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[EWI-Research Report]

The financing gap in the hydrogen market ramp-up: Analysis of demand and price scenarios

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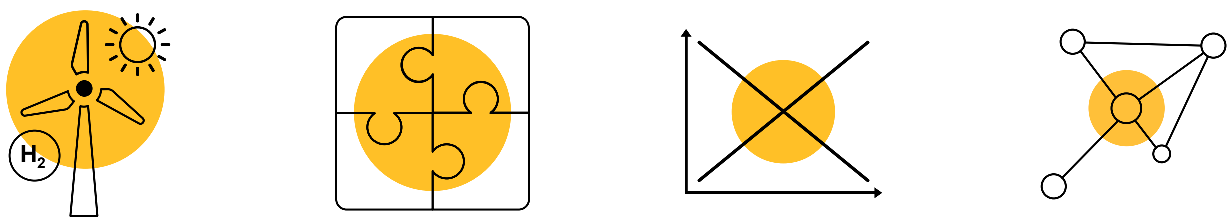

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Executive Summary

Low-carbon hydrogen can be a valid decarbonization option for processes that are technically and or economically hard to electrify. Therefore, it is projected to play a pivotal role in achieving Germany's goal of net greenhouse gas (GHG) neutrality by 2045 in relevant carbon-neutrality scenarios. The research report, "The financing gap in the hydrogen market ramp-up: analysis of demand and price scenarios," assesses the economic viability of the potential use of low-carbon hydrogen based on three hydrogen demand scenarios for Germany. On this basis, theoretical financing gaps are quantified.

For applications where conventional, fossil-based applications are cheaper than hydrogen-based ones, a market-driven adoption is improbable. If the scenario-based hydrogen demand is to be promoted nonetheless, a need for additional financing may arise. This research report estimates the theoretical financing gap for various demand and price scenarios. For this purpose, application-specific break-even prices for hydrogen, comparing the total cost of ownership (TCO) between greenfield conventional fossil-based processes and hydrogen-based alternatives are estimated. The theoretical financing gap arises when market prices for hydrogen exceed the break-even price, indicating a need for financial support to make the use of hydrogen economically viable.

Key Findings:

- By 2045, the annual financing gap for hydrogen adoption across all sectors is projected to range from €10 billion/a to €199 billion/a, depending on hydrogen demand and price scenarios. Hydrogen demand is expected to rise significantly, driven by key sectors such as steel, chemicals, electricity generation and transport. Against an uncertain future demand, the financing gap is estimated for three demand scenarios, outlining possible hydrogen consumption ranging from 227 TWh to 842 TWh annually by 2045.
- Break-even for hydrogen prices vary widely across applications in 2045, with the highest values for refineries (€227–€271/MWh) and the transport sector (€135–€399/MWh), while electricity generation and building heating show lower prices (€33–€69/MWh).
- A major uncertainty in the financing gap comes from the uncertain future level of hydrogen prices and hydrogen demand. Also, the regulatory framework, such as CO_2 pricing, tolls and energy taxation has a significant influence on future break-even prices for hydrogen and therefore on the financing gap.

This research report therefore indicates that some discussed applications may be cost-ineffective and that projected demand scenarios could create a potential financing gap. This highlights the need for targeted regulatory measures to support the adoption of hydrogen-based applications, especially if a specific hydrogen target is to be met despite cost disadvantages of the hydrogen-based alternative process. Without such measures, achieving hydrogen's full potential in decarbonizing the German economy may be hindered. The sufficiency of existing and planned regulatory measures is beyond the scope of this research report and shall be addressed in future research.

1 The future use of low-carbon hydrogen

According to the Climate Change Act, greenhouse gas (GHG) emissions must be reduced to the extent that net GHG neutrality is reached by 2045 in Germany (§ 3 Abs. 2 KSG[1]). To comply with this legislation, both CO_2 savings and avoidance must be achieved through governmental, corporate, and individual efforts. Many energy-related applications primarily use fossil fuels that need to be replaced by an alternative, emission-free option. In this context, the use of low-carbon hydrogen plays a central role in German climate neutrality scenarios. It can be a viable decarbonization option for processes that are technically and economically difficult to electrify. To sustain industrial capacity and security of electricity supply in particular, low-carbon hydrogen is discussed as an essential option.

At present, there is an approximated annual demand of 42 TWh for hydrogen in Germany, which predominantly originates in the (petro-)chemical sector. This amount is almost exclusively obtained from reforming natural gas and as a by-product of chlorine production and is therefore denoted as 'gray' hydrogen (EWI, 2024a). Switching from gray hydrogen to low-carbon hydrogen constitutes an immediate CO_2 avoidance option. Furthermore, additional low-carbon hydrogen demand potential could emerge from the transition of other applications from a fossil-based process to a hydrogen-based, emission-free alternative.

From a stakeholder perspective, the question of economic viability arises when switching to a hydrogen-based alternative. Compared to the conventional process, the hydrogen-based alternative may be more expensive and may therefore not establish itself on the market. In this case, the conventional alternative is economically more favorable and the hydrogen ramp-up is disrupted. If the use of hydrogen is nevertheless to be promoted, a need for additional financing may emerge to compensate for the difference in the hydrogen price and the willingness to pay.

Against this background, this research report aims to quantify the theoretical financing gap resulting from the projected hydrogen demand based on different scenarios for the demand. For this purpose, application-specific break-even prices for hydrogen for various applications are quantified, which are defined as the hydrogen price at which conventional and hydrogen-based alternatives are equally in cost. The break-even price is calculated as the difference in the total cost of ownership (TCO) between a fossil fuel-based conventional process and the low-carbon hydrogen-based alternative for the years 2030 and 2045. The theoretical financing gap equals the difference between break-even prices and market prices for hydrogen multiplied with the application-specific yearly demand for hydrogen.

Given the uncertainty regarding hydrogen, fossil fuel, and emission allowance prices as well as hydrogen technology market penetration, the financing gap is estimated in a scenario-based analysis. Three scenarios each for fossil fuel prices, hydrogen demand and hydrogen market prices are examined in order to reflect the uncertainty of future developments.

[1]Federal Climate Change Act (Bundes-Klimaschutzgesetz), 18th of August 2021.

2 Greenfield break-even prices for hydrogen

Break-even prices for hydrogen represent the price that consumers are willing to pay to avoid an increase in costs by switching from a fossil-fuel based process to a carbon-neutral alternative. The use of low-carbon hydrogen can differ across applications. It is either employed as a fuel, replacing natural gas or other fossil fuels in industrial process heat provision and the buildings sector, or as a feedstock in different industrial applications. Hydrogen can also replace conventional fuels in the transport sector in several modes of transport or natural gas in peak power plants.

2.1 Methodology

This research report quantifies the application-specific break-even price for hydrogen as the difference in the TCO between the conventional and the alternative, hydrogen-based application. The conventional application refers to established, carbon-intensive applications in each sector. In contrast, the alternative application refers to a low-carbon alternative application involving the use of low-carbon hydrogen. The TCO cover the total cost of an application over its lifetime. They include the capital expenditures (CAPEX) and the operational expenditures (OPEX) of the process as well as tolls and taxes, if applicable. The annuity method and an annual production volume or mileage are used to relate the costs to the output per year in tons or kilometers. For simplicity, it is assumed that the conventional and hydrogen-based alternatives have the same cost of capital. The implications of this assumption are discussed in chapter 4.1.

As shown in Figure 1, the break-even price for hydrogen is derived from a TCO comparison between the conventional (TCO_{Conv}) and hydrogen-based ($TCO_{Alt,\,w/o\,H2}$) alternative. By comparing the two processes, it is possible to determine the maximum amount that can be spent on

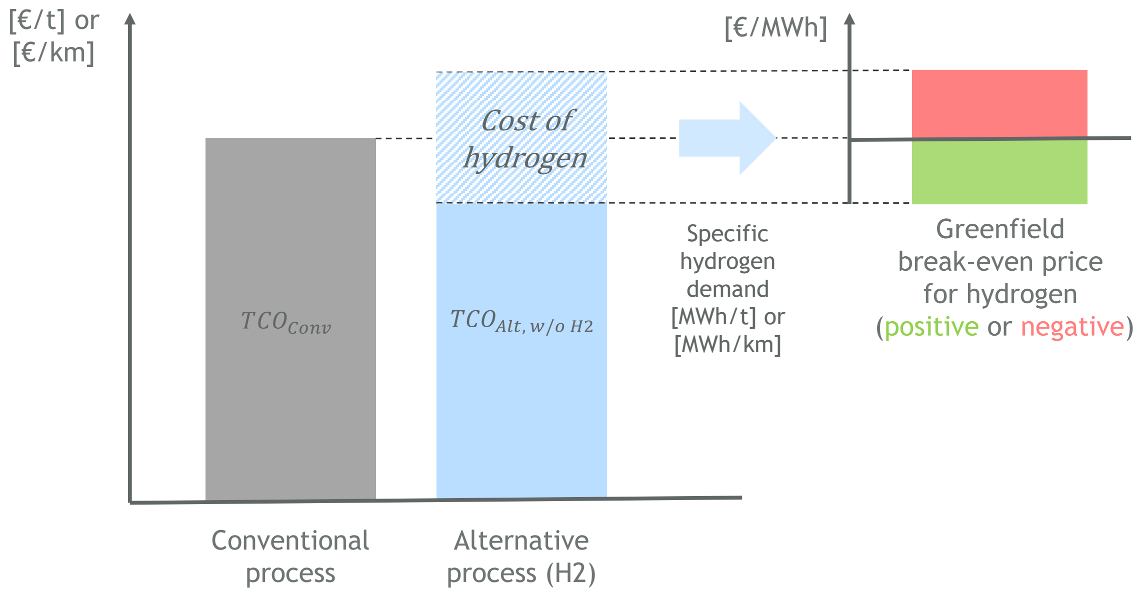

Figure 1: Methodological illustration of estimating greenfield break-even prices for hydrogen

hydrogen so that the TCO of the two processes are equal. The cost for hydrogen is shown in the shaded area. To determine the break-even price, this amount must be divided by the specific hydrogen requirement, which is indicated by the blue arrow. The break-even price thus indicates the maximum price that may be paid for a unit of hydrogen so that conventional and hydrogen-based alternatives are equally costly. The cost difference between the two production processes can either be positive or negative. If the break-even price is negative, there is no positive amount that can be spent on hydrogen. In fact, reaching the break-even point would require a subsidy. In this research report, the TCO of both the conventional and the hydrogen-based alternatives are based on greenfield investment costs. In reality, the conventional process is often already operational, and CAPEX are partly or entirely paid off. In this case, the TCO for the conventional alternative might be smaller than estimated in this research report. As a result, this comparison estimates the upper bound of the break-even prices. The term "break-even prices" as used in this research report is therefore to be understood as referring to the greenfield break-even prices.

The following research report only entails a hydrogen-based alternative to the conventional process. A comparison with other decarbonization options, in particular electrification, is not carried out. A comprehensive analysis of cost-efficient decarbonization requires an in-depth optimization of sector-specific decarbonization pathways.

2.2 Applications for low-carbon hydrogen and their parametrization

The following subsections outline how hydrogen may be employed in the industrial, transport, building, and electricity sectors, and which processes determine the break-even prices for hydrogen. For each application, the conventional process is defined and the TCO is calculated. For the hydrogen-based alternative, the process is defined with a specific hydrogen demand and the TCO is calculated. All input parameters are based on an extensive literature review.

2.2.1 Industry sector

In 2023, 23 % of CO_2 emissions in Germany originated in the industrial sector (kei, 2024). Reducing emissions in this sector is, therefore, crucial to achieving national climate targets. The energy-intensive industry has considerable future demand potential for low-carbon hydrogen. Hydrogen can either be used as an alternative fuel to natural gas or other fossil fuels to provide process heat. Processes already using hydrogen as feedstock are currently relying on gray hydrogen[2]. In these processes, low-carbon hydrogen can replace gray hydrogen. Additionally, other production processes can be converted to use low-carbon hydrogen as a feedstock instead of fossil fuels, such as the steel production.

[2]This holds true for the production process of methanol, ammonia, and refineries (EWI, 2023a).

Iron & Steel

Primary steel production requires ironmaking from naturally occurring iron oxide in the form of iron ore. The iron ore must be purified using a reducing agent. Historically, coking coal or natural gas have been used for this purpose, resulting in substantial CO_2 emissions. It is possible to implement this reduction with hydrogen and direct carbon emissions can be avoided. The production of 1 t crude steel requires 2 MWh of hydrogen (Neuwirth et al., 2022). Since the blast furnace production route is the predominant primary production route in Germany (Schneider et al., 2019), it is assumed to be the conventional process. Therefore, the break-even price for low-carbon hydrogen in the steel industry is calculated by comparing the TCO of the blast furnace production route with the direct reduction using hydrogen as the alternative route. The process parameterization is based on EWI (2021a), Fischedick et al. (2014) and Vogl et al. (2018).

Methanol

Methanol is an intermediate product of the petrochemical industry and requires hydrogen as a feedstock. The hydrogen requirement in methanol production is stoichiometric and corresponds to 6 MWh of hydrogen per ton of methanol (Neuwirth et al., 2022). The hydrogen demand of the current production is mainly obtained from fossil sources. Conventional hydrogen production typically relies on steam methane reforming (SMR). As an alternative to conventional hydrogen, low-carbon hydrogen can be used to avoid carbon emissions in the hydrogen production process. In this research report, the difference in TCO of the conventional and low-carbon hydrogen-based methanol synthesis is primarily attributable to the costs for hydrogen production by SMR. The synthesis process itself remains unchanged. The process parameterization is based on (VCI, 2019).

Ammonia

The case of ammonia and methanol share similar properties. Ammonia is an important intermediate product in the chemical industry. An example of a downstream product is fertilizer. The production of ammonia requires hydrogen as feedstock, consuming 6 MWh of hydrogen per ton of ammonia (VCI, 2019). Hence, ammonia could be synthesized using either conventionally obtained hydrogen from SMR or low-carbon hydrogen. As for methanol, the parameterization of EWI (2021a) and VCI (2019) was applied to estimate the break-even price for hydrogen associated with the production of ammonia. For this purpose, the conventional route and the alternative route are compared. Again, the difference in TCO of the conventional and low-carbon hydrogen-based ammonia synthesis is primarily attributable to the costs for hydrogen production by SMR.

Olefins

Among high-value chemicals, olefins are widely used as inputs in different industries, such as the electrical, textile, and pharmaceutical industries. In principle, various processes are available to produce olefins. In the chemical industry, high value chemicals are primarily produced through naphtha cracking, a process that involves the thermal breakdown of naphtha, a fraction obtained from crude oil distillation. This process yields a mixture of olefins and aromatics. This production process is chosen as the conventional method. In the cracking process, the carbon chains of naphtha are split thermally using gas and water vapor. In addition to olefins and aromatics, this process produces methanol, hydrogen, and heavy oil as by-products, which are burned to cover the energy requirements of the process, resulting in CO_2 emissions. Olefins can also be produced from methanol. This process is called methanol-to-olefins (MTO) and is used here as a low-carbon alternative. Low-carbon methanol acts as a feedstock from which olefins are produced in various steps. Along the MTO route, 18 MWh of hydrogen is required per ton of olefins (VCI, 2019). In this research report, the break-even price is determined only for ethylene, but not for other olefins such as propylene, and is assumed to be representative of all olefins. As with methanol and ammonia, the TCO for olefins were determined employing the commodity requirements from EWI (2021a) and VCI (2019). Investment and operating expenses from VCI (2019), Schneider et al. (2019) and DECHEMA (2017) supplement the parameters for calculating the TCO.

Refineries

Refineries use hydrogen in the processing of crude oil into mineral oil products. More specifically, it is used for desulphurization, hydrotreating, and hydrocracking. As in the case of ammonia and methanol, hydrogen is currently obtained from fossil sources and can be substituted by low-carbon hydrogen. In mineral oil refineries, a distinction is generally made between gross and net hydrogen demand. Gross hydrogen demand includes hydrogen from upstream processing units such as hydrocracking and catalytic reforming processes. Net hydrogen demand, on the other hand, refers to the share of hydrogen demand that must be met by a dedicated hydrogen source, such as SMR or electrolysis. Therefore, only the net hydrogen demand has to be replaced with low-carbon hydrogen. The net demand for hydrogen corresponds to 0.13 MWh and 0.05 MWh per ton of crude oil throughput for refineries with and without hydrocracking, respectively (based on EWI (2021b)).

In the case of refineries, the break-even price is not only influenced by the fossil fuel and emission allowance prices but also by costs arising from the GHG quota according to the Renewable Energy Directive II (RED II). The GHG quota is a regulatory instrument to fulfill climate protection targets in the transport sector. It obliges oil companies to reduce the emissions caused by fuels brought into circulation by a certain percentage each year. The quota applies to the production of petrol and diesel fuel only, as other refinery products are not subject to the Federal Immission Control Act (§ 37a Abs. 4 BImSchG[3]). The production of diesel and petrol accounts for around 64 % of crude oil throughput in German refineries (en2x, 2023).

The GHG quota concerns emissions associated with the use of crude oil as a fuel from well-to-wheel. For 2024, the quota mandates a well-to-wheel GHG-reduction by 9 %. If the predefined reduction is not adhered to, a penalty is charged. With the use of low-carbon hydrogen in fuel refining, only approx. 2 % of the well-to-wheel emissions can be avoided. Consequently, this research report assumes that all hydrogen used in the production of gasoline and diesel is subject to the GHG quota. The penalty payment amounts to € 600 per ton of CO_2 equivalent emitted (§ 37c Abs. 2 BImSchG). According to this research report, the penalty raises the break-even price for low-carbon hydrogen by 180 €/MWh hydrogen.

[3] Federal Immission Control Act (Bundes-Immissionsschutzgesetz), 10th of May 2023.

Non-ferrous metals, Non-metallic raw materials, Paper, Glass & Ceramics

The production of non-ferrous metals (e. g. aluminum, copper), non-metallic raw materials (e. g. cement, concrete), paper and glass & ceramics required process heat of high temperatures. In these processes, hydrogen demand may arise from the thermal use as a substitute for current natural gas demand. By using low-carbon hydrogen, CO_2 emissions from the combustion of natural gas for heating purposes can therefore be avoided. The break-even price for low-carbon hydrogen computes from the costs of natural gas, including the price of CO_2 emission certificates. The TCO only includes the OPEX of the processes because, as EWI (2021a) illustrate, the CAPEX of the conventional and alternative routes can be assumed to be equal.

2.2.2 Transport sector

In Germany, about 22 % of GHG emissions originated in the transport sector in 2023 (kei, 2024). Hydrogen-fueled vehicles are one possibility to lower carbon emissions in the transport sector. In the transport sector, the break-even price for low-carbon hydrogen results from the cost comparison of the investment and fuel costs of the fossil fuel-based transport option with the alternative hydrogen-based transport option. The research report distinguished between passenger cars, light duty vehicles, trucks, and public road transport. The fuel consumption assumptions for the various combustion engines are derived from EWI (2021a).

In addition to operating and investment costs, regulatory measures determine the break-even price for low-carbon hydrogen in the transport sector. The German transport sector is subject to two main regulations that shape the operational costs of both fossil- and hydrogen-based transport: All modes of transportation using conventional fossil fuels are subject to energy taxation and CO_2 emission costs, while trucks > 3.5 t are additionally subject to tolls. Energy tax is an umbrella term for all taxes on energy products such as fuels (petrol and diesel). For example, the tax on petrol has been 65 ct/l and on diesel 47 ct/l since 1 January 2003 (bpb, 2024). The energy tax is added to the TCO of the conventional process.

The toll for trucks is composed of four price components: infrastructure, air pollution, noise disturbance, and CO_2 emissions. Currently, hydrogen-fueled vehicles are exempt from all toll payments. From 2026, hydrogen vehicles will be subject to the air pollution and noise pollution components and 25 % of the infrastructure component only (Toll Collect, 2024). The toll also differentiates between the number of axles, emission classes, and the permissible total weight of the vehicle combination. Reference trucks were therefore used to determine the break-even price resulting from the toll payments. The different applicability of toll components influences the break-even price for low-carbon hydrogen because the CO_2 emissions component of the toll can be avoided. Thus, the break-even price for low-carbon hydrogen increases by the saved cost components.

2.2.3 Electricity sector

Energy systems that increasingly rely on renewable but intermittent electricity generation capacity require firm backup generation capacity to ensure the security of supply. In the future, this role could be filled by hydrogen-fired gas turbines. Consequently, there is demand potential for low-carbon hydrogen in the electricity sector. In the medium term, natural gas will be used to generate electricity in turbines, which could be fired with hydrogen in the future. The break-even price for hydrogen-fired gas turbines is determined by the conventional fuel, i.e., natural gas, and the associated TCO. In the case of electricity generation, these are composed of OPEX, such as the fuel costs as well as the CO_2 costs associated with the use of natural gas and CAPEX for the power plants based on EWI (2021a).

2.2.4 Building sector

In Germany, the building sector accounted for roughly 15 % of emissions in 2023 (kei, 2024). In addition to decarbonized district heating and heat pumps, hydrogen-fired gas heating is one option being discussed for decarbonizing the heating sector. The break-even price for hydrogen from buildings is determined by the conventional use of natural gas for heating buildings. Therefore, it is composed of the fuel costs and the costs associated with CO_2 emissions. As of 2027, the building sector will be subject to the EU ETS 2 carbon pricing (UBA, 2023a). For simplicity, this research report assumes the same carbon price for all sectors and applications. For the buildings sector, it is assumed that the investment costs for the conventional natural gas heating unit and the hydrogen-based heating unit are equal and can be neglected in the comparison of TCO.

2.3 Scenarios for fossil fuel and emission allowance prices

The application-specific TCO is greatly influenced by the prices for electricity, fossil fuels, and emission allowances. The development of prices for these parameters is subject to uncertainty and influenced by the regulatory landscape. Therefore, the application-specific break-even prices are estimated for three distinct fossil fuel and emission price scenarios, representing high, medium, and low price developments. As can be seen in Figure 2 in all three scenarios, electricity and natural gas prices decrease by 2030 and 2045, respectively. The scenarios differ in the rate of price decline. For the oil price, the baseline and low price scenarios assume a price decline by 2030 and 2045, while the high price scenario assumes an increase. All three scenarios involve a continuous increase in emissions prices, albeit at different rates.

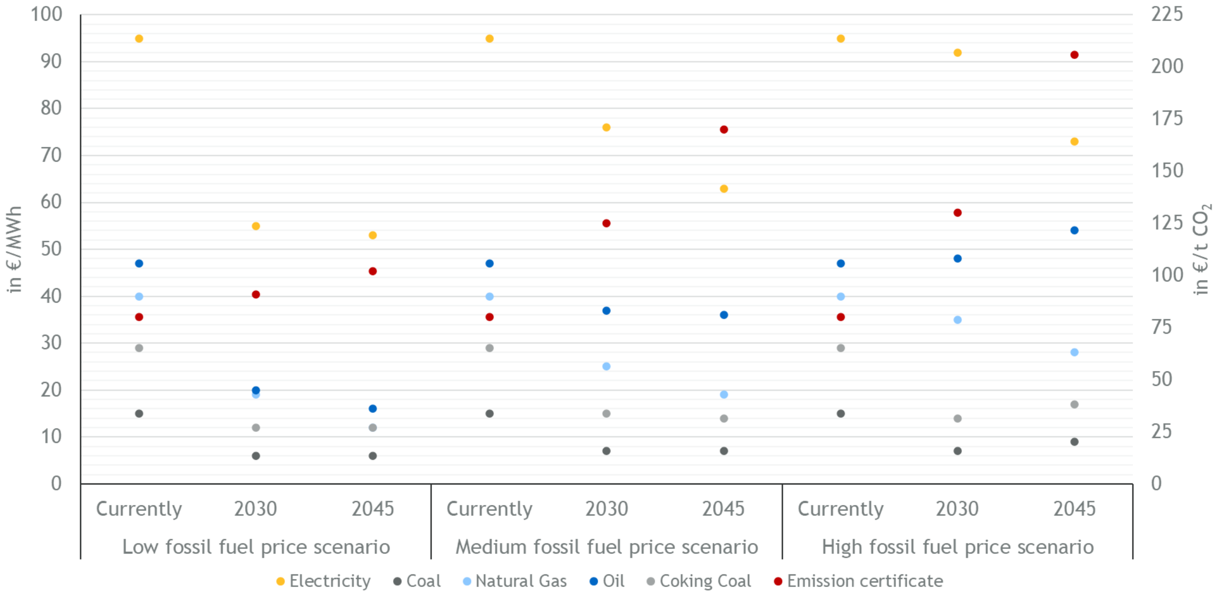

Figure 2: Fossil fuel price scenarios

In 2045, electricity and coal prices in the high-price scenario are around 40 % higher than in the low-price scenario. The price of gas and CO_2 is almost twice as high. The difference is greatest for oil, where the price in the high price scenario is approx. three times higher than in the low price scenario. The price scenarios applied are mainly based on the World Energy Outlook 2022 (IEA, 2022), complemented by BNetzA (2024), EWI (2023b) and UBA (2023b) can be found in Table 2, Table 3, and Table 4 in the Appendix.

2.4 Results

2.4.1 Greenfield break-even prices for hydrogen in 2030

The break-even price for hydrogen varies significantly across different applications. Figure 3 illustrates the break-even price for hydrogen expressed in €/MWh hydrogen in various industrial applications, while Figure 4 illustrates the break-even price for hydrogen for the transport, energy, and building sector. For refineries, the break-even price for hydrogen differs depending on the end product for which it is used. Around 64 % of crude oil is utilized for fuel production, which is subject to the GHG quota targets. The refinery industry, when accounting for GHG quotas, stands out in Figure 3 with the highest break-even price for hydrogen in the industry sector that ranges from 236 €/MWh to 269 €/MWh. Within this research report, the additional break-even price attributed to the quota accounts for 71 % of the total break-even price.

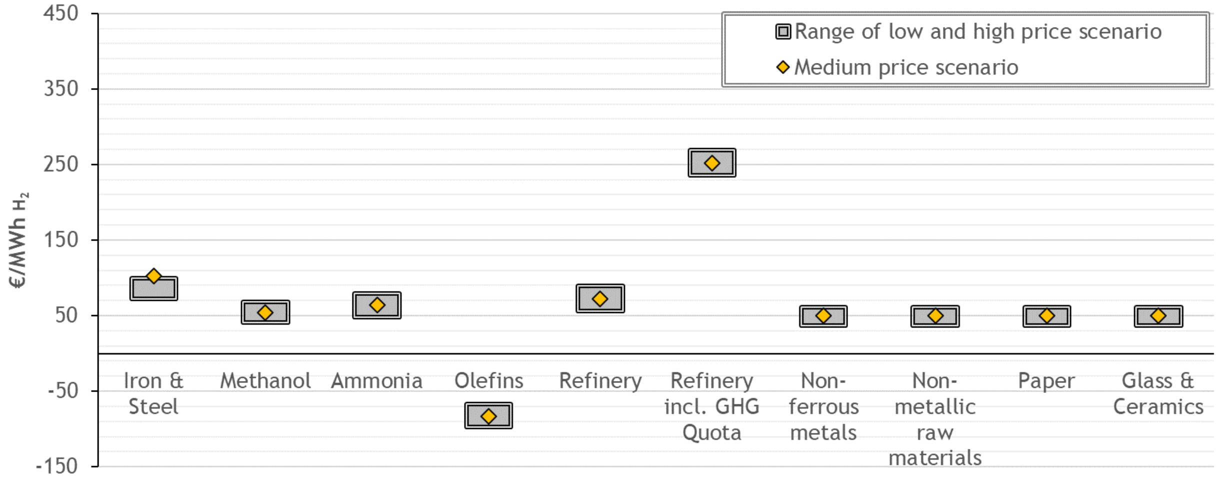

Figure 3: Greenfield break-even prices for hydrogen in the industrial sector in 2030

A striking observation is the negative break-even price of the application for olefins. In this research report, the TCO of the conventional process is lower than the TCO of the hydrogen-based alternative because of the significant electricity and methanol demand of the alternative process. A negative price implies that there is no positive hydrogen price at which the costs of the conventional process and the hydrogen-based alternative are balanced. The other industrial applications range between 50 €/MWh and 100 €/MWh in the medium fossil price scenario.

Among the non-energetic applications of hydrogen, the iron & steel industry shows a comparatively higher break-even price for hydrogen that ranges from 80 €/MWh to 100 €/MWh. In this case, it is noticeable that the break-even price for hydrogen in the medium price scenario is higher than in the high and low price scenarios. In general, the scenarios represent different, and inherently consistent price developments. As the commodity prices don't change at the same rate across the fossil fuel price scenarios, the break-even price is not linearly dependent on the fossil price scenario. In the example of the steel industry, the coking coal price is lower in the high price scenario than in the medium price scenario. In this way, the medium price scenario yields the highest break-even price for hydrogen in the iron & steel application.

In contrast to the industrial sector in Figure 3, Figure 4 shows that significantly higher break-even prices for hydrogen are achieved in the transport sector, with values ranging from approx. 100 €/MWh to 300 €/MWh in the medium fossil price scenario. In the entire transport sector, the costs of the conventional option are mainly driven by fuel and CO_2 costs, as well as costs for the energy tax. Additionally, trucks 3.5 – 12 t and trucks > 12 t pay a large part for the toll. By switching to the hydrogen-based transport option, the total CO_2 emission costs and most toll costs can be avoided. In figures, 18 % of the break-even price for hydrogen for trucks > 12 t can be attributed to the toll. It should be noted that the transport sector also is highly dependent on the price scenario. Depending on the mode of transport, break-even prices for hydrogen can range between 115 €/MWh and 330 €/MWh in the low to high fossil price scenario.

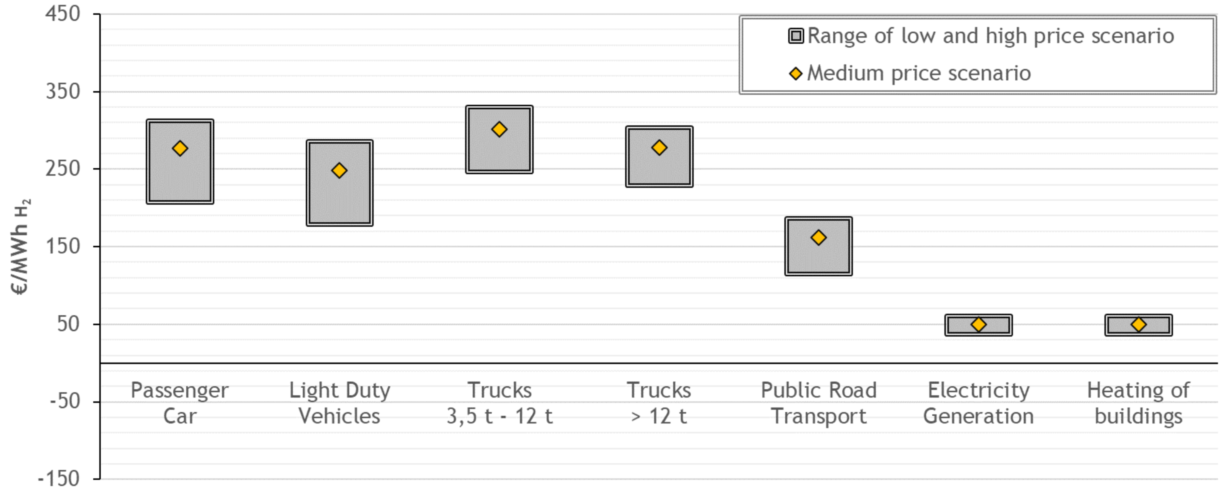

Figure 4: Greenfield break-even prices for hydrogen in the transport, electricity and building sector in 2030

The use of hydrogen for heat and electricity generation, on the other hand, shows comparatively lower break-even prices that range between 37 €/MWh and 61 €/MWh. In both processes, the break-even price is essentially determined by the natural gas and CO_2 costs. While it was assumed for heat generation that the investment costs of the conventional and hydrogen-based alternatives are identical, higher investment costs are taken into account for electricity generation. As can be seen in Figure 4, however, the effect is vanishingly small.

2.4.2 Greenfield break-even prices for hydrogen in 2045

Until 2045, fossil fuel price and emission cost trends are just as unclear as for 2030, if not more so. Higher prices for CO_2 emissions are expected. At the same time, the prices for fossil fuels barely rise or even fall according to the fossil price scenarios based on the W 2022 (IEA, 2022), complemented by BNetzA (2024), EWI (2023b) and UBA (2023b). In the baseline scenario, the prices for coal, coking coal and oil decline by 3 % to 5 % from 2030 to 2045. Additionally, prices of natural gas and electricity decline significantly by 24 % and 17 %, respectively. Emission certificates on the other hand are assumed to experience a cost increase by 36 % (see Table 2,

Table 4 in the Appendix). Rising emission costs in particular have a positive effect on the TCO and thus also on the break-even price.

Similar to 2030, the use of hydrogen in refineries subject to GHG quota regulation shows the highest break-even price for hydrogen in 2045 within the industry sector, as seen in Figure 5. Applications in the iron & steel industry are experiencing visible growth from 102 €/MWh in 2030 to 149 €/MWh in 2045 in the medium fossil price scenario. This is due to the rise in the price of CO_2 emission certificates. For iron & steel it can also be seen that the breakeven price in the high fossil fuel price scenario has moved further upwards compared to 2030. For other industrial

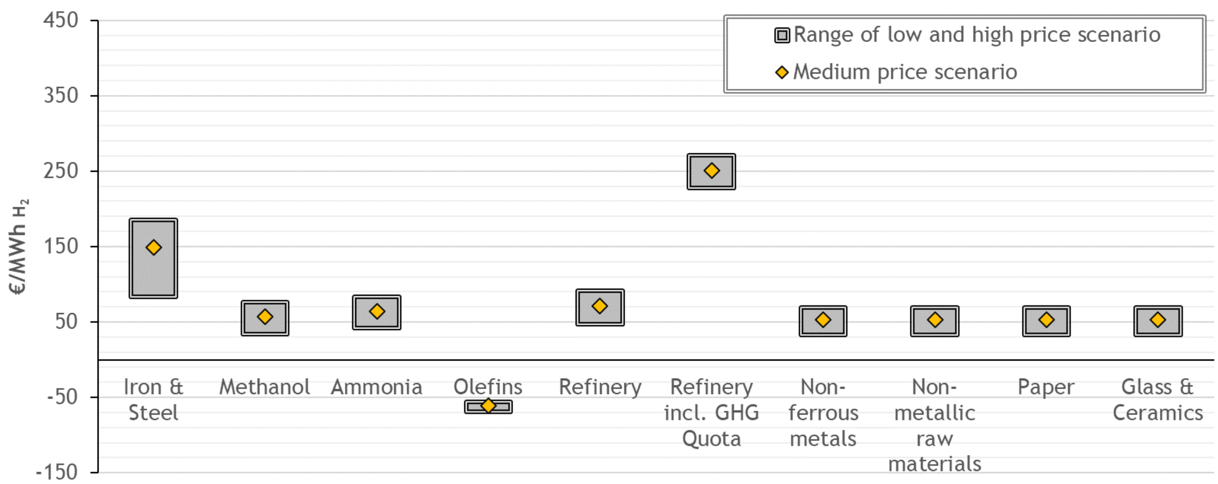

Figure 5: Greenfield break-even prices for hydrogen in the industrial sector in 2045

applications, the break-even prices in the medium fossil fuel price scenario barely change compared to 2030. However, the range for almost all industrial applications has widened, except for olefins. As in 2030, the break-even price for hydrogen in the production of olefins remains negative across all price scenarios.

In the transport sector, the break-even prices for hydrogen remain at a high level in 2045 due to the regulatory framework, as can be seen in Figure 6. For diesel and petrol, the fuel components change according to the oil price from 2030 to 2045. In the medium price scenario, this means a drop of around 5 %. This contrasts with a rising price for CO_2 emissions. Overall, the end customer price increases by around 23 % for petrol and diesel. A constant taxation for fuels and toll for trucks is assumed for both years. As mentioned, the break-even price for heat and electricity

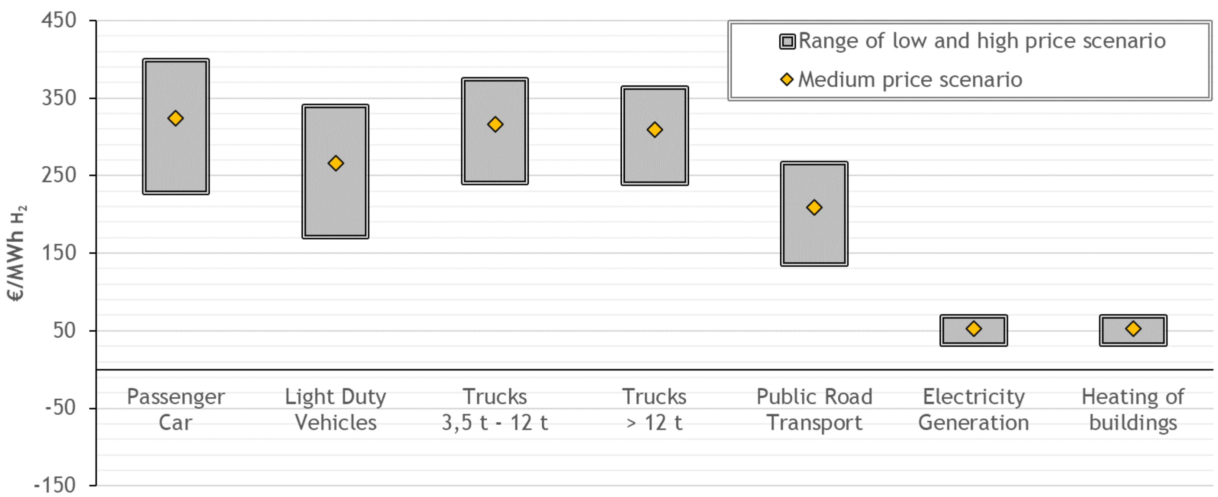

Figure 6: Greenfield break-even prices for hydrogen in the transport, electricity, and building sector in 2045

generation is almost exclusively made up of the costs of natural gas and emissions. Since all price scenarios assume a decrease of natural gas prices, the break-even price for hydrogen hardly changes compared to 2030 despite rising emission costs. Just as in the industrial sector, the ranges for the low and high fossil fuel price scenarios in the transport, electricity, and building sectors are widening at the upper end.

3 The scenario-specific financing gaps

The previous chapter described the greenfield break-even prices for hydrogen at which conventional and hydrogen-based process alternatives have equal total costs of ownership. If wholesale prices for hydrogen surpass the break-even prices, market-driven deployment of these applications might be economically hampered. In this case, there is a cost disadvantage because of higher TCO of the hydrogen-based alternative for the user. If the deployment of hydrogen is to be promoted nonetheless, this cost disadvantage can lead to a need for financing. The theoretical financing gap describes the capital requirement to compensate for the cost disadvantages resulting from the difference between the market prices for hydrogen and the break-even prices that end users are willing to pay.

3.1 Methodology

The estimated break-even prices for hydrogen range between -83 €/MWh and 301 €/MWh in 2030 and -61 €/MWh and 324 €/MWh in 2045 in the medium fossil price scenario. Depending on the development of future wholesale prices and hydrogen demand volumes, a need for external financing may arise. To stimulate a demand ramp-up as projected by the demand scenarios, this theoretical financing gap offers an estimation of the need for institutional incentivization. The following chapter presents the methodology behind the estimation of the financing gap against the background of the aforementioned uncertainties.

In mathematical terms, the financing gap FG estimates as the product of the (theoretical) hydrogen demand per year HD_i of application i, whose break-even hydrogen price BEP_i is below the market price for hydrogen MP, and the difference between the market price for hydrogen and the break-even hydrogen price (see Equation 1). The sum of the aforementioned products over all i applications constitutes the total economic financing gap per year.

$$FG = \sum_i (MP - BEP_i) * HD_i \text{ for } MP > BEP_i \tag{1}$$

For simplicity, the break-even price for hydrogen can be interpreted as the willingness to pay by the consumer. As described in the previous chapter, the break-even price is based on a comparison of TCO for greenfield investments. Thereby, the financing gap is the result of a greenfield-greenfield-comparison that usually overestimates the costs of the conventional process and thus the application-specific break-even price. Consequently, this research report estimates the financing gap's lower bound.

The calculated financing gaps present a snapshot of the yearly funding requirements for the years 2030 and 2045. This research report does not include the progress of the financing gap between those two years.

3.2 Hydrogen market price and demand scenarios

3.2.1 Hydrogen market price scenarios

In the absence of a liquid market for hydrogen, wholesale prices for hydrogen cannot (yet) be observed nor projected based on historical data. Instead, most price projections rely solely on cost-based estimations, such as the levelized costs of hydrogen (LCOH)[4]. These estimations cannot capture market dynamics such as excess supply and demand. Also, they often neglect to address the system cost of hydrogen use, which includes transport and storage cost components in the wholesale price for hydrogen. Therefore, both future hydrogen prices and thus the financing gap are subject to uncertainty. For this reason, this research report estimates the financing gap for three different hydrogen market price scenarios. The same market price scenarios for hydrogen are assumed for 2030 and 2045, as both years are subject to the same level of uncertainty. A market price of 100 €/MWh is assumed for the low price path, 200 €/MWh for the medium price path, and 300 €/MWh for the high price path. The financing gap varies with the level of hydrogen market prices, so if these are higher in future than assumed in the high price scenario, the financing gap will also increase. For context, a variety of sources are evaluated encompassing a range of estimates, from an estimation of levelized cost of hydrogen storage (LCOHS)[5], LCOH to estimates of wholesale prices and end-customer prices for hydrogen.

Estimates for the LCOH are provided by the EWI Global Power-to-X (PtX) Cost Tool, the results of the first hydrogen auction of the European Hydrogen Bank and the “Hydex Green” by E-Bridge Consulting GmbH. According to the PtX tool, the LCOH range between approx. 100 €/MWh and 200 €/MWh in the baseline scenario with a volatile load profile for the year 2045. The pipeline supply of low-carbon hydrogen from Morocco to Germany accounts to LCOH of 106 €/MWh. LCOH of 125 €/MWh corresponds to domestic hydrogen production, and 217 €/MWh corresponds to the LCOH of supplying Germany by ship from Australia (EWI, 2024b). The range of LCOH traded in the hydrogen auction in April 2024 of the European Hydrogen Bank is 135 to 255 €/MWh (BMWK, 2024a; European Commission, 2024). The “Hydex Green” is a cost-based spot price index for hydrogen and based on short-term electricity, gas and European emission allowances (EUA) prices excluding CAPEX (E-Bridge, 2024). On 18 September 2024, the hydrogen index was recorded at 135 €/MWh. In all examples, the LCOH estimates only include import costs, with transportation and storage costs within German being neglected. An EWI study estimates LCOHS depending on four different types of caverns (EWI, 2024c). The estimates vary between 20 to 53 €/MWh.

Since 2023, the European Energy Exchange (EEX) is publishing the first market-based price index for hydrogen “HYDRIX” on a weekly basis, which is based on price indications from established market participants in the industry and is calculated as an average of supply and demand (eex, 2024). The estimate from 11 September 2024 is 250 €/MWh for low-carbon hydrogen.

[4] LCOH are used to estimate the cost of producing hydrogen over a lifetime for a hydrogen production project. They include CAPEX, OPEX, fuel costs, and the project’s expected hydrogen output.

[5] LCOHS describe the costs of storing hydrogen in relation to the annual volume of hydrogen stored.

3.2.2 Hydrogen demand scenarios for Germany

In climate neutrality studies, the use of hydrogen is identified as an important pillar on the path towards carbon neutrality in Germany (PIK et al., 2022). In particular, hydrogen plays a role in maintaining industrial capacity and security of electricity supply across all scenarios. However, these studies differ in the assumed penetration of hydrogen applications and thus in the potential demand for hydrogen. As a result, they depict various market ramp-up scenarios. Therefore, this research report employs three hydrogen demand scenarios. The scenarios differ in the assumed market penetration of hydrogen applications[6]. The following paragraphs briefly outline the hydrogen demand scenarios. The scenarios are summarized in Table 1.

DENA (EWI, 2021a)

The dena pilot study (EWI, 2021a), abbreviated with *DENA*, is an all-encompassing climate neutrality study. In the examined scenario, hydrogen is used in all sectors. The transport sector is predominantly electrified, yet there will be demand for hydrogen in heavy duty transport starting in 2030. In the long term, other modes of transport will also demand hydrogen. In the industrial sector, it is primarily the chemical and iron & steel industries that will increasingly use hydrogen in the long term. In addition to electrification through heat pumps, the long-term conversion of methane-based gas networks to hydrogen for heat supply of the building sector is a relevant option. In the electricity sector, new and converted gas-fired peak power plants are creating demand for hydrogen. This is driven by the decommissioning of conventional generation capacities. With around 60 TWh/a and 470 TWh/a of hydrogen demand in 2030 and 2045, respectively, the EWI (2021a) scenario ranks at the upper end of the five major carbon neutrality scenarios of 2021 (PIK et al., 2022) but in the median of the three demand scenarios of this research report.

NWR (NWR, 2024a)

The second hydrogen demand scenario employed in this research report is based on the fundamental paper on future hydrogen demand by the National Hydrogen Council of Germany and is abbreviated with *NWR*. In contrast to the previous studies, this is not an all-encompassing carbon neutrality study. Instead, it constitutes an estimation of hydrogen requirements associated with GHG neutrality. Compared to the other scenarios, the demand of the transport and building sectors is significantly higher, while the demand in industrial applications shows similar ranges as the *DENA* scenario. In the long term up to 2045 there is demand in all sectors. As can be seen in Table 1, the total demand for hydrogen with 84 TWh/a in 2030 and 842 TWh/a in 2045 significantly exceeds the demand estimations in other scenarios. It therefore forms the upper bound in this research report.

[6] Both, Fraunhofer (2024) and the National Hydrogen Council (2024) only show aggregated hydrogen consumption in a few cases. Application-specific consumption figures are required to estimate the financing gap (see (1)). In these cases, the application-specific hydrogen consumption was estimated on the basis of EWI (2021) and the underlying assumptions in the respective scenario.

LFS III (Fraunhofer ISI et al., 2024)

The “Long-term Scenarios” by Fraunhofer ISI et al., abbreviated with *LFS III*, represent a carbon neutrality study like *DENA*. For this following research report, the O45-Strom Scenario of the 3rd issue of the ongoing study is used. As in the *DENA* scenario, the main demand arises in the chemical, iron & steel industry, as well as power generation. In the transport sector as well as in the building sector for heat generation, only a minor demand for hydrogen is estimated for 2045, which is neglected in this research report. In this research report, this scenario constitutes the lower bound for hydrogen demand with 20 TWh/a in 2030 and 227 TWh/a in 2045.

Table 1: Application-specific demand for hydrogen by scenario

	EWI (2021)		NWR (2024)		Fraunhofer (2024)	
Demand in TWh/a	2030	2045	2030	2045	2030	2045
Iron & Steel	26	75	29	70	13	38
Methanol	3	5	5	9	0	6
Ammonia	8	13	5	17	0	0
Olefins	4	51	5	44	0	31
Refineries	1	9	1	0	4	1
Refineries incl. GHG	1	5	1	0	2	1
Non-ferrous metals	1	4	1	5	0	6
Non-metallic raw materials	5	11	1	8	0	0
Paper	2	2	5	41	0	1
Glass & Ceramics	0	2	1	4	0	6
Passenger Car	0	6	1	0	0	0
Light Duty Vehicles	0	3	1	8	0	0
Trucks (3,5-12 t)	0	6	5	58	0	0
Trucks (>12 t)	3	35	13	65	0	0
Public Road Transport	1	2	4	0	0	0
Electricity Generation	0	163	0	200	1	137
Heating	5	79	1	313	0	0
Sum	60	470	84	842	20	227

Data given in publication

Own calculation based on input parameters given in the publication

The application-specific hydrogen demand presented in Table 1 is partly the result of own calculations, as the hydrogen demand of some applications in the studies are only specified at sector level. To be able to compare the sector demand across studies for individual applications, they were disaggregated by applying different methods.

- The hydrogen demand of the transport and chemical sectors as well as refineries with and without GHG quota in the *NWR* scenario and the demand of iron & steel production in *LFS III* were allocated according to the application's percentage share in the respective sector given in the studies.
- The hydrogen demand of the chemical applications in *LFS III* are derived from the specified end product production volumes for the respective year offset against the specific hydrogen requirement per unit of end product produced.
- None of the studies differentiates refineries with and without the GHG quota. The GHG quota is applied to refineries producing petrol or diesel. Thus, the refineries' hydrogen demand is estimated in the following way. Previous studies estimated a reduction in oil consumption to achieve climate neutrality in Germany (PIK et al., 2022). Declining oil consumption results in lower hydrogen demand from the processing of crude oil. Therefore, this research report assumes that demand for hydrogen by refineries develops in proportion to oil consumption. For this purpose, oil usage quantified by Fraunhofer ISI et al. (2024) and NWR (2024a) is used to determine the hydrogen demand of refineries. Consequently, the potential hydrogen demand arising from the synthetization of other products, such as synthetic naphtha or synthetic fuels, that replace crude oil processing, is not considered.

It should be noted that the demand scenarios are not the result of a market equilibrium, nor do they reflect price responses to hydrogen wholesale price scenarios. Instead, they assume that a hydrogen-based alternative will replace the conventional process at a predefined point in the future to meet emission targets. Thus, the demand scenarios are independent of potential price developments and the results should be interpreted accordingly.

3.3 Results

3.3.1 Sector-specific scenario demand curves for 2045

Figures Figure 7 to Figure 9 show the break-even prices for hydrogen in €/MWh at medium fossil fuel prices against the application-specific demand volumes of the three demand scenarios for the year 2045. The figures can be interpreted as scenario-based demand curves for low-carbon hydrogen. The levels of the three hydrogen price scenarios are plotted and the shaded areas beneath the line represent the resulting theoretical financing gap.

Figure 7 depicts the demand curve of the *DENA* demand scenario for 2045 for the medium fossil fuel price scenario. The total hydrogen demand amounts to 470 TWh/a in this scenario. As hydrogen prices rise, the number of applications declines for which switching to low-carbon hydrogen remains economical and the financing gap increases. Assuming the low hydrogen market price scenario, iron & steel, refineries, transport, and electricity generation are profitable. For the remaining applications, the break-even price is lower than the market price. Thus, transitioning to hydrogen-based alternatives would not be economical. In the medium market price scenario, only the transport sector and refineries including the GHG quota are economical. Assuming a high hydrogen price scenario, only cars, trucks > 12 t and trucks 3.5 – 12 t would exhibit a break-even price above the hydrogen price. Electricity generation accounts for the biggest share of the financing gap, followed by heating of buildings, olefins, and iron & steel. The size of the application-specific financing gap depends on the break-even price, the hydrogen demand, and the hydrogen price considered.

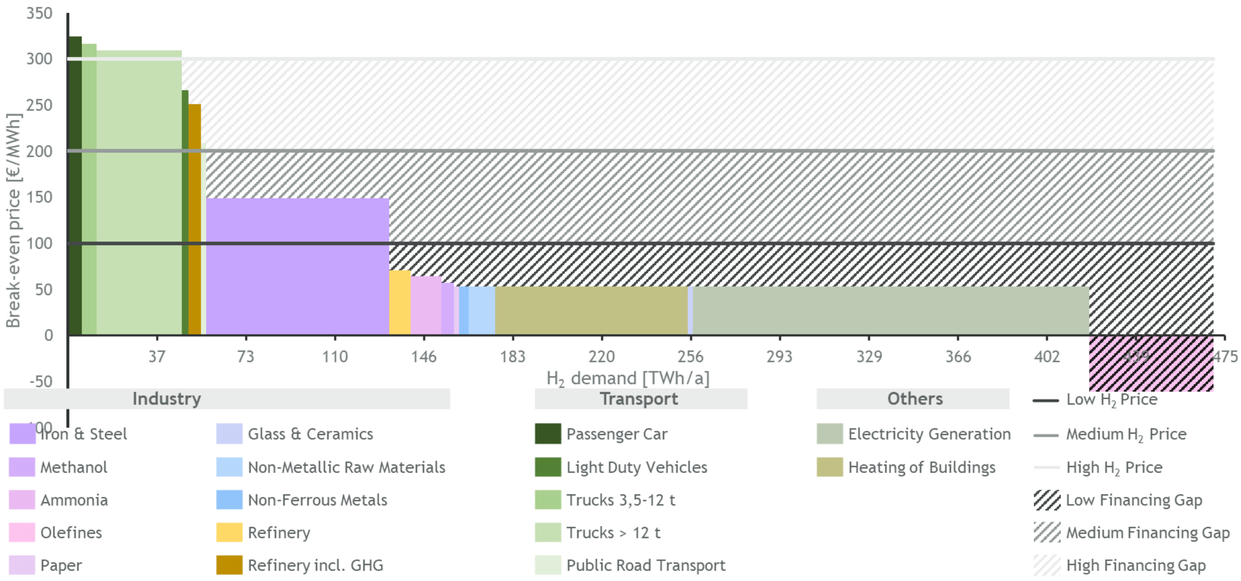

Figure 7: Scenario demand curve according to *DENA* for 2045

The break-even prices are independent of the demand scenarios, but the application-specific demands differ between the demand scenarios. Figure 8 illustrates the demand curve of the *NWR* demand scenario for 2045. In this demand scenario, the total hydrogen demand in 2045 is 842 TWh/a. The hydrogen demand of refineries equals zero in 2045. Thus, at a low hydrogen price, using low-carbon hydrogen is economical only for iron & steel, as well as the entire transport sector. At the medium hydrogen market price, hydrogen-based iron & steel production is no longer economical. In a scenario with high hydrogen prices, the break-even price for light duty vehicles is slower than the hydrogen price. The building sector contributes the highest share to this gap as it entails the largest hydrogen demand, followed by electricity generation, high value chemicals, and iron & steel.

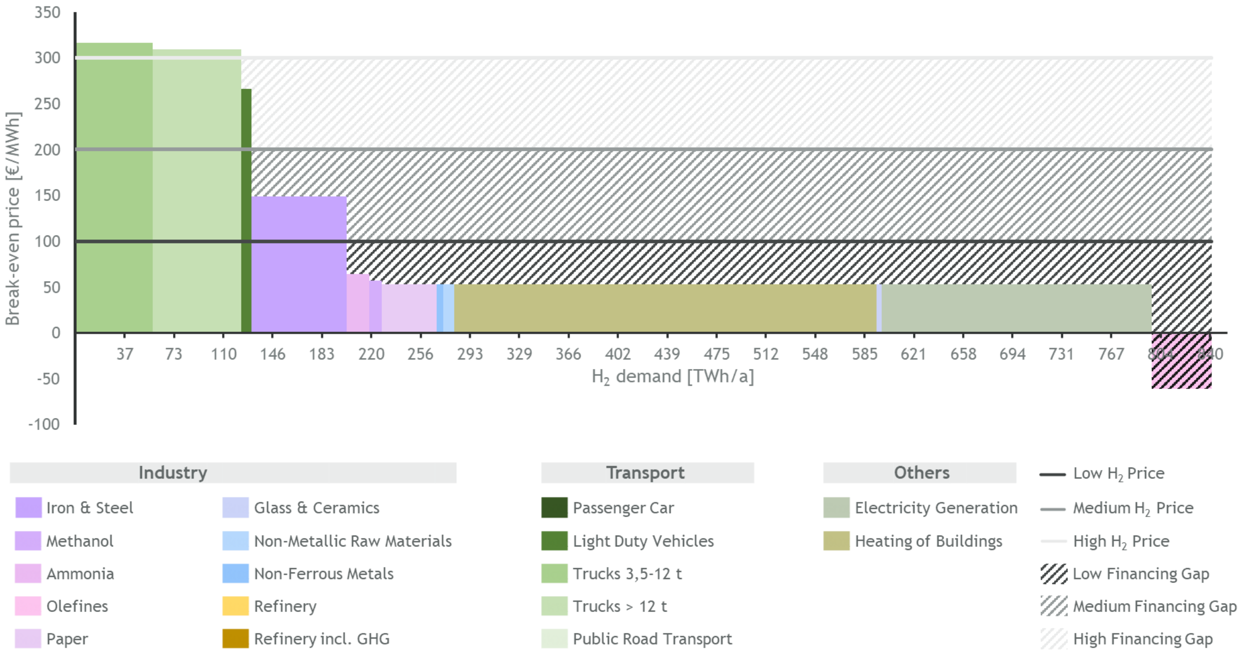

Figure 8: Scenario demand curve according to *NWR* for 2045

The scenario demand curve for *LFS III* is presented in Figure 9. This scenario accounts for 227 TWh/a of hydrogen demand in 2045 and depicts no hydrogen demand in the transport sector. For iron & steel as well as refineries with the GHG quota, switching to low-carbon hydrogen is economical under a low market price for hydrogen. For a medium hydrogen market price, a switch

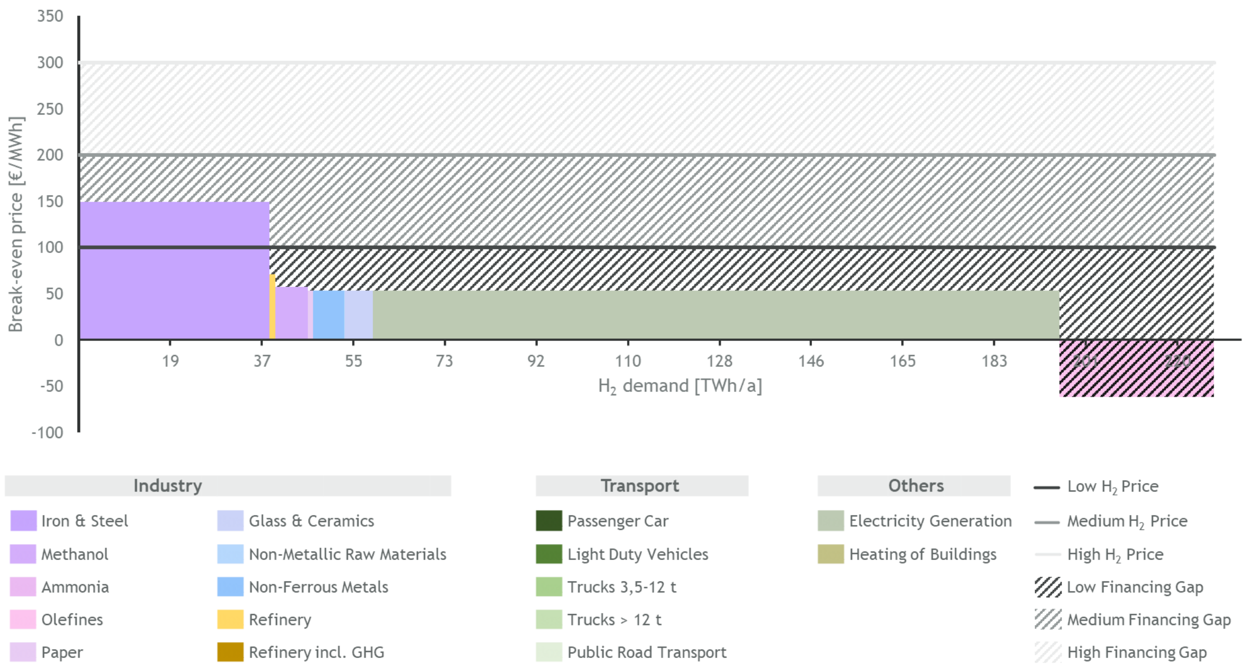

Figure 9: Scenario demand curve according to *LFS III for* 2045

to hydrogen is only profitable for refineries including the GHG quota, which exhibit a hydrogen demand of only 1 TWh/a in 2045. At a high hydrogen market price, the use of hydrogen is no longer profitable for any application. Across all hydrogen market price scenarios, electricity generation has the largest financing gap due to the highest demand.

3.3.2 The aggregated annual financing gap

The theoretical financing gap represents the need for additional financing per year to compensate for the difference in market and break-even prices for hydrogen while meeting exogenous hydrogen demands per application. Because the break-even prices represent an upper bound due to the greenfield investment assumption, the resulting financing gap may represent a lower bound.

The theoretical aggregated annual financing gap across all applications is presented for the three demand scenarios of *DENA*, *NWR*, and *LFS III* in combination with three fossil fuel and hydrogen market price scenarios each for 2045 in Figure 10. Across all demand, fossil fuel price, and hydrogen market price scenarios, the financing gap ranges from € 10 billion/a to € 199 billion/a in 2045. By focusing on the medium fossil fuel and hydrogen market price scenario, the financing gap ranges from € 33 billion/a to € 103 billion/a in the year 2045. The financing gap is significantly influenced by the total hydrogen demand of the demand scenarios under consideration. With 842 TWh/a, the *NWR* demand scenario exhibits the highest demand for hydrogen in 2045. Consequently, the financing gap in the *NWR* demand scenario is the largest in absolute terms compared with the *DENA* and *LFS III* scenarios.

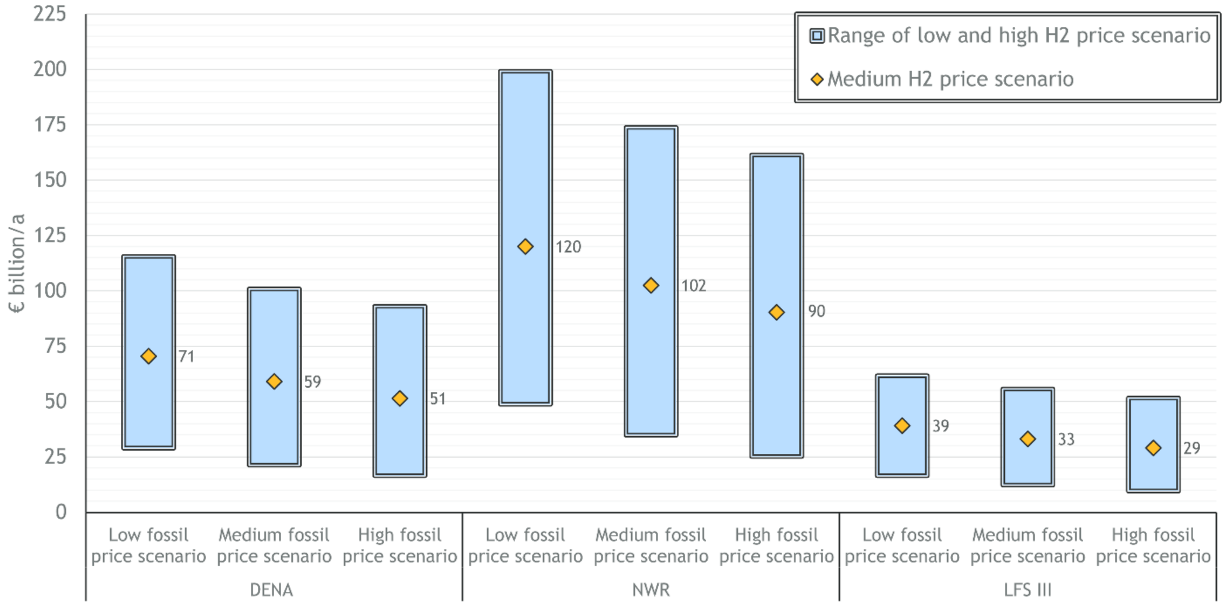

Figure 10: Aggregated annual financing gaps for 2045

Considering low fossil fuel prices in the *NWR* scenario, the theoretical gap ranges from € 49 billion/a to € 199 billion/a. With rising fossil fuel prices, the financing gap decreases. In the medium fossil fuel price scenario, the gap varies between € 35 billion/a to € 139 billion/a, and in the high fossil fuel price scenario between € 25 billion/a to € 136 billion/a depending on the assumed hydrogen price. Focusing on the medium market price for hydrogen, the financing gap for the three fossil fuel price scenarios ranges from € 90 billion/a to € 120 billion/a.

A similar pattern is observed regarding the theoretical financing gaps of the *DENA* demand scenario. In 2045, a total of 470 TWh/a of hydrogen will be demanded in this scenario. Assuming that fossil fuel prices are at a low level, the financing gap ranges from € 29 billion/a to € 116 billion/a. For the medium fossil fuel price scenario, the gap ranges from € 21 billion/a to € 101 billion/a, and for the high fossil fuel price scenario from € 29 billion/a to € 90 billion/a, depending on the hydrogen price considered. Assuming a medium hydrogen price, the gap across the fossil fuel price scenarios varies from € 51 billion/a to € 71 billion/a.

With a demand of 227 TWh, the *LFS III* scenario exhibits the lowest amount of low-carbon hydrogen demand in 2045. As a result, the corresponding theoretical financing gap is the smallest among all demand scenarios. Under the assumption of low fossil fuel prices, the financing gap in the *LFS III* scenario ranges from € 16 billion/a to € 62 billion/a. For a medium fossil fuel price development, it ranges from € 12 billion/a to € 56 billion/a, and for a high fossil fuel price development from only € 10 billion/a to € 52 billion/a. Considering the medium hydrogen price, the financing gap ranges from € 29 billion/a to € 39 billion/a. Thus, the demand scenario of the *LFS III* has the smallest range in absolute terms compared to *DENA* and *NWR*.

The theoretical financing gaps do not only vary across the different demand scenarios. Also, fossil fuel price scenarios as well as the hydrogen market price scenarios entail variations within a demand scenario. As illustrated Figure 10, the range of the financing gap of a respective demand scenario within a fossil fuel price scenario is larger across the hydrogen market price scenarios than within a demand scenario across the fossil fuel price scenarios. The wide spread between the hydrogen market price scenarios reflects the considerable uncertainties associated with the hydrogen market ramp-up. To illustrate, the price of natural gas varies between the low and high price scenarios from 12 €/MWh to 28 €/MWh that corresponds to a price increase of 49 %, while the market price of hydrogen ranges from 100 €/MWh to 300 €/MWh corresponding to a price increase of 67 %. But the range of the financing gaps corresponding to one fossil fuel price scenario defined by high and low hydrogen market prices is consistent across the demand and fossil price scenarios. As fossil fuel prices rise, the financing gap decreases across all hydrogen price scenarios, as the switch to hydrogen becomes more cost-effective in comparison to the conventional application.

Figure 11 illustrates the theoretical aggregated annual financing gap for the year 2030. Compared to the figure for 2045, the financing gaps are significantly smaller, ranging from € 0.2 billion to € 17 billion/a. This is due to a much lower hydrogen demand, which accounts for only 9 % to 13 % of the demand of 2045. By focusing on the medium hydrogen and fossil fuel market price scenario, the financing gap ranges from € 2 billion/a to € 10 billion/a in 2030.

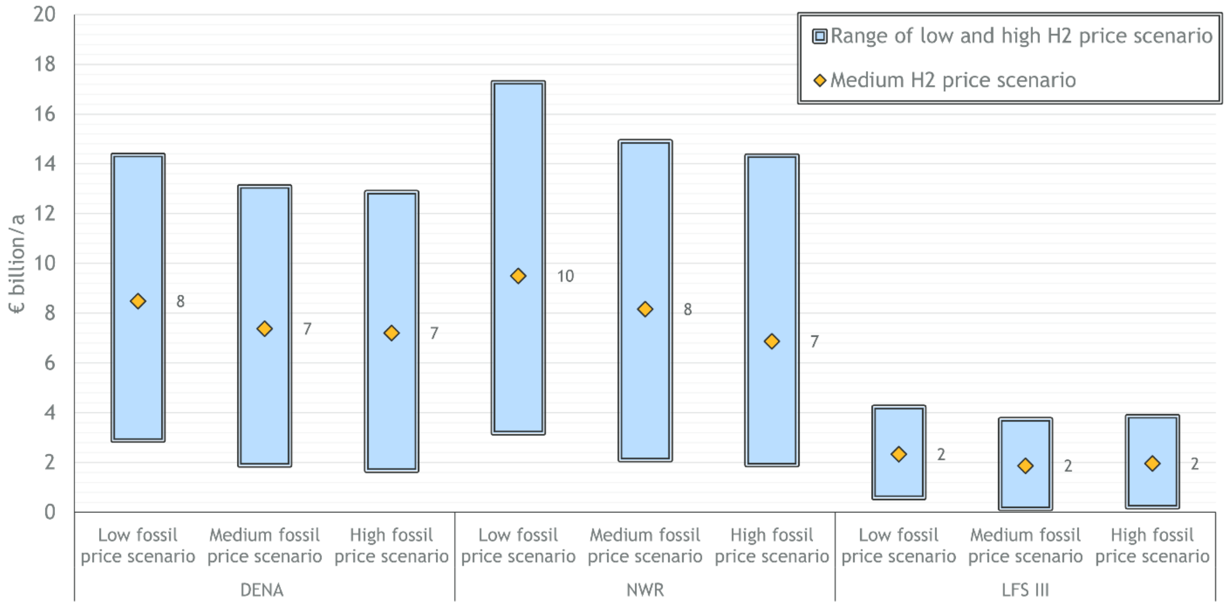

Figure 11: Aggregated annual financing gaps for 2030

Similar to 2045, the *NWR* has the highest hydrogen demand at 84 TWh/a, which also corresponds to the largest theoretical financing gaps. Across all price scenarios, the gap varies between € 2 billion/a and € 14 billion/a. In the medium fossil fuel price scenario at a medium hydrogen price, the gap amounts to € 8 billion/a.

In the *DENA* scenario, the theoretical gap exhibits variability between € 2 billion/a and € 14 billion/a across all price scenarios, with a total hydrogen demand of 60 TWh/a. In the medium fossil fuel price scenario and at medium hydrogen prices, the resulting gap is € 7 billion/a.

In the *LFS III*, a hydrogen demand of 20 TWh is projected for 2030. The corresponding theoretical gap ranges from € 0.2 billion/a to € 4 billion/a across all price scenarios. In the context of medium fossil fuel and hydrogen market prices, the resulting gap is estimated at € 2 billion/a.

4 The financing gap against current uncertainties

The preceding research report estimated the lower bound of the theoretical annual financing gap for multiple scenarios. 4.1 discusses the simplifications made for this purpose and further determinants of break-even prices for hydrogen. Additionally, 4.2 provides an outlook on the regulatory landscape and discusses the findings of this research report.

4.1 Uncertainties regarding the financing gap

The break-even price for low-carbon hydrogen and the resulting theoretical financing gaps presented here are subject to methodological limitations. Firstly, the low-carbon hydrogen demand based on the three demand scenarios does not result from an equilibrium model but constitutes exogenous scenarios towards a climate-neutral economy. The demand is not influenced by the actual economic competitiveness for low-carbon hydrogen applications. For example, future production output is influenced by the overall economic situation, as was seen during the recent energy crisis when ammonia production decreased due to high energy prices (Ruhnau et al., 2023). In addition, the industrial sectors examined are in global competition. In particular, globally traded products in the basic materials industry could be imported from countries where manufacturing costs are lower. This raises the question of what hydrogen demand volumes can be realized in the face of global competition. This question cannot be answered by this research report, but it does have an influence on the size of the financing gap.

In studies such as the *DENA* and *LFS III* scenarios, the technical feasibility of paths to carbon neutrality is examined in a partial equilibrium model. Other premises are disregarded and implicitly regarded as fulfilled. One example is the availability of sufficient capital to finance the scenario under investigation. Against this background, this research report can be seen as a supplementary reference that examines the financing requirements of a corresponding scenario.

The break-even price for low-carbon hydrogen presented here is based purely on a comparison of TCO of the conventional and alternative routes and is not the result of an equilibrium model. Not every conventional and alternative process is perfectly represented by the simplified version. Therefore, the break-even prices are to be considered as an estimate. In addition to the cost structure, there are numerous other factors that influence the level of a break-even price for low-carbon hydrogen, such as long-term economic growth, short-term business cycles, availability of infrastructure, and the regulatory framework.

Another factor that influences the results is that a greenfield-greenfield comparison of investment costs is undertaken within the TCO comparison. In reality, there is a capital stock of conventional applications. Therefore, a greenfield-greenfield comparison usually overestimates the costs of the conventional process and thus the application-specific break-even price. As a result, this research report estimates the lower bound for the theoretical financing gap, as the break-even price may be considered an upper bound. Except for the transport sector, the TCO for the years 2030 and 2045 are assumed to be the same, meaning that no cost degression based on additional research and development efforts, learning curve, and economies of scale is depicted.

The TCO comparison does not account for potential discrepancies in the cost of capital for conventional versus hydrogen-based alternatives. Given that hydrogen technologies are mostly novel technologies, they entail greater financial risks. Among other things, an increased financial risk arises from the uncertainty surrounding future hydrogen availability and hydrogen prices. Therefore, a higher cost of capital is to be expected, which has a negative effect on the break-even price and a positive effect on the theoretical financing gap.

Moreover, apart from the switch to low-carbon hydrogen, no other decarbonization option, such as the electrification of production processes or the use of synthetic fuels in the transport sector, is considered. Lastly, this research report assumes a decline in crude oil throughput in the refineries accompanied by a reduction in hydrogen demand. But no hydrogen demand to produce future novel products from refineries is considered. In this regard, the potential demand for low-carbon hydrogen in refineries is underestimated. However, the product range of refineries in the future and, consequently, their hydrogen demand is still uncertain.

4.2 Uncertainties regarding future regulatory framework

The five major climate neutrality studies have underlined the importance of hydrogen for climate neutrality in Germany. The previous analysis has shown that considerable theoretical financing gaps can occur at certain hydrogen wholesale prices. This can represent an obstacle to the development of a liquid market for hydrogen. Against this background, a regulatory framework may be needed to set the right incentives and close the financing gap.

The effect of existing regulatory elements, such as the CO_2 price, tolls, taxation, and a GHG quota was quantified in this research report and shown to be inadequate for closing the theoretical financing gap. For simplicity, this research report assumes the same carbon price for all sectors and applications. However, for example the building sector is subject to the EU ETS 2 starting in 2027. Higher ETS and the ETS 2 price can increase the break-even prices. Beside the existing framework, further regulatory measures are under debate or in implementation that address this issue. The following chapter discusses a range of measures that could serve to close the financing gap.

At the European level, the Renewable Energy Directive III (RED III) was adopted as part of the Fit for 55 package, which prescribes a binding target quota for the use of renewable fuels of non-biological origin (RFNBOs) in the transport and industrial sector by 2030. Low-carbon hydrogen is considered as RFNBO. By 2030, 5 % of the fuels used in the transport sector must be advanced biofuels or RFNBOs, of which 1 % must be RFNBOs. In the industrial sector, 42 % of the hydrogen used must meet the requirements of the RFNBO definition in 2030 and 60 % by 2035 (Hydrogen Europe, 2023; NWR, 2024b). The introduction of these mandatory quotas and the associated penalties could increase the break-even price for low-carbon hydrogen in a similar way as the GHG quota that is already in place. The implementation of the directive behind this quota is the responsibility of member states. At this point the implementation has not yet been conclusively determined.

The Fit for 55 package also includes a proposal to revise the Energy Tax Directive that defines the European rules of the taxation of energy products as motor fuel or heating fuel and of electricity. Currently, low-carbon hydrogen is not subject to national energy tax legislation, meaning that its use is not taxed. One exception is the use of low-carbon hydrogen as a fuel in an internal combustion engine (§ 1 Abs. 3 EnergieStG[7]). The reform of the Energy Tax Directive aims to achieve standardized European Union (EU)-wide exemptions for various applications and standardized minimum tax rates on energy products. It is an EU requirement that would have to be translated into national law. According to the directive, energy products are to be taxed depending on their energy content (Stiftung Umweltenergierecht, 2023). This could change the cost comparison between conventional and alternative applications. Accordingly, this would impact the break-even price for hydrogen and thus affect the financing gap.

Investing in alternative production technologies is associated with high costs and a variety of risks for companies. For this reason, the German government is currently discussing two measures to support the transition to low-carbon production processes. Firstly, green lead markets ("*Grüne Leitmärkte*") may pull climate-neutral products onto the market by creating demand for these products. The state can prioritize the use of certain climate-neutral products in its own procurement. Alternatively, or in addition, it can use regulatory measures to stipulate that private households and companies must use climate-neutrally produced goods in certain areas or under certain conditions or can grant benefits if they do so (BMWK, 2022). The objective of this measure is to create a demand that may not develop without those measures. In its concept for green lead markets, the Federal Ministry for Economic Affairs and Climate Action (BMWK) has focused on green steel, green cement and green chemical basic materials (BMWK, 2024b). As part of this, it was clarified what is to be understood by these terms.

Secondly, Carbon Contracts for Difference (CCfDs; "*Klimaschutzverträge*") can use subsidies to create a supply of climate-friendly goods and push them onto the market (BMWK, 2022). In March 2024 the BMWK launched the first auction of the CCfDs funding program. The auction addresses energy-intensive industries that successfully participated in the preparatory procedure in summer 2023. They were entitled to apply until July 2024 for a 15-year funding for their largest transition projects. The total funding volume is € 4 billion (BMWK, 2024c). A CCFD is a contract between the state and a company for the climate-friendly production of a good. It guarantees a payment that compensates the company for the higher costs of climate-neutral production. At the same time, it protects the company against fluctuations in the CO_2 price and other price risks (BMWK, 2022). Thus, CCfDs subsidize the cost difference between the conventional and alternative production processes. The estimated differential in TCO between the conventional and alternative routes could be seen as an indication of the subsidies intended to be paid out by CCfDs. In this way, CCfDs are designed to support the demand for low carbon hydrogen by closing the gap between the prevailing wholesale price and the break-even price for hydrogen.

Whether the presented measures will be sufficiently to support the hydrogen market ramp-up and thus close the gaps cannot be said on the basis of this research report. Further research is required to determine which measures are most effective in addressing the specific financing gap.

[7] Energy Duty Act (Energiesteuergesetz), 19th of December 2022.

5 Concluding remarks

This research report has estimated scenario-specific annual financing gaps for the hydrogen market ramp-up. The theoretical financing gap describes the additional capital requirement to compensate for the cost disadvantages resulting from the difference between the market prices for hydrogen and the break-even prices that end users are willing to pay. For this purpose, application-specific greenfield break-even prices for hydrogen have been estimated. These break-even prices indicate at what hydrogen wholesale prices a conventional and hydrogen-based alternative are equally in cost. Building on that, the scenario-specific financing gap equals the difference between market prices and break-even prices for hydrogen multiplied with the application-specific yearly demand for hydrogen. Given the uncertainty regarding the development of fossil fuel, emission allowances and hydrogen market prices as well as hydrogen demand, the financing gap is examined against three scenarios for each of these parameters.

Regarding the break-even prices in 2030, the refinery industry, particularly when accounting for GHG quotas, stands out with the highest break-even price for hydrogen in the industry sector that ranges from 236 €/MWh to 269 €/MWh. Also, the use of hydrogen in the iron & steel industry shows a comparatively high break-even price for hydrogen that ranges from 80 €/MWh to 100 €/MWh. Compared to the industrial sector, break-even prices in the transport sector exhibit significantly higher break-even prices due to regulatory instruments such as tolls, energy taxation, and the GHG quota. Depending on the mode of transport the break-even prices range from 115 €/MWh to 330 €/MWh. The use of hydrogen for heat and electricity generation shows comparatively lower break-even prices that range between 37 €/MWh and 61 €/MWh. In both processes, the break-even price is essentially determined by the natural gas and CO_2 costs. For the industrial applications, the break-even prices are higher in 2045 than in 2030, with refineries including the GHG quota remaining the highest. Compared to 2030, the break-even prices in the transport sector remain at a high level in 2045, while there is only a slight change in the break-even prices of electricity generation and heating buildings.

The annual scenario-specific financing gap represents the need for additional financing in 2030 and 2045, to compensate for the difference in market and break-even prices for hydrogen while meeting a predefined hydrogen demand. With regards to demand, this research report relies on three hydrogen demand scenarios, namely *DENA* with a medium hydrogen demand, *LFS III* with a low hydrogen demand and *NWR* with the highest hydrogen demand. In 2045, across all demand and price scenarios, the financing gap exhibits a wide range from € 10 billion/a to € 199 billion/a. The scenario-based analysis has demonstrated that the financing gap is sensitive to variations in hydrogen demand as well as prices of fossil fuels and hydrogen. The financing gap of the *DENA* hydrogen demand scenario varies between € 17 billion/a to € 116 billion/a. The demand in the *NWR* scenario implies a financing gap ranging from € 25 billion/a up to €199 billion/a and varies across the fossil fuel and hydrogen market price scenarios. Lastly, in the *LFS III* demand scenario the annual financing gap ranges from € 10 billion/a to € 61 billion/a. Despite the relevance of fossil fuel prices, the significant ranges within the demand scenarios are more influenced by the different hydrogen price scenarios.

The theoretical financing gaps illustrate the additional costs that may arise if a demand for hydrogen is to be promoted that would not develop on its own for economic reasons but according to different demand scenarios is necessary to reach climate neutrality in 2045. As this research report has performed a greenfield-greenfield comparison of TCO, the estimated gaps represent an upper bound of the break-even prices and thus a lower bound of the financing gap. The effects of existing regulatory elements such as CO_2 prices, tolls, taxes and GHG quotas were quantified as part of the break-even prices for hydrogen. It was shown that they increase the break-even price and thus have a dampening effect on the financing gap in certain scenarios. Beside the existing framework, there are further regulatory measures such as the RED III, green lead markets, and CCfDs aiming to close the financing gap under debate or in implementation. Whether these measures will be sufficient to support the hydrogen market ramp-up and thus to close the gap cannot be inferred based on this research report. Further research is required to determine which measures are most effective in addressing the theoretical financing gap.

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Abbreviations

BImSchG	Federal Immission Control Act (Bundes-Immissionsschutzgesetz)
BNetzA	Bundesnetzagentur
CAPEX	Capital expenditures
CCfD	Carbon Contract for Difference (”*Klimaschutzvertrag*”)
dena	Deutsche Energie-Agentur
EEX	European Energy Exchange
EnergieStG	Energy Duty Act (Energiesteuergesetz)
EU	European Union
EUA	European Emission Allowance
EWI	Institute of Energy Economics at the University of Cologne
GHG	Greenhouse Gas
KSG	Federal Climate Change Act (Bundes-Klimaschutzgesetz)
LCOH	Levelized costs of hydrogen
LFS III	Long-term Scenarios (Frauenhofer ISI, 2024)
MTO	Methanol-to-olefins
NWR	National Hydrogen Council of Germany (Nationaler Wasserstoffrat)
NZE	Net Zero Emissions by 2050
OPEX	Operational expenditures
PtX	Power-to-X
RED II	Renewable Energy Directive II
RED III	Renewable Energy Directive III
SMR	Steam methane reforming
STEPS	Stated Policy Scenario
TCO	Total Cost of Ownership

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Appendix

Table 2 presents the input parameters for the baseline scenario, and Table 3 and 4 for the high and low price scenarios. Except for the electricity prices, all fuel and CO_2 prices are taken from the Stated Policy and Net Zero Emissions by 2050 (NZE) scenarios in the WEO. The electricity prices are based on our own assumptions and calculations. The Stated Policy Scenario (STEPS) maps the current political landscape and the announced political measures sector by sector and extrapolates these into the future. The scenario NZE presents a theoretical pathway for achieving the 1.5-degree target with a 50 % probability by 2050 (IEA, 2022).

Table 2: Parameterization for the baseline-price scenario

Fuel Prices					
Fuel Type	Currently	2030	2045	Unit	Source
Electricity	95	76	63	€/MWh_{el}	BNetzA (2024), EWI (2023b), own assumption
Coal	15	7	7	€/MWh_{th}	IEA (2022)
Natural Gas	40	25	19	€/MWh_{th}	IEA (2022)
Oil	47	37	36	€/MWh_{th}	IEA (2022)
Coking Coal	29	15	14	€/MWh_{th}	Own assumption based on IEA (2022)
CO_2 (Feedstock)	0	0	0	€/tCO_2	Own assumption

Emission Certificate Price					
	Currently	2030	2045	Unit	Source
Emission certificate price	80	125	170	€/tCO_2	UBA (2023), IEA (2022)

Table 3: Parameterization for the high-price scenario

Fuel Prices					
Fuel Type	Currently	2030	2045	Unit	Source
Electricity	95	92	73	€/MWh_{el}	BNetzA (2024), EWI (2023b), own assumption
Coal	15	7	9	€/MWh_{th}	IEA (2022)
Natural Gas	40	35	28	€/MWh_{th}	IEA (2022)
Oil	47	48	54	€/MWh_{th}	IEA (2022)
Coking Coal	29	14	17	€/MWh_{th}	Own assumption based on IEA (2022)
CO_2 (Feedstock)	0	0	0	€/tCO_2	Own assumption

Emission Certificate Price					
	Currently	2030	2045	Unit	Source
Emission certificate price	80	130	206	€/tCO_2	UBA (2023), IEA (2022)

Table 4: Parameterization for the low-price scenario

Fuel Prices					
Fuel Type	Currently	2030	2045	Unit	Source
Electricity	95	55	53	€/MWh_{el}	BNetzA (2024), EWI (2023b), own assumption
Coal	15	6	6	€/MWh_{th}	IEA (2022)
Natural Gas	40	19	12	€/MWh_{th}	IEA (2022)
Oil	47	20	16	€/MWh_{th}	IEA (2022)
Coking Coal	29	12	12	€/MWh_{th}	Own assumption based on IEA (2022)
CO_2 (Feedstock)	0	0	0	€/tCO_2	Own assumption

Emission Certificate Price					
	Currently	2030	2045	Unit	Source
Emission certificate price	80	91	102	€/tCO_2	UBA (2023), IEA (2022)