOE and ENTSOG (2022).

	2030								
	Solar PV			Wind onshore			Wind offshore		
	REF	High-RES	TYNDP National trends	REF	High-RES	TYNDP National trends	REF	High-RES	TYNDP National trends
BG	0.8%	0.0%	0.9%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
EE	0.4%	0.3%	0.1%	0.5%	1.6%	0.3%	1.4%	0.0%	0.3%
FI	2.0%	1.5%	0.4%	6.0%	3.5%	4.0%	0.0%	0.0%	2.1%
GR	15.5%	27.9%	2.0%	0.3%	0.0%	2.2%	0.0%	0.0%	0.1%
HR	0.0%	0.0%	0.2%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%
HU	0.0%	0.0%	1.7%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
IE	0.0%	0.0%	0.2%	6.2%	2.2%	1.9%	7.7%	0.0%	4.8%
LT	0.5%	0.3%	0.3%	1.8%	0.9%	0.7%	0.8%	0.0%	1.9%
LU	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LV	0.1%	0.4%	0.0%	0.3%	0.9%	0.1%	2.0%	0.0%	0.7%
PL	0.0%	0.0%	1.4%	15.6%	1.0%	2.8%	5.8%	0.0%	8.1%
PT	4.6%	2.7%	2.1%	0.0%	0.0%	2.9%	0.0%	0.0%	0.4%
RO	1.2%	0.0%	1.3%	0.0%	0.0%	1.7%	0.0%	0.0%	0.0%
SE	0.0%	0.0%	2.0%	9.8%	4.5%	5.5%	0.0%	0.0%	6.9%
SI	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
AT	0.0%	0.0%	3.2%	0.0%	0.0%	2.9%	0.0%	0.0%	0.0%
BE	0.0%	0.0%	2.8%	5.3%	1.8%	1.5%	3.6%	0.0%	8.0%
CZ	0.0%	0.0%	2.2%	0.1%	0.0%	0.2%	0.0%	0.0%	0.0%
DE	0.0%	0.0%	25.6%	10.0%	6.4%	24.7%	23.1%	0.0%	32.4%
DK	0.0%	0.0%	1.7%	5.5%	21.9%	2.0%	29.6%	0.0%	9.4%
ES	18.4%	10.0%	12.2%	0.0%	0.0%	15.8%	0.0%	0.0%	0.3%
FR	0.0%	0.1%	11.7%	25.7%	16.4%	11.8%	0.0%	0.0%	7.5%
IT	56.6%	56.8%	13.8%	0.0%	0.0%	6.0%	0.0%	0.0%	1.2%
NL	0.0%	0.0%	7.3%	12.9%	38.8%	2.6%	26.0%	0.0%	15.7%
SK	0.0%	0.0%	0.3%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%

The national trends scenario describes a development of the European energy system until 2040, which aligns with the current national policies (ENTSOE and ENTSOG, 2022). Note that the scenario was published in early 2022, and some national targets have been adjusted since then.

Table C.6.: Relative RE capacity shares per EU country in the year 2040 in the scenarios *REF* and *High-RES* compared to the National Trends scenario in ENTSOE and ENTSOG (2022).

	2040								
	Solar PV			Wind onshore			Wind offshore		
	REF	High-RES	TYNDP National trends	REF	High-RES	TYNDP National trends	REF	High-RES	TYNDP National trends
BG	3.7%	0.0%	0.6%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
EE	0.1%	0.1%	0.2%	0.6%	0.9%	0.2%	2.1%	0.0%	0.6%
FI	1.4%	1.3%	0.7%	5.3%	3.7%	5.3%	5.9%	13.9%	3.1%
GR	11.4%	35.4%	1.7%	0.1%	0.0%	2.5%	0.0%	0.0%	0.2%
HR	0.0%	0.1%	0.3%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%
HU	0.0%	0.0%	2.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
IE	0.0%	0.0%	0.3%	6.3%	3.0%	1.6%	5.7%	0.0%	2.9%
LT	0.2%	0.1%	0.2%	0.9%	0.5%	0.6%	0.6%	0.0%	0.9%
LU	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LV	0.1%	0.2%	0.0%	0.3%	1.3%	0.1%	2.9%	7.4%	0.6%
PL	0.0%	0.0%	1.8%	7.9%	1.8%	1.8%	4.3%	11.2%	6.0%
PT	4.3%	2.0%	2.0%	0.0%	0.0%	3.4%	0.0%	0.0%	0.3%
RO	1.2%	0.0%	1.1%	0.0%	0.0%	1.7%	0.0%	0.0%	0.0%
SE	0.0%	0.0%	2.7%	8.5%	5.6%	4.9%	0.0%	0.0%	10.6%
SI	0.0%	0.0%	1.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
AT	0.0%	0.0%	5.5%	0.0%	0.0%	4.2%	0.0%	0.0%	0.0%
BE	0.0%	0.0%	3.0%	6.8%	1.3%	1.8%	2.7%	7.0%	3.6%
CZ	0.0%	0.0%	1.9%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
DE	0.0%	0.0%	23.2%	24.2%	3.6%	23.5%	17.1%	10.2%	24.9%
DK	0.0%	0.0%	1.7%	5.6%	32.1%	1.4%	39.5%	0.0%	7.2%
ES	21.8%	4.4%	14.2%	0.0%	0.0%	15.1%	0.0%	0.0%	0.7%
FR	0.0%	0.0%	10.7%	20.2%	13.5%	14.0%	0.0%	0.0%	16.8%
IT	55.8%	56.2%	11.9%	0.0%	0.0%	5.6%	0.0%	0.0%	2.6%
NL	0.0%	0.0%	7.7%	13.1%	32.7%	2.8%	19.2%	50.2%	18.7%
SK	0.0%	0.0%	0.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%

The national trends scenario describes a development of the European energy system until 2040, which aligns with the current national policies (ENTSOE and ENTSOG, 2022). Note that the scenario was published in early 2022, and some national targets have been adjusted since then.

D. Supplementary Material for Chapter 5

D.1. An Illustrative Two-by-Two Model of International Trade with LTCs

We want to illustrate our model of international trade with long-term contracts in the simple two-firm $i \in \{1,2\}$ two-country $j \in \{1,2\}$ case with symmetric trade costs $\tau > 0$ and zero internal costs. Firms 1 and 2 are located in countries 1 and 2, respectively, so that firm 1's home market is country 1, and firm 1's foreign market is country 2. Firms only have fixed costs $f_i > 0$ but zero variable costs $c_i = 0$ so that profits are given by

$$\pi_1 = p_1 x_{11} + (p_2 - \tau) x_{12} - f_1 \tag{D.1}$$

$$\pi_2 = (p_1 - \tau) x_{21} + p_2 x_{22} - f_2 \tag{D.2}$$

Demand in both markets is linear with

$$q_i = a_i - p_i / b_i \quad \Leftrightarrow \quad p_i = b_i (a_i - q_i) \tag{D.3}$$

Furthermore, let

$$A \equiv a_1 + a_2 \quad \text{and} \quad B \equiv [b_1^{-1} + b_2^{-1}]^{-1} \tag{D.4}$$

denote the sum of zero-price demand and the harmonic mean of the demand slope coefficients. Parameters A and a_i are expressed in the same units as demand and supply, and B and b_i are expressed as price increments per unit ($\$^2$/unit). Importantly, both firms have fixed capacity $\bar{x}_i$ so that

$$x_{11} + x_{12} = \bar{x}_1 \quad \text{and} \quad x_{21} + x_{22} = \bar{x}_2 \tag{D.5}$$

The first-order conditions for a profit maximum are simply given by maximizing the Lagrangean

$$\mathcal{L}_i = \pi + \lambda_i(\bar{x}_i - \sum_j x_{ij}) \tag{D.6}$$

with shadow price λ_i for the capacity constraint. This yields the four solutions

$$\begin{aligned} x_{11} &= [a_1 - x_{2,1} - \lambda_1/b_1]/2 && \text{(D.7)}\\ x_{12} &= [a_2 - x_{2,2} - (\lambda_1 + \tau)/b_2]/2 && \text{(D.8)}\\ x_{21} &= [a_1 - x_{1,1} - (\lambda_2 + \tau)/b_1]/2 && \text{(D.9)}\\ x_{22} &= [a_2 - x_{1,2} - \lambda_2/b_2]/2 && \text{(D.10)} \end{aligned}$$

There are four possible entry cases: (1) neither firm enters; (2) firm 1 enters alone; (3) firm 2 enters alone; or (4) both firms enter simultaneously. If either firm enters, each may serve one or two markets.

Consider first the case of a single firm entering the market, and assume it is firm 1. But which markets will firm 1 enter? As is apparent from the first-order conditions, firm 1 will enter market 1 if $\lambda_1 < a_1 b_1$ and enter market 2 if $\lambda_1 < a_2 b_2 - \tau$. The larger the trade cost τ, the less likely it is that firm 1 will enter the foreign market. If firm 1 only operates in its home market, the shadow price is $\lambda_1 = b_1(a_1 - 2\bar{x}_1)$ and the resulting market price is simply $p_1 = b_1(a_1 - \bar{x}_1)$. It is of course also possible that the firm only operates in the foreign market, if it is more profitable. Then the equilibrium price in that market is $p_2 = b_2(a_2 - \bar{x}_1)$, while the shadow price is $\lambda_1 = (a_2 - 2\bar{x}_1) - \tau$. The decision rule is therefore

$x_{11} > 0$	$x_{12} > 0$	Decision Rule
yes	no	$a_1 b_1 > a_2 b_2 - \tau$
no	yes	$a_1 b_1 < a_2 b_2 - \tau$
yes	yes	$a_1 b_1 = a_2 b_2 - \tau$

Entry into both markets is highly unlikely because it is a knife-edge situation where both markets needs to be equally profitable.

The more general case is that both firms will find it profitable to enter at the same time, in which case there is a number of permutations at the extensive margin. Each firm wants to serve the most profitable market. If markets are similar in size and τ is large, both firms will prefer serving their home markets only. They will not engage in the familiar "reciprocal dumping" to capture the monopolistic rents. The segmented market outcome requires that $a_1 b_1 > a_2 b_2 - \tau$ for firm 1 and $a_1 b_1 - \tau < a_2 b_2$ for firm 2. In other words, trade costs must be sufficiently high: $\tau > \max\{a_1 b_1/(a_2 b_2), a_2 b_2/(a_1 b_1)\}$.

The more likely scenario is that at least one firm will compete in both markets, and possibly both. Let us examine the case of both firms entering both markets. The two shadow prices compute as

$$\begin{aligned} \lambda_1 &= B(A - 2z_1 + z_2) \\ &- \tau b_1/(b_1 + b_2) \qquad \text{(D.11)} \\ \lambda_2 &= B(A - 2z_2 + z_1) \\ &- \tau b_2/(b_1 + b_2) \qquad \text{(D.12)} \end{aligned}$$

Thus shipments are

$$\begin{aligned} x_{11} &= \frac{\bar{x}_1 b_2 + \tau}{b_1 + b_2} + U \qquad \text{(D.13)} \\ x_{12} &= \frac{\bar{x}_1 b_1 - \tau}{b_1 + b_2} - U \qquad \text{(D.14)} \\ x_{21} &= \frac{\bar{x}_2 b_2 - \tau}{b_1 + b_2} + U \qquad \text{(D.15)} \\ x_{22} &= \frac{\bar{x}_2 b_1 + \tau}{b_1 + b_2} - U \qquad \text{(D.16)} \\ U &\equiv \frac{a_1 b_1 - a_2 b_2}{3(b_1 + b_2)} \qquad \text{(D.17)} \end{aligned}$$

These solutions indicate that rising trade costs boost domestic shipments and lower foreign shipments. The variable U captures how much larger market 1 is than market 2, so a positive U increases shipments to market 1, and a negative U increases shipments to market 2. The market prices follow as

$$\begin{aligned} p_1 &= a_1 b_1/3 + 2AB/3 - BX \qquad \text{(D.18)} \\ p_2 &= a_2 b_2/3 + 2AB/3 - BX \qquad \text{(D.19)} \end{aligned}$$

where $X \equiv \bar{x}_1 + \bar{x}_2$ is the total production capacity.

Exports from 1 to 2 will cease when trade costs exceed a viability threshold $\tau > b_1 \bar{x}_1 + (a_2 b_2 - a_1 b_1)/3$, and vice versa exports from 2 to 1 will cease when $\tau > b_2 \bar{x}_2 + (a_1 b_1 - a_2 b_2)/3$.

Will both firms find it profitable to enter? Essentially, this depends on the size of the fixed costs. This is precisely how sequential entry happens in an LTC model when f_i evolves over time due to subsidies or innovation.

The key to understanding the above model are two features: zero marginal production costs and capacity constraints for LTC projects. With zero marginal production costs, the role that variable costs play in a Cournot model is replaced by the shadow price of the capacity constraint: λ_i instead of c_i. Unlike the variable cost c_i, the shadow price λ_i is not independent of other producers. It is an economic variable that is determined simultaneously in the market place if there is more than one firm entering in a period. While it is possible to solve for the solution analytically in the 2×2 case, the difficult part is keeping track of the extensive margin: which firm enters which market given trade costs and relative market benefits, and which firm enters overall given profitability. In the main part of our paper we solve this issue by simultaneously solving numerically for the vectors of market-clearing prices p_j and shadow prices λ_i, allowing for the extensive margin to shift in numerous trade relationships.

D.2. Random Number Generation Techniques

In our simulation exercise we rely heavily on drawing from different distributions. Below we provide information on the specific methods we have used.

D.2.1. Heterogeneous Utilization

Utilization rates we draw from a Beta $B(\alpha, \beta)$ distribution where the scale parameters imply a mean of $\alpha/(\alpha + \beta)$ and a variance of $\alpha\beta/[(\alpha + \beta)^2(1 + \alpha + \beta)]$. We wish to draw numbers with an observational mean $\mu \in (0, 1)$ and a coefficient of variation ρ so that the standard deviation is given by $\rho\mu$. Then the shape parameters are determined by $\alpha = \mu z$ and $\beta = (1 - \mu)z$ with $z = (1 - \mu)/(\mu\rho^2) - 1$.

D.2.2. Fixed Cost Heterogeneity

For turquoise hydrogen projects we allow for a significant degree of technology uncertainty as there are competing technological methods. To simulate this type of differentiation, we draw fixed costs from a log-normal distribution $\mathrm{LN}(\mu, \nu)$ where μ and ν are the mean and variance of that distribution. We calibrate this to the observable mean $\bar{f}$ and allow for heterogeneity through a coefficient of variation ρ_f. Then the mean and standard deviation of the log-normal distribution are given by parameters $\mu = \ln(\bar{f}) - \nu/2$ and $\nu = \ln(1 + \rho_f^2)$. For turquoise hydrogen we use the same variation for the variable cost as for blue hydrogen.

D.2.3. Capacity Heterogeneity

We are also apportioning capacity C among n firms. For this purpose we draw n random numbers x_i from a normal distribution with mean zero and standard deviation equal to the coefficient of variation ρ_x.

$$\mathrm{softmax}(x_i; x_{-i}) \equiv \frac{\exp(x_i)}{\sum_{j=1}^{n} \exp(x_j)} \tag{D.20}$$

Then the capacity shares are given by $y_i = \mathrm{softmax}(x_i)$, and it is easy to see that $\sum_{i=1}^{n} y_i = 1$. Multiplying the total capacity with the random capacity shares provides a heterogeneous capacity distribution with observational mean C/n, and an observational coefficient of variation approximated by ρ.

D.2.4. Heterogeneous Variable Costs

The variable cost of producing blue hydrogen from natural gas increases with available capacity. This is tantamount to drawing random numbers from a Pareto distribution where $\bar{x}$ is the initial cost and parameter α captures the rate of cost increase, which we estimate from data sources. We draw random numbers from a Pareto distribution with parameters $\bar{x}$ and α indirectly. It is well understood that such random numbers can be obtained by drawing a uniform random variable $u_i \in (0, 1]$ and transforming it as $x_i = \bar{x} \cdot u_i^{-1/\alpha} \geq \bar{x}$, so that x_i is Pareto distributed. In some instances we are unable to estimate increasing costs, and α would tend to infinity as the cost structure is completely flat or exhibits a jump between two natural gas fields. In this case we pick randomly from two natural gas prices with a probability that matches the capacity shares of the two gas fields.

Bibliography

Abada, I., Ehrenmann, A., Smeers, Y., et al., 2014. Endogenizing long-term contracts in gas market models. Center for Operations Research and Econometrics (CORE) Discussion Papers.

Abdin, Z., Zafaranloo, A., Rafiee, A., Mérida, W., Lipiński, W., Khalilpour, K.R., 2020. Hydrogen as an energy vector. Renewable and Sustainable Energy Reviews 120, 109620.

ACER, 2019. Market Monitoring Report 2018 - Gas Wholesale Market Volume. Monitoring Report. Agency for the Cooperation of Energy Regulators (ACER) and Council of European Energy Regulators (CEER). Ljubljana.

ACER, 2021a. Key facts about gas in the EU. Factsheet. European Union Agency for the Cooperation of Energy Regulators (ACER). Ljubljana. URL: https://acer.europa.eu/en/Gas/Documents/ACER_FACT-SHEETS_2021-07_02.pdf. accessed: 2023-08-02.

ACER, 2021b. Market Monitoring Report 2019 – Electricity Wholesale Markets Volume. Monitoring Report. Agency for the Cooperation of Energy Regulators (ACER) and Council of European Energy Regulators (CEER). Ljubljana.

Alsulaiman, A., 2023. Renewable Hydrogen Import Routes into the EU, in: OIES Paper ET24, The Oxford Institute for Energy Studies (OIES).

Amelin, M., 2004. On Monte Carlo Simulation and Analysis of Electricity Markets. Doctoral thesis. Royal Institute of Technology. Stockholm.

Anderson, D., Leach, M., 2004. Harvesting and redistributing renewable energy: on the role of gas and electricity grids to overcome intermittency through the generation and storage of hydrogen. Energy Policy 32, 1603–1614.

Andersson, J., Grönkvist, S., 2019. Large-scale storage of hydrogen. International Journal of Hydrogen Energy 44, 11901–11919.

André, J., Auray, S., De Wolf, D., Memmah, M.M., Simonnet, A., 2014. Time development of new hydrogen transmission pipeline networks for france. International Journal of Hydrogen Energy 39, 10323–10337.

Antweiler, W., 2016. Cross-border trade in electricity. Journal of International Economics 101, 42–51.

Antweiler, W., Schlund, D., 2023. The emerging international trade in hydrogen and the role of environmental, innovation, and trade policies, in: USAEE Working Paper 23-589.

Antweiler, W and Schlund, D, 2024. The Emerging International Trade in Hydrogen: Environmental Policies, Innovation, and Trade Dynamics. URL: `https://data.mendeley.com/datasets/jzfs2zt89t/1`. accessed: 2024-15-07.

Appleby, A., 1990. From sir william grove to today: fuel cells and the future. Journal of Power Sources 29, 3–11.

Bai, F., Zhao, F., Liu, X., Mu, Z., Hao, H., Liu, Z., 2023. A techno-economic analysis of cross-regional renewable hydrogen supply routes in china. International Journal of Hydrogen Energy 48, 37031–37044.

Balistreri, E.J., Böhringer, C., Rutherford, T.F., 2017. Carbon policy and the structure of global trade. The World Economy 41, 194–221.

Ball, M., Wietschel, M., 2009a. The future of hydrogen–opportunities and challenges. International Journal of Hydrogen Energy 34, 615–627.

Ball, M., Wietschel, M., 2009b. The hydrogen economy: opportunities and challenges. Cambridge University Press, Cambridge.

Bauer, C., Treyer, K., Antonini, C., et al., 2022. On the climate impacts of blue hydrogen production. Sustainable Energy Fuels 6, 66–75.

Bauer, S., 2017. Underground Sun Storage. Final Report. RAG AG, Axiom, Verbund AG, Montanuniversität Leoben, Universität für Bodenkultur Wien, Energieinstitut an der Johannes Keplert Universität Linz. `https://www.underground-sun-storage.at/fileadmin/bilder/03_NEU_SUNSTORAGE/Downloads/Underground_Sun.Storage_Publizierbarer_Endbericht_English.pdf`. Accessed: 2022-16-05.

Baufumé, S., Grüger, F., Grube, T., Krieg, D., Linssen, J., Weber, M., Hake, J.F., Stolten, D., 2013. Gis-based scenario calculations for a nationwide german hydrogen pipeline infrastructure. International Journal of Hydrogen Energy 38, 3813–3829.

Baumann, C., Schuster, R., Moser, A., 2013. Economic potential of power-to-gas energy storages. 2013 10th International Conference on the European Energy Market (EEM) , 1–6.

Bernhofen, D.M., 1999. Intra-industry trade and strategic interaction: Theory and evidence. Journal of International Economics 47, 225–244.

Bhat, P., 2021. Carbon needs to cost at least $100/tonne now to reach net zero by 2050: Reuters poll. https://www.reuters.com/business/cop/carbon-needs-cost-least-100tonne-now-reach-net-zero-by-2050-2021-10-25/. Accessed: 2022-18-09.

BNetzA, 2021. smard. Bundesnetzagentur (BNetzA). URL: https://www.smard.de/en. accessed: 2021-08-30.

BNetzA, BKartA, 2020. Monitoring report 2019. Report. Bundesnetzagentur and Bundeskartellamt. Bonn. URL: https://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/Areas/ElectricityGas/CollectionCompanySpecificData/Monitoring/MonitoringReport2019.pdf?__blob=publicationFile&v=2. accessed: 2021-02-16.

Bocklet, J., Hintermayer, M., Schmidt, L., Wildgrube, T., 2019. The reformed eu ets-intertemporal emission trading with restricted banking. Energy Economics 84, 104486.

Bockris, J.O., 1972. A hydrogen economy. Science 176, 1323–1323.

Bockris, J.O.M., 2013. The hydrogen economy: Its history. International Journal of Hydrogen Energy 38, 2579–2588.

Bosch, J., Staffell, I., Hawkes, A.D., 2017. Temporally-explicit and spatially-resolved global onshore wind energy potentials. Energy 131, 207–217.

Bosch, J., Staffell, I., Hawkes, A.D., 2019. Global levelised cost of electricity from offshore wind. Energy 189, 116357.

Braeuer, F., Finck, R., McKenna, R., 2020. Comparing empirical and model-based approaches for calculating dynamic grid emission factors: An application to co2-minimizing storage dispatch in germany. Journal of Cleaner Production 266, 121588.

Brander, J., Krugman, P., 1983. A 'reciprocal dumping' model of international trade. Journal of International Economics 15, 313–321.

Brändle, G., Schönfisch, M., Schulte, S., 2021. Estimating long-term global supply costs for low-carbon hydrogen. Applied Energy 302, 117481.

Breyer, C., Tsupari, E., Tikka, V., Vainikka, P., 2015. Power-to-gas as an emerging profitable business through creating an integrated value chain. Energy Procedia 73, 182–189.

Burger, M., Klar, B., Müller, A., Schindlmayr, G., 2003. A spot market model for pricing derivatives in electricity markets. Quantitative finance 4, 109.

Buttler, A., Spliethoff, H., 2018. Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: A review. Renewable and Sustainable Energy Reviews 82, 2440–2454.

Böhringer, C., Fischer, C., Rosendahl, K.E., Rutherford, T.F., 2022. Potential impacts and challenges of border carbon adjustments. Nature Climate Change 12, 11–29.

Böhringer, C., Schneider, J., Asane-Otto, E., 2021. Trade in carbon and carbon tariffs. Environmental and Resource Economics 78, 669–708.

CEER, 2018. Status Review of Renewable Support Schemes in Europe for 2016 and 2017. Public report. Council of European Energy Regulators (CEER). Brussels. URL: `https://www.ceer.eu/documents/104400/-/-/80ff3127-8328-52c3-4d01-0acbdb2d3bed`. accessed: 2021-03-06.

Cerniauskas, S., Junco, A.J.C., Grube, T., Robinius, M., Stolten, D., 2020. Options of natural gas pipeline reassignment for hydrogen: Cost assessment for a germany case study. International Journal of Hydrogen Energy 45, 12095–12107.

Cherniwchan, J., Taylor, M.S., 2022. International trade and the environment: Three remaining empirical challenges. NBER Working Paper 30020.

Chevrier, V., 2018. Hydrogen uses in ironmaking. URL: `https://www.energy.gov/sites/prod/files/2018/08/f54/fcto-h2-scale-kickoff-2018-8-chevrier.pdf`. accessed: 2022-05-10.

Chiappinelli, O., Neuhoff, K., 2020. Time-Consistent Carbon Pricing: The Role of Carbon Contracts for Differences. DIW Berlin Discussion Paper no. 1859.

Clúa, J.G.G., Mantz, R.J., De Battista, H., 2018. Optimal sizing of a grid-assisted wind-hydrogen system. Energy Conversion and Management 166, 402–408.

Conte, B., Desmet, K., Nagy, D.K., Rossi-Hansberg, E., 2021. Local sectoral specialization in a warming world. Journal of Economic Geography 21, 493–530.

CRE, 2019. Wholesale Markets Observatory 1st quarter 2019. Report. Commission de Régulation de l'Énergie (CRE). URL: `https://www.cre.fr/en/Documents/Publications/Observatoire-des-marches/electricity-natural-gas-and-co2-market-observatory-1st-quarter-of-2019`. accessed: 2021-02-16.

Creti, A., Villeneuve, B., 2004. Long-term contracts and take-or-pay clauses in natural gas markets. Energy Studies Review 13, 75–94.

DBI, 2022. Wasserstoff speichern - so viel ist sicher. Technical Report. DBI Gas- und Umwelltechnik GmbH. In German.

De Blasio, N., Pflugmann, F., 2020. Geopolitical and market implications of renewable hydrogen: New dependencies in a low-carbon energy world. Belfer Center for Science and International Affairs, Harvard Kennedy School of Government.

DEA, 2022. Technology data for generation of electricity and district heating. Technical Report. Danish Energy Agenca (DEA). Esbjerg.

Deloitte, 2023. Study on hydrogen in ports and industrial coastal areas. Report. prepared for the Clean Hydrogen Partnership. Brussels.

Dieckhöner, C., 2012. Simulating security of supply effects of the nabucco and south stream projects for the european natural gas market. The Energy Journal 33, 153–182.

Dieckhöner, C., Lochner, S., Lindenberger, D., 2013. European natural gas infrastructure: The impact of market developments on gas flows and physical market integration. Applied Energy 102, 994–1003.

Dincer, I., Acar, C., 2017. Innovation in hydrogen production. International Journal of Hydrogen Energy 42, 14843–14864.

Dodds, P.E., Staffell, I., Hawkes, A.D., Li, F., Grünewald, P., McDowall, W., Ekins, P., 2015. Hydrogen and fuel cell technologies for heating: A review. International Journal of Hydrogen Energy 40, 2065–2083.

Dolci, F., Thomas, D., Hilliard, S., Guerra, C.F., Hancke, R., Ito, H., Jegoux, M., Kreeft, G., Leaver, J., Newborough, M., Proost, J., Robinius, M., Weidner, E., Mansilla, C., Lucchese, P., 2019. Incentives and legal barriers for power-to-hydrogen pathways: An international snapshot. International Journal of Hydrogen Energy 44, 11394–11401.

Dueñas, P., Gil, M., Leung, T., Reneses, J., 2013. Gas-electricity coordination in competitive markets under renewable energy uncertainty. ESD Working Paper Series no. 2013-19.

DVGW, 2019. Mehr Wasserstoff technisch sicher verankern. Press release. Deutscher Verband des Gas- und Wasserfaches e.V. (DVGW). `https://www.dvgw.de/der-dvgw/aktuelles/presse/presseinformationen/dvgw-presseinformation-vom-09042019-mehr-wasserstoff-technisch-sicher-verankern`, accessed: 2021-01-09.

Eaton, J., Kortum, S., Sotelo, S., 2013. International trade: Linking micro and macro, in: Acemoglu, D., Arellano, M., Dekel, E. (Eds.), Advances in Economics and Econometrics: Tenth World Congress. Cambridge University Press, pp. 329–370.

EHB, 2023. The European Hydrogen Backbone (EHB) initiative. URL: `https://ehb.eu/`. accessed: 2023-07-17.

Ehrlich, L.G., Klamka, J., Wolf, A., 2015. The potential of decentralized power-to-heat as a flexibility option for the german electricity system: A microeconomic perspective. Energy Policy 87, 417–428.

El-Emam, R.S., Özcan, H., 2019. Comprehensive review on the techno-economics of sustainable large-scale clean hydrogen production. Journal of Cleaner Production 220, 593–609.

Elberg, C., Hagspiel, S., 2015. Spatial dependencies of wind power and interrelations with spot price dynamics. European Journal of Operational Research 241, 260–272.

Elgowainy, A., Mintz, M., Lee, U., Stephens, T., Sun, P., Reddi, K., Zhou, Y., Zang, G., Ruth, M., Jadun, P., et al., 2020. Assessment of Potential Future

Demands for Hydrogen in the United States. Technical Report. Argonne National Lab.(ANL), Argonne, IL (United States).

ElSayed, M., Aghahosseini, A., Caldera, U., Breyer, C., 2023. Analysing the techno-economic impact of e-fuels and e-chemicals production for exports and carbon dioxide removal on the energy system of sunbelt countries–case of egypt. Applied Energy 343, 121216.

ENA, 2021. Britain's hydrogen network plan. Energy Networks Association (ENA). URL: https://www.energynetworks.org/industry-hub/resource-library/britains-hydrogen-network-plan.pdf. accessed: 2023-07-17.

Engie, 2021. How can we decarbonise aviation. https://innovation.engie.com/en/news/interview/green-mobility/how-can-we-decarbonise-aviation/26159. Accessed: 2022-17-06.

ENTSOE, ENTSOG, 2022. Ten-Year Network Development Plan (TYNDP) 2022. Scenario Report. European Network of Transmission System Operators for Gas (ENTSOG) and European Network of Transmission System Operators for Electricity (ENTSOE). Brussels.

ENTSOG, 2018. Ten-Year Network Development Plan (TYNDP 2018). Infrastructure Report. European Network of Transmission System Operators for Gas (ENTSOG). Brussels.

ENTSOG, 2018. Ten-Year Network Development Plan (TYNDP) 2018. Report. European Network of Transmission System Operators for Gas (ENTSOG). Brussels.

ENTSOG, 2019. Transmission Capacity Map 2019. European Network of Transmission System Operators for Gas (ENTSOG). URL: https://entsog.eu/maps#transmission-capacity-map-2019. accessed: 2020-08-22.

ENTSOG and ENTSOE, 2020. Ten-Year Network Development Plan (TYNDP 2020). Scenario Report. European Network of Transmission System Operators for Gas (ENTSOG) and European Network of Transmission System Operators for Electricity (ENTSOE). Brussels.

ENTSOG and ENTSOE, 2023. Ten-Year Network Development Plan (TYNDP) 2022. Report. European Network of Transmission System Operators for Gas

(ENTSOG) and European Network of Transmission System Operators for Electricity (ENTSOE). Brussels.

ESMAP, 2020. Global photovoltaic power potential by country. Study. World Bank. Washingtion, DC.

EUC, 2023. Fit for 55. Council of the European Union (EUC). URL: https://www.consilium.europa.eu/en/policies/green-deal/fit-for-55-the-eu-plan-for-a-green-transition/. accessed: 2023-08-02.

European Commission, 2018. Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources. URL: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32018L2001. accessed: 2022-01-06.

European Commission, 2020a. A European Green Deal. URL: https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en. accessed: 2020-01-21.

European Commission, 2020b. A hydrogen strategy for a climate-neutral Europe (COM(2020) 301 final). Communication. Brussels. URL: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52020DC0301&from=EN. accessed: 2021-03-06.

European Commission, 2021. Regulation of the European Parliament and the Council on the internal markets for renewable and natural gases and for hydrogen. URL: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52021PC0804. accessed: 2023-08-02.

European Commission, 2022. REPowerEU plan. URL: https://commission.europa.eu/publications/key-documents-repowereu_en. accessed: 2022-07-26.

European Commission and Joint Research Centre and Dolci, F, 2018. Green hydrogen opportunities in selected industrial processes – Workshop summary report (26th of June 2018, Centre Albert Borschette, Brussels, Belgium). Publications Office, Luxembourg.

Eurostat, 2008. NACE Rev. 2 - Statistical classification of economic activities. Methodologies and Working papers. Publications Office of the European Union. Luxembourg. Accessed: 2020-08-15.

Eurostat, 2020. Natural gas price statistics. URL: https://ec.europa.eu/eurostat/web/main/data/database. accessed: 2021-03-06.

Eurostat, 2023. Supply, transformation and consumption of gas. URL: https://ec.europa.eu/eurostat/web/main/data/database. accessed: 02-08-2023.

Fasihi, M., Bogdanov, D., Breyer, C., 2016. Techno-economic assessment of power-to-liquids (ptl) fuels production and global trading based on hybrid pv-wind power plants. Energy Procedia 99, 243–268.

Faye, O., Szpunar, J., Eduok, U., 2022. A critical review on the current technologies for the generation, storage, and transportation of hydrogen. International Journal of Hydrogen Energy 47, 13771–13802.

Ferrero, D., Gamba, M., Lanzini, A., Santarelli, M., 2016. Power-to-gas hydrogen: techno-economic assessment of processes towards a multi-purpose energy carrier. Energy Procedia 101, 50–57.

Finon, D., Menanteau, P., 2003. The static and dynamic efficiency of instruments of promotion of renewables. Energy Studies Review 12, 53–82.

Fleschutz, M., Bohlayer, M., Braun, M., Henze, G., Murphy, M.D., 2021. The effect of price-based demand response on carbon emissions in european electricity markets: The importance of adequate carbon prices. Applied Energy 295, 117040.

FNB, 2023. Hydrogen core network. Vereinigung der Fernleitungsnetzbetreiber Gas e.V. (FNB). URL: https://fnb-gas.de/en/hydrogen-core-network/. accessed: 2023-07-17.

Fragiacomo, P., Genovese, M., 2020. Technical-economic analysis of a hydrogen production facility for power-to-gas and hydrogen mobility under different renewable sources in southern italy. Energy Conversion and Management 223, 113332.

Franzmann, D., Heinrichs, H., Lippkau, F., Addanki, T., Winkler, C., Buchenberg, P., Hamacher, T., Blesl, M., Linßen, J., Stolten, D., 2023. Green hydrogen cost-potentials for global trade. International Journal of Hydrogen Energy 48, 33062–33076.

Frischmuth, F., Schmitz, R., Härtel, P., 2022. Imagine–market-based multi-period planning of european hydrogen and natural gas infrastructure, in: 2022 18th International Conference on the European Energy Market (EEM), IEEE, Ljubljana, Slovenia. pp. 1–11.

Galyas, A.B., Kis, L., Tihanyi, L., Szunyog, I., Vadaszi, M., Koncz, A., 2023. Effect of hydrogen blending on the energy capacity of natural gas transmission networks. International Journal of Hydrogen Energy 48, 14795–14807.

Gasunie, 2023. Hydrogen network Netherlands. URL: https://www.gasunie.nl/en/projects/hydrogen-network-netherlands. accessed: 2023-07-17.

GEM, 2023. GEM wiki global gas infrastructure tracker. Global Energy Monitor (GEM). URL: https://globalenergymonitor.org/projects/global-gas-infrastructure-tracker/. accessed: between October 2022 and July 2023.

van Gessel, S., Hajibeygi, H., 2023. Hydrgen TCP-task 42 underground hydrogen storage. Final Report. International Energy Agency (IEA). Paris.

GIE, 2018. GIE Storage Map. Gas Infrastructure Europe (GIE). URL: https://gie.eu/index.php/gie-publications/maps-data/gse-storage-map. accessed: 2020-08-22.

GIE, 2019. GIE LNG Map. Gas Infrastructure Europe (GIE). URL: https://gie.eu/index.php/gie-publications/maps-data/lng-map. accessed: 2020-08-22.

GIE, 2021. GIE Storage Database. Gas Infrastructure Europe (GIE). URL: https://www.gie.eu/transparency/databases/storage-database/. accessed: 2023-08-10.

GIE, 2022. GIE LNG databse. Gas Infrastructure Europe (GIE). URL: https://www.gie.eu/transparency/databases/lng-database/. accessed: 2023-08-09.

GIE, 2023. GIE aggregated gas storage inventory. Gas Infrastructure Europe (GIE). URL: https://agsi.gie.eu/. accessed: 2023-08-04.

Gierkink, M., Cam, E., Diers, H., Keutz, J., Kopp, J., Lilienkamp, A., Moritz, M., Wiedmann, M., Zinke, J., 2022. Scenarios for the price development of energy commodities. Study. Institute of Energy Economics at the University of Cologne (EWI). Cologne.

Gillingham, K., Stock, J.H., 2018. The cost of reducing greenhouse gas emissions. Journal of Economic Perspectives 32, 53–72.

Glenk, G., Reichelstein, S., 2019. Economics of converting renewable power to hydrogen. Nature Energy 4, 216–222.

Glenk, G., Reichelstein, S., 2020. Synergistic value in vertically integrated power–to–gas energy systems. Production and Operations Management 29, 526–546.

Götz, M., Lefebvre, J., Mörs, F., Koch, A.M., Graf, F., Bajohr, S., Reimert, R., Kolb, T., 2016. Renewable power-to-gas: A technological and economic review. Renewable Energy 85, 1371–1390.

Graetz, J., 2009. New approaches to hydrogen storage. Chemical Society Reviews 38, 73–82.

Green, R., Hu, H., Vasilakos, N., 2011. Turning the wind into hydrogen: The long-run impact on electricity prices and generating capacity. Energy Policy 39, 3992–3998.

de Groot, M., Crijns-Graus, W., Harmsen, R., 2017. The effects of variable renewable electricity on energy efficiency and full load hours of fossil-fired power plants in the european union. Energy 138, 575–589.

Gross, R., Hanna, R., 2019. Path dependency in provision of domestic heating. Nature Energy 4, 358–364.

Haas, R., Eichhammer, W., Huber, C., Langniss, O., Lorenzoni, A., Madlener, R., Menanteau, P., Morthorst, P.E., Martins, A., Oniszk, A., Schleich, J., Smith, A., Vass, Z., Verbruggen, A., 2004. How to promote renewable energy systems successfully and effectively. Energy Policy 32, 833–839.

Haeseldonckx, D., D'haeseleer, W., 2007. The use of the natural gas pipeline infrastructure for hydrogen transport in a changing market structure. International Journal of Hydrogen Energy 32, 1381–1386.

Hagemann, S., 2013. Price determinants in the german intraday market for electricity: An empirical analysis. EWL Working Papier 18/13, University of Duisburg-Essen, Chair for Management Science and Energy Economics, Essen.

Head, K., Mayer, T., 2014. Gravity equations: Toolkit, cookbook, workhorse, in: Gopinath, G., Helpman, E., Rogoff, K. (Eds.), Handbook of International Economics. volume 4. chapter 3, pp. 131–195.

Helgeson, B., Peter, J., 2020. The role of electricity in decarbonizing European road transport – Development and assessment of an integrated multi-sectoral model. Applied Energy 262, 114365.

Hendriks, C., Graus, W., van Bergen, F., 2004. Global carbon dioxide storage potential and costs. Ecofys, Utrecht 64.

Heuser, P.M., Grube, T., Heinrichs, H., Robinius, M., Stolten, D., 2020. Worldwide hydrogen provision scheme based on renewable energy. Preprints .

Holland, S.P., Hughes, J.E., Knittel, C.R., 2009. Greenhouse Gas Reductions under Low Carbon Fuel Standards? American Economic Journal: Economic Policy 1, 106–146.

Hölling, M., Weng, M., Gellert, S., 2017. Bewertung der Herstellung von Eisenschwamm unter Verwendung von Wasserstoff. Stahl und Eisen 137, 47–53. In German.

Horschig, T., Adams, P.W., Gawel, E., Thrän, D., 2018. How to decarbonize the natural gas sector: A dynamic simulation approach for the market development estimation of renewable gas in Germany. Applied Energy 213, 555–572.

Howarth, R.W., Jacobsen, M.Z., 2021. How green is blue hydrogen? Energy Science & Engineering 9, 1676–1687.

Hubbard, R.G., Weiner, R.J., 1986. Regulation and long-term contracting in us natural gas markets. The Journal of Industrial Economics , 71–79.

Huber, J., Lohmann, K., Schmidt, M., Weinhardt, C., 2021. Carbon efficient smart charging using forecasts of marginal emission factors. Journal of Cleaner Production 284, 124766.

Hurtubia, B., Sauma, E., 2021. Economic and environmental analysis of hydrogen production when complementing renewable energy generation with grid electricity. Applied Energy 304, 117739.

Hwang, H.T., Varma, A., 2014. Hydrogen storage for fuel cell vehicles. Current Opinion in Chemical Engineering 5, 42–48.

Hychico, 2018. Hychico project website. http://www.hychico.com.ar/eng/index.html. Accessed: 2022-16-05.

Hydrogen Europe, 2018. HyLAW Online Database. URL: https://www.hylaw.eu/. accessed: 2020-12-22.

Hystock, 2022. Hystock project website. https://www.hystock.nl/en. Accessed: 2022-16-05.

IEA, 2019. The Future of Hydrogen. Report. International Energy Agency (IEA). Paris. URL: https://www.iea.org/reports/the-future-of-hydrogen. accessed: 2020-12-22.

IEA, 2020. World Energy Outlook 2020. Report. International Energy Agency (IEA). Paris. URL: https://www.iea.org/reports/world-energy-outlook-2020. accessed: 2021-02-16.

IEA, 2021a. Global Hydrogen Review 2021. Report. International Energy Agency (IEA). Paris. URL: https://www.iea.org/reports/global-hydrogen-review-2021. accessed: 2022-07-06.

IEA, 2021b. Hydrogen Project Database. https://www.iea.org/data-and-statistics/data-product/hydrogen-projects-database. Accessed: 2022-6-17.

IEA, 2021c. Proving the viability of underground hydrogen storage. Technology Report. International Energy Agency (IEA). URL: https://www.iea.org/articles/proving-the-viability-of-underground-hydrogen-storage. accessed: 2022-16-05.

IEA, 2021d. World Energy Outlook 2021. https://www.oecd-ilibrary.org/content/publication/14fcb638-e.

IEA, 2021e. World energy statistics. https://www.oecd-ilibrary.org/content/data/data-00510-en. Accessed: 2022-05-02.

IEA, 2022a. Global hydrogen review 2022. Report. International Energy Agency (IEA). Paris.

IEA, 2022b. World Energy Outlook 2022. Report. International Energy Agency (IEA). Paris. URL: https://www.iea.org/reports/world-energy-outlook-2022.

IEA, 2023a. Global hydrogen review 2023. Report. International Energy Agency (IEA). Paris.

IEA, 2023b. World Energy Outlook 2023. Report. International Energy Agency (IEA). Paris. URL: https://www.iea.org/reports/world-energy-outlook-2023.

IETA, 2022. Ghg market sentiment survey 2022. https://www.ieta.org/resources/Documents/IETA%20GHG%20Market%20Sentiment%20Survey%20Report%202022.pdf. International Emissions Trading Association (IETA). Accessed: 2022-10-09.

Ioannis, T., Wouter, N., Dalius, T., Pablo, R.C., 2020. Towards net-zero emissions in the EU energy system by 2050. Publications Office of the European Union, Luxembourg.

IRENA, 2022a. Global Hydrogen Trade to meet the 1.5°C- Part I Trade Outlook for 2050 and Way Forward. https://www.irena.org/publications/2022/Apr/Global-hydrogen-trade-Part-II. International Renewable Energy Agency (IRENA). Accessed: 2022-29-08.

IRENA, 2022b. Global Hydrogen Trade to meet the 1.5°C- Part II Technology Review of Hydrogen Carriers. https://www.irena.org/publications/2022/Jul/Global-Hydrogen-Trade-Outlook. International Renewable Energy Agency (IRENA). Accessed: 2022-02-09.

IRENA, 2023. World energy transitions outlook 2023: 1.5°Cpathway. https://www.irena.org/Publications/2023/Nov/World-Energy-Transitions-Outlook-2023-vol2. International Renewable Energy Agency (IRENA). Accessed: 2023-21-08.

Jørgensen, C., Ropenus, S., 2008. Production price of hydrogen from grid connected electrolysis in a power market with high wind penetration. International Journal of Hydrogen Energy 33, 5335–5344.

Kakoulaki, G., Kougias, I., Taylor, N., Dolci, F., Moya, J., Jäger-Waldau, A., 2021. Green hydrogen in europe–a regional assessment: Substituting existing production with electrolysis powered by renewables. Energy Conversion and Management 228, 113649.

Kildegaard, A., 2008. Green certificate markets, the risk of over-investment, and the role of long-term contracts. Energy Policy 36, 3413–3421.

Kintner-Meyer, M.C., Conzelmann, G., Kim, H., Zhou, N., DeStephano, P., Durga, S., Elgowainy, A., Hamilton, B., Kanudia, A., Khanna, N., et al., 2022. The Net Zero World Initiative's Preliminary Analysis of Decarbonization Pathways for Five Countries. Technical Report. Lawrence Berkeley National Lab.(LBNL), Berkeley, CA (United States).

Koirala, B., Hers, S., Morales-España, G., Özdemir, Ö., Sijm, J., Weeda, M., 2021. Integrated electricity, hydrogen and methane system modelling framework: Application to the dutch infrastructure outlook 2050. Applied Energy 289, 116713.

Kopp, M., Coleman, D., Stiller, C., Scheffer, K., Aichinger, J., Scheppat, B., 2017. Energiepark mainz: Technical and economic analysis of the worldwide largest power-to-gas plant with pem electrolysis. International Journal of Hydrogen Energy 42, 13311–13320.

Kreuter, W., Hofmann, H., 1998. Electrolysis: the important energy transformer in a world of sustainable energy. International Journal of Hydrogen Energy 23, 661–666.

Krieg, D., 2012. Konzept und Kosten eines Pipelinesystems zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff. volume 144. Forschungszentrum Jülich, Jülich.

Kulakov, S., Ziel, F., 2021. The impact of renewable energy forecasts on intraday electricity prices. Economics of Energy & Environmental Policy 10.

Lambert, M., 2020. EU Hydrogen Strategy - A case for urgent action towards implementation, in: Oxford Energy Comment, The Oxford Institute for Energy Studies.

Lambert, M., Schulte, S., 2021. Contrasting european hydrogen pathways: An analysis of differing approaches in key markets, in: OIES Paper: NG166, The Oxford Institute for Energy Studies. pp. 1–51.

Lazard, 2021a. Lazard's levelized cost of energy analysis–version 15.0. https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf. Accessed: 2022-26-08.

Lazard, 2021b. Lazard's levelized cost of hydrogen analysis–version 2.0. https://www.lazard.com/media/451922/lazards-levelized-cost-of-hydrogen-analysis-version-20-vf.pdf. Accessed: 2022-26-08.

Leung, D.Y., Caramanna, G., Maroto-Valer, M.M., 2014. An overview of current status of carbon dioxide capture and storage technologies. Renewable and Sustainable Energy Reviews 39, 426–443.

Lippkau, F., Franzmann, D., Addanki, T., Buchenberg, P., Heinrichs, H., Kuhn, P., Hamacher, T., Blesl, M., 2023. Global hydrogen and synfuel exchanges in an emission-free energy system. Energies 16, 3277.

Lochner, Stefan; Bothe, D., 2007. From Russia with gas: an analysis of the Nord Stream pipeline's impact on the European Gas Transmission System with the TIGER-Model. EWI Working Papers no. 07/02.

Lochner, S., 2011a. Identification of congestion and valuation of transport infrastructures in the European natural gas market. Energy 36, 2483–2492.

Lochner, S., 2011b. Modeling the european natural gas market during the 2009 russian–ukrainian gas conflict: Ex-post simulation and analysis. Journal of Natural Gas Science and Engineering 3, 341–348.

Lochner, S., 2011c. The Economics of Natural Gas Infrastructure Investments Theory and Model-based Analysis for Europe. Ph.D. thesis. Universität Köln. Cologne.

Luck, L., Larscheid, P., Maaz, A., Moser, A., 2017. Economic potential of water electrolysis within future electricity markets, in: 2017 14th International Conference on the European Energy Market (EEM), IEEE. pp. 1–6.

Lynch, M., Devine, M.T., Bertsch, V., 2019. The role of power-to-gas in the future energy system: Market and portfolio effects. Energy 185, 1197–1209.

Mantzos, L., Wiesenthal, T., Neuwahl, F., Roszai, M., 2019. The POTEnCIA Central Scenario: An EU Energy Outlook to 2050. Publications Office of the European Union, Luxembourg.

Marinelli, M., Cutululis, N.A., Hahmann, A.N., 2014. Pan European climate data. Technical University of Denmark (DTU).

Matute, G., Yusta, J.M., Beyza, J., Correas, L.C., 2021. Multi-state techno-economic model for optimal dispatch of grid connected hydrogen electrolysis systems operating under dynamic conditions. International Journal of Hydrogen Energy 46, 1449–1460.

Matute, G., Yusta, J.M., Correas, L.C., 2019. Techno-economic modelling of water electrolysers in the range of several mw to provide grid services while generating hydrogen for different applications: A case study in spain applied to mobility with fcevs. International Journal of Hydrogen Energy 44, 17431–17442.

Melaina, M.W., Antonia, O., Penev, M., 2013. Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues. Technical Report. National Renewable Energy Laboratory (NREL).

Menanteau, P., Finon, D., Lamy, M.L., 2001. Prices versus quantities: Environmental policies for promoting the development of renewable energy, in: Institut d'économie et de politique de l'énergie.

Menanteau, P., Finon, D., Lamy, M.L., 2003. Prices versus quantities: Choosing policies for promoting the development of renewable energy. Energy Policy 31, 799–812.

Molburg, J.C., Doctor, R.D., 2003. Hydrogen from steam-methane reforming with CO2 capture, in: 20th annual international Pittsburgh coal conference, pp. 1–20.

Møller, K.T., Jensen, T.R., Akiba, E., Li, H.w., 2017. Hydrogen-a sustainable energy carrier. Progress in Natural Science: Materials International 27, 34–40.

Moraga, J.L., Mulder, M., Perey, P., 2019. Future markets for renewable gases and hydrogen. Report. Centre on Regulation in Europe (CERRE).

Moreno-Benito, M., Agnolucci, P., Papageorgiou, L.G., 2017. Towards a sustainable hydrogen economy: Optimisation-based framework for hydrogen infrastructure development. Computers & Chemical Engineering 102, 110–127.

Moritz, M., Schönfisch, M., Schulte, S., 2023. Estimating global production and supply costs for green hydrogen and hydrogen-based green energy commodities. International Journal of Hydrogen Energy 48, 9139–9154.

Müller-Syring, G., Henel, M., 2014. Wasserstofftoleranz der Erdgasinfrastruktur inklusive aller assoziierten Anlagen. Final Report. Hg. v. DVGW Deutscher Verein des Gas-und Wasserfaches eV Technisch-wissenschaftlicher Verein. Bonn. URL: `https://www.dvgw.de/medien/dvgw/forschung/berichte/g1_02_12.pdf`. in German.

Nansai, K., Tohno, S., Kono, M., Kasahara, M., 2002. Effects of electric vehicles (ev) on environmental loads with consideration of regional differences of electric power generation and charging characteristic of ev users in japan. Applied Energy 71, 111–125.

Narajewski, M., Ziel, F., 2020. Econometric modelling and forecasting of intraday electricity prices. Journal of Commodity Markets 19, 100107.

Neuhoff, K., von Hirschhausen, C., 2006. Long-term vs. short-term contracts; a european perspective on natural gas. Cambridge Working Papers in Economics.

Neumann, F., Zeyen, E., Victoria, M., Brown, T., 2023. The potential role of a hydrogen network in europe. Joule 7, 1793–1817.

Nguyen, T., Abdin, Z., Holm, T., Mérida, W., 2019. Grid-connected hydrogen production via large-scale water electrolysis. Energy conversion and Management 200, 112108.

Nguyen, T.A., Crow, M.L., 2016. Stochastic optimization of renewable-based microgrid operation incorporating battery operating cost. IEEE Transactions on Power Systems 31, 2289–2296.

Nikolaidis, P., Poullikkas, A., 2017. A comparative overview of hydrogen production processes. Renewable and Sustainable Energy Reviews 67, 597–611.

Nunn, N., 2007. Relationship-specificity, incomplete contracts, and the pattern of trade. Quarterly Journal of Economics 122, 569–600.

Nuñez-Jimenez, A., De Blasio, N., 2022. Mighty: Model of international green hydrogen trade. Belfer Center for Science and International Affairs, Harvard Kennedy School. Environment and Natural Resources Program Papers , 1–37.

NWR, 2021. Die Rolle der Untergrund-Gasspeicher zur Entwicklung eines Wasserstoffmarktes in Deutschland. Nationaler Wasserstoffrat (NWR). Briefing Paper. In German.

Ordoudis, C., Delikaraoglou, S., Pinson, P., Kazempour, J., 2017. Exploiting flexibility in coupled electricity and natural gas markets: A price-based approach. 2017 IEEE Manchester PowerTech, Powertech 2017 .

Ordoudis, C., Pinson, P., Morales, J.M., 2019. An Integrated Market for Electricity and Natural Gas Systems with Stochastic Power Producers. European Journal of Operational Research 272, 642–654.

Otsuki, T., Komiyama, R., Fujii, Y., Nakamura, H., 2023. Temporally detailed modeling and analysis of global net zero energy systems focusing on variable renewable energy. Energy and Climate Change 4, 100108.

Panchenko, V., Daus, Y.V., Kovalev, A., Yudaev, I., Litti, Y.V., 2023. Prospects for the production of green hydrogen: Review of countries with high potential. International Journal of Hydrogen Energy 48, 4551–4571.

Papaefthymiou, G., Klockl, B., 2008. Mcmc for wind power simulation. IEEE Transactions on Energy Conversion 23, 234–240.

Pape, C., Hagemann, S., Weber, C., 2016. Are fundamentals enough? explaining price variations in the german day-ahead and intraday power market. Energy Economics 54, 376–387.

Parra, D., Valverde, L., Pino, F.J., Patel, M.K., 2019. A review on the role, cost and value of hydrogen energy systems for deep decarbonisation. Renewable and Sustainable Energy Reviews 101, 279–294.

Pfennig, M., Böttger, D., Häckner, B., Geiger, D., Zink, C., Bisevic, A., Jansen, L., 2023. Global gis-based potential analysis and cost assessment of power-to-x fuels in 2050. Applied Energy 347, 121289.

Pietzcker, R.C., Stetter, D., Manger, S., Luderer, G., 2014. Using the sun to decarbonize the power sector: The economic potential of photovoltaics and concentrating solar power. Applied Energy 135, 704–720.

Pinegar, H.K., Moats, M.S., Sohn, H.Y., 2011. Process simulation and economic feasibility analysis for a hydrogen-based novel suspension ironmaking technology. Steel Research International 82, 951–963.

Pototschnig, A., 2021. Renewable hydrogen and the "additionality" requirement: why making it more complex than is needed? Florence School of Regulation. 2021/36.

Proost, J., 2019. State-of-the art capex data for water electrolysers, and their impact on renewable hydrogen price settings. International Journal of Hydrogen Energy 44, 4406–4413.

Quarton, C.J., Samsatli, S., 2018. Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling? Renewable and Sustainable Energy Reviews 98, 302–316.

Renewable Energy Act, 2021. (in German). URL: `https://www.gesetze-im-internet.de/eeg_2014/`. accessed: 2021-08-30.

Richter, J., 2011. DIMENSION - A Dispatch and Investment Model for European Electricity Markets. EWI Working Papers no. 11/03.

Roach, M., Meeus, L., 2020. The welfare and price effects of sector coupling with power-to-gas. Energy Economics 86, 104708.

Robinius, M., 2015. Strom-und Gasmarktdesign zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff. Ph.D. thesis. Dissertation, RWTH Aachen, 2015. Aachen.

Rosen, M.A., Koohi-Fayegh, S., 2016. The prospects for hydrogen as an energy carrier: an overview of hydrogen energy and hydrogen energy systems. Energy, Ecology and Environment 1, 10–29.

van Rossum, R., Jens, J., La Guardia, G., Wang, A., Kühnen, L., Overgaag, M., 2022. European Hydrogen Backbone - A European hydrogen infrastructure vision covering 28 countries. Report. European Hydrogen Backbone (EHB) initiative. Utrecht.

Ruhnau, O., 2022. How flexible electricity demand stabilizes wind and solar market values: the case of hydrogen electrolyzers. Applied Energy 307, 118194.

Ruth, M.F., Jadun, P., Gilroy, N., Connelly, E., Boardman, R., Simon, A., Elgowainy, A., Zuboy, J., 2020. The Technical and Economic Potential of the H2@ Scale Hydrogen Concept within the United States. Technical Report. National Renewable Energy Lab (NREL), Golden, CO (United States).

Rystad Energy, 2020. Gas market cube. Commercial Database.

Rystad Energy, 2022. Gas market cube. Commercial Database.

Rystad Energy, 2023. Gas market cube. Commercial Database.

Saba, S.M., Müller, M., Robinius, M., Stolten, D., 2018. The investment costs of electrolysis – a comparison of cost studies from the past 30 years. International Journal of Hydrogen Energy 43, 1209–1223.

Salmon, N., Bañares-Alcántara, R., 2021. Green ammonia as a spatial energy vector: a review. Sustainable Energy & Fuels 5, 2814–2839.

Samsatli, S., Staffell, I., Samsatli, N.J., 2016. Optimal design and operation of integrated wind-hydrogen-electricity networks for decarbonising the domestic transport sector in great britain. International Journal of Hydrogen Energy 41, 447–475.

Scarlat, N., Dallemand, J.F., Fahl, F., 2018a. Biogas: Developments and perspectives in Europe. Renewable Energy 129, 457–472.

Scarlat, N., Fahl, F., Dallemand, J.F., Monforti, F., Motola, V., 2018b. A spatial analysis of biogas potential from manure in Europe. Renewable and Sustainable Energy Reviews 94, 915–930.

Scharf, H., Arnold, F., Lencz, D., 2021. Future natural gas consumption in the context of decarbonization - A meta-analysis of scenarios modeling the German energy system. Energy Strategy Reviews 33, 100591.

Schlund, D., 2023. Integrating cross-border hydrogen infrastructure in european natural gas networks: A comprehensive optimization approach. EWI Working Paper No. 23/08.

Schlund, D., Gierkink, M., Moritz, M., Kopp, J., Junkermann, J., Diers, H., Vey, M., 2023. Analyse der globalen Gasmärkte bis 2035. URL: `https://www.ewi.uni-koeln.de/de/publikationen/analyse-der-globalen-gasmaerkte-2035/`. in German. Accessed: 02-08-2023.

Schlund, D., Schönfisch, M., 2021. Analysing the impact of a renewable hydrogen quota on the european electricity and natural gas markets. Applied Energy 304, 117666.

Schlund, D., Schulte, S., Sprenger, T., 2022. The who's who of a hydrogen market ramp-up: A stakeholder analysis for germany. Renewable and Sustainable Energy Reviews 154, 111810.

Schlund, D., Theile, P., 2022. Simultaneity of green energy and hydrogen production: Analysing the dispatch of a grid-connected electrolyser. Energy Policy 166, 113008.

Schmidt, L., 2020. Puncturing the waterbed or the new green paradox? the effectiveness of overlapping policies in the eu ets under perfect foresight and myopia. EWI Working Paper No. 20/07.

Schneider, S., Bajohr, S., Graf, F., Kolb, T., 2020. State of the art of hydrogen production via pyrolysis of natural gas. ChemBioEng Reviews 7, 150–158.

Schönfisch, M., 2022. Charting the development of a global market for low-carbon hydrogen. EWI Working Paper No. 22/03.

Schulte, S., Weiser, F., 2019. Natural gas transits and market power: The case of turkey. The Energy Journal 40, 77–100.

Sens, L., Piguel, Y., Neuling, U., Timmerberg, S., Wilbrand, K., Kaltschmitt, M., 2022. Cost minimized hydrogen from solar and wind–production and supply in the european catchment area. Energy Conversion and Management 265, 115742.

Sensfuß, F., Ragwitz, M., Genoese, M., 2008. The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in germany. Energy Policy 36, 3086–3094.

Siegemund, S., Trommler, M., Kolb, O., Zinnecker, V., Schmidt, P., 2017. E-Fuels Study. The potential of electricity-based fuels for low-emission transport in the EU. Report. Berlin.

Smil, V., 2017. Energy and civilization: a history. MIT Press.

Speirs, J., Balcombe, P., Johnson, E., Martin, J., Brandon, N., Hawkes, A., 2018. A greener gas grid: What are the options. Energy Policy 118, 291–297.

Staffell, I., Scamman, D., Abad, A.V., Balcombe, P., Dodds, P.E., Ekins, P., Shah, N., Ward, K.R., 2019. The role of hydrogen and fuel cells in the global energy system. Energy & Environmental Science 12, 463–491.

Stöckl, F., Schill, W.P., Zerrahn, A., 2021. Optimal supply chains and power sector benefits of green hydrogen. Scientific Reports 11.

Tarkowski, R., 2019. Underground hydrogen storage: Characteristics and prospects. Renewable and Sustainable Energy Reviews 105, 86–94.

Teichmann, D., Arlt, W., Wasserscheid, P., Freymann, R., 2011. A future energy supply based on liquid organic hydrogen carriers (lohc). Energy & Environmental Science 4, 2767–2773.

Tezi, G., Caraglio, M., Stella, A.L., 2021. Entropic measure unveils country competitiveness and product specialization in the world trade web. Scientific Reports 11.

The World Bank, 2022. Carbon pricing dashboard. https://carbonpricingdashboard.worldbank.org/. Accessed: 2022-07-01.

Thema, M., Bauer, F., Sterner, M., 2019. Power-to-gas: Electrolysis and methanation status review. Renewable and Sustainable Energy Reviews 112, 775–787.

Thiel, C., Nijs, W., Simoes, S., Schmidt, J., van Zyl, A., Schmid, E., 2016. The impact of the eu car co2 regulation on the energy system and the role of electro-mobility to achieve transport decarbonisation. Energy Policy 96, 153–166.

Thomaßen, G., Kavvadias, K., Navarro, J.P.J., 2021. The decarbonisation of the eu heating sector through electrification: A parametric analysis. Energy Policy 148, 111929.

Timmerberg, S., Kaltschmitt, M., 2019. Hydrogen from renewables: Supply from North Africa to Central Europe as blend in existing pipelines – Potentials and costs. Applied Energy 237, 795–809.

Umweltbundesamt, 2021. Entwicklung der spezifischen Kohlendioxid-Emissionen des deutschen Strommix in den Jahren 1990 - 2020 (in German). URL: https://www.umweltbundesamt.de/sites/default/files/medien/5750/publikationen/2021-05-26_cc-45-2021_strommix_2021_0.pdf. accessed: 2021-08-30.

USGS, 2018. International minerals statistics and information. https://www.usgs.gov/centers/national-minerals-information-cente r/international-minerals-statistics-and-information#B. Accessed: 2022-06-21.

USGS, 2022. Mineral commodity summaries. https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. Accessed: 2022-05-02.

van Leeuwen, C., Mulder, M., 2018. Power-to-gas in electricity markets dominated by renewables. Applied Energy 232, 258–272.

Vandewalle, J., Bruninx, K., D'Haeseleer, W., 2015. Effects of large-scale power to gas conversion on the power, gas and carbon sectors and their interactions. Energy Conversion and Management 94, 28–39.

Velazquez Abad, A., Dodds, P.E., 2020. Green hydrogen characterisation initiatives: Definitions, standards, guarantees of origin, and challenges. Energy Policy 138, 111300.

de Vries, H., Mokhov, A.V., Levinsky, H.B., 2017. The impact of natural gas/hydrogen mixtures on the performance of end-use equipment: Interchangeability analysis for domestic appliances. Applied Energy 208, 1007–1019.

Weber, C.L., Jaramillo, P., Marriott, J., Samaras, C., 2010. Life cycle assessment and grid electricity: what do we know and what can we know? Environmental Science & Technology 44.

WEC, 2019. World Energy Scenarios 2019. World Energy Council (WEC), London.

Welder, L., Ryberg, D.S., Kotzur, L., Grube, T., Robinius, M., Stolten, D., 2018. Spatio-temporal optimization of a future energy system for power-to-hydrogen applications in germany. Energy 158, 1130–1149.

World Steel Association, 2021. 2021 world steel in figures. https://worldsteel.org/wp-content/uploads/2021-World-Steel-in-Figures.pdf. Accessed: 2022-04-22.

World Steel Association, 2022. Steel statistics. https://worldsteel.org/steel-by-topic/statistics/. Accessed: 2022-04-22.

Yang, C., Ogden, J., 2007. Determining the lowest-cost hydrogen delivery mode. International Journal of Hydrogen Energy 32, 268–286.

Yang, H., Qiu, J., Zhang, S., Lai, M., Dong, Z.Y., 2015. Interdependency assessment of coupled natural gas and power systems in energy market. International Journal of Emerging Electric Power Systems 16, 525–536.

CURRICULUM VITAE

David Schlund

PERSONAL DATA

Date of Birth	September 7, 1993
Place of Birth	Kirchheim/Teck
Nationality	German

RESEARCH INTERESTS

Hydrogen Markets, Natural Gas Markets, Energy System Modeling

EDUCATION

03/2019 - 03/2024	**Department of Economics, University of Cologne** Doctoral Candidate in Economics
04/2022 - 06/2022	**University of British Columbia, Vancouver** Visiting PhD Research Student
10/2016 - 10/2018	**Karlsruhe Institute of Technology (KIT)** Master of Science in Industrial Engineering and Management
08/2017 - 12/2017	**University of Iceland, Reykjavik** Study abroad
10/2012 - 03/2016	**Karlsruhe Institute of Technology (KIT)** Bachelor of Science in Industrial Engineering and Management
06/2012	**Schlossgymnasium, Kirchheim/Teck** Maturity/Abitur

WORKING EXPERIENCE

since 04/2024	**Uniper SE** Commercial Manager – Hydrogen Germany
11/2022 - 03/2024	**Institute of Energy Economics at the University of Cologne (EWI)** Senior Research Consultant
03/2019 - 10/2022	**Institute of Energy Economics at the University of Cologne (EWI)** Research Associate
10/2016 - 09/2018	**KIT, Institute for Industrial Prduction (IIP), Karlsruhe** Student Assistant at the Chair of Energy Economics
04/2017 - 07/2017	**EnBW Energie Baden-Württemberg AG, Karlsruhe** Student Assistant in Analysis Trading
09/2014 - 02/2016	**EnBW Energie Baden-Württemberg AG, Karlsruhe** Internship and Student Assistant in Controlling Operations
09/2013 - 07/2014	**KIT, Institute of Information Systems and Marketing (IISM), Karlsruhe** Student Assistant at the Chair of Information and Market Engineering

LANGUAGES

German	Mother tongue
English	Proficient

PUBLICATIONS

Articles in Peer-Reviewed Journals:

- Schlund, D. and Theile, P. (2022). Simultaneity of Green Energy and Hydrogen Production: Analysing the Dispatch of a Grid-connected Electrolyser. *Energy Policy* Vol. 166, July 2022, 113008.
- Schlund, D., Sprenger, T. and Schulte, S. (2022). The who's who of a hydrogen market ramp-up: A stakeholder analysis for Germany. *Renwable and Sustainable Energy Reviews* Vol. 154, February 2022, 11810.
- Schlund, D. and Schönfisch, M. (2021). Analysing the Impact of a Renewable Hydrogen Quota on the European Electricity and Natural Gas Markets. *Applied Energy* Vol. 304, December 2022, 117666.
- Mengelkamp, E., Schlund, D. and Weinhardt, C. (2021). Development and real-world application of a taxonomy for business models in local energy markets. *Applied Energy* Vol. 256, December 2019, 113913.

Working Papers:

- Schlund, D. (2023). Integrating Cross-Border Hydrogen Infrastructure in European Natural Gas Networks: A Comprehensive Optimization Approach. *EWI Working Paper* 23/08.
- Antweiler, W. and Schlund, D. (2022). The Emerging International Trade in Hydrogen and the Role of Environmental, Innovation, and Trade Policies. *USAEE Working Paper* 23-589.

Further Publications:

- Schlund, D., Gierkink, M., Moritz, M., Kopp, J., Junkermann, J., Diers, H. and Vey, M. (2023), Analysis of the global gas markets until 2035, *Study on behalf of the German Ministry for Economic Affairs and Climate Action*.
- Schlund, D. and Theile, P. (2021), Strombezugsoptionen für Power-to-Gas-Anlagen, *emw*, 4/2021.
- Baumgart, M., Schulte, S., Berger, F., Lencz, D., Mansius, F. and Schlund, D., Der Regulierungsrahmen für Wasserstoffnetze – Eine ökonomische und rechtliche Einordnung vor dem Hintergrund des angestrebten Markthochlaufs, *RdE Recht der Energiewirtschaft, Vol. 3, March 2021.*

Cologne, 13.03.2024