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Quantifying hydrogen's role in multi-sector decarbonization using price-elastic demand curves

Drin Marmullaku [a,b,*], Gian Müller [a,b], Tim Lux [a], Theresa Klütz [a], Thomas Schöb [a], Jann Michael Weinand [a], Jochen Linßen [a], Detlef Stolten [b]

[a] *Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems, Jülich Systems Analysis, 52425 Jülich, Germany*
[b] *RWTH Aachen University, Faculty of Mechanical Engineering, 52062 Aachen, Germany*

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ABSTRACT

Green hydrogen is a key component of the transition to greenhouse gas neutrality, but its future uptake is highly sensitive to price dynamics. This study addresses a crucial research gap by quantifying price-elastic hydrogen demand within a greenhouse gas neutral, sector-coupled energy system for Germany. Using a national energy system model, the analysis captures cross-sectoral interactions and identifies the main drivers of hydrogen demand across the industry, transport, power, and buildings sectors. Hydrogen demand exhibits strong price sensitivity across sectors, with a non-linear increase that accelerates sharply at lower prices, rising from 163 TWh to 1164 TWh. Hydrogen remains indispensable for the decarbonization of emission-intensive industrial processes, with high-price demand of about 144 TWh persisting in steel, ammonia and methanol production, and high-temperature heat, underscoring the need for substantial price reductions to enhance future competitiveness. In the power sector, hydrogen provides critical backup flexibility, with demand rising from 12 to 381 TWh as prices decline, reflecting its high price sensitivity. In transport, electrification remains dominant across most applications, while fuel-cell trucks drive demand growth at lower prices. In buildings, hydrogen plays only a minor role, with notable uptake emerging solely at very low prices. These findings demonstrate hydrogen's pivotal role in decarbonizing sectors with high abatement barriers. Overall, substantial price reductions are essential to accelerate early market formation and ensure a cost-effective transition, underscoring the need for targeted, sector-specific policies to achieve greenhouse gas neutrality.

1. Introduction

As part of the European Green Deal [1], the European Commission has outlined a strategy to reduce greenhouse gas (GHG) emissions and establish Europe as the first continent to achieve GHG neutrality by 2050. While electrification represents a central pillar of this transformation, renewable-based hydrogen and its derivatives can complement the decarbonization of hard-to-abate sectors such as the chemical industry, steel production, heavy-duty road transport, maritime shipping, and aviation, while also addressing renewable energy intermittency through large-scale energy storage [2].

In 2024, global production of low-emission hydrogen increased by nearly 10 %, with projections of a fivefold growth by 2030, driven largely by renewable-based production [3]. Despite its higher cost compared to hydrogen from unabated fossil fuels, green hydrogen is expected to account for 4–11 % of final energy consumption by 2050, as the cost gap is projected to narrow [4]. The level of ambition in reducing GHG emissions will strongly influence this trajectory, with less stringent targets leading to lower demand [4]. As one of Europe's most energy-intensive economies, Germany is likely to become a major hydrogen consumer. Its updated National Hydrogen Strategy [5] emphasizes the importance of domestic production while acknowledging that substantial imports and expanded cross-border infrastructure will be essential in the near term.

As the green hydrogen market emerges, substantial short- to medium-term investments are needed to achieve economies of scale across the supply chain and support an accelerated market ramp-up. During this period the gap between the willingness to pay for hydrogen and the hydrogen price needs to be addressed by market-based support schemes. A variety of support mechanisms have been introduced. While early efforts focused on funding demonstration projects, the majority are now shifting toward price-based mechanisms to support

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* Corresponding author.
E-mail address: d.marmullaku@fz-juelich.de (D. Marmullaku).

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large-scale deployment of hydrogen production [6]. Examples of such mechanisms include Carbon Contracts for Difference (CCfDs) [7], the Innovation Fund (INNOVFUND) of the European Commission [8], Australia's Hydrogen Headstart program [9], and the German H2Global scheme [10]. Through a double-auction mechanism, H2Global addresses both the supply and demand sides to support imports from outside the EU by compensating for the differential between high supply-side costs and lower demand-side prices, thereby reducing risks associated with the market ramp-up of green hydrogen, as described in [10].

Production cost projections for green hydrogen in Germany and potential export regions have been extensively analyzed across various supply chains. Hofrichter et al. [11] examine green hydrogen production for four exemplary PV and wind sites. Winkler et al. [12] assess hydrogen cost potentials for Sub-Saharan Africa, while Fasihi et al. [13] and IRENA [14] provide global cost projections. In addition, Franzmann et al. [15] focus on 28 countries worldwide, deriving cost-potential curves for the export of liquid hydrogen. These costs are influenced by variations in capital (CAPEX) and operational expenditure (OPEX) across the components of the hydrogen value chain, such as renewable energy supply, electrolyzers, infrastructure, and storage. The cost development of these components is characterized by considerable uncertainty, as it is influenced by factors such as technological learning [16], policy frameworks [17] and risk perception of investors [18]. The Forschungsstelle für Energiewirtschaft (FfE) [19] further emphasizes that production costs are often underestimated because investment costs typically exclude expenditures for planning, installation, and project management, while electricity costs are also frequently underestimated. Furthermore, the production costs strongly depend on the temporal availability and potential of renewable energy resources, which differ significantly across regions.

The willingness to pay for green hydrogen in the context of a GHG-neutral energy system, including all relevant sectors, remains less investigated. The study of the Institute of Energy Economics at the University of Cologne (EWI) [20] examines various end-use applications across sectors to estimate break-even prices for hydrogen in Germany, defined as the maximum price at which hydrogen-based alternatives and conventional fossil fuel-based processes result in equal total costs of ownership. Furthermore, scenario-based hydrogen demand curves are derived by plotting break-even prices against application-specific hydrogen demand, derived from literature values. These scenarios, however, do not capture actual price responsiveness in relation to hydrogen wholesale prices and the demand is therefore not influenced by the actual economic competitiveness of hydrogen end use applications. Similarly, Ruth et al. [21] project hydrogen demands across various applications and sectors, including oil refining, ammonia production, and medium and heavy duty fuel cell electric vehicles (FCEVs). For each application, a threshold price is estimated, which refers to the hydrogen price necessary to compete with the next-best alternative solution. Based on these application specific quantities and threshold prices, national hydrogen demand curves are derived.

Zheng et al. [22] derive hydrogen demand curves for Germany and China in the context of road transport using the simulation model HyDAM-T. The hydrogen demand curves are derived for the years 2030 and 2050 based on 15 hydrogen supply price pathways. The results show that for Germany, hydrogen demand in 2050 is sensitive to supply prices ranging from 178 to 224 €/MWh. Under the lowest price pathway, the total demand for road transport in Germany reaches up to 30 TWh, with heavy-duty trucks accounting for approximately 78 % of this demand. In contrast, no hydrogen demand is observed in the passenger transport segment, as electric vehicles remain dominant. However, this study is limited to the road transport sector and does not capture cross-sectoral competition. Weißenburger et al. [23] derive aggregated and sector-specific hydrogen demand curves for Germany along a transformation pathway from 2025 to 2045. Different methodological approaches are applied across sectors, including an optimization model for energy conversion, a bottom-up simulation model for the industry and road transport sectors, and a literature-based assessment for non-road transport and decentralized building heat. Hydrogen demand is evaluated across 15 different hydrogen wholesale price pathways, enabling the derivation of price-elastic demand curves for each year and sector. The results show that the industry sector maintains a high baseline hydrogen demand of around 250 TWh, even at higher prices (182 €/MWh in 2045). In contrast, a large share of hydrogen demand in the energy conversion sector is highly price-sensitive, while contributions from the road transport sector and heating remain comparatively low across price levels. However, since different approaches are used for the different sectors, cross-sectoral dependencies are not captured accurately. This is addressed in Blanco et al. [24], which applies the sector-coupled bottom-up model JRC-EU-TIMES to calculate transformation pathways for EU28+ under various scenarios targeting 80–95 % CO_2 reduction by 2050 compared to 1990. The model captures competition between energy carriers such as hydrogen, power-to-liquid (PtL), synthetic fuels, and electricity. To derive hydrogen demand curves, hydrogen supply is detached from the system by setting fixed external hydrogen prices, allowing the assessment of sectoral demand responses at different price levels. Nevertheless, this approach does not consider a fully GHG-neutral energy system, which is a critical factor to consider. This is particularly relevant given that the role of hydrogen can become more significant under more ambitious GHG reduction targets and can therefore have a substantial impact on its price elasticity [4]. Alanazi et al. [25] apply a similar approach, using the global TIAM-Grantham model to derive hydrogen demand curves for 2050 under a 1.5 °C climate scenario. However, Germany is only included as part of a broader Western Europe region, which limits the geographical detail. Furthermore, the temporal resolution is typically defined by six time divisions within a year, called "time-slices", which do not reflect finer temporal dynamics such as hourly load variations or short-term flexibility requirements that can be crucial for assessing variable renewable integration. Peterssen et al. [26] analyze hydrogen supply scenarios for Germany by varying possible hydrogen import prices and assessing their implications for demand. The demand side is modeled in an aggregated form across six main applications: hot water, space heating, electric loads, process heat, petrochemicals, and mobility. This enables a system-wide perspective on energy carrier competition, although reduced demand-side granularity may limit both the accuracy and resolution in capturing hydrogen price elasticity.

Against this background, many existing studies focus on individual sectors and do not consider the cross-sectoral substitution and interdependence between hydrogen, electricity, fossil fuels, and other energy carriers. This limits their ability to capture the cross-sectoral role of hydrogen in the broader energy system. In addition, other studies do not fully integrate hydrogen demand into holistic transformation pathways towards GHG neutrality, or they rely on limited temporal resolution and simplified demand-side modeling. Therefore, an integrated, sector-coupled energy system analysis is required to assess hydrogen demand across all relevant sectors and its price sensitivity under long-term decarbonization targets, while also capturing its broader system implications.

This study closes that gap by analyzing the price elasticity of green hydrogen with a sector-coupled energy-system model for Germany. A transformation pathway aiming for GHG neutrality by 2045 is modeled with hourly temporal resolution, covering the industry, power, transport, and building sectors. Based on this approach, aggregated and sector-specific hydrogen demand curves are derived for selected years. An extensive review of existing literature is conducted to define 16 green hydrogen price pathway scenarios. These scenarios are used to quantify the price elasticity of hydrogen demand across the relevant sectors and applications, while also capturing interdependencies between sectors and alternative energy carriers. This enables the identification of key drivers of hydrogen demand along the transformation pathway. Furthermore, this analysis provides valuable insights into the development of the green hydrogen market in Germany. The findings offer important implications for decision makers, such as policymakers and industry stakeholders, by illustrating how hydrogen prices affect demand across sectors.

The structure of the study is as follows: Section 2 outlines the methodology, including the energy system model, the definition of hydrogen price pathways, and the methodology for deriving hydrogen demand curves. Section 3 presents the results, focusing on the overall transformation pathway as well as aggregated and sector-specific hydrogen demand curves. In addition, the impacts of limited renewable resource availability and alternative price trajectories are assessed. The discussion and main conclusion are presented in Sections 4 and 5, respectively.

2. Methodology

This section presents the methodological approach for analyzing price-elastic hydrogen demand in Germany, beginning with a description of the underlying energy system model ETHOS.NESTOR (Section 2.1), followed by the definition of price pathways (Section 2.2), and the systematic derivation of hydrogen demand curves (Section 2.3).

2.1. ETHOS.NESTOR

The energy system model ETHOS.NESTOR (see Refs. [27,28]) is a national, sector-integrated, single-node optimization model with hourly temporal resolution, developed within the ETHOS.FINE modeling framework as described in Klütz et al. [29]. Its hourly resolution ensures that the demand for electricity, heat, fuels, and mobility services is met in each hour of the year, thereby capturing the temporal variability of renewable energy supply and demand. ETHOS.NESTOR encompasses the sectors power, industry, buildings, and transport, each represented through detailed process chains, as illustrated in Fig. 1. These process chains capture the demand and use of resources and commodities and are endogenously optimized within the model.

The objective of optimization is to minimize total system costs over the transformation period from 2025 to 2045 under perfect foresight, with 2020 defined as the base year and 2025 as the first optimized year. The analysis is conducted in five-year intervals within the context of the German energy transition and its GHG neutrality targets [30]. These targets represent a central constraint of the optimization model by enforcing a limited cumulative emissions budget throughout the transformation pathway and achieving net zero by 2045. Consequently, CO_2 prices are not modeled explicitly, as they emerge endogenously from the optimization and reflect the marginal cost of complying with the emissions budget. Emission reductions in the model can be achieved both through the substitution of process routes and through carbon dioxide capture technologies, including point-source capture and atmospheric removal via direct air capture, under an imposed CO_2 storage limit of 90 Mt CO_2 per year, as described by Schöb et al. [31]. Additional constraints ensure system consistency, including capacity restrictions, efficiency relations, and balance equations for conversion processes. A detailed description of these formulations and the underlying energy system model can be found in Lopion [32].

The sectoral integration of ETHOS.NESTOR enables competition between different GHG abatement measures across sectors and leverages the benefits of sectoral interconnections. The model explicitly represents both conventional technologies and low-emission alternatives. Renewable electricity technologies are included as possible substitutes for fossil-based power supply. In industry, low-carbon processes, such as hydrogen-based direct reduction in steelmaking, are considered, amongst many other process chains. The transport sector covers passenger and freight transport across road, rail, aviation, and shipping, with multiple propulsion technologies represented. In buildings, residential and service-sector demand for heat, cooling, and appliances is differentiated by building classes. Demand is typically defined exogenously at the level of final energy or transport services (e.g., person-kilometers), and the endogenous optimization determines the choice of energy carriers and technologies to meet these demands. Schöb et al. [31] present an application of the ETHOS.NESTOR model to analyze future hydrogen demand in Germany, while additional analyses are provided by Maier et al. [27] and Tsani et al. [28].

2.2. Price pathways

The following subsection presents a range of projected price pathways for green hydrogen between 2025 and 2050, which are subsequently used to estimate the price elasticity of hydrogen demand, extending the approach introduced in Weißenburger et al. [23]. Sixteen variations of hydrogen price pathways (Variations V0–V15), representing the spectrum from the lowest to the highest cost projections, are illustrated in Fig. 2 for the period 2025 to 2050. These pathways are derived from supply cost and price estimates reported in the literature for the years 2030 and 2050, including studies on domestic production in Germany as well as analyses of imports from global export regions to the German market [33–46]. The data are converted to € 2024 using the

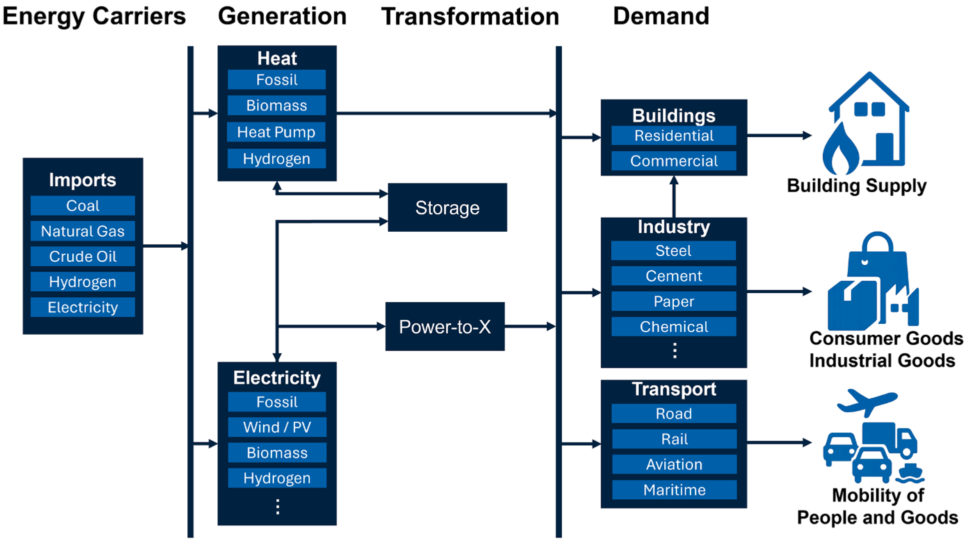

Fig. 1. Simplified schematic representation of the energy system model ETHOS.NESTOR.

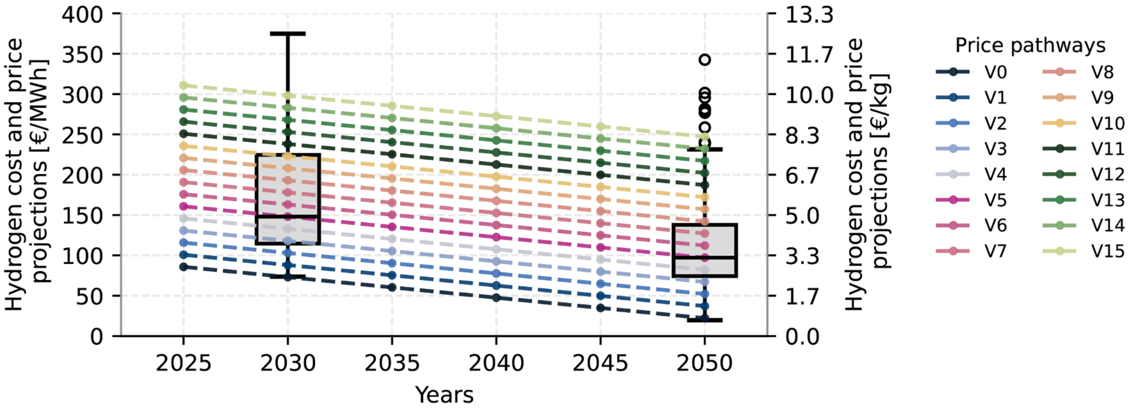

Fig. 2. Green hydrogen cost and price projections for 2030 and 2050 based on literature sources [33–46] shown as boxplots, together with the derived price pathways (V0–V15) for the base scenario. Values are based on the lower heating value (LHV) of hydrogen.

Consumer Price Index (CPI) for the European Union (EU27) from the OECD Data Explorer [47] and exchange rates from the Deutsche Bundesbank [48]. It should be noted that the majority of studies consider production costs, including transportation, rather than market prices, such as wholesale or end-consumer prices. While the lowest price pathway (V0) aligns with the lowest reported production costs in the literature, it can be considered a justified lower-bound estimate, as market prices typically include additional components beyond production, such as profit margins, taxes, and tariffs. Conversely, the highest price pathway (V15) reflects a more conservative assumption, incorporating higher cost estimates and less favorable production conditions, such as limited availability of renewable energy resources. The box plots illustrate the distribution of the data, which ranges from 74 to 375 €/MWh in 2030, with a median value of 148 €/MWh, and from 20 to 343 €/MWh in 2050, with a median of 97 €/MWh. The wide distribution of the data reflects varying techno-economic assumptions, including differences in renewable energy availability, investment levels across the hydrogen supply chain, such as renewable supply, electrolyzers, storage, and transport infrastructure, as well as operational parameters like conversion efficiencies. The price pathway V5 is constructed by linearly interpolating between the median values for 2030 and 2050, with extrapolation applied to 2025. This curve serves as the baseline, which is shifted in 15 €/MWh increments to generate higher (V6–V15) and lower (V0–V4) price trajectories. Furthermore, to capture the impact of different price decline rates, two additional price pathway scenarios are defined: a conservative scenario with a delayed trajectory and a progressive scenario with an accelerated trajectory, as discussed in Section 3.6.2.

2.3. *Derivation of hydrogen demand-curves*

Extending the methodological concept introduced by Weißenburger et al. [23], this study applies a fully integrated, sector-coupled energy system model to derive hydrogen demand elasticities across sectors based on the price pathways defined in Section 2.2. The energy system optimization model ETHOS.NESTOR serves as the foundation to calculate transformation pathways for Germany from 2025 to 2045. The model, as outlined in Section 2.1, incorporates the four primary sectors: industry, transport, buildings, and power. It is an integrated model, capturing interactions among these sectors, as well as the competition between various energy carriers, including electricity, hydrogen, and gas. This structure enables a cost-optimal allocation of energy carriers to meet service demands across sectors. The outputs of the model include final and secondary energy demand, encompassing both sector- and technology-specific hydrogen demand. The resulting hydrogen demand in the model is sensitive to its shadow price, which is endogenously determined during the optimization process. To allow for a systematic derivation of demand curves, the model is adapted to use exogenous hydrogen price levels, as illustrated in Fig. 3. This is achieved through the implementation of a virtual trading hub (VTH), that supplies green hydrogen to sectoral processes at a fixed wholesale price. In this configuration, domestic hydrogen production via electrolysis is prohibited, ensuring that all hydrogen is provided at the predefined price. This modeling choice allows isolating demand-side responses to uniform hydrogen price signals across sectors. Conversion losses associated with hydrogen production are therefore not represented within the energy system model. Instead, these upstream losses are implicitly reflected in the assumed hydrogen price trajectories. This modification effectively simulates a wholesale market environment where all processes face a uniform and fixed hydrogen wholesale price level. The model is optimized for each of the 16 predefined price pathways (V0–V15), enabling an analysis of the resulting hydrogen demand for each price scenario and year. By aggregating the modeled hydrogen demand across price levels for a given year, a hydrogen demand curve can be constructed. This analysis can also be performed at the sectoral level to derive sector-specific demand curves.

3. Results

This section outlines the main results, starting with an integrated analysis of how hydrogen price pathways influence the development of primary energy consumption (Section 3.1). It subsequently examines the aggregated (Section 3.2) and sector-specific hydrogen demand curves (Section 3.3–3.5), followed by a sensitivity analysis (Section 3.6) addressing the effects of limited renewable resource availability and alternative hydrogen price trajectories.

3.1. *Development of primary energy consumption*

To analyze the broader implications of different hydrogen price pathways for the overall energy system and transformation pathway, primary energy consumption is examined with a focus on the role of hydrogen. Primary energy consumption is shown in Fig. 4a across the target years for the medium pathway (V7) and two extreme scenarios (min. V0 and max. V15), which together span the full range of price-path scenarios.

The German energy system is largely dominated by fossil fuels in 2020, such as coal, mineral oil, and natural gas, representing about 79 % of total primary energy consumption. By 2045, primary energy consumption decreases by 24–32 % to 2217–2500 TWh. The reduction is driven by efficiency gains and the expansion of renewables, while fossil fuel use declines to meet GHG emission targets. The share of renewable energy in primary energy consumption rises steadily, primarily due to onshore and offshore wind, photovoltaics, and biomass, while

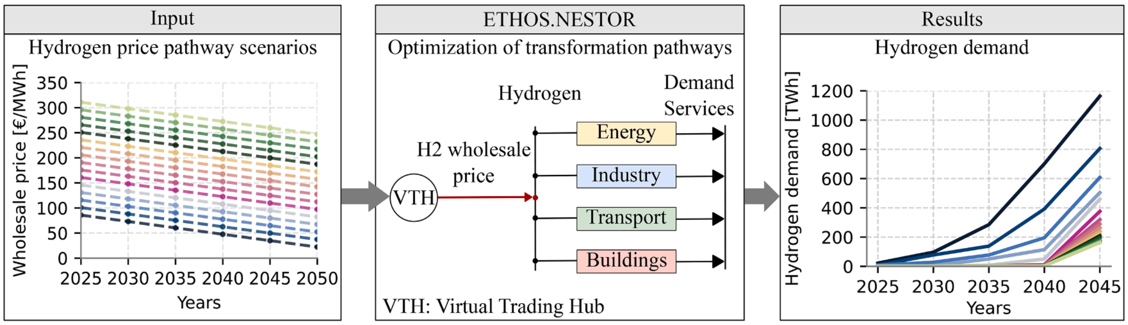

Fig. 3. Conceptual methodology for deriving hydrogen demand curves using the optimization model ETHOS.NESTOR.

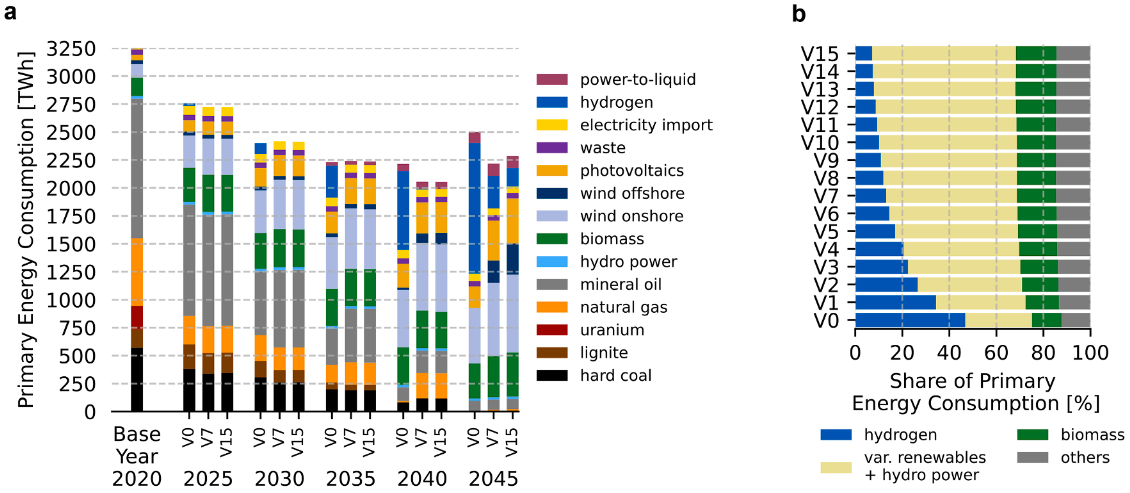

Fig. 4. a, Evolution of total primary energy consumption for three hydrogen price pathways (V0, V7, and V15). b, Shares of total primary energy consumption across hydrogen price pathways in 2045.

hydropower remains nearly constant.

In the lowest-price pathway (V0), hydrogen deployment begins in 2025, the first year of optimization, and increases substantially, reaching 47 % of total primary energy consumption by 2045. As a result, hydrogen largely replaces fossil fuels, leading to an almost complete gas phase-out by 2040. In contrast, in the mid- and high-price pathways (V7 and V15), hydrogen is predominantly utilized only in 2045, implying a delay of 20 years in its deployment. At that point, its use reaches 291 and 163 TWh, respectively, thereby accounting for 7–13 % of total primary energy consumption. In addition, the gas phase-out in V7 and V15 is delayed by five years compared to V0, occurring in 2045, with gas consumption remaining at marginal levels. Primary energy consumption in 2040 and 2045 in V7 and V15 is lower than in V0, as electrification tends to be more efficient than hydrogen-based alternatives, thereby reducing overall primary energy demand. This is particularly evident in sectors such as buildings, where technologies like heat pumps and electric boilers are deployed more extensively than hydrogen boilers in V7 and V15, resulting in lower energy demand for heating. The modest 3 % rise in primary energy consumption from V7 to V15 is primarily driven by a shift from hydrogen-based pathways to alternative decarbonization routes in heavy industry. This is particularly evident in methanol production, where increased reliance on biomass gasification leads to higher demand for high-temperature process heat, thereby increasing overall primary energy consumption.

As illustrated in Fig. 4b, variable renewable energy sources (vRES), including hydro power dominate the share of total primary energy consumption in 2045 across most of the price pathways (V3–V15). In the highest price pathway (V15), vRES including hydro power account for approximately 61 % of the primary energy consumption, followed by biomass at around 17 % and the remaining energy carriers, aggregated as "others", contributing roughly 14 %. The remaining ~7 % of hydrogen indicates that, even at high prices, hydrogen is needed to fully decarbonize the energy system. With decreasing price levels, hydrogen shares rise with improved competitiveness, while vRES consumption declines. With biomass and other sources remaining relatively constant across hydrogen price levels, this inverse relationship between hydrogen and vRES reflects a strong substitution effect, underscoring their competition in decarbonizing the energy consumption source. This effect is particularly pronounced at lower price levels, where vRES shares reach a minimum of 28 % in the lowest-price pathway (V0), while hydrogen shares simultaneously increase to a maximum of 47 %.

3.2. *Aggregated hydrogen demand curves*

The aggregated hydrogen demand for Germany and selected wholesale price trajectories across all price pathways for the years 2025 to 2045 are shown in Fig. 5a. An overall upward trend in hydrogen demand is observed across all price pathways, with an increase in demand ranging from 163 to 1164 TWh by 2045. Price pathways characterized by elevated costs (V5–V15) lead to a delayed trajectory in hydrogen uptake, resulting in a maximum total demand of up to 376 TWh by 2045, while demand remains marginal until 2040. Conversely, lower price pathways (V0–V4) lead to an accelerated uptake, with demand rising to a maximum of 97 TWh by 2030. As hydrogen prices decrease uniformly across scenarios, demand experiences a disproportionately strong increase.

A sectoral breakdown of demand (Fig. 5b) shows that marginal hydrogen consumption begins at price levels of 133 €/MWh in 2030,

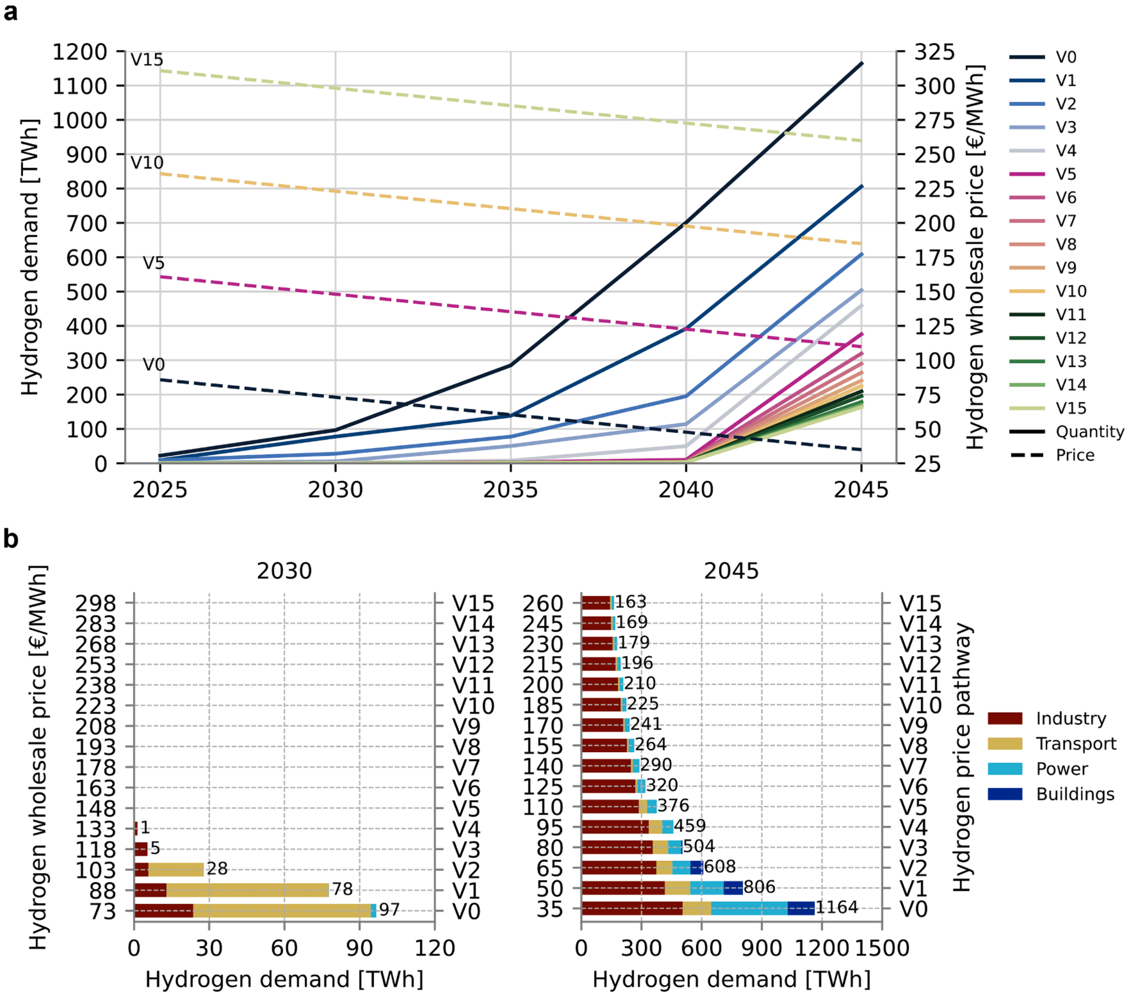

Fig. 5. a, Aggregated hydrogen demand under different hydrogen price pathways over time. b, Sectoral hydrogen demand at hydrogen wholesale price levels corresponding to the predefined price pathways (V0–V15) in 2030 and 2045.

initiated by the industry sector. As prices decline, demand rises in both industry and the transport sector, with the latter emerging as the primary driver of growth. Conversely, demand from the buildings and power sectors remains negligible, with the power sector exhibiting low demand at the lowest price level. By 2045, demand shows price sensitivity across all price levels. Despite elevated prices, a baseline demand for hydrogen persists, primarily driven by the industrial sector, with modest contributions from the transportation and power sectors. As prices decrease, total demand shows an upward trend, resulting in an approximately 3.5-fold increase in demand from the industrial sector. This trend is also evident in the transport sector, where demand rises more significantly below a price level of 125 €/MWh. A continuous increase in demand from the power sector is observed, with a disproportionately strong rise at lower price levels. In contrast, the overall contribution of the buildings sector remains marginal across a broad range of price levels, with demand increasing by up to 135 TWh only at a price level of $\leq$ 80 €/MWh.

3.3. Industry sector

The aggregated hydrogen demand for the industry sector, along with selected wholesale price trajectories from 2025 to 2045, is shown in Fig. 6a. Additionally, subsector-specific demands are presented for the years 2030 and 2045. Hydrogen uptake remains limited for most price pathways (V4–V15) until 2040. However, by 2045, demand increases between 144 and 336 TWh across these pathways. For price pathways below V4, hydrogen uptake begins earlier, reaching a maximum of 24 TWh in 2030 and 505 TWh in 2045. The results indicate limited hydrogen uptake by 2030, as most transformation is deferred to 2045.

As no hydrogen demand is observed for price levels above 133 €/MWh in 2030 (see Fig. 6b), this indicates that hydrogen is not cost-competitive compared to other alternatives, such as fossil fuels or biofuels. Below this threshold, hydrogen becomes a viable option for certain consumers, exhibiting a more price-sensitive response. Among these, demand for ammonia production increases by up to 13 TWh. At the lowest price level, additional hydrogen demand is observed for high-temperature heat (HT-Heat) and steel production. Hydrogen demand in other subsectors increases by 2045, with the largest share at the highest price level coming from steel production. This highlights hydrogen's potential as a decarbonization option, as the usage of conventional technologies, such as blast furnaces, is limited by GHG emissions associated with achieving the net-zero target. Even when combined with carbon capture and storage (CCS), these processes are still limited due to residual emissions and limited CO_2 storage capacity. The second-highest demand is observed for methanol production, which is primarily used to produce high-value chemicals, such as olefins, based on the methanol-to-olefins process, followed by smaller shares in high-temperature heat and ammonia production. This base demand at high prices reflects the limited availability of viable alternatives in emission-intensive industrial processes, as the use of fossil fuels is restricted by the defined GHG targets. The share of steel production remains almost constant at lower prices, showing a relatively inelastic response to price changes across

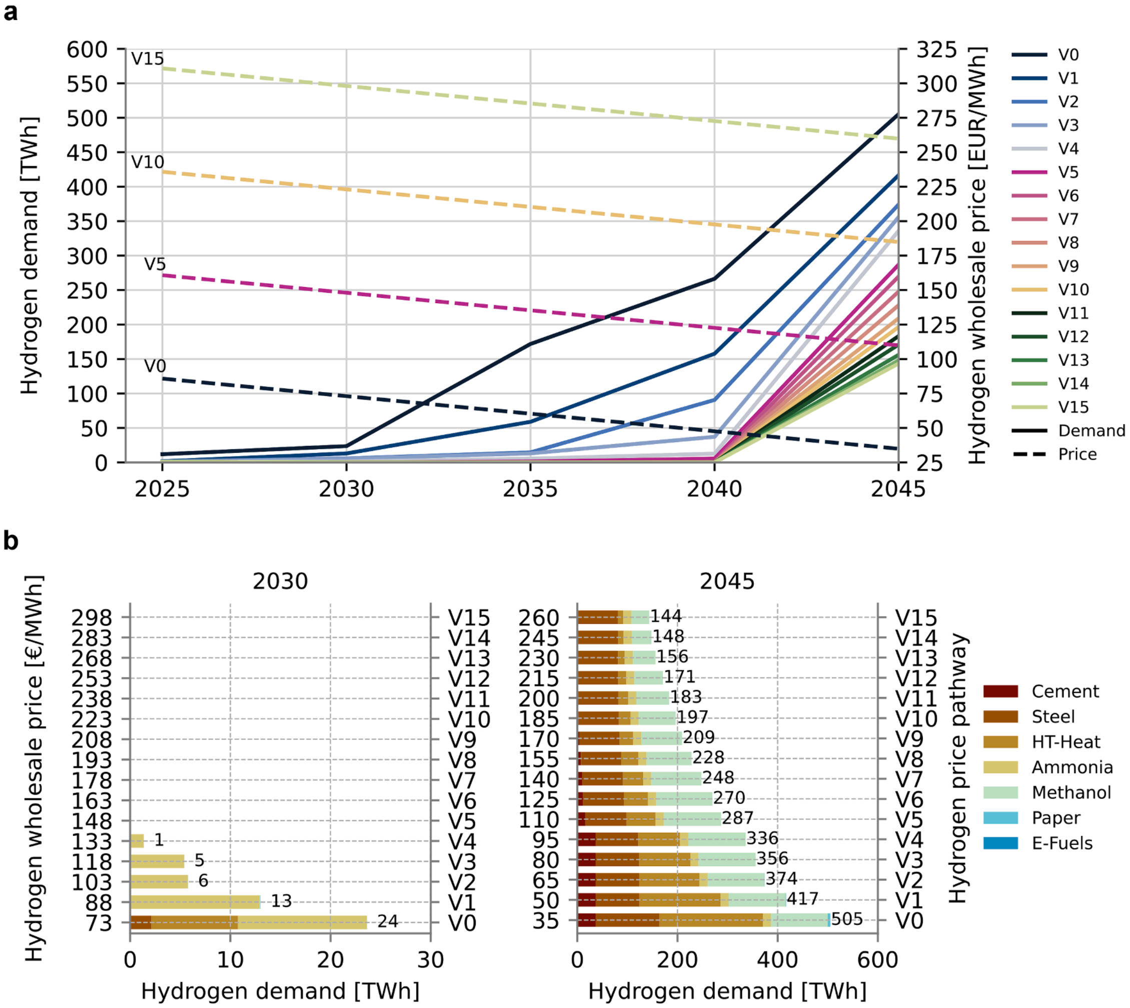

Fig. 6. Hydrogen demand in the industry sector. a, Aggregated hydrogen demand under different hydrogen price pathways over time. b, Sectoral hydrogen demand at hydrogen wholesale price levels corresponding to the predefined price pathways (V0–V15) in 2030 and 2045.

most price levels. In contrast, hydrogen demand for HT-Heat increases disproportionately at lower prices, reflecting a higher price sensitivity. For prices ≤ 170 €/MWh, the cement industry shows an increase in hydrogen demand, reaching a maximum of 37 TWh at the lowest price level. The viability of hydrogen for paper production is limited to the lowest price pathway, while demand remains marginal.

3.4. *Transport sector*

The aggregated hydrogen demand in the transport sector, alongside selected hydrogen wholesale price trajectories for 2025–2045, is shown in Fig. 7a. Hydrogen demand exhibits an overall upward trajectory across years and price pathways. For price pathways ≥ V6, demand remains minimal (< 10 TWh) across the years. For pathways below V6, total demand reaches up to 142 TWh in 2045, and the uptake shifts to earlier years, with the lowest-price pathway peaking at 71 TWh in 2030–2035.

As shown in Fig. 7b, hydrogen demand in 2030 is driven primarily by fuel-cell trucks, which account for 47 % of the truck technology mix at 73 €/MWh, while the remaining part is predominantly covered by conventional fossil fuels. Besides train transportation, hydrogen does not play a role in other transport subsectors. In passenger cars, conventional fossil-fuel technologies remain dominant, with battery-electric vehicles taking a growing share.

In 2045, a base demand of about 8 TWh exists, predominantly attributable to trains and buses. Across the price range of 125–260 €/MWh, hydrogen demand remains largely inelastic to price. Below this range, demand becomes price-elastic, with a significant increase in the truck segment, reaching up to 55 TWh. Hydrogen becomes competitive in passenger cars at price levels ≤ 50 €/MWh, with demand rising to as much as 40 TWh. Even under the lowest-price pathway, however, about 50 % of the passenger-car fleet consists of battery-electric vehicles, underscoring the continued competitiveness of electrification. In addition, a maximum hydrogen demand of 32 TWh is observed for the consumption of E-Fuels, which substitute kerosene imports in aviation and supply the maritime sector, as well as hybrid vehicles in road transport.

3.5. *Power and buildings sector*

The results for the power sector are shown in Fig. 8a. A general upward trend for the hydrogen demand is observed starting in 2035. However, for price pathways ≥ V5, a delayed uptake is observed, thereby shifting demand to 2045, resulting in a range of 12–48 TWh. Below V5, hydrogen uptake shifts to earlier years, reaching up to 43 TWh in 2035, while the demand in 2030 remains marginal. This indicates that hydrogen remains uncompetitive in the power sector up to the year 2030, as conventional technologies, such as gas-fired power plants, are more cost-efficient. Nevertheless, as the available budget for GHGs is reduced over time, hydrogen becomes increasingly competitive with conventional alternatives in terms of its potential to provide flexibility in electricity supply.

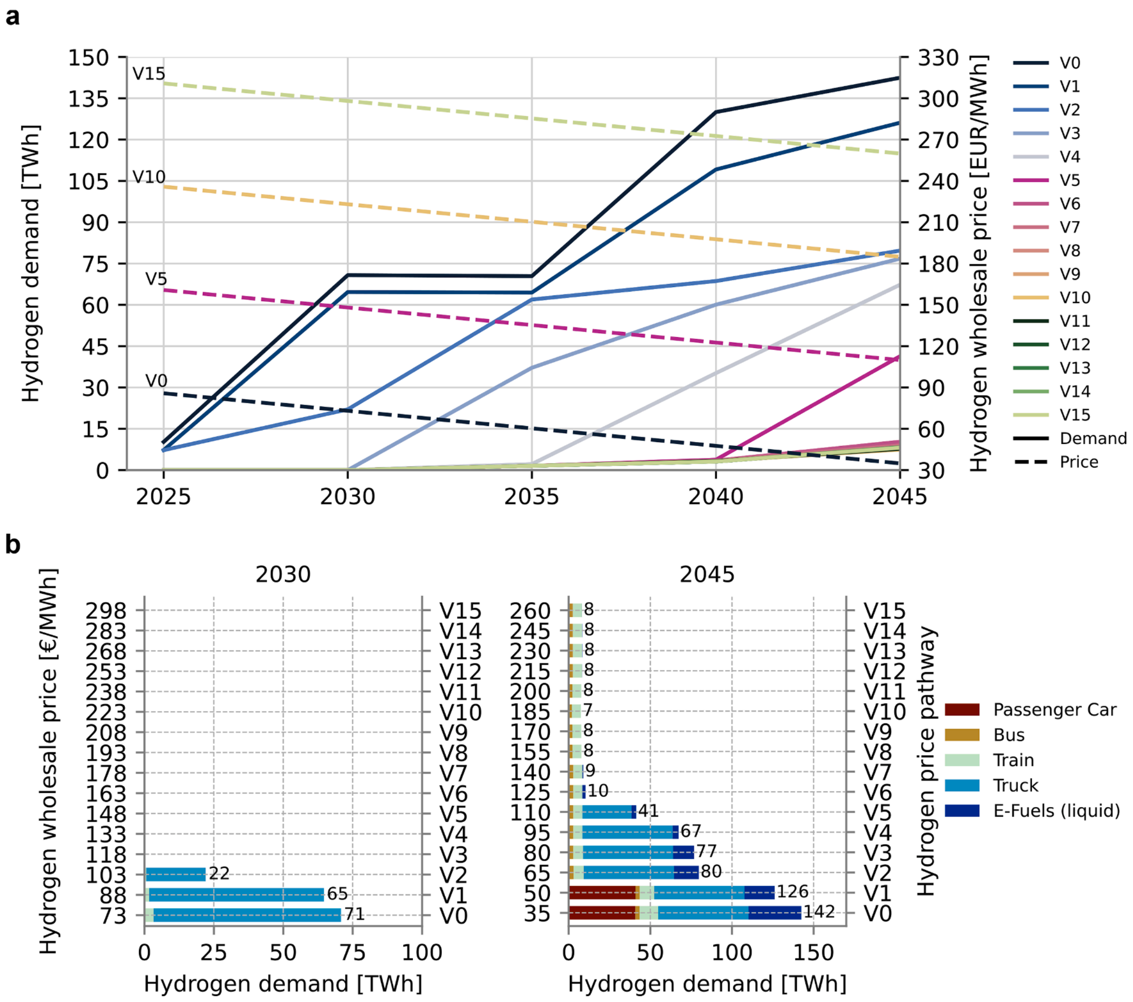

Fig. 7. Hydrogen demand in the transport sector. a, Aggregated hydrogen demand under different hydrogen price pathways over time. b, Sectoral hydrogen demand at hydrogen wholesale price levels corresponding to the predefined price pathways (V0–V15) in 2030 and 2045.

In 2045, as hydrogen prices decline uniformly across all scenarios, demand exhibits a disproportionately strong increase at the lower end of the price range (see Fig. 8b). Hydrogen demand remains price-elastic across all price levels, with a base demand of 12 TWh attributable to hydrogen-fired power plants, including gas turbines and combined-cycle gas turbines. These technologies are particularly relevant for achieving GHG neutrality, as they provide flexible backup capacity and enable seasonal storage, thereby complementing hydropower and short-term solutions, such as battery storage. As hydrogen prices decrease, demand for hydrogen-fired power plants exhibits a continuous increase, reaching a maximum of 145 TWh. Their operational pattern shifts from infrequent, winter-dominated use, primarily to balance fluctuations in supply and residual loads, to more consistent, year-round utilization, with average full-load hours reaching up to 2161 hours. At price levels of ≤ 50 €/MWh, hydrogen demand from combined heat and power (CHP) plants increases disproportionately, while also contributing additional heat to district heating networks. In contrast, fuel cells are only deployed at the lowest price level.

The results for the buildings sector are shown in Fig. 8c,d. Hydrogen demand begins to increase from 2040 onward for price pathways ≤ V2, corresponding to price levels below 78 €/MWh, and reaches up to 135 TWh, remaining constant through 2045. Overall, hydrogen is not competitive across any price level before 2035, as more cost-effective, decentral decarbonization options, such as heat pumps and electric boilers, are available. Hydrogen boilers emerge as a competitive alternative at price levels of approximately 80 €/MWh and experience increasing demand as prices decline further. They primarily replace electric boilers and heat pumps by 84 % and 34 %, respectively, at the lowest price level, resulting in a reduction in overall electricity demand. Alternative technologies, such as fuel cells or solid oxide fuel cells (SOFCs), are not deployed. The results indicate that direct electrification technologies are economically more attractive due to their higher efficiencies. Hydrogen boilers can only achieve economic competitiveness with direct electrification technologies if hydrogen prices decrease to levels below 80 €/MWh.

3.6. Sensitivity analyses

This section presents sensitivity analyses addressing two key aspects. First, the impact of constrained renewable energy potential is examined by introducing a synthetic period of limited renewable electricity supply, referred to as a "Dunkelflaute". Secondly, the robustness of the results is assessed by analyzing alternative price trajectories.

3.6.1. Impact of dunkelflaute

Energy systems characterized by high shares of renewable energy supply technologies such as onshore and offshore wind, as well as solar photovoltaic (PV), can experience extended periods with heavy overcast skies and poor wind conditions, leading to significant reductions in electricity supply. These meteorological events, referred to as “Dunkelflaute”, can last from a few hours to multiple days [49,50]. As a consequence, the energy system becomes stressed, as the availability of

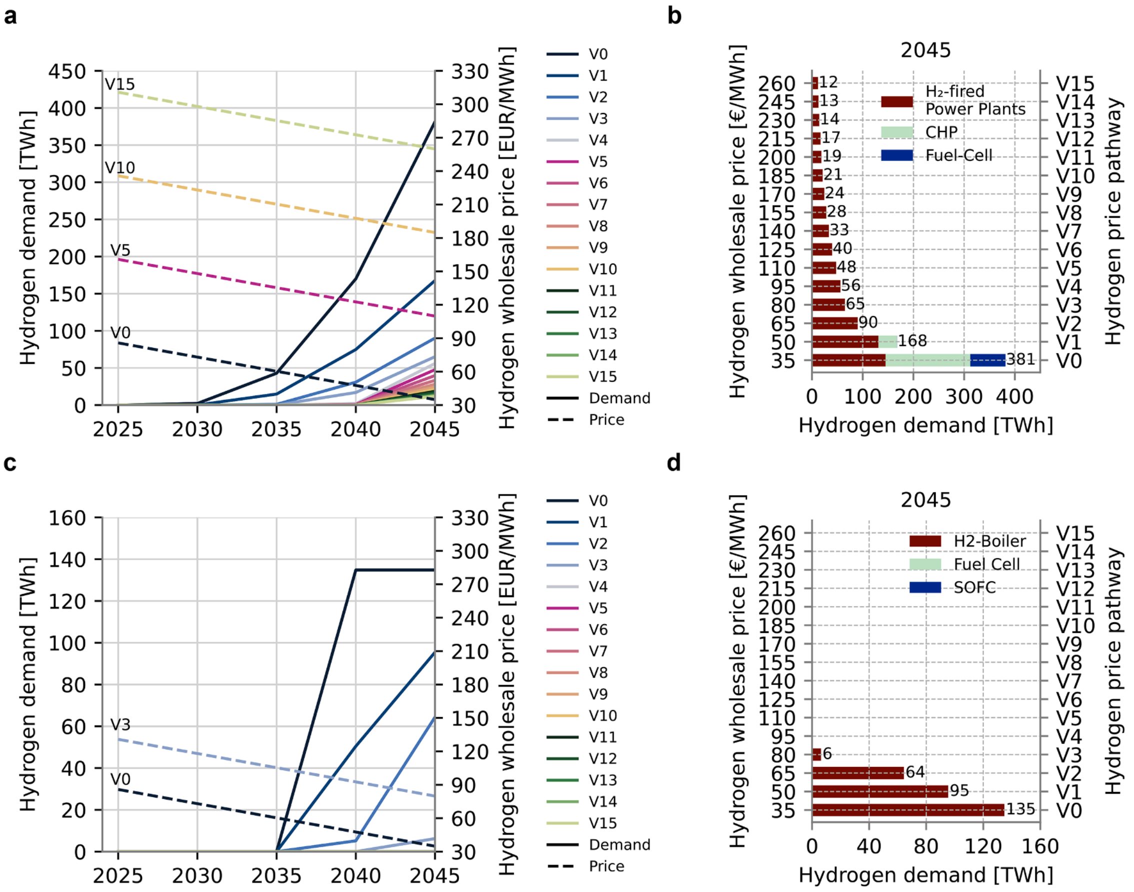

Fig. 8. Hydrogen demand in the power sector (a, b) and building sector (c, d). a, c, Aggregated hydrogen demand under different hydrogen wholesale price projections over time. b, d, Sectoral hydrogen demand at hydrogen wholesale price levels corresponding to the predefined price pathways (V0–V15) in 2030 and 2045.

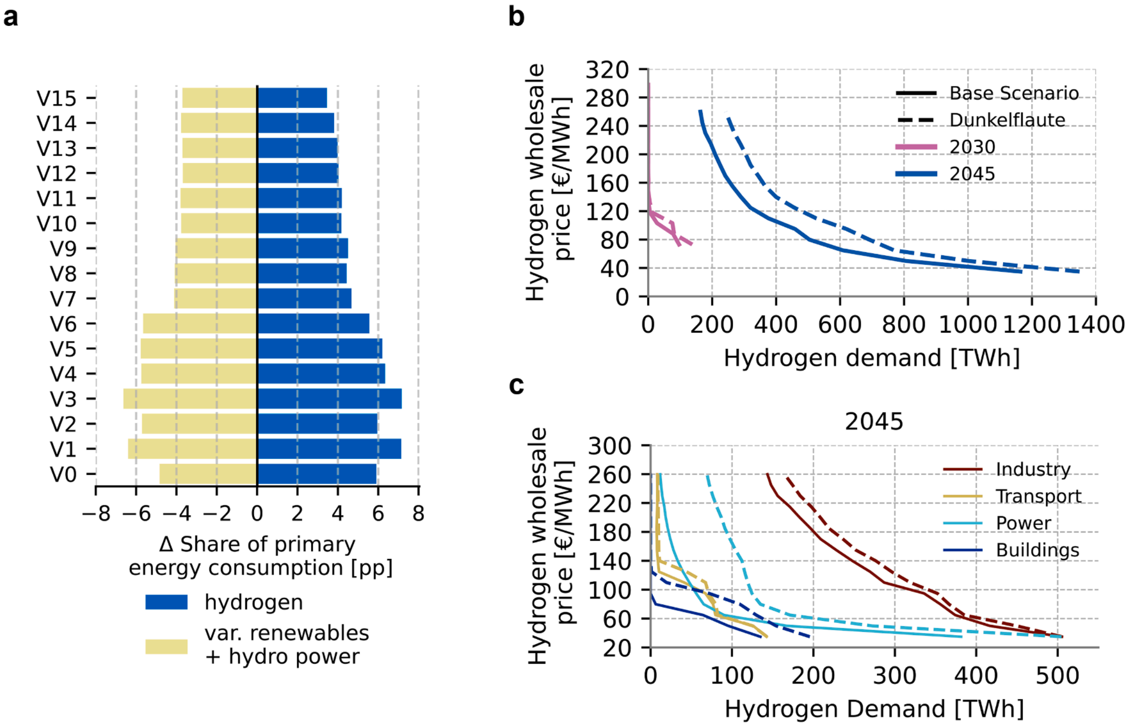

Fig. 9. Comparison of the Dunkelflaute and base scenarios: a, Absolute differences (percentage point differences) in the shares of electricity and hydrogen in total primary energy consumption across price pathways between the Dunkelflaute and base scenarios in 2045; b, Aggregated hydrogen demand curves for 2030 and 2040; c, Sectoral hydrogen demand curves for 2045.

electricity is limited, making back-up supply capacities essential to bridge this period. To assess its potential impact, a synthetic Dunkelflaute scenario is introduced into the energy system by restricting the availability of solar PV and onshore and offshore wind to a maximum of 10 % of their supply potential over a 14-day period in January.

Fig. 9a compares the shares of electricity and hydrogen in total primary energy consumption, illustrating the absolute differences, calculated as percentage point differences, between the Dunkelflaute and base scenario. Negative values indicate a lower share in the Dunkelflaute scenario compared to the base scenario, while positive values indicate an increase. Across all price pathways, an increase in hydrogen shares is observed, while electricity shares decrease. At the highest hydrogen price level, the hydrogen share rises by approximately 3.5 %, and the electricity share declines by about 3.7 %. As hydrogen prices decrease, their share increases further, reaching a maximum of approximately 7.1 %. In parallel, the electricity share continues to decline, with a maximum reduction of 6.6 %. These trends indicate that, under the Dunkelflaute scenario, hydrogen increasingly substitutes electricity across the energy system, resulting in a shift towards hydrogen-based options when renewable electricity availability is limited. Other energy carriers, such as biomass and fossil fuels, show no significant change across all price levels, with deviations of <1 % compared to the base scenario.

In Fig. 9b, hydrogen demand curves are compared between the base and Dunkelflaute scenarios for the years 2030 and 2045. The results show that hydrogen demand remains largely inelastic at price levels above 133 €/MWh in 2030. Below this threshold, hydrogen demand in the Dunkelflaute scenario increases by up to 138 TWh, resulting in an overall higher demand compared to the base scenario. In 2045, hydrogen demand in the Dunkelflaute scenario is consistently higher than in the base scenario since fewer alternative options remain to compensate for the loss of supply during the Dunkelflaute period as conventional fossil power plants are phased out. An offset of approximately 80 TWh is observed at the highest price level, increasing almost continuously to nearly 190 TWh as prices decrease. This suggests that hydrogen-based solutions become more competitive at low prices in the Dunkelflaute scenario than in the base case.

In Fig. 9c, the scenarios are compared at the sectoral level for the year 2045. The power sector exhibits the largest change in hydrogen demand. This is driven by the increased role of hydrogen in bridging the renewable electricity supply gap during the Dunkelflaute, primarily through hydrogen-fired power plants and combined heat and power supply. As a result, hydrogen demand in the power sector rises from 12 TWh to about 70 TWh at the highest price level. The offset remains between 57 and 81 TWh down to a price level of 65 €/MWh. Below this threshold, hydrogen becomes increasingly attractive, with additional demand reaching up to 123 TWh at the lowest price level.

In the building sector, hydrogen demand becomes competitive at higher price levels than in the base scenario, reaching approximately 20 TWh at 110 €/MWh, and increasing to around 195 TWh at the lowest price level, which corresponds to an increase of around 45 % relative to the base scenario. Hydrogen boilers increasingly replace heat pumps and electric boilers, leading to a reduction in electricity demand for decentralized heating applications. However, above a price level of 110 €/MWh, hydrogen-based options remain largely uncompetitive compared to direct electrification.

The price level at which fuel cell trucks enter the market shifts to higher levels, around 125 €/MWh, while the remaining demand curve experiences no significant change. In contrast, hydrogen demand in the industry sector increases by up to 20 TWh under the highest price pathway. This is primarily attributable to increased demand for high-temperature heat and methanol production. This change, however, declines continuously as prices decrease, reaching nearly zero at the lowest price level.

3.6.2. *Impact of different price trajectories*

The sensitivity of the hydrogen demand curves to the hydrogen price trajectory is assessed by analyzing alternative price trajectory developments and their influence on the price elasticity of green hydrogen. Two scenarios are considered, as illustrated in Fig. 10a: a conservative scenario, which assumes a delayed price reduction, and a progressive scenario, which assumes an earlier price decline. To ensure comparability, hydrogen prices in 2025 and 2045 are held constant across both scenarios, while varying the temporal progression of prices between these two points.

The aggregated hydrogen demand for the price pathways V0 up to V5 is shown in Fig. 10b and compared between the scenarios. Overall, the progressive scenario results in higher hydrogen demand compared to the base scenario, due to lower hydrogen prices between 2030 and 2040. In 2030, demand increases by approximately a factor of two. However, this effect weakens over time, reaching an increase of around 6 % by 2045 relative to the base scenario. Although both scenarios converge to the same price level in 2045, the progressive scenario enables earlier adoption of hydrogen-based options across the energy system. This early transformation improves their economic viability in 2045, leading to higher hydrogen demand. However, this effect diminishes for higher price pathways, as the market ramp-up of hydrogen is increasingly delayed until 2045. As a result, hydrogen demand becomes less sensitive to the shape of the price trajectories with higher price pathways, since most of the transformation occurs in 2045. The opposite trend is observed for the conservative scenario, where hydrogen demand is overall reduced compared to the base scenario. While the difference in demand is negligible in 2030, the demand decrease becomes more pronounced up to 2040 and reaches about 5 % in 2045.

The demand curves for the years 2030 and 2045 are compared in Fig. 10c. Overall, hydrogen demand in 2030 shows little sensitivity across most price levels. The significant increase at the lowest price point for the progressive scenario is primarily driven by the absolute price difference compared to the base scenario. As illustrated in Fig. 5, hydrogen demand becomes highly sensitive to price changes at lower price ranges, resulting in substantial increases in demand even in response to small price variations. The general pattern in 2045 is similar, with no significant differences between the scenarios across most price levels. However, as discussed above for the lowest price level, demand increases in the progressive scenario due to earlier adoption of hydrogen-based technologies, while demand decreases in the conservative scenario as a result of delayed adoption.

4. Discussion

The role of green hydrogen is examined in a broader context by comparing our findings with relevant literature and by assessing its contribution to achieving GHG neutrality, the dynamics of the market ramp-up, associated policy implications, and the limitations of this study.

4.1. *The role of hydrogen in achieving GHG neutrality*

At the system level, the results indicate that green hydrogen is essential for achieving GHG neutrality, which is consistent with the comparative analysis of multiple GHG-neutral transformation studies of the German energy system conducted by acatech, Leopoldina, and Akademienunion [51]. In our study, green hydrogen is deployed even under high-price scenarios, contributing approximately 7 % to total primary energy consumption. This highlights its critical role in substituting conventional processes, particularly in emission-intensive industrial sectors, such as steel production, high-temperature heat, and the chemical industry, where electrification is limited by technical or economic constraints.

Under lower price pathways, hydrogen uptake increases substantially, with its share in primary energy consumption reaching up to 47

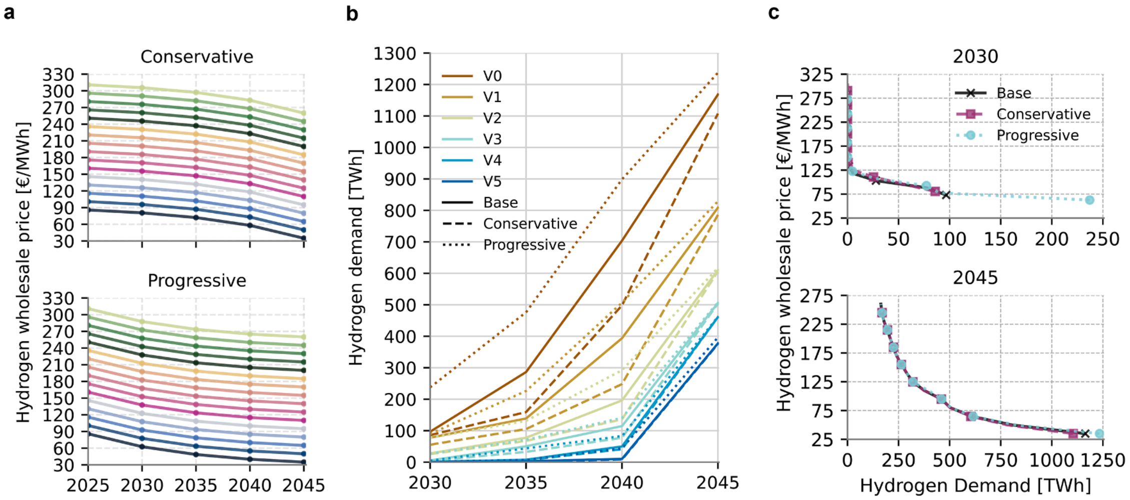

Fig. 10. Comparison between the conservative, progressive, and base scenarios. a, Green hydrogen wholesale price pathways for the conservative and progressive scenarios. b, Aggregated hydrogen demand for selected hydrogen price pathways over time. c, Hydrogen demand curves for 2030 and 2045.

%. Pronounced substitution effects between hydrogen and electricity highlight the competition between hydrogen-based solutions and direct electrification in decarbonizing consumption sources. The overall contribution of hydrogen to achieving GHG neutrality, however, strongly depends on its price trajectory. Hydrogen demand in 2045 shows pronounced price sensitivity at lower price levels, where small price reductions lead to significant demand increases. While hydrogen demand approximately doubles from 260 €/MWh to 125 €/MWh, it rises by more than a factor of 3.6 between 125 €/MWh and 35 €/MWh. Therefore, achieving hydrogen prices in the lower price ranges can significantly increase its penetration across sectors. However, reaching such high levels of hydrogen integration would require very low prices (≤ 35 €/MWh), which represent an extremely low value compared to median projections of around 97 €/MWh by 2050 (see Fig. 2). Moreover, the wide range of cost projections highlights substantial uncertainties, and most studies consider only production costs, while excluding additional components such as profit margins, which would further increase the final market price. Recent studies, such as that of the Forschungsstelle für Energiewirtschaft (FfE) [19], also emphasize that hydrogen production costs are often underestimated because key cost components, particularly investment and electricity expenditures, tend to be projected too low. Given these factors, achieving such low-price levels remains highly challenging. Consequently, direct electrification remains a cornerstone of decarbonization due to its overall higher conversion efficiency.

4.2. *Hydrogen market ramp-up*

The temporal development of hydrogen demand reflects considerable system inertia, leading to a delayed market ramp up, with uptake largely concentrated in 2045 across most price pathways (V5–V15). This delay is attributable to the prioritization of direct electrification over hydrogen in many subsectors due to its higher conversion efficiency for reducing GHG emissions. Direct electrification is not only more efficient, but also more cost-effective under these price pathways. Secondly, the transformation of conventional processes that are difficult to electrify tends to progress slowly, particularly in sectors with high barriers to emission reduction, such as the steel or chemical industries. This is primarily attributable to the comparatively low cost of fossil fuels, even when accounting for GHG constraints, as well as the tendency to utilize existing capital stock over its full technical lifetime. Collectively, these factors tend to delay the transition until 2045, when the constraints of GHG neutrality must be met.

According to the National Hydrogen Strategy [5], a rapid market ramp-up is targeted, with hydrogen demand, including derivatives, projected to range between 95 and 130 TWh by 2030. The most significant shares are projected to stem from the industry and heavy-duty transport sectors, which are also identified in this study as the primary off takers. However, achieving such a substantial uptake, with demand exceeding 78 TWh as early as 2030, would necessitate a decline in hydrogen prices below 88 €/MWh. Estimates of hydrogen production costs for 2024, as reported by the IEA [3], range from approximately 94 €/MWh globally and 172 €/MWh in Europe to over 333 €/MWh, thereby underscoring the necessity for substantial cost reductions. However, as analyzed by Shafiee and Schrag [52], the delivered price of green hydrogen for end-use sectors, including storage, distribution, and refueling, can be substantially higher, since these figures only reflect production costs.

In contrast, alternatives such as blue hydrogen, produced from natural gas with carbon capture, utilization, and storage, are generally cheaper, with estimated European prices of approximately 72–103 €/MWh in 2030 according to the IEA [3], and could therefore facilitate the market ramp-up. However, fugitive emissions, such as upstream emissions from methane leakage, are often excluded from national hydrogen strategies, as described in Longden et al. [53]. Together with residual emissions from carbon capture processes, these factors limit their compatibility with stringent, long-term greenhouse gas emission constraints [54]. Zeyen et al. [55] show, using a sector-coupled European energy system model, that hydrogen production pathways may shift directly from grey to green hydrogen, largely bypassing blue hydrogen, unless highly optimistic assumptions are made regarding steam methane reforming investment costs, carbon capture rates, or CO_2 storage availability. In addition, social acceptance barriers [56] and potential lock-in effects [5] may further constrain the long-term deployment of blue hydrogen under greenhouse gas neutrality targets.

4.3. *Sectoral drivers and limitations of hydrogen demand*

The strongest drivers of hydrogen demand are found in the industry sector, particularly in steel production, followed by methanol, high temperature heat, and ammonia, together accounting for a base demand of 144 TWh (see Fig. 11). This pattern is broadly consistent with the ranking by Johnson et al. [57], who categorize hydrogen applications by their competitiveness relative to alternative technologies. In their framework, these subsectors are classified as necessary or possible uses of hydrogen, except for HT-heat, due to potential alternatives such as direct electrification. Although electrification is generally expected to achieve higher efficiencies, it should be noted that this varies strongly by

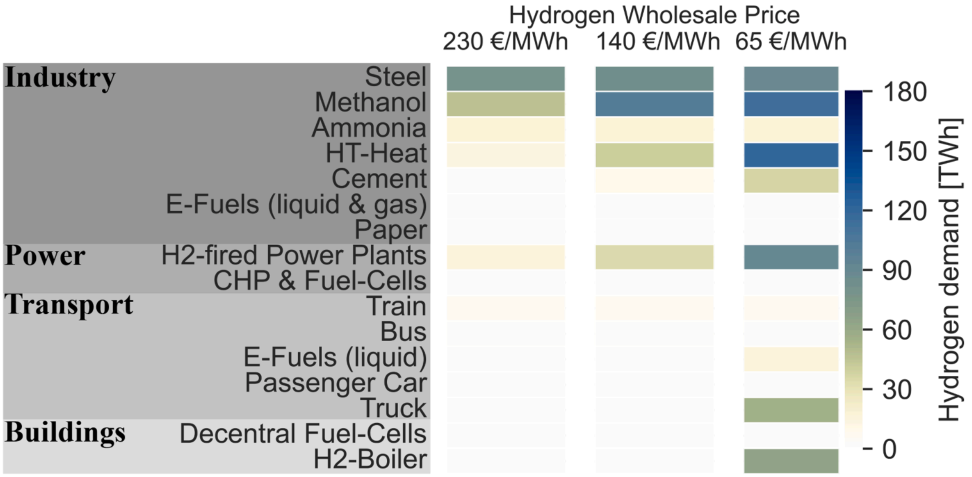

Fig. 11. Overview of hydrogen demand in 2045. The heat map presents sectoral demand under the high-price (V13), medium-price (V7), and low-price (V2) pathways.

the specific application and likely requires a more substantial retrofit of the stock of installations, compared to a switch to hydrogen-based solutions, as described by Fleiter et al. [58].

In the power sector, hydrogen-fired gas plants emerge as a major driver of demand. The importance of flexible, hydrogen-based generation becomes particularly evident under the Dunkelflaute scenario, to compensate for prolonged periods of low renewable supply. These findings highlight the critical role of hydrogen-based generation as backup capacity in a renewable-dominated energy system, enabled by hydrogen's capability for long-duration storage. While batteries can balance intraday fluctuations, extended supply shortages require cost-efficient, large-scale storage, for which geological hydrogen storage is considered a viable, low-emission solution [57].

Hydrogen plays only a minor role in decentralized building heating across most price pathways, as direct electrification through heat pumps and electric boilers, combined with energetic renovation of buildings, remains the more cost-effective option. This finding is consistent with Rosenow's [59] meta-analysis of 54 studies, which concludes that hydrogen is generally less efficient than electrification-based alternatives. In the transport sector, fuel cell trucks emerge as the main driver of hydrogen demand, consistent with the findings of Agora Think Tanks et al. [60]. In this study, however, their role materializes only at prices $\leq$ 110 €/MWh. Electrification remains the dominant option for transport across most price pathways, reflecting its higher efficiency. The role of fuel cell passenger cars is limited to prices $\leq$ 50 €/MWh, which would require substantial price reductions.

4.4. Comparison of hydrogen demand with existing literature

In the meta-analysis conducted by Bühler et al. [41], 28 studies are compared, and hydrogen demand projections for Germany are presented, differentiated by low, medium, and high market ramp-up. Their findings indicate hydrogen demand between 0 and 193 TWh for 2030, with the upper value reflecting a rapid ramp-up and substantially exceeding the 60 TWh projected under a moderate ramp-up. These projections are generally consistent with our base scenario of 0–97 TWh. For 2045, hydrogen demand is projected in the range of 132–648 TWh, with one outlier at 976 TWh. Our results largely fall within this range (163–806 TWh), except for the lowest-price pathway (V0), which reaches 1164 TWh and represents an extreme case, as discussed above.

In Fig. 12, the hydrogen demand curves for Germany in 2030 and 2045 are compared with the results of Weißenburger et al. [23], enabling a direct comparison since both studies assess the price elasticity of hydrogen within GHG-neutral transformation pathways. However, it is important to note that the studies are based on different modeling approaches: The present study employs a sector-coupled energy system model, whereas Weißenburger et al. [23] use separate models for individual sectors. The aggregated results for German hydrogen demand

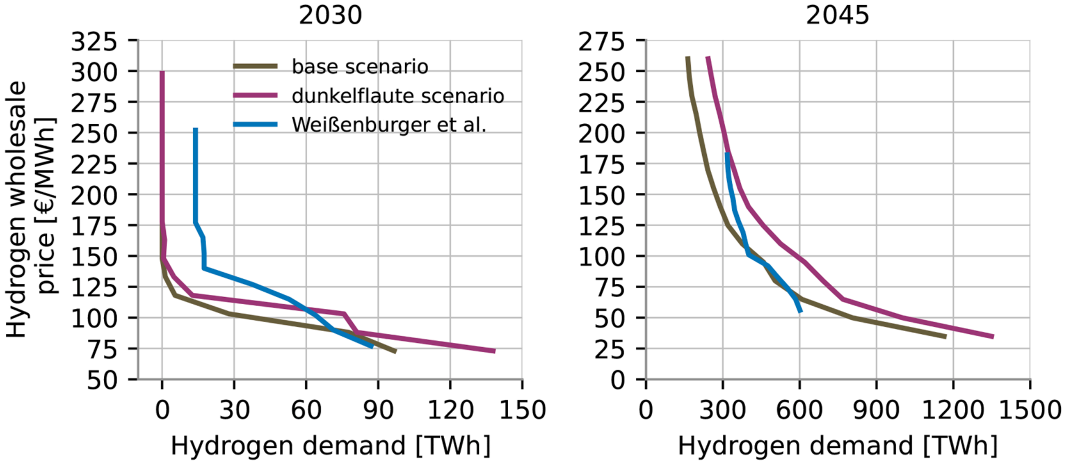

Fig. 12. Comparison of the modeled hydrogen demand curve for Germany with literature data for 2030 and 2045. Literature values are taken from Weißenburger et al. [23].

from Weißenburger et al. [23] were extracted using the tool WebPlotDigitizer [61] and may therefore exhibit minor deviations from the original values.

In 2030, price elasticity shows a similar trend within the overlapping price ranges. At high price levels above 175 €/MWh, hydrogen demand remains largely inelastic in both studies. Weißenburger et al. [23] report a minimum industrial hydrogen demand of 14 TWh. In contrast, no demand is observed at that price level in this study, as electrification continues to represent the most cost-effective decarbonization pathway. Moreover, the decarbonization of emission-intensive industrial processes is deferred to 2045 under such high-price conditions. At lower price levels, Weißenburger et al. [23] observe accelerated demand growth below 140 €/MWh. In this study, demand increase starts at approximately 133 €/MWh, with a stronger rise in demand for prices below 118 €/MWh. Hydrogen demand converges to similar levels, ranging between approximately 87 and 97 TWh, at the lowest price range (73–77 €/MWh). An exception is the Dunkelflaute scenario, in which demand increases more substantially at the lowest price level. This is primarily driven by the conversion sector, where hydrogen becomes more economically attractive to compensate for the renewable electricity supply shortfall during Dunkelflaute conditions.

In 2045, the curve trajectory in Weißenburger et al. [23], compared to the base scenario of this study, follows an almost identical pattern within the price range of approximately 56 to 100 €/MWh. Above this range, hydrogen demand converges to a similar level as in the Dunkelflaute scenario. The demand is primarily driven by the industry sector, with the second-largest contribution coming from the conversion sector. In contrast, hydrogen is not utilized in the building and transport sectors. These findings are consistent with this study, with the exception that a small share of <8 TWh is allocated to the transport sector, specifically for train and bus transportation. At lower price levels, the Dunkelflaute scenario exhibits a significantly higher demand, approximately 300 TWh more than in Weißenburger et al. [23]. As in 2030, this increase is mainly driven by the conversion sector, reflecting the greater need for flexible supply options during Dunkelflaute conditions. Overall, the consistent demand patterns within overlapping price ranges support the robustness of the findings and align with existing literature.

4.5. Limitations

While this approach enables a sector-specific analysis of price elasticity, modeling demand sectors with a single-node framework introduces uncertainties by neglecting spatial variation. In practice, production and demand sites are expected to be regionally distributed and connected through infrastructure, such as hydrogen pipelines, as analyzed in Neumann et al. [62] and Hoffmann et al. [63], and this spatial heterogeneity can affect both hydrogen demand and price responsiveness. Incorporating higher spatial resolution could therefore improve the robustness of the analysis by enabling a more realistic representation of regional supply–demand matching and infrastructure constraints. Moreover, the virtual trading hub does not impose constraints on the volume of hydrogen traded, meaning that end-use sectors do not compete for a limited supply. This may influence the dynamics of the price-elastic demand response.

In addition, the model reflects a system-planner perspective and imposes a uniform hydrogen price across all sectors. It therefore does not differentiate between consumer-specific cost structures, such as tariffs, taxes, or policy support. In practice, such cost components may vary across sectors and consumer groups, potentially affecting sectoral or subsectoral price sensitivity.

Moreover, the binding GHG-neutrality target for 2045 significantly limits the use of conventional industrial processes that rely on fossil fuels, rather than hydrogen, biomass, or direct electrification. Given the imposed CO_2 storage limit of 90 Mt CO_2 per year, CCS-based routes in the steel and chemical industries are not viable alternatives to hydrogen-based processes, even at higher price levels. The main reason is that available CO_2 storage capacity is primarily allocated to CO_2 captured via direct air capture or biomass-based power plants to provide negative emissions that offset residual emissions. As shown by Schöb et al. [31], these negative emissions are required to achieve GHG neutrality. Consequently, insufficient CO_2 storage capacity remains to store additional CO_2 captured from potential applications in the steel or chemical industries. Higher CO_2 storage capacity or lower emission reduction targets could allow for the use of alternative processes that rely on fossil fuels combined with CCS. Under such conditions, industrial demand for hydrogen at higher price levels could decrease if CCS-based processes become more cost-effective than hydrogen-based alternatives.

Furthermore, the model does not consider domestic hydrogen production to isolate demand-side responses to uniform hydrogen price signals. Consequently, it does not capture the competition between domestic electricity supply for hydrogen production via electrolysis and other electricity uses. As a result, the total renewable electricity that is available can be allocated to direct electrification. The integration of domestic hydrogen production in accordance with national targets, as outlined in the National Hydrogen Strategy Update [5], which aims to achieve 10 GW of electrolysis capacity by the year 2030, could potentially reduce the share of renewables available for direct electrification. This could influence sectoral demand patterns and overall system design and should therefore be addressed in future research.

Given that hydrogen supply to the virtual trading hub is located outside the model boundary, upstream correlations, such as the relationship between endogenously determined electricity prices and exogenous hydrogen prices, are not represented explicitly. Instead, hydrogen prices influence electricity prices indirectly by affecting the optimal technology mix and sectoral energy use, thereby changing overall electricity demand and the endogenously calculated prices through adjustments in renewable capacity allocation and utilization.

Finally, the sensitivity study considering different hydrogen price trajectories reflects different price development pathways and implicitly captures uncertainties related to techno-economic assumptions and non-technical factors, including policy support. However, the study does not explicitly analyze uncertainties on the renewable electricity supply side. Variations in renewable cost developments could influence renewable allocation and competition between electricity-based applications and hydrogen. Including these sensitivities could further enhance the robustness of the analysis.

5. Conclusions

This study demonstrates that green hydrogen demand is strongly shaped by price dynamics, with a highly heterogeneous price response across sectors that reflects differences in the availability and cost-competitiveness of alternative decarbonization options.

Hydrogen is expected to play a key role in industry, where few technically viable and cost-competitive alternatives exist for the decarbonization of emission-intensive processes, such as steel production, ammonia and methanol synthesis, and HT-heat supply. The low-price elasticity observed at high price levels in the demand curves indicates significant competitiveness risks for these industries, underscoring that substantial price reductions will be essential to ensure future competitiveness. Conversely, the high price sensitivity at lower price ranges reveals considerable market potential, as even small cost reductions can substantially increase hydrogen uptake.

In contrast, hydrogen is expected to have a more limited role in buildings and transport, due to the availability of cost-effective electrification technologies, such as heat pumps and battery-electric vehicles. Fuel-cell trucks may complement the latter at lower hydrogen price ranges, representing a potential driver of demand under favorable price conditions. In the power sector, hydrogen can provide crucial backup capacity during periods of low renewable generation through hydrogen-fired power plants, although its contribution will remain strongly price dependent.

Taken together, the results indicate that a substantial decline in hydrogen prices is essential to enable meaningful uptake by 2030, as many hydrogen-based decarbonization options would otherwise be postponed to 2045. These findings underscore the importance of targeted, sector-specific policy measures to facilitate a cost-effective market ramp-up of hydrogen as part of Germany's pathway to greenhouse gas-neutrality, while also confirming the continued central role of direct electrification. In addition, the quantified hydrogen demand curves provide a valuable basis for future research to assess hydrogen market developments by analyzing supply and demand dynamics at both sectoral and aggregated levels.

Declaration of generative AI and AI-assisted technologies in the writing process

During the preparation of this work, the authors used ChatGPT and DeepL to improve the language of the manuscript. After using this tool/service, the authors reviewed and edited the content as needed and take full responsibility for the content of the published article.

CRediT authorship contribution statement

Drin Marmullaku: Writing – review & editing, Writing – original draft, Visualization, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Gian Müller:** Writing – review & editing, Writing – original draft, Visualization, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Tim Lux:** Methodology, Conceptualization. **Theresa Klütz:** Writing – review & editing, Supervision. **Thomas Schöb:** Writing – review & editing, Supervision. **Jann Michael Weinand:** Writing – review & editing, Supervision. **Jochen Linßen:** Writing – review & editing, Supervision. **Detlef Stolten:** Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

Data will be made available on request.

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