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Meta-Analysis of the Costs of and Demand for Hydrogen in the Transformation to a Carbon-Neutral Economy

Study commissioned by the North Rhine-Westphalian Renewable Energy Association (LEE NRW e. V.)

Frank Merten and Alexander Scholz

With contributions from
Simon Heck and Steffen Lange

Wuppertal Institut

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Project coordination:
Frank Merten
Systems and Infrastructures Research Unit
Future Energy and Industry Systems Division
Döppersberg 19, 42103 Wuppertal, Germany
E-mail: frank.merten@wupperinst.org
Tel.: +49 202 2492-126

Legal information

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Wuppertal Institut für Klima, Umwelt, Energie gGmbH
Döppersberg 19
42103 Wuppertal
Germany
www.wupperinst.org/en/

Contact:
Prof. Dr. Stefan Lechtenböhmer
Future Energy and Industry Systems Division
stefan.lechtenboehmer@wupperinst.org
Tel.: +49 202 2492-216

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1 Background and objectives

Since the publication of the "Assessment of the Advantages and Disadvantages of Hydrogen Imports Compared to Domestic Production", a study commissioned by the North Rhine-Westphalian Renewable Energy Association (LEE NRW) and carried out by the Wuppertal Institute at the end of 2020 (Merten et al., 2020), the conditions for the hydrogen ramp-up in Germany have changed – significantly, in some respects. These changes include:

- the ambition announced by Germany's new Federal Government to double electrolysis capacity for the domestic production of H_2 from 5 GW_{el} to 10 GW_{el} by 2030, plus the relaxation of the country's National Hydrogen Strategy (NWS) vis-à-vis blue hydrogen, as currently discussed and planned;
- the recent very sharp increase in the number of plans for new electrolysis plants by 2030, with the total capacity rising from 5.6 gigawatts in July 2022 to 8.1 gigawatts in February 2023 according to (EON, 2023);
- the intensification and acceleration of the national expansion of renewables for electricity generation through various measures within the framework of the Federal Ministry for Economic Affairs and Climate Action's so-called Easter Package, which are intended to ensure that electricity in Germany is sourced almost entirely from renewable energy by 2035; and
- last but not least, the Russian war of aggression against Ukraine as of February 2022, which has led to a severe shortage of previously low-cost natural gas imports and, consequently, substantial increases in the costs of natural gas and electricity and to significant changes in Germany's energy supply strategy.

In addition, a number of new studies in the field of climate change mitigation and transformation have been published in the meantime, which in some cases offer new and differentiated assessments of H_2 costs and development pathways. Most notably, these include the climate neutrality scenarios known as the "Big 5": *Towards a Climate-Neutral Germany 2045 (Agora Energiewende et al., 2021), Climate Paths 2.0 (BDI, 2021), Towards Climate Neutrality (dena, 2021b), Long-Term Scenarios (BMWi, 2021)* and *Germany on the Way to Climate Neutrality (Ariadne, 2021a).* The literature is augmented by specific H_2 studies such as (Aurora, 2022; EHB & Guidehouse, 2022; Staiß et al., 2022). Against this background, the **objectives** of this study[1] are as follows:

1 | To update the meta-analysis of the H_2 study referred to at the beginning with regard to the cost and quantity ranges for the future production and supply of green (and also, as far as possible, blue) hydrogen to Germany.

2 | To offer a critical discussion and assessment of the current debate on blue hydrogen, i.e. whether and to what extent it could represent a sensible interim solution in the transition to green hydrogen.

3 | To assess Germany's demand for hydrogen based on the choice of sectors where it will be used.

[1] The German version „Wasserstoffkosten und -bedarfe für die CO2-neutrale Transformation" can be found here: https://wupperinst.org/p/wi/p/s/pd/2224

2 Principal results and findings

Since the last meta-analysis study on hydrogen costs and imports was carried out for LEE NRW at the end of 2020, the conditions for the hydrogen ramp-up in Germany have changed substantially and very dynamically.

Most of the studies published since 2021 and covered in this current meta-analysis were not able to take into account many of the recent changes, especially the impacts of the war in Ukraine. In this context, the study results relating to blue hydrogen in particular must be viewed in a critical light due to heightened uncertainties regarding the future prices and availability of natural gas.

The level of H_2 demand in Germany in 2030 anticipated by the earlier studies has decreased significantly in some respects compared with the previous meta-analysis. However, expectations for the development of long-term demand still range very widely. As a result, there is considerable uncertainty over not only future supply and demand trends but also the infrastructure required (pipelines and storage).

According to the studies covered by this analysis, demand for climate-friendly hydrogen is expected to be between 29 and 101 TWh per annum **by 2030** across all sectors in addition to the grey hydrogen available today (approx. 55 TWh per annum). Meanwhile, the NWS itself forecasts 35 to 55 TWh of additional hydrogen demand by 2030. **In almost all scenarios, industry and the energy sector are the two most important sources of demand.** Hydrogen for the transport sector has at least a small role to play in 2030 (up to 11 TWh) in all but one scenario, while its use for space heating in buildings only features in two scenarios (and even then, only to a maximum of 6 TWh).

In terms of total H_2 demand, the scenarios examined indicate a wide range of around 200 to 700 TWh per year **in the long term** (by 2045/2050). They anticipate that significant quantities will be used by industry (75 to 360 TWh) and by the energy sector (15 to 375 TWh), but the predicted amounts vary enormously. **Large-scale use in transport is only envisaged in those scenarios that put a very strong focus on hydrogen across the board.** In the buildings sector, a mixed picture emerges. Six of the scenarios foresee little to no demand here, but three assume that substantial amounts will be used, ranging from 80 to 180 TWh. The total long-term demand is largely in line with the results of the first meta-analysis.

The anticipated costs of producing green hydrogen in Germany have decreased in comparison with the previous study and are mostly below the costs of imports by ship. The lowest cost estimates in the medium and long term are for imports by pipeline from North Africa, Spain, Eastern and Northern Europe.

In the future, the **investment costs** for electrolysers are expected to fall sharply in all scenarios. More recent studies also estimate that the investment costs over all time frames will be much lower than the figures identified in the previous meta-analysis. The **costs of supplying** green hydrogen **in 2030** fall into a wide range of between 4.5 and 20.5 ct/kWh. In the case of imported H_2, costs are mainly dependent on the mode of transport chosen and study-related assumptions about production. In general, pipeline imports are assumed to be cheaper than options for transport by ship in every case. Only four studies make predictions about the anticipated costs of producing hydrogen in Germany in 2030, namely from 7 to 13.5 ct/kWh. In many cases, these costs are competitive with imports by pipeline and ship in the overall comparison.

By 2050, the range of costs for supplying H_2 decreases to between 4.2 and 11 ct/kWh, with the most favourable estimates in each case given for import via pipeline. Only three studies indicate costs for production in Germany, which, at between 6.7 and 8.5 ct/kWh H_2, continue to be competitive in many cases. **This remains particularly true in comparison with imports by ship from far-flung regions of the world.**

New studies tend towards more favourable cost estimates for H_2 imports.

As an illustrative comparison of imports from the North African region shows, the median costs of the current scenarios for both time frames are lower than those of the older studies (10.6 ct/kWh H_2 vs. 14.5 ct/kWh H_2 in 2030 and 6.9 ct/kWh H_2 vs. 10 ct/kWh H_2 in 2050). When compared with the assumed costs of production in Germany of between 7 and 13.5 ct/kWh H_2 in 2030, it is clear once again that domestic production can achieve cost parity.

Focusing on the use of hydrogen for no-regret applications has the potential to significantly reduce future H_2 demand and thus also the required generation and import volumes. This is contingent on a high degree of direct electrification and greater efficiency gains.

Expectations are that both domestic H_2 production and H_2 imports will not be able to keep pace with the sharp increase in demand for H_2 in the short to medium term. As a consequence, shortages and high market prices are likely to have an impact on the H_2 ramp-up. In this context, a focus on so-called no-regret applications seems advantageous and advisable. No-regret applications are all those that cannot be electrified or "decarbonised" in any other technically or economically expedient way. They include the production of ammonia, primary steel, basic chemicals and selected refinery products as well as, in some cases, the generation of high-temperature process heat and, where appropriate, heavy goods transport. It is important to bear in mind here that hydrogen will not only be in demand on a large industrial scale but will also be required by small and medium-sized enterprises.

For reasons of efficiency and the availability of alternatives, using H_2 for heating residential buildings and as a fuel basis for the passenger car segment of the transport sector are not priority applications from today's perspective. Efficiency considerations should also take precedence when it comes to industrial process heat. The demand for hydrogen can be kept to a "minimum" by focusing on efficiency, especially with regard to low to medium temperatures.

In scenarios with a broad range of applications and high H_2 demand, focusing the use of H_2 on the industrial and conversion sectors could lead to a significant to substantial reduction (of around 40 to 470 TWh) in H_2 demand in the long term and to corresponding decreases in the production and import volumes required. From today's perspective, however, it is not yet possible to say to what extent such a focus on no-regret H_2 applications will be necessary or optimal in the long term.

Due to the time needed to develop the production facilities and the necessary H_2 pipelines in particular, blue hydrogen will probably not be available in large quantities until just before 2030, so it does not represent a short-term transitional solution. It will not be available any more quickly than green hydrogen either, but it has the potential to make an additional contribution to the H_2 ramp-up and thus help alleviate shortages. However, due to blue hydrogen's residual greenhouse gas (GHG) emissions, it is important that lock-in effects and expansion in the longer term are avoided.

Worldwide, there are currently only four large-scale production plants (steam reforming plus CCS) for blue hydrogen. A massive expansion in new plants and the corresponding infrastructure would therefore be needed in order to ramp up blue H_2. Current plans in Norway – which is potentially a very important supplier of blue hydrogen to Germany – indicate that the supply chain will not go into operation until 2027 at the earliest. These plans foresee a capacity of 2 GW or maximum production quantities of around 18 TWh by 2030. Such figures are roughly of the same order of magnitude as the target for domestic green H_2 production by 2030. However, supplies from Norway are also dependent on the new H_2 pipeline being completed by the 2030 deadline. Supplies of blue hydrogen from other European countries, such as Belgium, France and the Netherlands, are not expected any earlier for similar reasons (and due to the foreseeable, and in some cases considerable, domestic demand in these countries), and even then, much lower quantities are anticipated.

Even when very favourable assumptions are made (capture rates of 90% or more and low upstream emissions), blue hydrogen still has significantly higher GHG emissions than green hydrogen.

Existing blue hydrogen production plants only achieve average capture rates of about 56% and would therefore "only" be able to reduce GHG emissions by about half compared with grey hydrogen. At 120 g CO_2/kWh, their direct emissions alone are thus still above the CertifHy benchmark[2] of around 104 g CO_2/kWh and far above those of green hydrogen with pure upstream emissions of about 25 g CO_2/kWh. To meet the CertifHy benchmark, the capture rate would have to be increased to at least 66%; and to bring emissions well below 50 g CO_2/kWh, capture rates of at least 90% would be needed. The required plant technology would first have to be further developed and scaled up from pilot stage to commercially available technological maturity. This process can take several years and requires additional time afterwards for the expansion of production capacity.

When using natural gas with higher upstream emissions (e.g. from the USA) or taking into account the short-term climate impact of methane,

2 CertifHy is an ongoing project funded by the European Commission with the aim of developing and establishing a certification system for the hydrogen market. There are also parallel developments at both EU and German federal level for the purpose of setting regulated thresholds by means of delegated acts and ordinances.

the GHG emissions are (sometimes significantly) above the CertifHy benchmark.

Even with very high capture rates, high levels of (unavoidable) upstream emissions can lead to GHG emissions that, as well as being above the CertifHy benchmark, are far in excess of those associated with green hydrogen. This is especially the case for LNG imports from the USA and the Arab states, and particularly for unconventional sources of natural gas. Since natural gas imports from Norway with very low upstream emissions are not currently sufficient to satisfy the demand for natural gas in Germany, a focus on blue hydrogen would necessitate the use of these LNG imports as marginal sources of supply for blue H_2 production in Germany (which would then be associated with high indirect emissions). The impact of methane on the climate, which is greater than that of carbon dioxide in the short term (based on 20-year global warming potential rather than 100-year global warming potential), must also be taken into account.

Due to the great variability and uncertainties surrounding blue hydrogen's GHG emissions, its contribution to climate change mitigation must be considered uncertain.

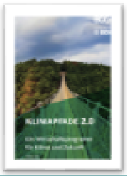
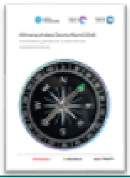
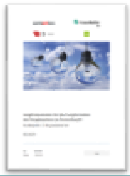
Outlook

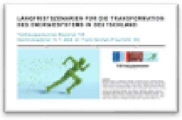
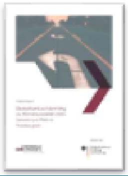
Ensuring a sustainable and timely H_2 ramp-up in the face of surging demand is still a huge challenge for the transformation to climate-neutral energy and industrial systems. It is therefore important that not only the supply side but also the demand side be considered in detail in the upcoming decision-making processes. Focusing on no-regret applications for hydrogen in the short- to medium-term will help to minimise shortages, high prices and undesirable developments, enabling a robust roll-out. Taking this approach also has the potential to greatly reduce overall demand, thereby lowering the import volumes required in the longer term and increasing opportunities for energy self-sufficiency and, ultimately, independence.

Acceleration of the expansion of electricity generation from renewables and of the electricity and hydrogen infrastructure, as well as increased efficiency gains and energy-saving measures, remain important prerequisites for the transformation to climate-neutral systems. Given the uncertainties involved in obtaining H_2 imports in the medium term, as shown in the studies, H_2 production in both Europe and Germany needs to be pursued with maximum ambition. This should include meeting, if not exceeding, Germany's 10 GW domestic expansion target, which already requires additional efforts. In view of the expansion targets outlined in the Easter Package, the extent to which the 10 GW of electrolysis capacity could be used to exploit the anticipated amount of surplus electricity would also appear to be worth investigating.

3 Overview of the studies under examination

Figure 3-1 lists the studies into future hydrogen demand and costs that are examined in this meta-analysis and characterises them according to key features. An important requirement when selecting the studies was their current relevance, judged by their publication date, which had to be no earlier than 2021. Furthermore, the studies needed to be orientated towards the goal of achieving greenhouse gas neutrality by 2050 at the latest and contain quantitative information about the demand for and/or costs of hydrogen. In addition to the so-called Big 5 recent climate neutrality studies, some publications with an explicit focus on hydrogen were also considered. It should be noted that most of the studies, with the exception of (Aurora, 2022; SCI4climate.NRW, 2023), were carried out and published before the "turning point" marked by Russia's war of aggression in Ukraine. However, it was not possible to evaluate other relevant publications on the topic, such as (Ragwitz et al., 2023) and (FZJ-IEK3, 2021), within the limited scope of this analysis.

				
Study title	dena pilot study: Towards Climate Neutrality	Climate Paths 2.0	Towards a Climate-Neutral Germany by 2045: How Germany can reach its climate targets before 2050	Long-Term Scenarios for the Transformation of the Energy System in Germany III
Year of publication	2021	2021	2021	2021
Commissioned by	German Energy Agency (dena)	Federation of German Industries (BDI)	Climate Neutrality Foundation, Agora Energiewende, Agora Verkehrswende	German Federal Ministry for Economic Affairs and Energy (BMWi)
Prepared by	Institute of Energy Economics at the University of Cologne (EWI)	BCG	Prognos, Institute for Applied Ecology (Öko-Institut), Wuppertal Institute	Consentec, Fraunhofer ISI, ifeu, TU Berlin
Mitigation scenarios examined	KN100	"Zielpfad" (target path)	KN45	TN-H2
GHG neutral by	2045	2045	2045	2050

				
Study title	Long-Term Scenarios for the Transformation of the Energy System in Germany III	The economics of hydrogen imports: Better to stay local?*	Germany on the Way to Climate Neutrality in 2045 – Scenarios and Pathways through a Comparison of Models	Options for Importing Green Hydrogen to Germany by 2030
Year of publication	2022	2023	2021	2022
Commissioned by	German Federal Ministry for Economic Affairs and Energy (BMWi)	-	German Federal Ministry of Education and Research (BMBF)	BMBF
Prepared by	Consentec, Fraunhofer ISI, ifeu, TU Berlin	Aurora	Ariadne	Acatech, Leopoldina, Union of the German Academies of Sciences and Humanities
Mitigation scenarios examined	T45-Strom, T45-H2	-	Strom-Import, H2-Import	TN-Strom, TN-H2
GHG neutral by	2045	-	2045	2050

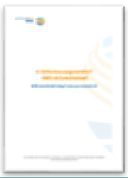
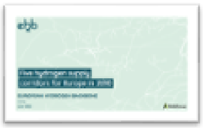
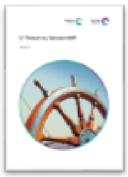
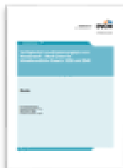
				
Study title	Greenhouse Gas Neutrality in Germany by 2045	EHB	12 Insights on Hydrogen	DVGW
Year of publication	2023	2022	2022	2022
Commissioned by	Ministry of Economic Affairs, Industry, Climate Action and Energy of the State of North Rhine-Westphalia	EHB – European Hydrogen Backbone	-	German Technical and Scientific Association for Gas and Water (DVGW e. V.)
Prepared by	Wuppertal Institute, German Economic Institute (IW)	Guidehouse	Agora Energiewende, Agora Industrie	Frontier Economics Limited
Mitigation scenarios examined	S4C-KN	-		-
GHG neutral by	2045	2045	2045	2045

Figure 3-1: List and characterisation of the studies examined.

Source: Own illustration based on (Agora Energiewende et al., 2021; Agora Energiewende & Agora Industrie, 2022; Ariadne, 2021a; Aurora, 2022; BDI, 2021; BMWi, 2021; BMWK, 2022; dena, 2021b; DVGW & Gatzen, 2022; EHB & Guidehouse, 2022; SCI4climate.NRW, 2023; Staiß et al., 2022)

4 Meta-analysis of the costs of and demand for hydrogen

In the meta-analysis, the studies presented in Chapter 2 are first evaluated in terms of the anticipated costs of supplying and producing H_2 and then with regard to H_2 demand (total and by sector). The analysis covers both the medium-term (2030) and the long-term (2045/2050) time horizons.

4.1 Future hydrogen costs

Another focus of the meta-analysis is on the **interpretation** of recent study data in terms of the **costs of supplying hydrogen**. Information about the investment, operating, transport and full costs of sourcing H_2 has been gathered for this purpose.

Figure 4-1 begins by showing current estimated investment costs of electrolysis plants over time. It is apparent that certain figures deviate significantly from the others. If these are ignored (*S4C-KN* for the current situation and *Öko-Institut* for 2050), the estimated investment costs fall within a relatively small range. For the current situation, capital expenditure is given as between €690/kW and €1,000/kW of electrolysis capacity (electrical); for 2030, the estimate is between €544/kW and €625/kW; and for the long-term outlook, it ranges from €100/kW to €375/kW. The Institute for Applied Ecology (Öko-Institut) gives by far the lowest figure for the latter time frame. In their study, the authors refer to different possible trends, but are of the opinion that investment costs of €100/kW are conceivable in the long term. It was not possible to identify the specific electrolysis technologies to which the cost data refer. However, some studies generally refer to the use of low-temperature (dena), alkaline (BMWi) or PEM (BMWi, BDI) electrolysers.

In the future, electrolyser investment costs are thus expected to fall sharply in all scenarios, resulting in much lower production costs for hydrogen – regardless of the plant location. In comparison with the first meta-analysis carried out in 2020, the recent studies show a trend towards more favourable cost estimates. For example, the older publications gave median capital expenditure of €1,300/kW for the current situation, €735/kW for 2030 and €505/kW for the long-term outlook. The average investment costs in the older scenarios are thus always above the estimates in the recent studies.

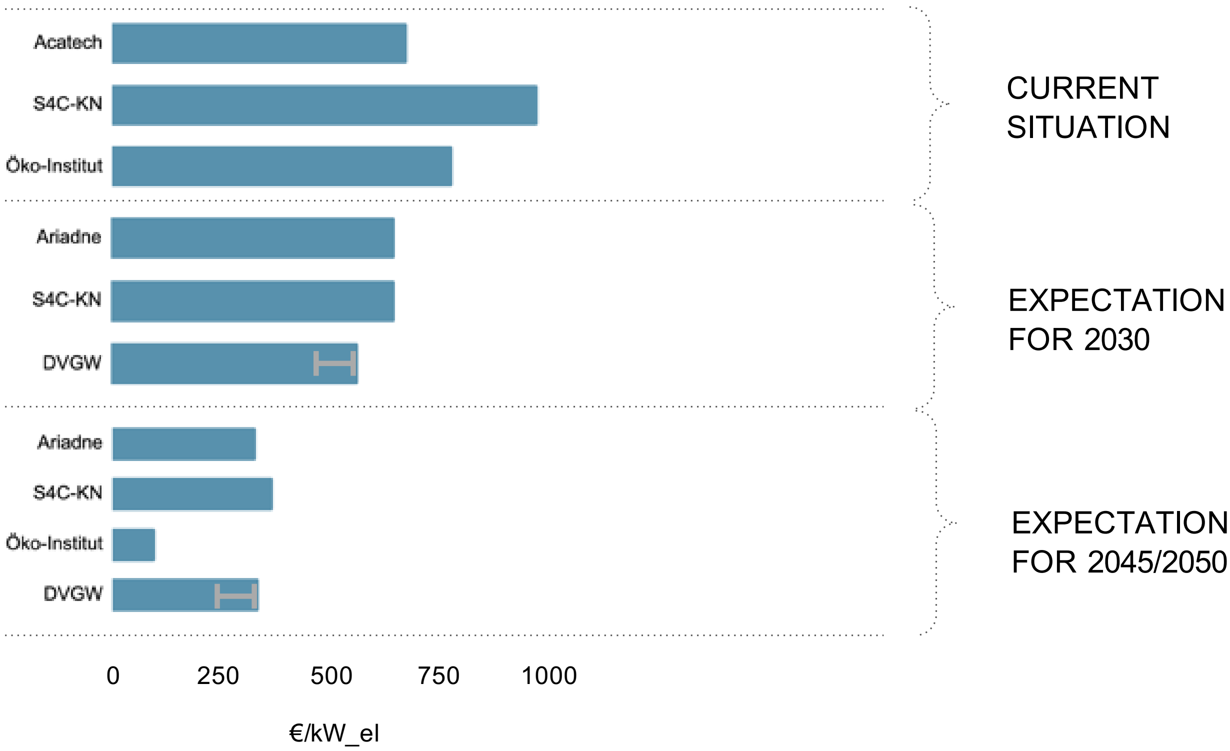


Figure 4-1: Electrolyser investment costs.

Source: Own illustration based on the studies under examination (see Chapter 3)

Figure 4-2 shows the results of the meta-analysis with respect to the costs of supplying hydrogen in 2030. Seven of the twelve studies evaluated provide explicit information in this regard. Each point on the diagram stands for a cost estimate in the respective study; in the case of imports, the costs of transport to Germany are included. Red dots represent production within Germany, green dots symbolise imports by ship and grey dots supplies obtained by pipeline. None of the costs include costs for the domestic distribution of hydrogen.

What stands out initially is the wide spectrum of cost estimates for 2030, from 4.5 to 20.5 ct/kWh H_2. The range with regard to imports is mainly due to the mode of transport chosen and the distance from the country of production; some studies[3] also offer different scenarios based on explicitly optimistic or pessimistic assumptions. In general, importing hydrogen by pipeline is assumed to be cheaper than transport by ship in every case. The most favourable estimates are given for pipeline imports from Spain, north-western Europe, Romania, North Africa and Ukraine. Four studies make predictions about the costs of producing hydrogen in Germany, proposing figures between 7 and 13.5 ct/kWh H_2, which, in many cases, are competitive in the overall comparison. This last point is particularly true in the case of imports by ship from distant regions of the world, such as South Africa, the United Arab Emirates, Chile or Australia. A note of caution must be added here to the effect that the cost figures presented in the studies typically refer to a specific location and are therefore

[3] Acatech, Agora, DVGW.

neither weighted by quantity nor subject to limits on potential. In addition, the data on both imports and production in Germany are based on just a small number of individual estimates of possible future costs.

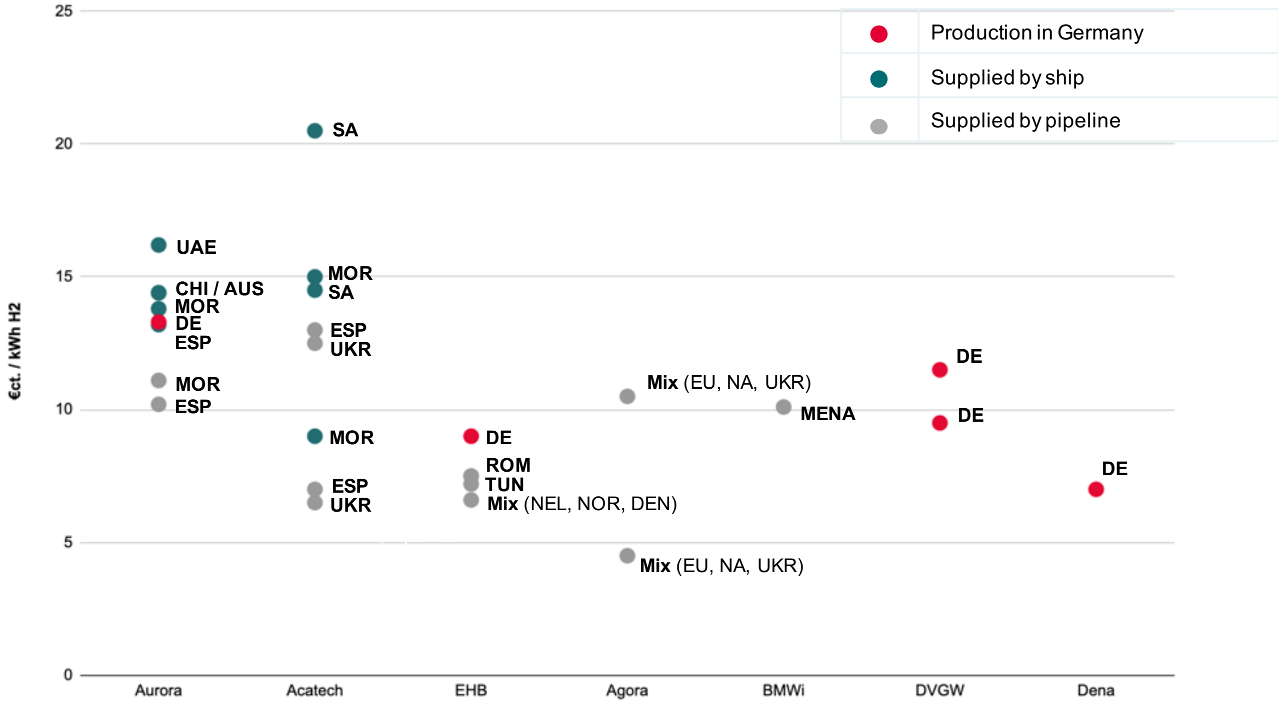


Figure 4-2: Costs of supplying hydrogen in 2030.

Note: UAE = United Arab Emirates, MOR = Morocco, CHI = Chile, AUS = Australia, SA = South Africa, ESP = Spain, UKR = Ukraine, ROM = Romania, TUN = Tunisia, NA = North Africa, DE = Germany.

Source: Own illustration based on the studies under examination (see Chapter 3)

Figure 4-3 shows the results of the meta-analysis with respect to the costs of supplying hydrogen in the long-term outlook, i.e. in 2045 or 2050, depending on the publication. As previously, seven out of the total of twelve studies evaluated provide explicit information in this regard, but the publications are not always the same as those in the medium-term outlook shown in Figure 4-2 (estimates from *BDI* feature here instead of from *Acatech*). Once again, each point on the diagram stands for a cost estimate in the respective study; in the case of imports, the costs of transport to Germany are included. Red dots represent production within Germany, green dots symbolise imports by ship and grey dots supplies obtained by pipeline. None of the costs include costs for the domestic distribution of hydrogen.

The basic assertions remain the same as described above for 2030: a range of cost estimates can also be seen for the long-term outlook, although it is significantly smaller at 4.2 to 11 ct/kWh H_2. Importing hydrogen by pipeline is still always assumed to be cheaper than transporting it by ship. The most favourable estimates are given for pipeline imports from North Africa, Spain, and eastern Europe. Three studies make predictions about the costs of producing hydrogen in Germany, proposing figures between 6.7 and 8.5 ct/kWh H_2. Such costs sit in the middle of the range in the overall comparison, making them competitive in many cases. This last point continues to be particularly true in the case of imports by ship from distant regions of the world, such as the United Arab Emirates, Chile or Australia. As before, the long-term outlook is subject to the qualification that some of the data on both imports and domestic production relate to just a small number of individual estimates of possible future costs, thereby limiting the usefulness of the data in a direct comparison.

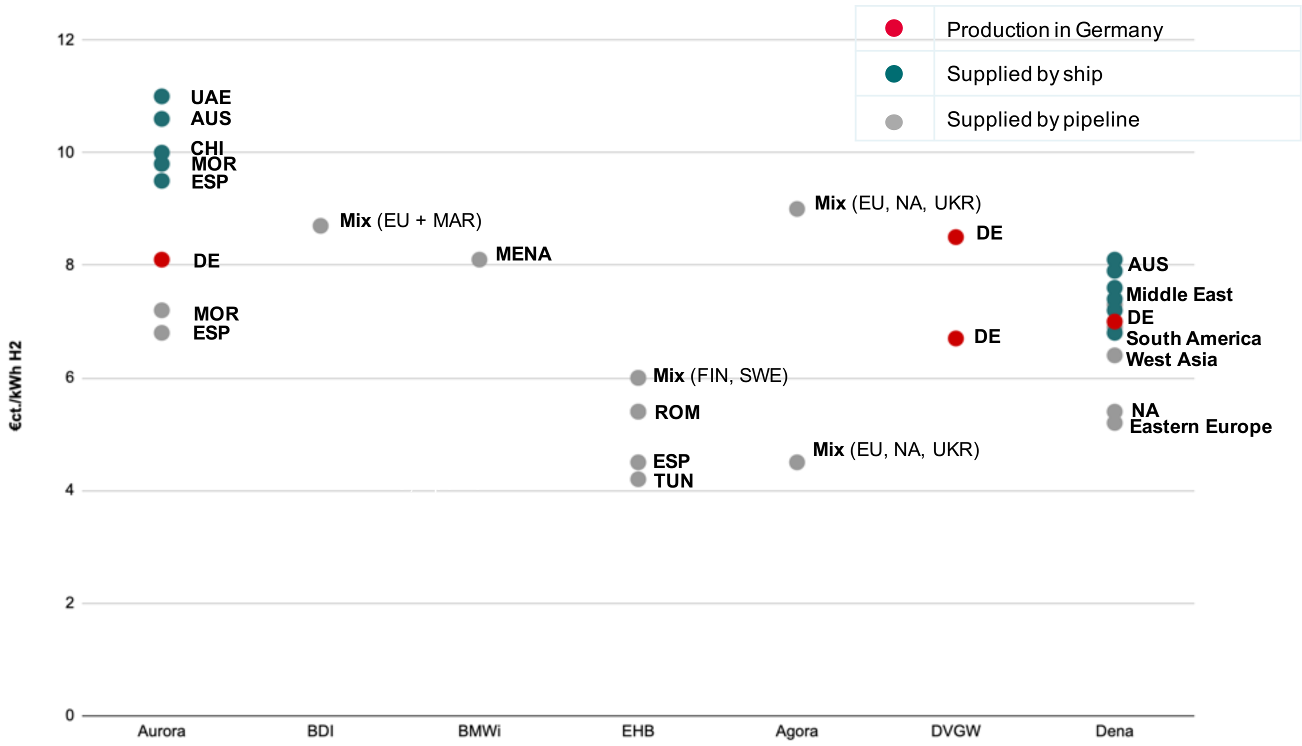


Figure 4-3: Costs of supplying hydrogen in 2045/2050.

Note: UAE = United Arab Emirates, MOR = Morocco, CHI = Chile, AUS = Australia, ESP = Spain, ROM = Romania, UKR = Ukraine, TUN = Tunisia, NA = North Africa, FIN = Finland, SWE = Sweden, DE = Germany.

Source: Own illustration based on the studies under examination (see Chapter 3)

Figure 4-4 compares the cost estimates for importing H_2 from North Africa in 2030 with the scenarios presented by earlier publications, which were analysed as part of the previous LEE study. In the case of the recent studies, where the original source envisaged imports from Morocco or Tunisia, the cost estimates have been allocated to the North African region. In addition, the cost ranges for producing H_2 within Germany cited in the various studies are shown as dashed lines (lowest and highest value respectively). Making a direct comparison between these figures reveals a trend. More recent studies published after 2020 tend to give a somewhat more favourable estimate of the costs of imports from North Africa in 2030 than those published before 2020. That is to say, at 14.5 ct/kWh, the median costs set out by the older studies are much higher than those taken from the more recent publications (10.6 ct/kWh). Furthermore, the most favourable cost estimate can be found in the newer studies and the most expensive in the older publications. There are no appreciable differences in the cost estimates for production within Germany.

The comparatively small amount of data given the number of publications must be noted by way of qualification at this point. In addition, the highest cost estimates in the older studies are attributable to sensitivities that examined the influence of assumptions with a cost-increasing effect.

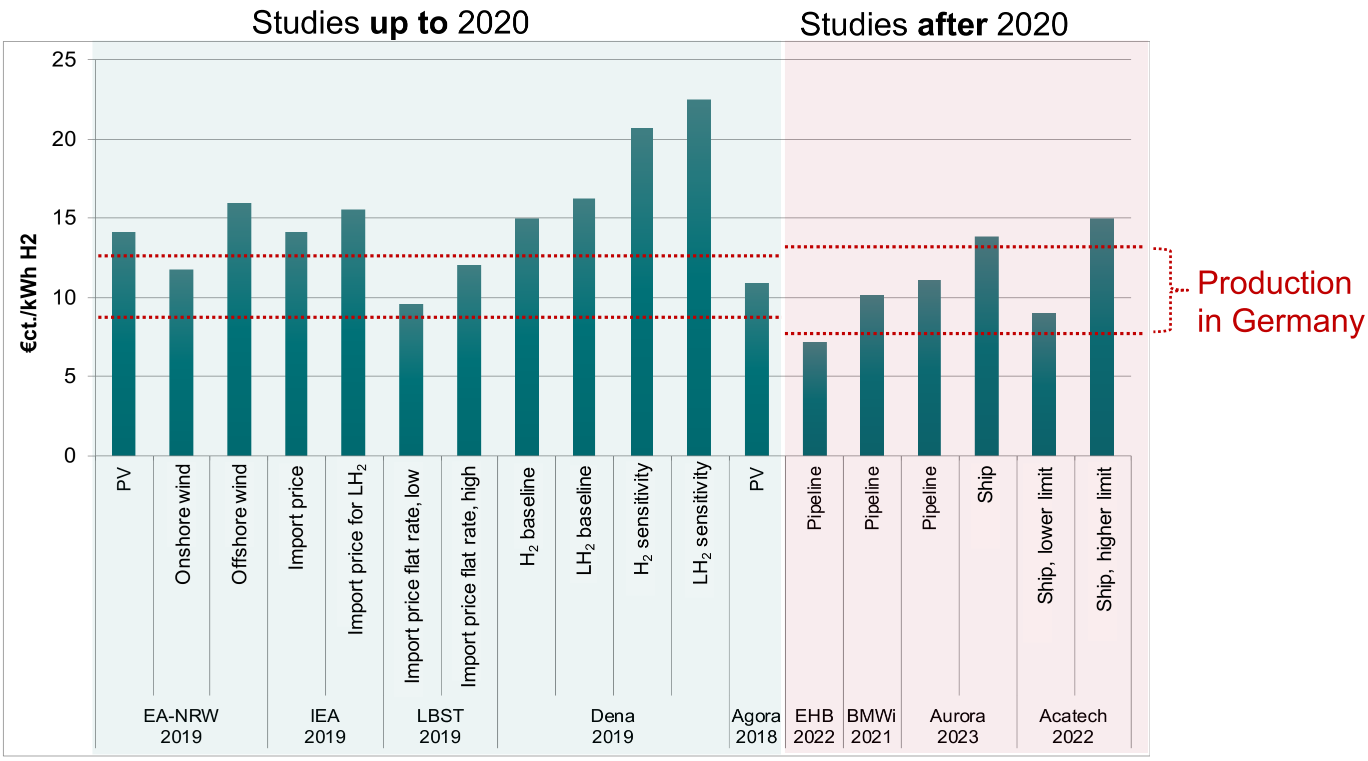


Figure 4-4: Comparison of the study data relating to the costs of importing H_2 from North Africa and the costs of producing H_2 in Germany in 2030.

Source: Own illustration

Note: Since dena (2019) does not specify any transport costs, the same flat-rate transport costs per EA-NRW (2019) were assumed for the purpose of this comparison (= 2.9 ct/kWh). The red dotted lines symbolise the cost ranges for producing H_2 in Germany given in the various studies.

As Figure 4-5 shows, the same basic assertion can also be made regarding the long-term outlook for hydrogen imports from North Africa. Thus, the more recent studies present much more favourable cost estimates overall than those published before 2020. At 10 ct/kWh, the median costs set out by the older studies are significantly higher than those in the more recent scenarios (6.9 ct/kWh). At the same time, the range for H_2 production in Germany is also much smaller in the more recent studies and lies at the upper end of the costs of importing from North Africa.

However, the above qualifications also apply in particular to the long-term comparison, as the amount of data here is still somewhat smaller than previously.

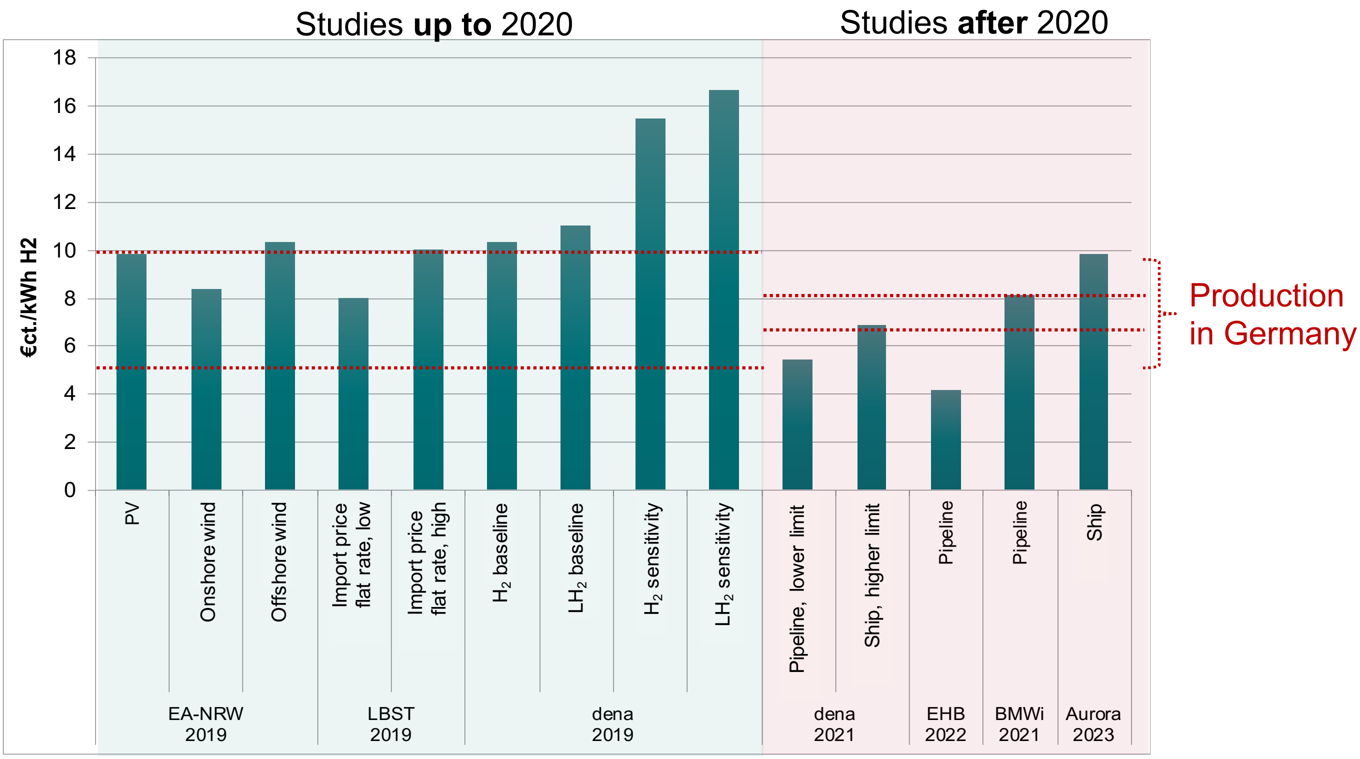


Figure 4-5: Comparison of the study data relating to the costs of importing H_2 from North Africa and the costs of producing H_2 in Germany in 2050.

Source: Own illustration

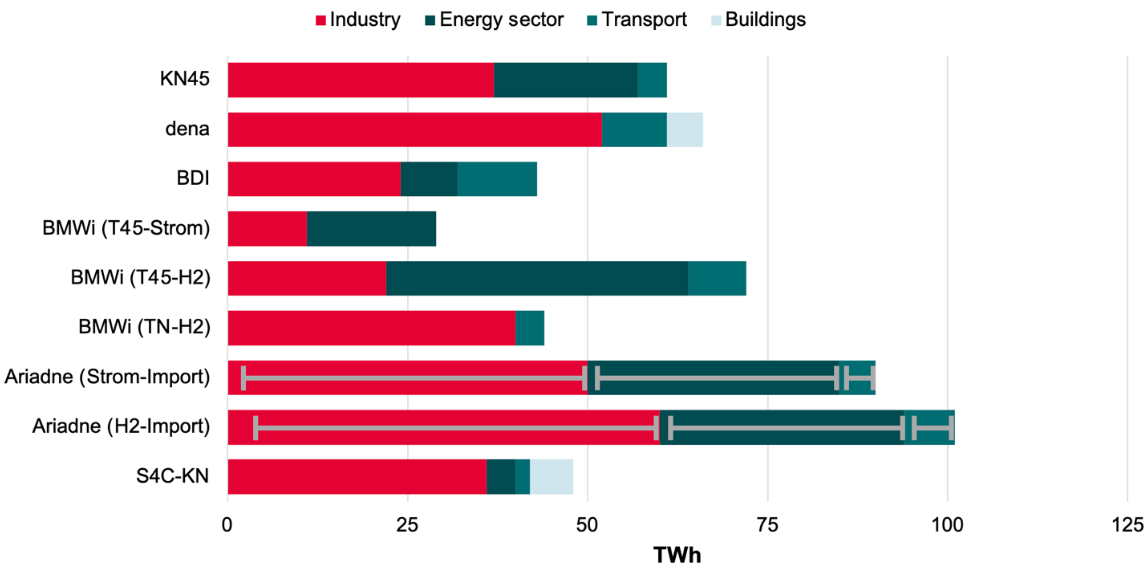
Note: Since dena (2019) does not specify any transport costs, the same flat-rate transport costs per EA-NRW (2019) were assumed for the purpose of this comparison (= 2.9 ct/kWh). The red dotted lines symbolise the cost ranges for producing H_2 in Germany given in the various studies.

4.2 Future hydrogen demand

Figure 4-6 shows the the evaluation results for the year 2030. The examined scenarios give a wide range of results in terms of both total demand and demand levels by sector. The total demand across all sectors amounts to between 29 and 101 TWh H_2. In almost all scenarios, industry and the energy sector are the two most important sources of demand. For the industrial sector, all scenarios foresee hydrogen demand of 2 to 60 TWh in 2030 – in addition to the amounts of grey H_2 used today. The energy sector also requires hydrogen in almost all scenarios, with the quantities used ranging between 0 and 42 TWh. In the transport sector, hydrogen plays at least some role in all scenarios – with the exception of *BMWi T45 Electricity* – although the demand is only up to 11 TWh. In buildings, hydrogen is used in just two scenarios, namely *dena* and *S4C-KN*, and in each case only in small quantities of up to 6 TWh.

When these results are compared with the first meta-analysis carried out for LEE NRW in 2020, it is apparent that the H_2 demand figures projected in the older studies (published up to 2019) tend to be higher and lie at the upper end of the recent scenarios (published in or after 2021). Only three of the more recent scenarios estimate that H_2 demand in 2030 will be at least 80 TWh (lower end of the demand spectrum in older studies), while the other six predict that less hydrogen will be used – significantly less in some cases.

Ranging between 90 and 110 TWh H_2, the demand levels for 2030 stated in Germany's National Hydrogen Strategy (NWS) are in line with those identified in older studies. However, the NWS forecast includes 55 TWh of grey H_2, which is currently mainly used as feedstock in industrial processes. By contrast, the studies examined in this analysis show the additional demand for climate-friendly hydrogen that will be needed by 2030 if the country is to pursue a path that will lead to greenhouse gas neutrality. If the increase in demand compared with today's level is the only aspect considered, the NWS calculates that 35 to 55 TWh of additional hydrogen will be needed by 2030, a figure that falls in the middle of the range indicated by the recent studies.



H_2 demand considered **realistic** in **first** LEE study

80–110 TWh

Figure 4-6: Hydrogen demand by sector in 2030.

Source: Own illustration based on the studies under examination (see Chapter 3)
Note: In each case, the Ariadne scenarios give H_2 demand in ranges.

Figure 4-7 shows the evaluation results relating to hydrogen demand for the long-term outlook, i.e. for the target year 2045 or 2050, depending on the scenario. The examined scenarios give an even wider range of results than for 2030 in terms of both total demand and demand levels by sector. The total demand across all sectors amounts to between 184 and 690 TWh of hydrogen. The result is a huge range of 506 TWh H_2, highlighting the considerable uncertainty over not only future supply and demand trends but also the infrastructure required (pipelines and storage).

In the sector-specific analysis, however, a more differentiated picture emerges compared with the medium-term outlook. As before, each scenario predicts that significant quantities of hydrogen will be used in industrial applications, ranging between 74 and 359 TWh. Most of the scenarios also foresee considerable demand in the energy sector. In some cases, this even exceeds the demand from industry (see

BMWi TN H_2 at 375 TWh and *BMWi T45 Electricity* at 259 TWh), but in others it only accounts for minor additional demand (see *S4C-KN* at 16 TWh and *BMWi TN H_2* at 24 TWh).

The studies do not provide a uniform picture for the transport and buildings sectors either, but some conclusions can be drawn. All scenarios – with the exception of *BMWi T45 Electricity* – envisage the use of at least small amounts of H_2 in the mobility sector. By contrast, widespread use is only anticipated by those scenarios that always focus heavily on hydrogen (*BMWi T45 H_2* and *TN H_2* as well as *Ariadne H_2 Imports*). The findings are consistent when it comes to supplying heat in buildings. While six scenarios forecast no demand at all or only very low demand for heating, three of the scenarios (*BMWi TN H_2*, *Ariadne H_2 Imports* and *dena*) envisage that the use of hydrogen will, in some cases, be considerable at between 79 and 178 TWh.

Overall, the total long-term demand is largely in line with the results of the first meta-analysis (with the exception of a few recent scenarios that have an explicit focus on hydrogen).

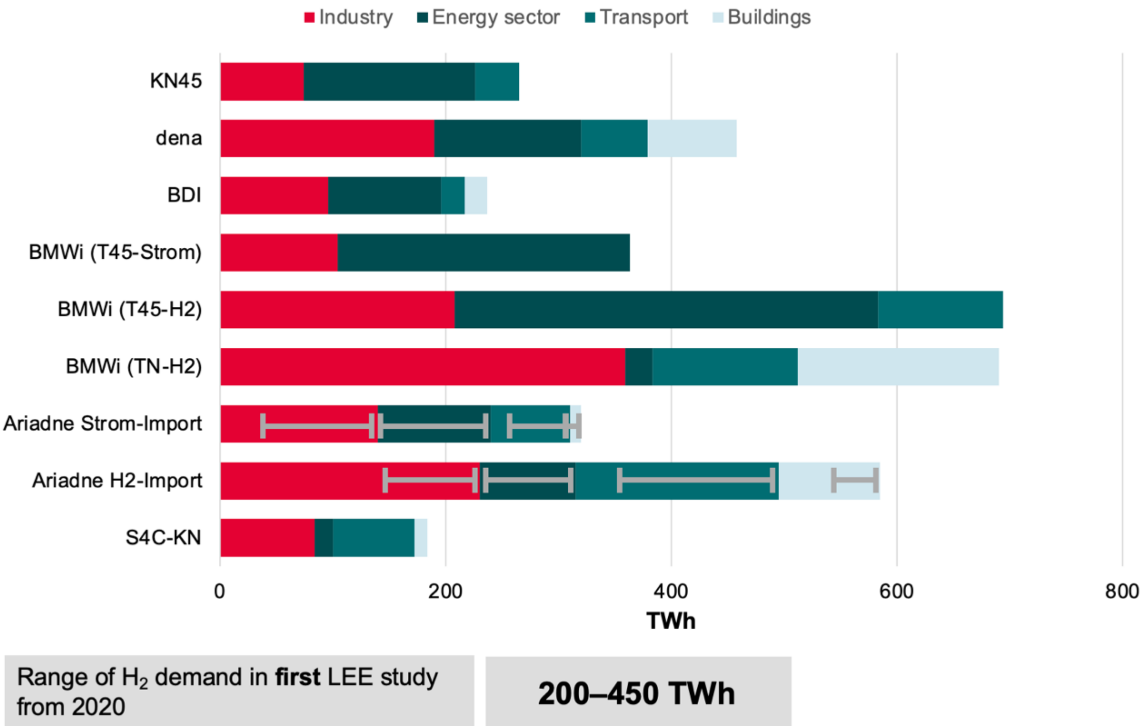


Figure 4-7: Hydrogen demand by sector in 2045/2050.

Source: Own illustration based on the studies under examination (see Chapter 3)
Note: In each case, the Ariadne scenarios give H_2 demand in ranges.

Although all scenarios predict that, at around 30 to 100 TWh H_2, H_2 demand will already be appreciable by 2030, the picture in terms of the supply of hydrogen is mixed. As Figure 4-8 shows, there are no imports whatsoever in 2030 in three of the scenarios, which is why supplies are provided solely by means of domestic production. In scenario S4C-KN, H_2 imports are necessary only after 2030 due to a major expansion of renewables and very moderate hydrogen demand. The BDI proceeds on the assumption that all of the H_2 required will be produced domestically by 2030, as transport by ship is not competitive and pipelines do not yet exist. The BMWi scenario T45 Electricity generally bases its figures on the highest possible rates of electrification and therefore only requires H_2 imports from 2040 onwards to supplement domestic production. However, six of the scenarios anticipate significant hydrogen imports up to a maximum of 35 to 57 TWh.

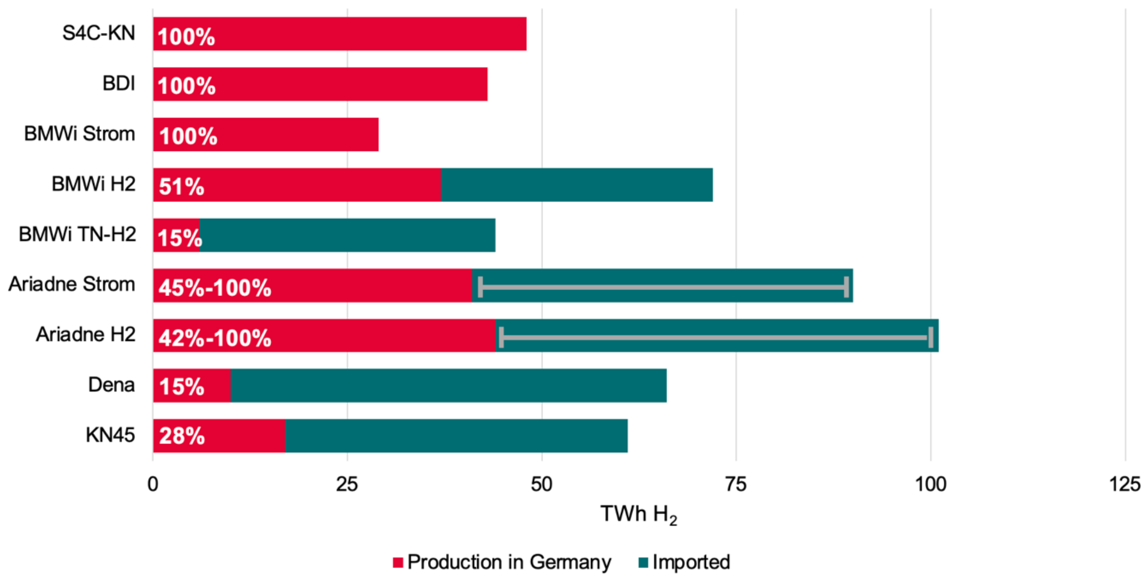


Figure 4-8: Proportion of domestic H_2 production vs. H_2 imports in 2030.

Source: Own illustration based on the studies under examination (see Chapter 3)
Note: The Ariadne scenarios each present ranges for the quantities of hydrogen used and the proportion of imports.

The percentages for domestic generation in 2030 shown in Figure 4-8 range from 15% (BMWi TN H_2 and dena) to 100% (*S4C-KN*, *BDI*, *BMWi Electricity* and the *Ariadne* scenarios in part). This means that all the scenarios envisage some production locations in Germany – assuming that the forecast demand is to be met.

In the long term, i.e. up to 2045 or 2050, all studies anticipate extensive imports of hydrogen (see Figure 4-9). Once again, there are two sides to the picture. Around half of the scenarios assume imports of up to around 200 TWh H_2 – although the figure is significantly less in some cases (see *S4C-KN* at just 78 TWh) – while four estimates are around 400 TWh H_2.

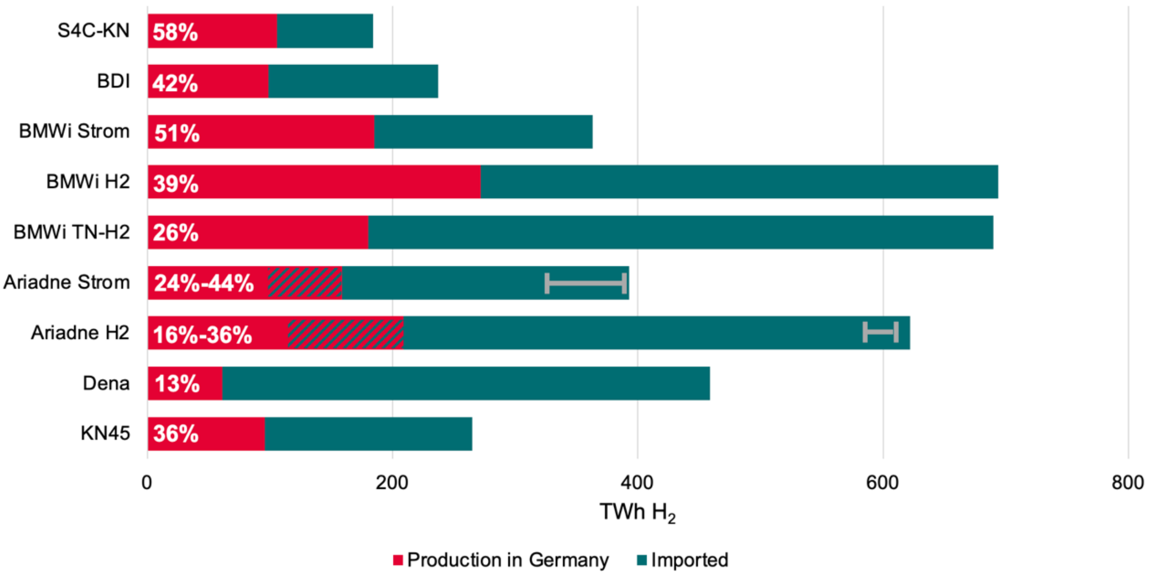


Figure 4-9: Proportion of domestic H_2 production vs. H_2 imports in 2045/2050.

Source: Own illustration based on the studies under examination (see Chapter 3)
Note: The Ariadne scenarios each present ranges for the quantities of hydrogen used and the proportion of imports.

As shown in Figure 4-9, the proportion of domestic H_2 production ranges between 13% (dena) and 58% (S4C-KN) in the long term. The higher the total demand for hydrogen in the respective scenarios, the greater the dependence on imports.

In summary, the meta-analysis shows that there will already be significant demand for additional, climate-friendly hydrogen in 2030; demand that could be largely met by domestic production in most scenarios. However, the levels of demand forecast for the medium term, and the long term in particular, range very widely. Some studies envisage the possibility of achieving greenhouse gas neutrality with about 200 TWh H_2 and generating about half of the required quantities of hydrogen in Germany. Other publications suggest that hydrogen will be used much more extensively and are therefore much more reliant on imports.

4.3 Summary of the key findings

- **The anticipated H_2 demand up to 2030 has decreased significantly in some respects compared with the previous study.**
- In the long term (by 2045/2050), expected H_2 demand continues to range widely, from around 200 to 700 TWh, across all sectors.
- The costs of producing H_2 in Germany are envisaged as being between 7 and 13 ct/kWh in the medium term and between 7 and 9 ct/kWh in the long term.
- They are thus mostly below the costs of importing by ship from far-flung regions (approx. 9 to 21 ct/kWh in 2030 and 7 to 11 ct/kWh in 2050) and equal to around the average of the pipeline supply costs (approx. 5 to 15 ct/kWh in 2030 and 4 to 12 ct/kWh in 2050).
- The most favourable estimates are given for pipeline imports from Spain, eastern Europe, northern Europe and North Africa.
- More recent studies indicate a trend towards more optimistic cost estimates for hydrogen imports (at least from the North African region).

5 Critical assessment of sources of hydrogen demand

Both the National Hydrogen Strategy and the studies examined in Chapter 3 expect H_2 demand in Germany to progressively increase over time (up to 2045), with levels of demand generally being much higher than anticipated domestic H_2 production. Consequently, it is assumed that greater or lesser amounts of hydrogen will need to be imported in order to meet the demand.[4] However, there is still a great deal of uncertainty, at least until around 2030, as to whether H_2 imports will be available quickly enough (SCI4climate.NRW, 2021). Shortages and the resulting high costs of obtaining H_2 are therefore likely to be features of the necessary H_2 ramp-up in the longer term. For that reason, and in order to avoid unnecessarily high import dependencies, it would be advisable and advantageous to limit initial demand to the applications that are truly necessary in order to bring about a transformation to a climate-neutral economy. The wide variation in long-term H_2 demand in the climate change mitigation studies examined above indicates that it is possible to serve a reduced range of applications with relatively little hydrogen.

“Truly necessary” or “no-regret” H_2 applications are all those that it would otherwise be technically or economically infeasible to electrify or “decarbonise” in any other way. According to (Ariadne, 2021b, pp. 6f, 26) and (Wietschel, M., et al., 2021, p. 24ff), the small number of no-regret H_2 applications[5] include:

- ammonia and primary steel production and
- basic chemicals and refineries.

High-temperature process heat[6] in the industrial sector and road-based heavy goods transport are among the other H_2 applications where, for technical and economic reasons, uncertainty remains as to whether they will be electrified directly using renewable electricity or indirectly using green hydrogen (or derivatives) (Wietschel, M., et al., 2021, p. 24).

In order to maintain security of supply, especially in the event of future periods of inadequate sun or wind, the authors believe that the seasonal storage of green hydrogen or its reconversion in gas-fired power plants should be added to the list of no-regret H_2 applications, at least in the long term.

5.1 Significance of no-regret hydrogen

Unlike the above-mentioned no-regret applications in the basic materials sector, in the supply of electricity and, where appropriate, in transport, the use of H_2 in other areas must be subject to reservations. More efficient alternatives are available for heating applications in particular, especially when it comes to space heating and, generally speaking, industrial process heat requirements.

4 Germany and its neighbouring countries (with the exception of France) are also seen as the principal import region in the context of European infrastructure planning (EHB & Guidehouse, 2022).

5 This includes the use of hydrogen as both a chemical substance and an energy carrier. A very detailed and continuously refined classification and description of H_2 applications can also be found here: https://www.deassociation.ca/newsfeed/the-clean-hydrogen-ladder-now-updated-to-v41.

6 Unlike high temperatures, process heat at low to medium temperatures (≤ 300°C) can be supplied very effectively and efficiently by means of “high-temperature” heat pumps and electrode boilers.

Figure 5-1 illustrates the implications of using hydrogen boilers versus heat pumps and energy-saving refurbishment for **space heating** based on a case study. It pays particular attention to existing buildings with typical useful energy demand for two reasons. Firstly, they dominate the building stock and, secondly, the use of H_2 – at least indirectly – is accepted in parts of the current discourse as an “alternative” to the difficulties of accelerating the refurbishment process.[7] In order to use hydrogen in boilers to meet the heating requirements of around 19,000 residential units in this case study, approximately 25 MWh of electricity per residential unit would need to be generated in Germany each year to produce H_2. This would necessitate a total of around 64 onshore wind turbines, each with a capacity of 3 MW. In comparison, a total of only 14 wind turbines and 5.6 MWh of electricity per dwelling per year would be sufficient to heat the same number of buildings using heat pumps. In other words, 50 fewer wind turbines would have to be built and operated, and an 80% saving in electricity consumption could be made if heat pumps were used for space heating instead of H_2 boilers. These figures were originally calculated on the basis of a purely domestic supply, but they can also be applied to H_2 exporting countries, at least in terms of efficiency comparisons.

Furthermore, energy-saving refurbishment would also help to bring down energy consumption for space heating considerably in the long term and contribute to a permanent reduction in the associated operating costs and dependence on imports.

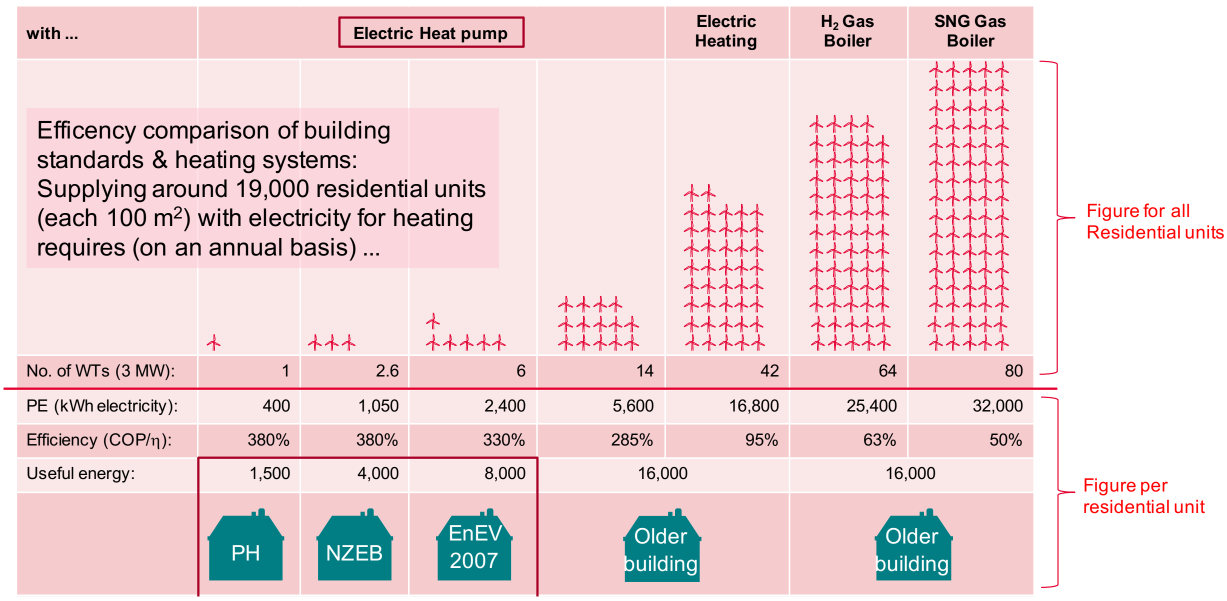


Figure 5-1: Comparing efficiency and supply for the provision of space heating by means of heat pumps, electric heaters, H_2 boilers and SNG boilers based on a German case study.

Source: Illustration based on (Schüwer, D., et al., 2021, p. 14ff)
NSH: night storage heaters, SNG: synthetic natural gas, WT: wind turbine, PE: primary energy, COP: heat pump efficiency (coefficient of performance), PH: passive house, NZEB: net zero energy building

7 “In the TN PtG/PtL and TN H_2 G scenarios, the development of the building stock is only slightly more ambitious than in the past. Most investments go into providing renewable fuels. They are therefore more consumptive in nature. These fuels facilitate the continued use of boiler technology. Technological advances are not made within, but rather outside the buildings sector.” (Schubert, n.d., p. 25)

Industrial process heat plays a significant role in Germany's energy system today. With an energy demand of approximately 450 TWh, it accounts for about two-thirds of the industrial sector's total consumption and just under 19% of Germany's total final energy demand (IN4Climate.NRW, 2022). At present, this demand is largely covered by fossil fuels (especially natural gas) and district heating, while electricity, biomass and green gases combined only contribute about 15% (see Figure 5-2). The importance of electricity and green gases, which in the scenarios presented in the diagram mainly consist of green hydrogen from 2030 onwards, is expected to grow considerably in the long term, although to different extents depending on the scenario. The contribution made by green hydrogen to the supply of industrial process heat in 2045 ranges from 9% (BMWi TN Electricity scenario) to as much as 62% (BMWi TN H_2 scenario). The figure from the BDI scenario lies between the two others, with H_2 making up a 26% share and renewable electricity providing most of the supply.

The considerable – in absolute terms, almost diametrically opposed – differences in the use of electricity and hydrogen in the two BMWi scenarios can be explained by the different emphasis they place on sources of energy. The particularly elevated consumption of H_2 for process heat in the TN H_2 scenario results from a high level of use for the provision of steam. This need could also be met by electrode boilers and high-temperature heat pumps. Demand for H_2 can thus be reduced in this scenario by approximately 91 TWh to 124 TWh in 2045, leaving it only moderately higher than in the BDI scenario. Further potential substitutes for hydrogen (e.g. biomass) are also available for the provision of industrial process heat, including for high temperature requirements.

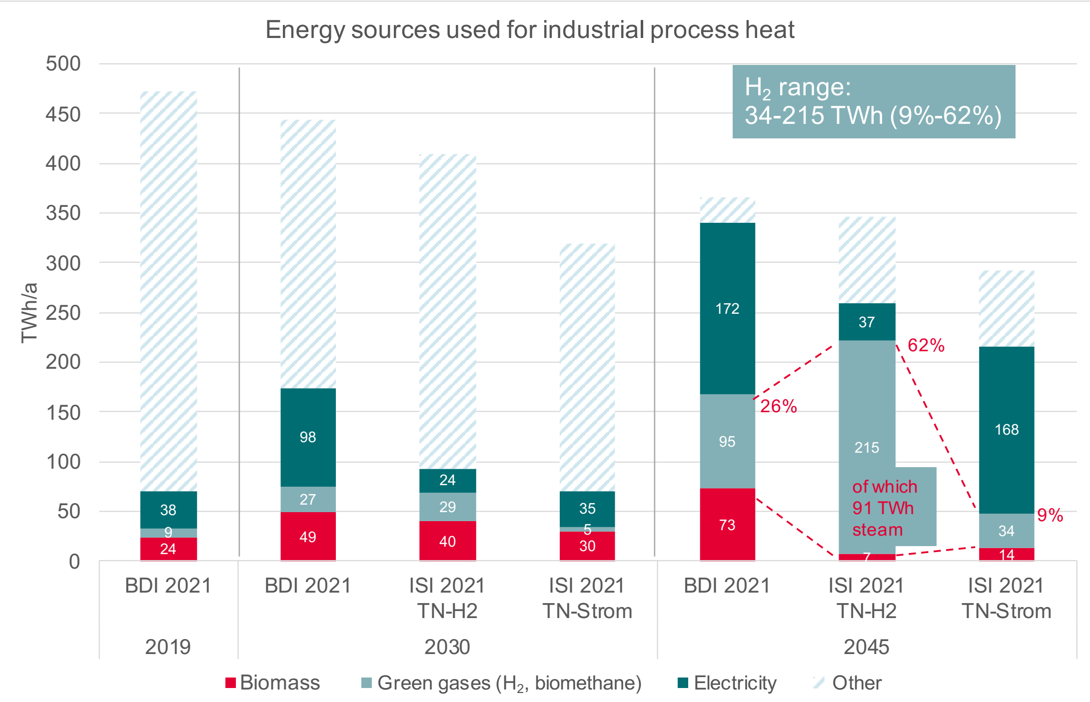


Figure 5-2: Energy sources used for industrial process heat in 2019, 2030 and 2045 by scenario.

Source: Own illustration based on the studies under examination (see Chapter 3)

Focusing on electricity for the provision of process heat where technically and economically feasible can thus save large quantities of H_2 and reduce the demand for H_2 production and imports. In turn, however, an increased supply of renewable electricity is needed to cover the final energy demand for industrial process heat. The amount of electricity required is nevertheless significantly lower in comparison with the hydrogen input, because using electricity directly is more efficient. In the low and medium temperature range, however, efficiency gains are also possible through the use of heat pumps and industrial waste heat, where appropriate. As a result, the demand for electricity does not increase at the same rate as the demand for H_2 decreases.

In the transport sector, too, direct electrification should always be preferred to the use of hydrogen or e-fuels for reasons of energy efficiency. As Figure 5-3 shows, vehicles powered by hydrogen-based fuel cells require about twice as much electricity per 100 km as a battery-powered electric vehicle when assessed over their entire life cycle. The use of so-called e-fuels (i.e. liquid synfuels based on hydrogen) requires as much as seven times the amount of electricity compared with a battery-powered electric vehicle. Using these energy carriers therefore has clear disadvantages, at least in the passenger car segment. It is only in road-based heavy goods transport and other heavy commercial vehicles that direct electrification strategies could reach their limits, which is why the use of hydrogen products for such purposes is under discussion.

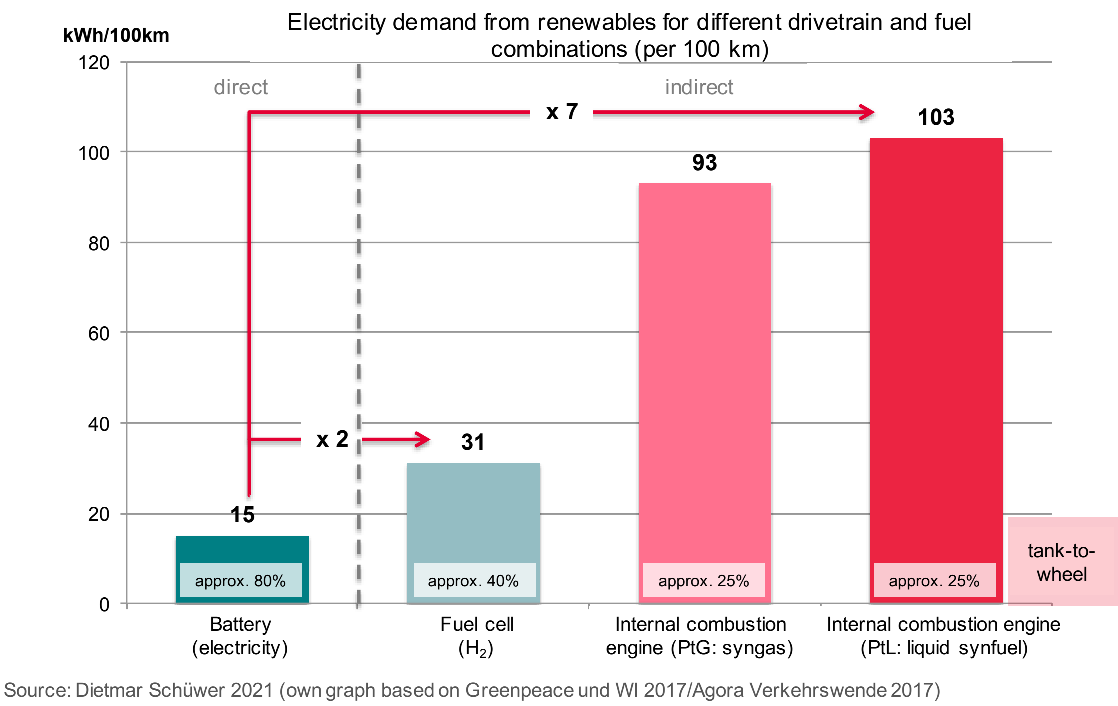


Figure 5-3: Comparison of direct and indirect electrification of passenger cars.

Source: (Schüwer, 2021)
Note: The electricity demand figures shown in kWh/100 km refer to the overall life cycle assessment (well-to-wheel). In addition, the efficiency of each vehicle type (tank-to-wheel) is indicated in the respective bars.

Figure 5-4 shows the influence that focusing on no-regret hydrogen can have on H_2 demand and the proportion of H_2 produced in Germany in the long term. Depending on the scenario and without placing any restrictions on H_2 use, total H_2 demand is expected to increase to values between just under 240 TWh (BDI scenario) and 690 TWh (BMWi TN H_2 scenario) by the middle of the century. On the other hand, when the use of hydrogen is limited to no-regret applications in the industrial and conversion sectors in these two "extreme" scenarios, the H_2 demand can be reduced by 41 TWh to 196 TWh in the BDI scenario, and by around 470 TWh to just 221 TWh in the BMWi TN H_2 scenario. As a result, H_2 imports could be avoided to the same degree, and the proportion produced in Germany could be increased from the previous 13%–42% to 21%–82% with the same level of domestic H_2 production.

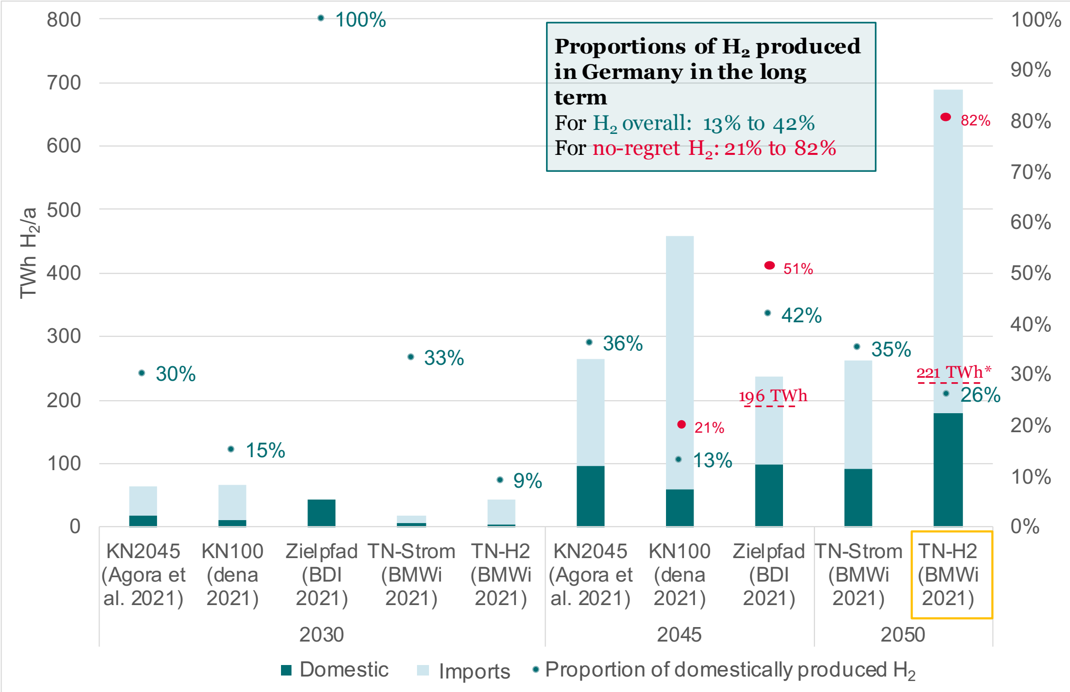


Figure 5-4: Domestic H_2 production and H_2 imports in 2030 and 2045/2050, plus the resulting proportions of H_2 produced in Germany, including for no-regret hydrogen, according to the individual scenarios.

Source: Own illustration based on the studies under examination (see Chapter 3)

Focusing on no-regret H_2 applications would therefore have a considerable influence on the "necessary" H_2 demand. In turn, this would have the potential to significantly reduce the required production and import quantities, while favouring direct electrification and efficiency gains. From today's perspective, however, it is not yet possible to say to what extent such a focus on no-regret H_2 applications will be necessary or optimal in the long term.

From a system standpoint, greater use of hydrogen and the gas infrastructure could also relieve the pressure on the electricity system, i.e. the necessary expansion of electricity generation and grids, and increase the resilience of the overall system. In the short to medium term, however, no-regret hydrogen will be advantageous for the H_2 ramp-up and the transformation of CO_2-intensive applications that are difficult to electrify directly.

6 Critical assessment of blue hydrogen

The predominant conventional way of producing grey hydrogen is via the steam reforming method, using fossil sources of energy (mostly natural gas) as the feedstock. When the CO_2 emissions released in this process are significantly reduced by means of subsequent carbon capture and storage (CCS), grey hydrogen becomes blue hydrogen. It can then be described and traded as "low-carbon" hydrogen if it complies with certain CO_2 emissions factors (threshold values), such as those defined by the CertifHy benchmark.[8]

The importance of carbon-neutral hydrogen to Germany can be inferred as follows from the June 2020 version of the National Hydrogen Strategy (NWS), which is currently still applicable (BMWi, 2020, p. 3). The NWS anticipates that a European and global H_2 market will be in place by 2030, on which blue (and turquoise[9]) hydrogen will also be traded. Because Germany is well connected to European infrastructure, blue hydrogen – where available – should also play a role and be used there. Compared with this indirect and rather non-committal reference, the issue of blue hydrogen is now addressed more explicitly in the new German Federal Government's recent update to the NWS. On page 8 of the revised draft dated 24 February 2023 (seen by the authors but as yet unpublished), which has been agreed between the ministries, it states:

- "To ensure that the hydrogen market is established and ramped up quickly, and to prevent supply shortages during the transformation phase, we will also make use of low-carbon hydrogen imports. We are therefore designing the hydrogen regulation framework in such a way that it is open to all technologies and allows the use of blue and turquoise hydrogen, which must, however, comply with the ambitious CO_2 threshold mentioned above (25 grams per CO_2e/MJ_{H2}, analogous to EU taxonomy)."

This implies that the focus for the production of blue hydrogen is regarded as being abroad and not in Germany.

Thus, one of the prime motivations for the planned incorporation of blue hydrogen into both the NWS and the current energy policy debate is the expectation that it can be made available quickly and on a large scale in addition to green hydrogen – and that it will also be needed to meet the demand for low-carbon H_2 expected by 2030. Additional assumptions made in blue hydrogen's favour are that it can be produced (for the time being) at a lower cost than green hydrogen and that it has lower CO_2 emissions than grey hydrogen.

The main arguments put forward by the proponents of blue hydrogen can therefore be summarised and analysed as follows:

- Quickly and widely available in addition to green hydrogen

[8] CertifHy is an ongoing project funded by the European Commission with the aim of developing and establishing a certification system for the hydrogen market. The defined threshold stipulates that CO_2 emissions must be reduced by at least 60% compared with grey H_2 produced via steam reforming and amounts to 36.4 g CO_2/MJ_{H2} (CertifHy, 2023; Longden et al., 2022a).

[9] Turquoise hydrogen is produced by means of methane pyrolysis in combination with CCS. The process uses heat to split methane into hydrogen and solid carbon.

- Can be produced with lower emissions than grey hydrogen and is “low-carbon”
- Less expensive than green hydrogen in the short to medium term

All three arguments are examined in more detail below. The first two points are discussed in greater depth, as they have a decisive role to play in the ramp-up of hydrogen use. The issue of cost, on the other hand, can only be considered briefly and qualitatively as part of this study.

6.1 Speed and scale of blue H_2 supplies

Table 6-1 provides an overview of those of the studies examined that envisage blue, or indeed turquoise, hydrogen also being used – at least provisionally – to support the transformation to a GHG-neutral economy. Above all, it shows the amounts of blue, and in some cases turquoise, hydrogen that the studies anticipate over time as well as the assumptions (columns 3 and 4) underlying these figures. It should be noted that the studies were produced before both the conclusion of the new German government’s coalition agreement and the energy policy and energy industry upheavals caused by Russia’s war of aggression in Ukraine, and therefore do not take these factors into account. This point is particularly relevant with regard to the economic calculations on which the development pathways for blue hydrogen are based in the individual studies and scenarios.

Table 6-1: Overview of studies featuring “blue” hydrogen, their motivations and expectations

Study title	Hydrogen colour	Transition/ support technology	Option or alternative to green H_2[a]	Available amount of blue* H_2 per year					H_2 origin
				2030	2035	2040	2045	2050	
dena pilot study		✓	✓	5 TWh	32 TWh	–	–	–	Germany
Towards a Climate-Neutral Germany		✓		X	X	?	?	–	Germany
EHB[b]		✓		Approx. 107 TWh	X	209 TWh	X	0 TWh	Europe
12 Insights			✓	X	X	X	X	X	
DVGW			✓	150+50[b] TWh	X	X	150+50[b] TWh	X	Germany

Source: Own illustration based on the studies under examination (see Chapter 3)
*Notes: * Blue may also include turquoise hydrogen; a) under strict specifications (e.g. compliance with threshold values due to low leakage rates) and depending on the price of natural gas; b) according to the base-case scenario (disruptive scenario with rapid technology ramp-up). Same values for blue and turquoise hydrogen in the optimistic scenario.*
X: Blue H_2 is used, but no quantity figures provided; ?: blue H_2 use unclear; –: no use of blue H_2.

Assessment of the DVGW[10] study

As shown in the table, the (DVGW & Gatzen, 2022) study is the only one to assume that the potential availability of blue (150 TWh) and turquoise (50 TWh) hydrogen in

[10] DVGW: German Technical and Scientific Association for Gas and Water

Germany will be high enough by 2030[11] that they alone could meet the H_2 demand (including demand for H_2 derivatives) of 95 to 130 TWh predicted in the current NWS. The production of such large quantities of blue and turquoise H_2 is linked to the following key assumptions and preconditions in both the "base-case" and the "optimistic" scenario:

- The realisation of disruptive technological ramp-ups for H_2 production ("similar to the PV boom in 2008–2012") and, at the same time, the readiness of turquoise production plants to go into large-scale operation by 2030.[12]
- Little restriction in terms of attitudes or general conditions relating to blue/turquoise hydrogen, or an appropriate proactive policy to that effect.

It appears that the findings for the high quantities of blue and turquoise H_2 were also influenced by the following assertions and assumptions (DVGW & Gatzen, 2022, pp. 8, 17):

- "As far as individual processes (such as blue or turquoise hydrogen) are concerned, it is not so much technological readiness but rather political will that is decisive for future availability."
- "The assumptions made about blue and turquoise hydrogen are not limited by questions over the availability of suitable sites or the like, but primarily reflect assumptions about 'political will' and the technological readiness of pyrolysis."

By contrast, the "pessimistic" scenario envisages no potential for blue hydrogen in the event of conservative technological development (i.e. turquoise hydrogen not being production-ready by 2030) and restrictive general conditions (i.e. lack of political will).

The possible ramp-up of blue and turquoise hydrogen in (DVGW & Gatzen, 2022) is thus highly dependent on political will. However, such a will is not entirely obvious in the approach of Germany's current Federal Government or in its National Hydrogen Strategy, where green hydrogen continues to be given priority and interest in blue hydrogen has so far focused explicitly on imports rather than domestic production. Furthermore, the political and legal acceptance of CCS as a basic technology for blue hydrogen is controversial in Germany. Therefore, current support for blue hydrogen mainly relates to import projects, such as the most recent plans to source it from Norway (euractiv, 2022; Geinitz & Oslo, 2023).

In addition, the ramp-up is dependent on multiple technological developments being made and successfully implemented on time. In the case of blue hydrogen, this will require not only many[13] new and innovative CCS plants capable of significantly higher rates of carbon capture (≥ 90% instead of today's 50%–60%) in order to bring

[11] The same quantities are also assumed for 2045, which suggests that all investments in and construction of blue and turquoise H_2 production plants will take place in the short period before 2030. This begs the question why such an ambitious development pathway would grind to a halt after just a few years.

[12] In view of the current technological readiness level (TRL of 5–6) according to (DVGW & Gatzen, 2022), this is an ambitious assumption, as both further technological development and upscaling of the plant technology would have to take place by 2030.

[13] According to (Longden et al., 2022a), there are only four blue H_2 production plants anywhere in the world so far, only one of which makes provision for the permanent storage of captured CO_2.

about sufficient reductions in CO_2 emissions (see below), but also CO_2 infrastructure (pipelines and ships) to transport CO_2 to the storage sites, e.g. in Norway. Planning, approval and construction of the infrastructure in particular is likely to take so long that its availability by 2030 is extremely uncertain. Furthermore, no work – at least not on projects within Germany – can begin before a national Carbon Management Strategy has been drawn up and the legal framework has been adjusted accordingly.

In the case of turquoise hydrogen, simply having plants available and ready to go into large-scale production by 2030 will not be enough. Sufficiently extensive investments and planning procedures would also have to be in place from the very beginning in order to achieve such high H_2 production figures.

The final point to be made regarding the potential for a rapid ramp-up of blue hydrogen is that, even if the developments proceed as assumed in (DVGW & Gatzen, 2022), blue hydrogen will be available in large quantities only (very) marginally before 2030. However, the risk of missing the deadline remains high.

Assessment of the EHB study

The (EHB & Guidehouse, 2022) study also calculates that relatively large quantities of blue H_2 will be available by 2030 (approximately 107 TWh), but for the whole of Europe. About two-thirds of this output, or 30 TWh each, is expected to be produced in the United Kingdom and Norway, and a further 32 TWh in Germany's neighbouring countries Belgium, France and the Netherlands. However, it is assumed that no blue hydrogen will be produced in Germany itself.

Based on the expected production quantities, Germany's blue hydrogen could come primarily from the UK and Norway (approximately 30 TWh each) as well as from Belgium (15 TWh), the Netherlands (9 TWh) and France (8 TWh). Like Germany, however, Belgium and the Netherlands are considered to be a key import region, as their demand clearly exceeds the possible supply. Therefore, Belgium and the Netherlands must be called into question as definite direct suppliers of large quantities of blue hydrogen to Germany. Although the UK is an important potential supplier country, its infrastructure is only indirectly connected to Germany via the Netherlands. The lack of H_2 pipelines and the need to cover domestic demand in both the UK and the Netherlands cast doubt on Germany's ability to source blue hydrogen from the UK until at least 2030.[14]

Of the countries named in the study, this leaves only Norway and France as potentially significant European suppliers of relatively large quantities of blue hydrogen to Germany by 2030. While Norway is currently pursuing a definite strategy to send its exports to Germany, France could also supply Belgium directly. Assuming that both countries reach the anticipated production levels by 2030 and make them exclusively available to Germany, they would jointly supply about 38 TWh of blue hydrogen, thus covering no more than 28% to 42% of Germany's H_2 demand in 2030 as projected by the NWS. Nevertheless, it cannot be assumed that

14 With the UK's production levels expected to stagnate at 30 TWh until 2040, this situation can be expected to continue in the longer term.

industrial nations such as Norway and France will export all the blue hydrogen they produce.

However, statements from RWE, which together with other partners is heavily involved in expanding production and infrastructure for Norwegian blue hydrogen, indicate that the quantities of H_2 likely to be exported from Norway could initially be well below the figures stated in (EHB & Guidehouse, 2022). According to (RWE, 2023a), production capacity of 2 GW (reformer capacity) is currently planned by 2030 as part of H2morrow,[15] and this could produce a maximum of 17.5 TWh of blue hydrogen in base-load operation and make it available for export. The potential quantity of blue H_2 able to be supplied from France and Norway by 2030 thereby decreases to an estimated 25.5 TWh, equivalent to 19% to 28% of Germany's expected total H_2 demand. This amount is thus comparable with planned domestic production of green hydrogen.

The figures for potential production by 2030, however, reveal little about the speed of the blue H_2 ramp-up compared with green hydrogen. According to (Launert, 2021), the entire supply chain for blue hydrogen from Norway is not expected to be in place before 2027. Of course, this also depends on the timely completion of the planned new H_2 pipeline from Norway to Germany. (GTAI, 2022) reports that, if the feasibility study prepared and due for publication by the Norwegian pipeline operator Gassco and the German Energy Agency (dena) "provides a good basis for investment, [then] hydrogen could start flowing as early as 2030". While the planned pipeline's 4 Mt annual capacity (equivalent to 133 TWh) will be large enough to import significant amounts of H_2 from Norway,[16] imports cannot actually begin until it is completed. It is a similar picture for potential imports or transits from Belgium, which is planning to accelerate the connection of its H_2 network to Germany, France and the Netherlands by 2028 (vanderstraeten.belgium.be, 2022, pp. 7, 39).

General assessments of the studies and the speed

Compared with the two studies cited above, the amount of blue hydrogen expected by 2030 in the German Energy Agency's pilot study (dena, 2021a) is relatively modest (5 TWh) and would make only a small additional contribution towards covering demand until that point. This seems reasonable given the assumption that it is only a transitional solution. What is interesting in this scenario is that the available quantity then continues to increase up to 32 TWh by 2035, although blue hydrogen no longer plays a role in the transformation after that. The other two studies factor in the use of blue hydrogen in line with their motivations, although they do not specify quantities. In one case, it is used only until 2035 (and not at all after that) (Agora Energiewende, 2021); but in the other, usage extends as far as 2050 (Agora Energiewende & Agora Industrie, 2022).

[15] By 2038, 10 GW of reformer capacity with CCS are planned, which should then be able to generate and supply about 87.5 TWh of blue hydrogen.

[16] "Construction of such a pipeline is currently being investigated by Gassco, Equinor and third parties. The intention is that, by the year 2038, up to 10 gigawatts of blue hydrogen will be produced in Norway and transported via a pipeline to Germany." (RWE, 2023b)

In total, three of the five studies that specifically consider blue hydrogen in addition to green hydrogen do not envisage a long-term future for blue hydrogen in Germany (see Table 6-1).

Aside from the construction of production plants, which, for economic and political reasons, are mostly expected to be built outside Germany and in the vicinity of CO_2 storage sites,[17] the speed of the blue H_2 ramp-up is largely determined by the availability of H_2 pipelines. According to the latest plans described above, it is doubtful that these pipelines will be operational before 2030. As a result, blue hydrogen is not likely to be available in Germany any sooner than green hydrogen. However, if the current production plans are implemented on time, blue hydrogen could foreseeably be available by 2030 in roughly the same quantities as domestic green hydrogen and thus play a supporting role for Germany.

Table 6-4 presents examples of additional factors that either favour or oppose a rapid ramp-up of blue hydrogen.

Table 6-2: Favourable and unfavourable factors affecting the speed of blue hydrogen

Favourable	Unfavourable
+ Moderate specific investment requirements for new plants + A few large-scale plants could already supply significant quantities + Addition of CCS to existing SMR plants is possible in principle + Proactive potential supplier countries, such as Norway and Saudi Arabia, plus stakeholders like Equinor and RWE	– Worldwide, only very few plants for CCS or blue hydrogen are in operation (a total of four, only one of which uses CCS, otherwise in conjunction with enhanced oil recovery) (Longden et al., 2022a, p. 4) – Start of production for current new projects often not planned until after 2025 – CO_2 infrastructure in some cases still lacking or still in development – Lack of acceptance and unfavourable conditions in Germany

Source: Own table

6.2 GHG emissions from blue hydrogen

The GHG emissions from blue hydrogen depend primarily on the achievable carbon capture rates (CR) and the level of unavoidable upstream emissions (especially methane losses) resulting from the extraction, processing and transport of natural gas. The first factor demands a technological solution, while the second factor is determined by the origin of the natural gas and can therefore be influenced only to a limited extent by Germany through its choice of supplier countries[18] and their gas deposits.

[17] This is based on the assumptions that natural gas for blue H_2 production can be obtained at much lower cost in the supplier countries under consideration, such as Norway, that the production plants can be built closer to the storage sites and, last but not least, that the political and societal conditions for CCS in Germany are unfavourable.

[18] Technical improvements in extraction and transport in the supplier countries themselves could also help to minimise methane losses.

Figure 6-1 shows an overview of different levels of GHG emissions that can be achieved for blue hydrogen depending on plant technology and upstream emissions versus figures for natural gas, grey hydrogen and green hydrogen (electrolysis using renewable electricity). The blue dots show the GHG emissions for natural gas and grey and blue hydrogen that result from using Norwegian natural gas, for which the upstream emissions of approximately 9 g CO_2e/kWh are especially low. Based on this information, existing blue H_2 production plants with capture rates of about 56% could help reduce emissions from grey hydrogen by around 51%. However, their direct emissions alone (120 g CO_2/kWh) would still exceed the CertifHy benchmark[2] of around 104 g CO_2/kWh, so this blue hydrogen would not qualify as low carbon.[19]

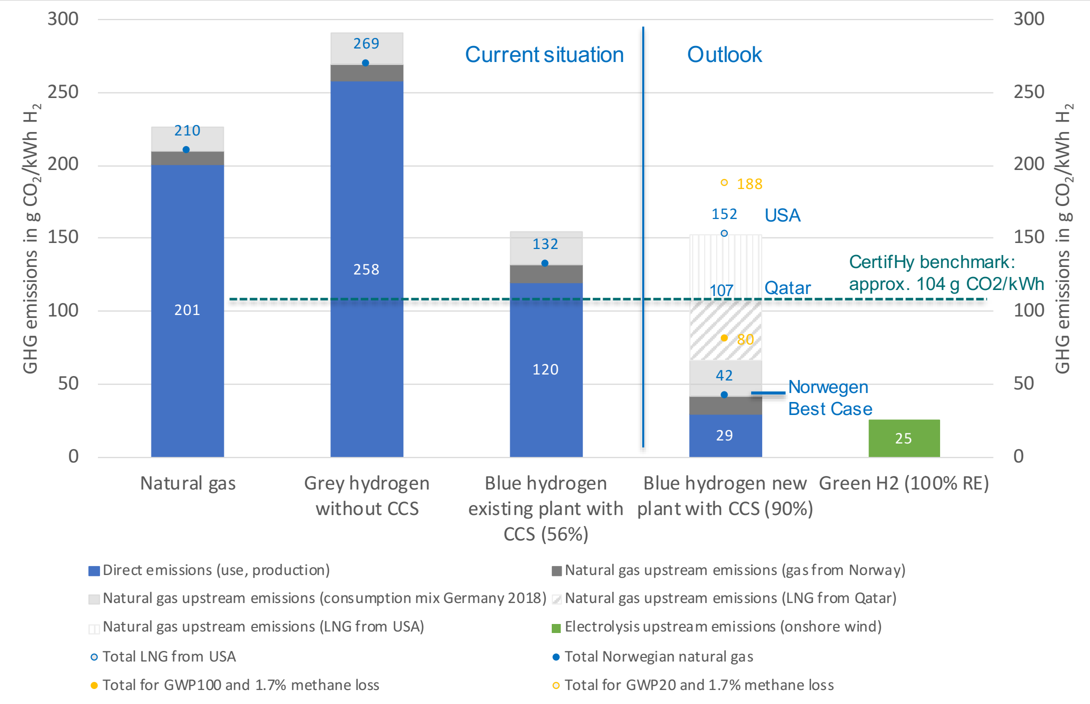


Figure 6-1: GHG emission ranges for blue hydrogen based on different technologies, capture rates, gas origin and GWP factors.

Source: Own illustration and calculations per (Howarth & Jacobson, 2021a; Longden et al., 2022b; UBA, 2021b; Zukunft Gas, 2021a) and (UBA, 2021a, p. 53f)

To reduce these GHG emissions to well below 50 g CO_2/kWh, and thus close to those of green hydrogen at 25 g CO_2/kWh, capture rates of at least 90% would have to be reached. Such high capture rates have not yet been realised in large-scale commercial CCS plants;[20] in fact, they have only been achieved in Japan's Tomakomai CCS Demonstration Project (with CR up to 98%) (Longden et al., 2022a, p. 5). The capture rate up to which the technology can be scaled up or further developed in practice depends not only on technical matters but also on the additional costs or

[19] According to our own calculations, the capture rate would have to be increased to at least 66% just to narrowly meet the benchmark. However, given the remaining GHG emissions, increasing requirements and carbon prices, this additional effort would only be worthwhile in the case of very high capture rates.

[20] According to (BMBF, 2022), "up to 90 per cent of the CO_2 can be stored."

resulting CO_2 abatement costs. Therefore, it cannot be completely ruled out that new plants will also be built with capture rates ≤ 90% for financial reasons.

However, the GHG emissions even from new plants with CR ≥ 90% can far exceed those associated with green hydrogen if the upstream emissions are significantly higher than they are in Norway.[21] Until deliveries were suspended as a result of the Russian war of aggression against Ukraine, this was most notably the case for Russian natural gas, with emissions of approximately 38 g CO_2/kWh (UBA, 2021b, p. 36ff). The same will apply, in particular, to LNG imports from the USA and the Arab states. Here, the upstream emissions estimated in (Zukunft Gas, 2021b) of 54 g CO_2/kWh for LNG from Qatar and 85 g CO_2/kWh for LNG from the USA and unconventional sources are around six to a good nine times higher than for natural gas from Norway. Since natural gas imports from Norway are not sufficient to satisfy the current and medium-term demand for natural gas in Germany, these LNG imports should be used as marginal sources of supply for blue H_2 production in Germany, or supplied directly as blue hydrogen from these countries. In this case, the GHG emissions rise to 107 g CO_2/kWh (Qatar) and 152 g CO_2/kWh (USA) and are thus not only above the CertifHy benchmark but also much higher than those associated with green hydrogen due to the origin of the gas.

Another factor that has a significant impact on the GHG emissions of natural gas, and in turn blue hydrogen, is the time horizon used for methane's global warming potential (GWP) factor, which according to (Howarth & Jacobson, 2021b), has often been overlooked in previous studies. For a residence time of 100 years (GWP_{100}), as used in official IPCC reporting, this factor is 25 or 28, whereas it is 75 or 86 for a residence time of 20 years.[22] However, due to methane's short residence time in the atmosphere of approximately 12 years, the GWP_{20} factor should also be used for methane losses, so that the contribution that already has an impact in the short term can be taken into account as well (Howarth & Jacobson, 2021b, p. 8f).[23] The resulting differences between the long-term and the short-term GWP factors are certainly noteworthy, as indicated by the small orange dots in Figure 6-1 for methane loss rates of 1.7% (standard global IPPC value). According to these calculations, the long-term GWP factor results in GHG emissions of approximately 80 g CO_2/kWh and the short-term factor a figure of approximately 188 g CO_2/kWh. This is a considerable difference (of over 100 g CO_2/kWh) due solely to an alternative mathematical assessment of the climate impact.

The preceding analysis shows that the GHG emissions for blue hydrogen range widely depending on the strength of the relevant factors. Only blue hydrogen from supplier countries like Norway with low upstream emissions has the potential to make a significant contribution towards GHG reduction, subject to appropriate

[21] In any case, compliance with the CertifHy benchmark is no longer possible at methane losses of 3% or more, even with the best capture technology (Longden et al., 2022a, p. 5).

[22] The lower values are taken from (UBA, 2022) and the upper values from (Howarth & Jacobson, 2021b).

[23] Another argument in favour of using the GWP_{100} factor is that GHG emissions are predominantly calculated on the basis of CO_2 emissions, which continue to have an impact on the climate even after a thousand years, whereas reducing and abating methane emissions plays a particularly important role in achieving GHG emission reductions in the short term.

availability and the use of the best plant technology. Otherwise, blue hydrogen cannot reliably contribute towards climate change mitigation to a sufficient extent.

Finally, Table 6-3 summarises these and other factors that argue for and against using blue hydrogen to reduce GHG emissions.

Table 6-3: Pros and cons of blue hydrogen in terms of GHG emissions

Pros	Cons
+ Significant to appreciable CO_2 reductions possible compared with grey H_2 (via steam reforming) and yellow H_2 (electricity mix) + Large and inexpensive carbon storage sites available in Norway and the Netherlands	– High capture rates (CR ≥ 90%) require new and more cost-intensive plant concepts – Additional natural gas input and associated (upstream) emissions for CCS with high CRs – Upstream emissions continue to be unavoidable – Storage needed for appreciable to considerable volumes of CO_2 (depending on the amount of H_2)

Source: Own table

6.3 Costs of blue hydrogen

Within this study, it has not been possible to carry out the same degree of analysis as previously into the costs of blue hydrogen. Doing so would also seem to be of limited use, as the studies examined do not take account of the price increases, new price risks or shortages of natural gas that have recently ensued from Russia's war against Ukraine. The potential production cost advantages of sustained low gas prices, which are often assumed in the studies when calculating costs, must be viewed in a critical light and re-evaluated against the backdrop of the latest developments and new market risks. The risk of stranded investments in the construction of plants for the production of blue hydrogen has increased.

Table 6-4 presents the key factors that, in the authors' view, argue for and against the cost advantages of blue hydrogen and investing in this technology.

Table 6-4: Pros and cons of blue hydrogen in terms of economic viability

Pros	Cons
+ Gas prices are lower than electricity prices + Carbon prices have risen and are likely to rise further in the long term + Addition of CCS to existing SMR plants is possible + Proactive exporting countries such as Norway and Saudi Arabia	– In the interim, natural gas prices have recently risen very sharply and are likely to be unstable in the long term due to Russia's war against Ukraine – Additional operating costs (+20% to +80%) for high capture rates (~90%)[1] – Special write-downs can be expected due to limited lifetimes (≤ 20 years) – Danger of stranded investments

Source: Own illustration, [1] (Longden et al., 2022a)

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