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Hydrogen production costs

Determinants, status and perspectives

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Summary

This study identifies the various cost determinants of hydrogen production and describes cost corridors for different production routes in the short, medium and long term. The analysis focuses on hydrogen production from electrolysis – both renewable and low-carbon – and from natural gas reforming.

The cost of producing hydrogen depends on a variety of parameters. For electrolytic hydrogen, the decisive parameters are the input costs of electricity, utilisation rates of electrolysers, investment costs, and the conversion efficiency. For hydrogen produced by steam reforming with carbon capture and storage (CCS) (i.e. blue hydrogen), the decisive parameters are the natural gas costs and the CO_2 disposal costs.

In Germany, the cost of producing renewable electrolytic (green) hydrogen currently exceeds 7.50 EUR/kg, whereas the cost of producing hydrogen by steam reforming ranges between 3.50 and 4.50 EUR/kg. While the specific cost developments for these two production methods are uncertain, it is estimated that the cost of producing electrolytic hydrogen could fall substantially over time. Cost estimates suggest that production costs of between 4.50 and 6.00 EUR/kg could be achieved in the medium term, potentially decreasing to between 2.50 and 4.00 EUR/kg in the long term. Substantially lower cost levels could be achieved in countries with better conditions for producing renewable electricity. With a view to imports, the cost advantages of foreign production must outweigh the transport costs. Current trends in the natural gas market indicate a slight downward trend for the cost of producing hydrogen from steam reforming with CCS. Costs are estimated to range between 3.00 and 4.00 EUR/kg in the medium term, potentially falling to between 2.50 and 4.00 EUR/kg in the long term. However, due to the substantial uncertainties surrounding natural gas prices and CO_2 disposal costs, it is not possible to conduct a robust assessment of these production costs. Greater transparency is needed regarding CO_2 disposal costs in particular to enable informed decisions to be made in the blue hydrogen sector.

In the medium to long term, clean hydrogen will only fulfil its role in the transition to climate neutrality if the cost can be reduced to 3.00 EUR/kg or less, thereby enabling its profitable use. Such a cost level is achievable, but cost reduction measures would have to be implemented in technical, economic and regulatory areas. In particular, the requirements for electricity procurement and certification for producing renewable and low-carbon electrolytic hydrogen are important levers for reducing costs, especially in the short and medium term. Relief from ancillary electricity costs (e.g. grid fees, taxes and levies) would also lead to substantial cost reductions. In order to ramp up hydrogen production, a suitable regulatory framework must be established to enable the market-orientated operation of electrolysers; offshore wind and hybrid concepts must be promoted to increase utilisation of electrolysers, learning curve effects supported, and instruments implemented to reduce financing costs internationally.

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1 Aim and structure of this study

The analyses in this study aim to make transparent the cost determinants for producing hydrogen via different production routes in terms of their relevance and over the various time horizons and to classify them. Using comparatively broad sensitivity analyses, cost corridors are calculated and reference values for the impacts of changes in the energy sector environment or the regulatory framework are determined. Finally, conclusions and recommendations are derived for current and upcoming fields of action in policy and regulatory realms.

The first step is to specify the technological routes for producing hydrogen considered in this study that are relevant to the supply of renewable or low-carbon hydrogen (Chapter 2). On this basis, the individual determinants of production costs are categorised systematically (Chapter 2). The cost determinants resulting primarily from the configurations of hydrogen production systems are described for three different time horizons. Firstly, exemplary cases are considered for the cost determinants that depend on the mode of operation and the energy market environment. Since the system's mode of operation largely depends on the regulatory framework, particularly with a view to hydrogen certification, and since this has a significant cost impact, the taxonomy of hydrogen and the relevant legal bases are documented (Chapter 3). Chapter 4 presents an interim analysis of current modelling work to evaluate what cost determinants may arise in the future in the context of certification regulations for electricity market-orientated operation that have been implemented or are under discussion. As cost determinants for hydrogen production depend on the operating mode and the energy sector environment, Chapter 5 presents a large number of sensitivity analyses and categorises their results. In Chapter 6, these results are compared with the cost and price indicators of the most important market data providers. Chapter 7 categorises the cost levels that have been determined and reported for producing renewable or low-carbon hydrogen. Chapter 8 presents the conclusions from the analyses and corresponding recommendations. Finally, the appendix contains a list of references and further explanations of the parameters used in the cost calculations.

2 Determinants, ranges and development perspectives for hydrogen costs

2.1 Technological routes of hydrogen production

When discussing hydrogen and its derivatives, the costs and implications for climate policy can and should be evaluated. Firstly, the technological routes and the associated investment and operating costs are important factors.

- In real world terms, producing hydrogen via water electrolysis is particularly relevant[1]; various technological approaches are being pursued in this respect, e.g. alkaline electrolysis, proton exchange membrane (PEM) electrolysis, solid-state/solid oxide electrolysis.

- Hydrogen is also produced by reforming fossil hydrocarbons, primarily from natural gas. The standard is conventional steam methane reforming (SMR), while autothermal reforming (ATR) is being pursued as a new technology. Both production technologies are initially associated with considerable carbon emissions. However, carbon capture facilities can be added to these technologies, enabling the captured carbon to be transported and stored permanently in geological formations. Whether the hydrogen produced with CCS qualifies as low-carbon depends on the respective regulatory requirements (Chapter 3).

- In addition to these two technological routes, there are many other options, such as producing hydrogen via pyrolysis. However, these will not play a significant role in the foreseeable future and a well-founded cost analysis cannot be carried out (yet).

As the cost determinants for the various production routes substantially differ in part, the following analyses distinguish between configuration- and operation-based factors influencing the costs of producing hydrogen. The configuration-based factors primarily result from investment decisions and can thus only be changed within narrow limits after the investment. The operational cost determinants partly result from the energy sector environment (e.g. electricity and gas prices, CO_2 transport and storage costs) and partly from the regulatory framework (e.g. electricity input costs and the annual capacity utilisation of electrolysis systems). Examples of operational cost determinants and the configuration-based factors are considered first and then, in a subsequent step, the cost determinants are analysed in greater depth (Chapter 5).

In view of the dynamic developments that sometimes occur (e.g. in investment costs) and the changing framework conditions (e.g. with a view to the decarbonisation of the electricity system or the energy sector environment), analyses are carried out for three exemplary time horizons in this study:

[1] In addition to water electrolysis, hydrogen can be produced as a by-product of chlor-alkali electrolysis. However, since this process is primarily used to produce chlorine and caustic soda, it is not considered further here. In the following, the term 'electrolysis' always refers to water electrolysis.

- The short-term time horizon refers to the situation that can be expected over the period from 2025 to 2030, as viewed from today's perspective.
- The medium-term time horizon describes developments that could occur by the mid-2030s from today's perspective. As a pragmatic approximation, it presents the lower range of possible short-term developments and the upper range of possible long-term developments.
- The long-term time horizon is a situation that can be expected in the period from 2040 to 2050, as viewed from today's perspective.

The cost of producing hydrogen depends on a relatively large number of framework conditions and basic assumptions. While some of these factors have a huge impact on the results, the impact of others is of either medium or minor importance. To keep the sensitivity analyses and classifications clear in terms of the different time horizons, this study distinguishes between three categories of relevance:

- Decisive: The parameters categorised as decisive are ones that substantially influence the levelised costs of hydrogen. They determine the order of magnitude of hydrogen production costs. For configurations and operating modes typical of renewable or low-carbon hydrogen production, and considering different time horizons, these decisive factors account for more than one-fifth of the costs in most cases and when their combined effects are considered (e.g. investment and financing costs).
- Important: The parameters categorised as important also have a significant impact on the total costs but influence them to a (much) lesser extent. They determine around 10 and 20 % of the total costs.
- Subordinate: The parameters categorised as subordinate only have a minor impact on the levelised costs of hydrogen. These determinants have cost shares of (significantly) less than 10 % in most cases.

The various cost determinants are partly mutually dependent; for example, miscellaneous operating costs are expressed as a percentage of investment costs. In such cases, categorisation is determined by the cost determinants that have the greater impact.

It should be noted that these classifications relate to cost structures for one of the time horizons in question and do not immediately allow any direct conclusions to be drawn about corresponding potentials of cost reductions over time.

At this stage, cost analyses do not yet consider the (wide) range of operating conditions resulting from regulatory requirements or those heavily dependent on the energy sector environment (see Chapter 3, 4 and 5). Rather, they consider a representative spectrum of operating conditions.

2.2 Electrolytic hydrogen

The following cost determinants for producing hydrogen via water electrolysis are considered and classified according to the corresponding preliminary analyses (see also Table 2 and Chapter 5):

1. Decisive cost determinants:

    a. Input costs of electricity: These are the costs incurred for supplying power to an electrolyser for hydrogen production. As well as the actual generation costs, they may include other elements such as structuring costs (e.g. storage, portfolio formation), grid fees, taxes, surcharges and levies.[2] The total input costs of electricity depend largely on how the systems are operated and on the market environment.

    b. Capacity utilisation of electrolyser: This refers to the ratio of the quantity of hydrogen (or other products) actually produced to the maximum production that is theoretically possible under optimum conditions. It is typically expressed as the electrolyser's number of operating hours in the rated power operation over the course of a year.

    c. Investment costs of the electrolyser: These include all costs incurred in constructing the electrolyser at the hydrogen production site, up to the point at which it becomes operational. As well as the actual cost of the electrolyser itself, these costs include those for planning, delivery and construction. The proportion of overall costs contributed by investment costs depends on the learning curve effects (i.e. investment cost reductions) of the hydrogen ramp-up, which are largely determined by the mode of operation (above all the capacity utilisation) of the electrolyser system.

    d. Efficiency of the electrolyser: This refers to the ratio of the energy input in the form of electricity to the resulting energy output in the form of hydrogen produced by electrolysis. The system's efficiency has a relatively strong influence on investment costs.

2. Important cost determinants:

    a. Financing costs: These are the costs incurred to finance investments through equity and borrowed capital, such as interest and returns. These costs are usually stated as the weighted average cost of capital (WACC).[3] Financing costs naturally rise and fall in line with investment costs.

    b. Stack replacement: The stack is the core component of an electrolyser, where the electrolysis process takes place. As the stack has a shorter

2 In Germany, electrolysers are exempt from electricity tax (see Section 9a No. 1 of the German Federal Electricity Tax Act). Electrolysis plants commissioned by 2026 will be exempt from grid utilisation fees for 20 years (see Section 118 (6) of the German Federal Energy Industry Act). These regulations are not mandatory in other countries.

3 This indicator shows the average cost of capital, calculated by weighting the various financing components (equity and debt) according to their respective shares.

service life than most other components of the electrolysis system, replacing it is an important part of maintenance and servicing.

c. Other operating costs: These include all costs incurred in operating the systems, except those for water procurement. These include maintenance, personnel, insurance and administration costs. They are usually stated as a percentage of the investment costs and therefore fluctuate accordingly.

3. Subordinate cost determinants:

   a. Water: These are the costs incurred for supplying water for the electrolysis process. Around 9-15 litres of water are needed for every kilogram of hydrogen produced.

   b. Service life: This refers to the technical service life of the electrolyser, which is typically expressed in terms of operating hours or years.

Table 1 shows the ranges for the various cost determinants and time horizons, which were determined based on literature research, market information, and expert assessments. Initially, examples of the expected values were used as a basis for the electricity input costs and capacity utilisation of the electrolysis systems. See Chapter 5 andTable A-1 in the appendix for the corresponding assumptions and sensitivities, and the specific bases for the other parameters.

Table 1: Costs and their influence for electrolytic hydrogen

	Short-term (high)	**Medium-term** (currently usually in lower range/ long term in upper range)	**Long-term (low)**	**Remarks**
Decisive				
Electricity input costs	80 - 100 EUR_{2023}/MWh	40 - 50 EUR_{2023}/MWh	35 - 50 EUR_{2023}/MWh	Mainly depends on the site, business model, market environment, time horizon, etc.
Capacity utilisation of electrolysis	3,000 – 4,000h	4,000 – 4,500h	4,500 – 6,000h	
Investment costs of electrolyser	1,200 – 1,700 EUR_{2023}/kW	750 - 850 EUR_{2023}/kW	350 - 500 EUR_{2023}/kW	Cost degression expected over time
Efficiency (NCV)	57 - 62 %	65 - 70 %	67 - 75 %	Efficiency increase expected through research and development
Important				
Financing costs / WACC	8 - 10 %	8 %	6 - 8 %	Scaling creates trust in technology
Service life of electrolysis stack	60,000 - 80,000h	80,000 - 90,000h	90,000 – 120,000h	
Costs of replacing electrolysis stack	25 - 35 %			
Other operating costs	2 - 4 % of the investment costs			
Subordinate				
Costs for water	0.02 EUR_{2023}/kg H_2			
Service life	20 - 25 years	25 years	25 - 30 years	Use of improved materials
Levelised costs of hydrogen (NCV)	**5.9 - 11.3 EUR_{2023}/kg H_2**	**2.9 - 4.3 EUR_{2023}/kg H_2**	**1.8 - 3.0 EUR_{2023}/kg H_2**	Overall significant reduction in costs expected

Notes: The costs for hydrogen and the efficiency values for electrolysis refer to the net calorific value (NCV), as is usual in the hydrogen sector.

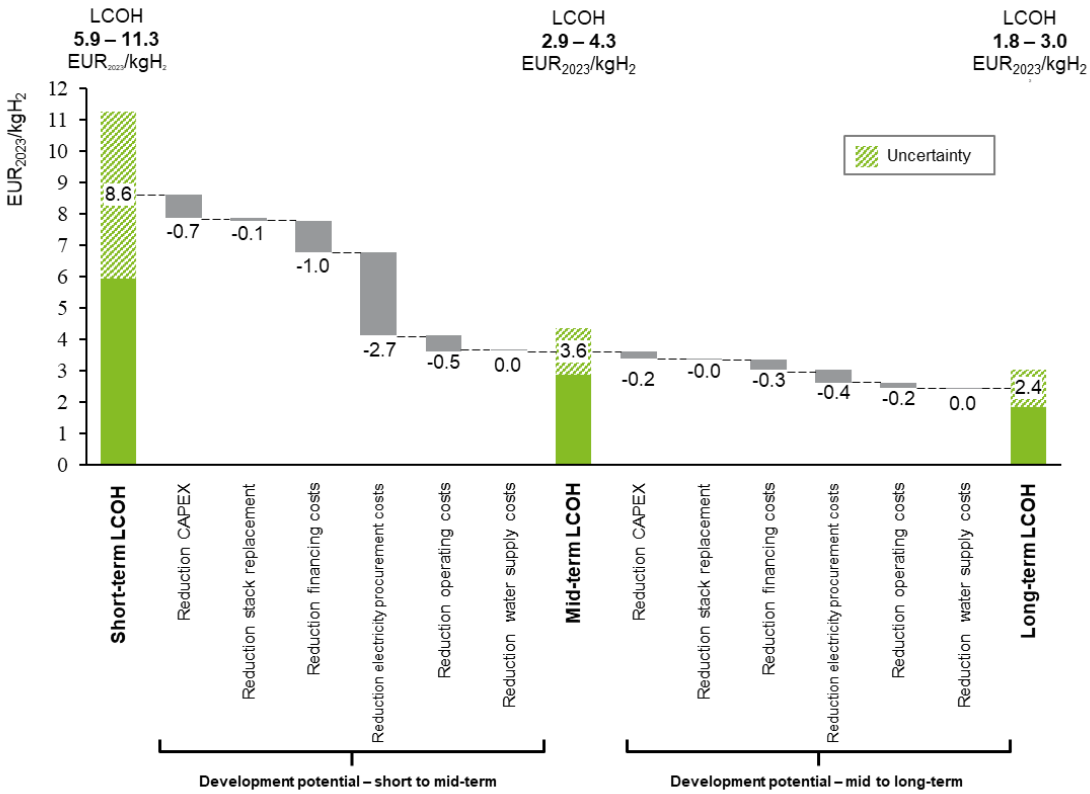
Source: Authors' own compilation and assumptions. For individual references, see Chapter 5 and Table A-1 in the appendix.

Based on the assumptions shown in Table 1, the following developments occur in the generation costs and their determinants over time:

- In the medium term, it is expected that the levelised costs of electrolytic hydrogen will fall by over 50 %.

- The main drivers of this reduction are falling electricity procurement costs, which could result from increased efficiency in renewable technologies (e.g. higher wind turbine hubs) and decreased investment costs due to significant global scaling.
- Any reductions in the investment costs of electrolysis systems, as well as the associated financing costs, also have an important influence on the medium-term reduction in the cost of electrolytic hydrogen.
- Further reductions in the levelised costs of electrolytic hydrogen are to be expected in the medium to long term, albeit less significantly.
- Further reduction potentials in investment and financing costs can be expected.
- In the long term, the levelised costs of electrolytic hydrogen could fall by over 70 %, to below 30 % of today's level.

Figure 1: Expected development of cost elements for electrolytic hydrogen over time



Note: The values shown are the average of the upper and lower end of the cost range.

Source: Authors' own calculations

Figure 1 shows the contributions of the various factors of the levelised costs of hydrogen (LCOH), providing an overview of the medium- and long-term potentials of cost reductions. Exemplary values were used to determine the operational and market-related cost factors. Therefore, the electricity procurement costs have the greatest potential for cost reduction in the medium and long term. The investment costs (CAPEX) and the associated financing costs have the next largest potentials. Increases in stack lifetimes, water costs and other operating costs play a subordinate role.

Table 2: Cost structures for producing electrolytic hydrogen

Cost elements	Short-term (high)	Medium-term (medium)	Long-term (low)
Electricity procurement costs (influenced by efficiency, capacity utilisation and electricity input costs)	43 - 76 %	54 - 74 %	54 - 89 %
Share of system costs (influences investment costs, capacity utilisation, service life and efficiency)	6 - 24 %	4 - 14 %	3 - 11 %
Financing costs (influenced by investment costs, service life and WACC)	8 - 30 %	10 - 20 %	4 - 15 %
Costs for replacing the electrolysis stack (influenced by investment costs, service life of stack, capacity utilisation)	1 - 3 %	1 - 3 %	0 - 2 %
Other operating costs (influenced by investment costs and share of operating costs)	3 - 19 %	4 - 14 %	2 - 11 %
Costs of water supply	close to 0 %	0 - 1 %	0 - 1 %

Source: Authors' own compilation and calculations

However, the factors that determine hydrogen production costs tend to be uniform, but have significantly different effects on the cost structure:

- Electricity procurement costs are not only the main driver of expected cost reductions, but also the main component of levelised costs. Depending on the development of other cost elements, these could account for between 43 % and 89 % of the total costs.
- The financing costs also play an important role. They are influenced by investment costs, the service life of the electrolyser, and the WACC. In the short term, they could account for between 8 % and 30 % of total costs. In the long term, expected improvements in the three parameters in favour of hydrogen production would reduce the proportion of financing costs to between 4 % and 15 % in the long term.
- A similar trend can be expected with a view to the share of investment costs. These could decrease from 6 % to 24 % today to 3 % to 11 % in the long term. This is due to the expected positive developments in investment costs and capacity utilisation as well as increased efficiency and service life.
- The share of other operating costs follows a similar trend. Here too, the shares could decrease from 3 % to 19 % today to 2 % to 11 % in the long term, primarily due to the significant reduction in investment costs of up to 80 %.
- The costs of the stack replacement and of the water supply account for a comparatively small proportion of the total costs.

At the very least, it is possible to make robust predictions about overall development. The substantial continuous increase in renewable electricity generation worldwide will reduce the input costs of the renewable shares of electricity generation, which could lead to a greater utilisation of electrolysers. Combined with the decreasing investment costs due to learning curve effects, this would lead to a gradual reduction in hydrogen production costs. In this context, the uncertainties relate less to the fundamental realisation of these cost reduction effects and more to the time horizons involved.

2.3 Hydrogen production via steam reforming

The following cost determinants for producing hydrogen via the steam reforming of natural gas coupled with CCS are considered and categorised according to the preliminary analyses[4]:

1. Decisive cost determinants:

    a. Input costs of natural gas: These are the costs incurred for supplying natural gas for producing hydrogen by steam reforming. As well as the market prices of natural gas, these costs may include other elements such as structuring costs, grid fees, taxes, levies and charges. These operating costs are largely determined by the energy market environment.

    b. CO_2 transport and storage costs: These include all costs incurred for transporting the CO_2 captured in the CCS process to long-term storage facilities. These costs are typically included in the levelised costs of hydrogen as operating costs and are expressed in Euro per tonne of stored CO_2. Over time, market prices will also emerge for these cost determinants, i.e. they will depend on the environment of the CO_2 storage market.

2. Important cost determinants:

    a. Investment costs: These cover all costs incurred in constructing the production system on site up to its operation. In addition to the actual investment costs, they include planning, delivery and construction costs.

    b. Financing costs / WACC: These are the costs incurred when financing investments through equity and borrowed capital, such as interest and returns. These costs are usually stated as the weighted average cost of capital (WACC). Financing costs naturally rise and fall in line with investment costs.

    c. Natural gas input: This is the quantity of natural gas needed in the steam reforming process to produce a specific quantity of hydrogen. It is usually specified as the input needed per kilogram of hydrogen produced. This value depends largely on the technology used, is not very variable, and is crucial to the direct emissions of the process before capture.

[4] The analysis takes into account steam reforming using SMR technology, which is equipped with a carbon capture system. In addition to SMR technology, ATR technology could also play a role in the future as a new application. However, due to the low level of development of ATR technology and the lack of reliable field data, this analysis is based on established SMR technology. In view of the EU Gas Market Directive requirements, standards for natural gas supplies with low greenhouse gas emissions in the upstream chain (especially with regard to methane emissions) could be met using SMR with high (>80%) capture efficiencies and, in any case, using ATR systems.

d. Direct emissions before carbon capture: These are the CO_2 emissions produced directly by the process of hydrogen production before measures of carbon capture are applied. In addition to CO_2 emissions of the process's energy supply, the quantity is particularly determined by process emissions arising as a by-product of the chemical reactions.

e. Carbon capture rate: This indicates how effectively a CCS plant can capture CO_2 from an exhaust gas stream. This rate is crucial in assessing the efficiency of CCS technologies.

f. Carbon price: This is the price paid for residual emissions that are not sequestered. In the EU, Norway, Iceland and Liechtenstein, the carbon price is determined by the EU's Emissions Trading System (EU ETS).

g. Other operating costs: These encompass all other costs incurred in system operation, including maintenance, personnel, insurance and administration costs. They are usually stated as a percentage of investment costs and depend heavily on them.

3. Subordinate cost determinants:

   a. Service life: This refers to the system's technical service life and is typically expressed in years.

   b. Capacity utilisation: This refers to the system's ability to operate at its maximum potential output (rated power). Maintenance work, in particular, decreases utilisation of the system's capacity. The utilisation of steam reforming plants is usually specified as a percentage of maximum availability and is typically very high and not very variable.

   c. Costs arising from electricity demand: These are all the costs incurred when supplying electricity for hydrogen production. As well as electricity costs, they are determined by the electricity needed for the process. This value is largely dependent on the technical design and not very variable.

Table 3 shows the ranges for the different cost determinants and time horizons, as determined based on literature research, market information, and expert assessments. Initially, examples of expected values were used for the input costs of natural gas and the costs of the transportation and long-term storage of CO_2. See Chapter 5 and Table A-2 in the appendix for the corresponding assumptions and sensitivities, and the specific bases of the other parameters.

Table 3: Costs of hydrogen produced by steam reforming with CCS and their influence

	Short-term	Medium-term	Long-term	Remarks
Decisive				
Natural gas input costs (GCV)	35 - 45 EUR_{2023}/MWh	30 - 35 EUR_{2023}/MWh	15 - 25 EUR_{2023}/MWh	After the energy crisis, a decrease in natural gas costs is expected
CO_2 transport and storage costs	30 - 150 EUR_{2023}/t CO_2			Substantial uncertainties due to lack of experience
Important				
Investment costs SMR & CCS	1,300 - 1,700 EUR_{2023}/kW	1,200 - 1,600 EUR_{2023}/kW	1,100 - 1,500 EUR_{2023}/kW	Low cost degression
Financing costs / WACC	10 - 13 %			
Natural gas utilisation (NCV)	47 MWh/kg H_2	48 MWh/kg H_2	49 MWh/kg H_2	Increase due to rising CO_2 capture rates
Direct emissions before carbon capture	9 - 10 kg CO_2/kg H_2			
Carbon capture rate	80 %	85 %	90 %	Improvement through research and development
Carbon price (CO_2 costs under EU ETS)	70 - 80 EUR_{2023}/t CO_2	130 - 180 EUR_{2023}/t CO_2	200 - 250 EUR_{2023}/t CO_2	Expected increase over time
Subordinate				
Service life	20 - 25 years			
Capacity utilisation	85 - 95 %			Consistently high
Electricity procurement for SMR & CCS	1.4 kWh/kg H_2			
Levelised costs for hydrogen (NCV)	**3.2 - 5.1 EUR_{2023}/kg H_2**	**2.9 - 4.6 EUR_{2023}/kg H_2**	**2.1 - 4.1 EUR_{2023}/kg H_2**	**Slight reduction expected over time**

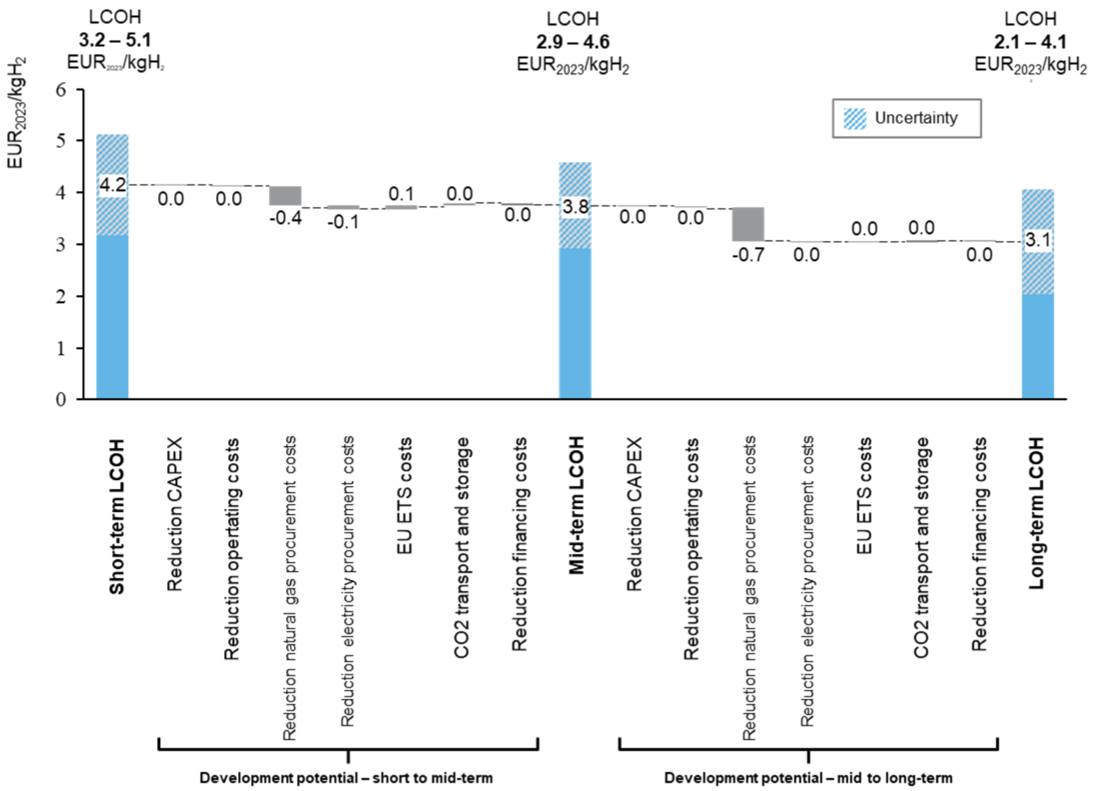
Notes: As is customary in the natural gas market, the prices and costs of natural gas are based on the gross calorific value (GCV). In contrast, the costs of hydrogen refer to the lower calorific value (net calorific value - NCV), as is customary in the hydrogen sector.

Source: Authors' own compilation and assumptions. For the specific references, see Chapter 5 and Table A-2 in the appendix.

With a view to the medium- and long-term cost trends, the following points in particular should be stressed (Figure 2):

- The medium-term reduction potential of the levelised costs of hydrogen is driven by the energy prices, which show a downward trend. The analysis follows the price projections of the International Energy Agency in the 2023 and 2024 editions of the World Energy Outlook. In this context, the price of natural gas has the greatest leverage. Falling electricity costs also offer potential for medium-term reductions in the levelised costs of hydrogen.
- The reduction potential is counteracted by rising costs for emission allowances. This effect depends on CO_2 capture rates and the corresponding residual emissions. In the medium to long term, however, rising carbon prices will be offset by higher carbon capture rates. Consequently, changes in the costs of CO_2 disposal do not have a significant overall impact on the development of levelised costs.
- The main uncertainty regarding the costs of CO_2 disposal persists. The development of these costs remains unclear and cannot be determined with any certainty.
- The long-term reduction potential of the levelised costs of blue hydrogen is between 15 % and 30 %.

Figure 2: Expected development of the costs of producing hydrogen via steam reforming with CCS over time



Note: The values shown are the average of the upper and lower end of the cost range.

Source: Authors' own calculations

Overall, the medium- to long-term development dynamics of blue hydrogen costs thus depend largely on the development of the natural gas price. The costs or prices for the transportation and permanent storage of CO_2 – which are currently difficult to estimate – will substantially influence the level of hydrogen production costs. However, only a substantial rise or fall in costs or prices could be expected to result in a dynamic over time, and this cannot be predicted with any degree of certainty at present.

Accordingly, the expected cost structures will change over time. However, this will be to a much lesser extent for blue hydrogen than for hydrogen produced by electrolysis:

- The main component of hydrogen production costs from steam reforming with CCS is the cost of natural gas procurement. These costs are particularly influenced by the natural gas price. Currently accounting for between 40 % and 64 % of the total costs, these costs have a downward trend as the input costs of natural gas fall (the long-term cost share is 23 % to 53 %).

Table 4: Cost structures of producing hydrogen from steam reforming with CCS

Cost elements	Short-term (high)	Medium-term (medium)	Long-term (low)
Procurement costs of natural gas (influenced by input costs of natural gas and by natural gas input)	40 - 64 %	37 - 59 %	23 - 53 %
Costs for CO_2 transport and storage (influenced by carbon capture rate and costs of CO_2 disposal)	5 - 29 %	6 - 32 %	8 - 43 %
Share of system costs (influenced by investment costs, capacity utilisation and efficiency)	5 - 9 %	6 - 9 %	6 - 12 %
Financing costs (influenced by investment costs, service life and WACC)	8 - 19 %	8 - 19 %	9 - 25 %
Other operating costs (influenced by investment costs and share of operating costs)	2 - 8 %	2 - 8 %	3 - 11 %
Costs for unrecorded CO_2 emissions (influenced by carbon price and CO_2 capture rate)	2 - 5 %	4 - 8 %	5 - 11 %
Electricity input costs (influenced by electricity input and by electricity costs):	4 - 6 %	2 - 4 %	2 - 4 %

Source: Authors' own compilation and calculations

- The costs of CO_2 disposal are the second most important cost factor in hydrogen production from steam reforming with CCS. Depending on the capture rate and the transport and storage costs of CO_2, the current share lies between 5 % and 29 %. In the long term, this cost element will account for a larger proportion of the total cost (8 % to 43 %). This considerable range results from the high level of uncertainty surrounding the realisable costs of transporting and storing CO_2 and prices of large-scale CCS applications.

- The levelised costs are also determined by financing costs, which account for 8 % to 25 % of the total costs. Due to the limited potential for reducing investment costs, financing costs remain constant over time. Return expectations in the oil and gas industry, which are primarily relevant in the production of fossil-based low-carbon hydrogen, are higher than those in the electrolysis industry, as reflected in the differences in WACC.

- Compared to electrolytic hydrogen, system costs for steam reforming with CCS play a smaller role (around 5 % to 12 % of total costs). Due to the comparatively constant influence of investment costs, capacity utilisation and efficiency, the proportion of system costs remains relatively stable.
- Other cost elements, such as electricity procurement costs, other operating costs and the carbon costs incurred for residual emissions, typically account for less than 10 % of the cost of producing low-carbon hydrogen through the steam reforming of natural gas.

Overall, it should be noted that the cost of blue hydrogen can only be estimated with a high degree of uncertainty. This is primarily due to its strong dependence on the unpredictable cost of natural gas procurement, which is influenced by various factors (such as demand, trends in provision and promotion and the geopolitical situation), particularly in the context of the energy transition towards climate neutrality. The uncertainties surrounding the other key cost factor — the cost of transporting and safely storing the captured CO_2 — are more relevant with a view to the levels than the dynamics over time. Given the considerable uncertainties surrounding the main cost determinants, it is not possible to answer the question of whether the costs of blue hydrogen are more likely to rise or fall over time with certainty, even if the combinations analysed in this study indicate a slight downward trend for the constellation of cost determinants. In any case, based on the currently foreseeable developments, the changes over time will be relatively small at best.

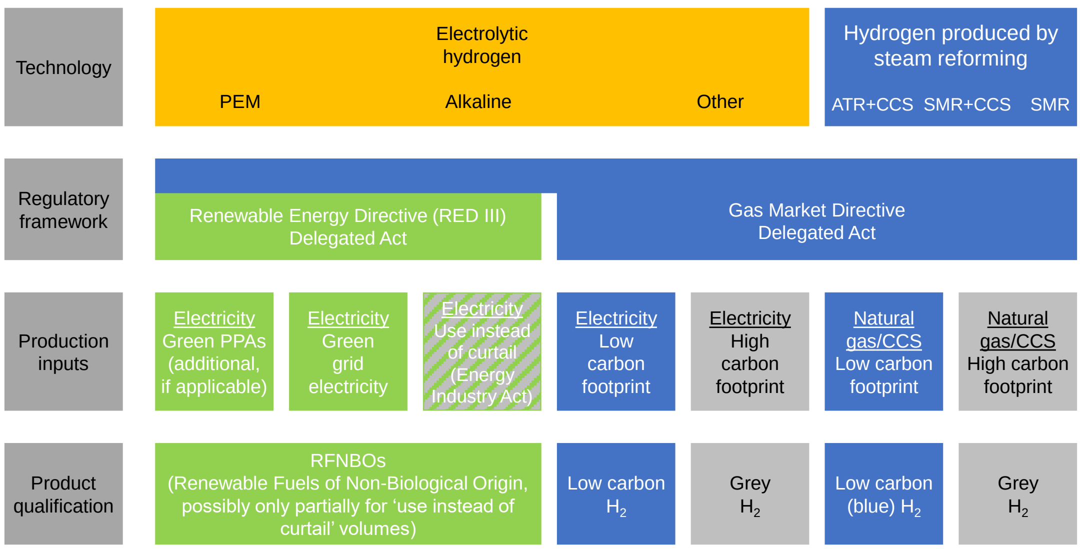
3 The regulatory dimension of cost determinants: taxonomy of hydrogen

In addition to technological routes and associated parameters, the regulatory framework for classifying various hydrogen production options in terms of climate policy provides another dimension for analysing the cost determinants of hydrogen production:

- The overarching regulatory framework is provided by the Directive on common rules for internal markets for renewable gas, natural gas, and hydrogen, which was passed in 2024 and sets out the basic requirements for categorising low-carbon hydrogen (EU 2024). Based on this directive, the European Commission is currently developing a delegated act to implement these requirements in a certification standard.

- The EU's Renewable Energy Directive (RED III) of 2023 (EU 2023a) specifically addresses hydrogen production from renewable energy sources. To implement this directive, the European Commission adopted two delegated regulations: one regulating the use of electricity to produce renewable hydrogen (EC 2023a), and the other regulating emissions accounting for renewable hydrogen and the use of carbon to produce hydrogen derivatives (EC 2023b).

Figure 3: Dimensions of classifying hydrogen



Source: Authors' own presentation

On this basis, the inputs for producing hydrogen and the resulting classification of the hydrogen as either renewable or low-carbon can be categorised as follows (Figure 3):

- the procurement of electricity, via power purchase agreements (PPAs), from renewable energy projects to produce renewable hydrogen;

- the procurement of electricity from the grid, which has a very high share of renewable energy available, to produce renewable hydrogen;

- as a special case, the regulated procurement of electricity from the grid under the ‘use instead of curtail’ rules in Germany (§13k of the Energy Industry Act), which should normally qualify as an input for producing renewable hydrogen;
- the procurement of electricity from the grid with a very low carbon load can also be classified as low-carbon hydrogen, in addition to the renewable shares;
- the production of hydrogen from natural gas can be classified as low-carbon hydrogen if the natural gas is procured with low upstream emissions (especially with regard to methane leakage) and combined with CCS facilities with very high capture rates (70% emission reduction compared to the 94 kg CO_2eq/MJ fossil fuel comparator);
- the remaining variants for using electricity or natural gas to produce hydrogen cannot be classified as renewable or low-carbon and are therefore classified as grey hydrogen.

The above-mentioned legal regulations contain a multitude of specific provisions, particularly regarding the requirements for energy sources (in terms of carbon load and green electricity generation), commissioning dates and sites of the plants, the temporal relationship between electricity and hydrogen generation, and the system design (especially with regard to carbon capture rates). Some of these provisions are subject to transitional arrangements.

4 Excursus: Price levels and carbon load in the German electricity system and their implications for producing renewable and low-carbon hydrogen

Taking into account existing and upcoming certification regulations for renewable and low-carbon hydrogen, questions arise as to the impact on electricity input costs of hydrogen electrolysis and utilisation rates for electrolysers.

Power purchase agreements (PPAs) are relevant to producing renewable hydrogen, except in bidding zones in which the electricity supply is almost entirely green. These contracts reflect the full costs of the respective renewable generation options in the price, provided that the plants are new (as set out in the current certification regulations from 2021). Capacity utilisation will also depend on the generation characteristics of the respective systems. Electricity market-based indicators can, however, also be used to certify renewable hydrogen.

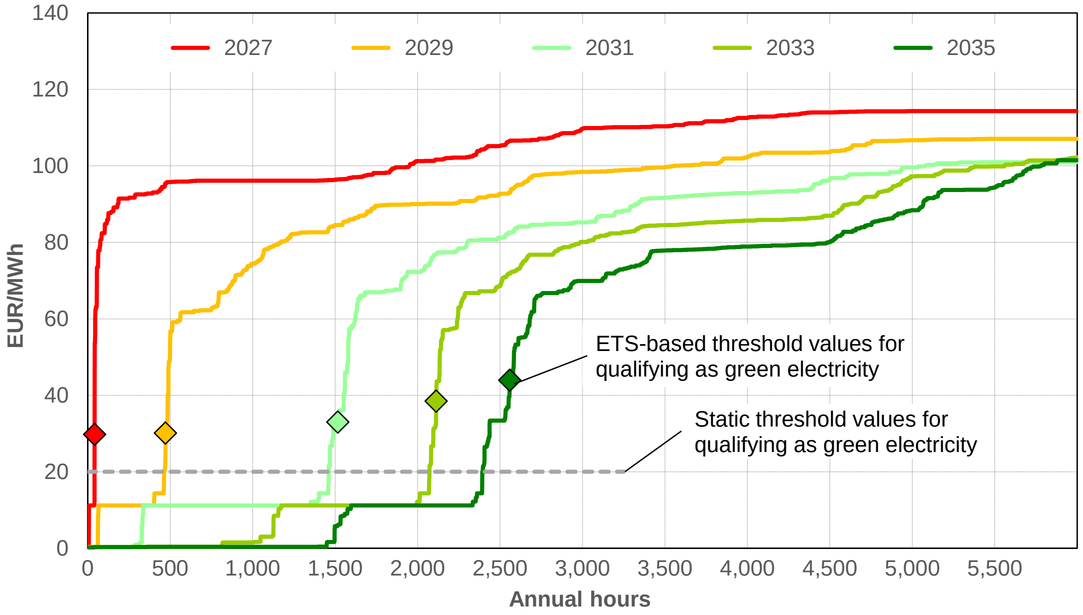
According to Section 7 (3) 37 of the German Federal Immission Control Act (BReg 2024)[5], the additionality restrictions of Sections 7 (1) and (2) for the hourly supply of green electricity for producing hydrogen are lifted if the price on the wholesale market is 20 EUR/MWh or lower (static threshold) or below a dynamic threshold based on the price in the European Union's Emissions Trading System (0.36 times the ETS price).

Based on modelling data for the 2024 Projection Report (UBA 2024) for the period 2027-2035, Figure 4 shows that the dynamic threshold value enables electrolysers to be operated to produce renewable hydrogen over longer periods than the static threshold value. In the medium term, this could result in electricity input costs of 35-45 EUR/MWh and a capacity utilisation of 1,500-2,500 hours per year.

In discussions about the delegated act for certifying low-carbon hydrogen (see Chapter 4), the possibility of using the carbon load of electricity generation as a criterion is also being considered. Using annual average values for a 70 % emission reduction compared to the reference value for fossil fuels (94 kg CO_2eq per MJ or 338 g CO_2/kWh) in Germany would effectively rule out producing low-carbon hydrogen with grid electricity until further notice. However, the situation is substantially different when hourly values are examined (as envisaged in the latest draft version dated 29 April 2025). Figure 5 shows this, based on a specific analysis of the modelling data employed in the 2024 Projection Report.

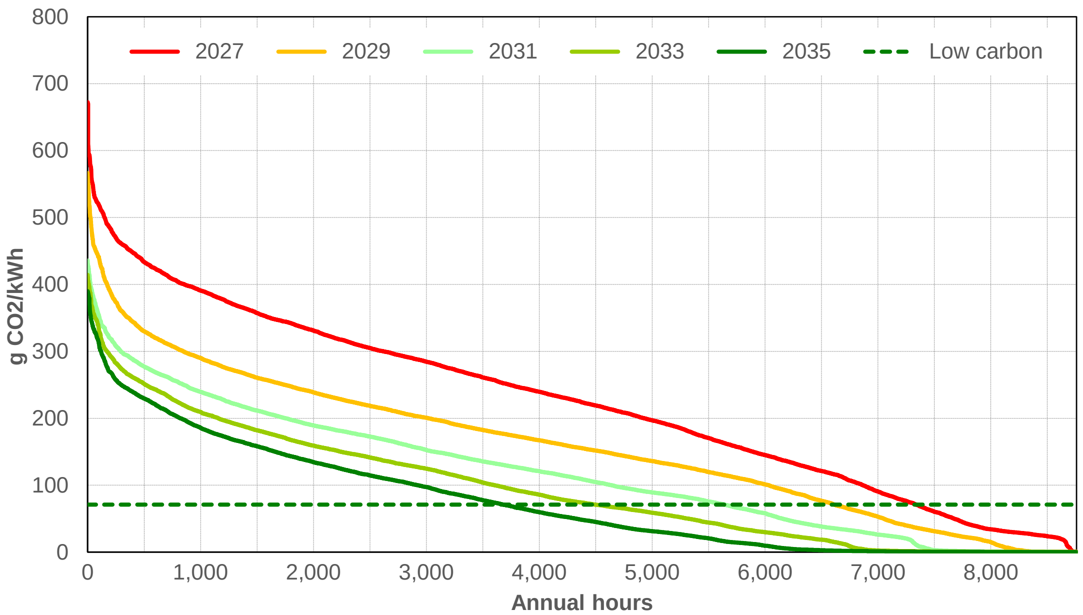
[5] The 37th Immission Control Act incorporated the relevant EU legal requirements (EK 2023a) into German legislation.

Figure 4: **Prices on the German wholesale market based on modelling from the 2024 Projection Report and on price thresholds for qualifying as green electricity according to the 37th Immission Control Act for the period 2027-2035**



Source: Authors' own calculations based on UBA (2024)

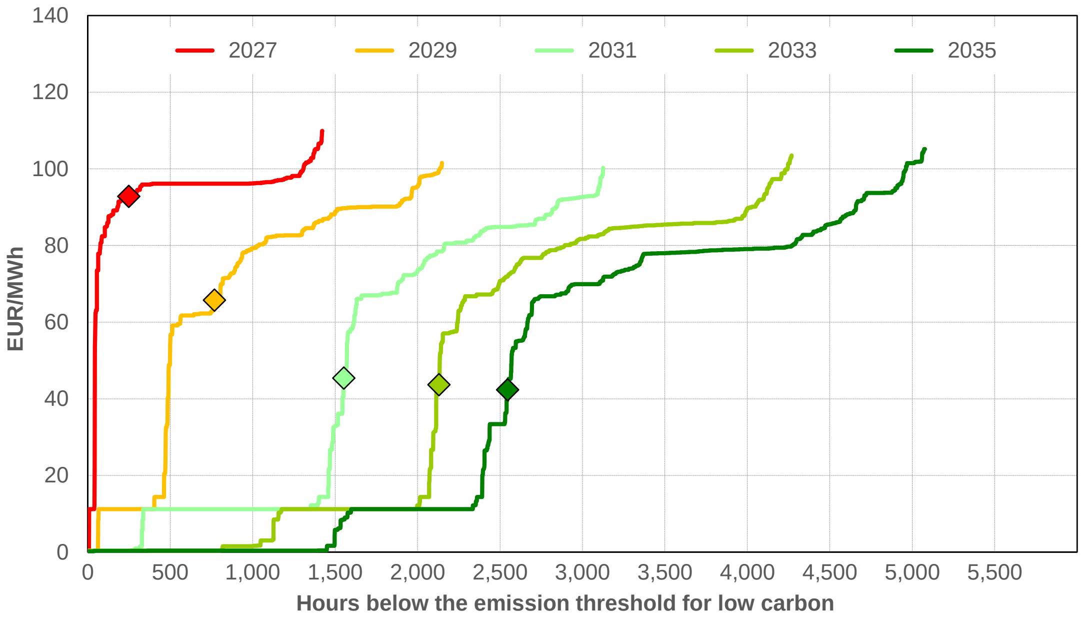
Figure 5: **Hourly carbon load of the electricity mix on the German wholesale market based on the 2024 Projection Report, 2027-2035**



Source: Authors' own calculations based on UBA (2024)

The hourly carbon load of electricity generation will decrease significantly in the years ahead. Consequently, the above-mentioned reduction target will be substantially exceeded in increasingly long periods of time. Based on these models, electrolysis systems for producing low-carbon hydrogen with grid electricity could operate for fewer than 1,500 hours per year in 2027 – a figure that falls below the threshold for the carbon load of the electricity system. In subsequent years, these operating periods will increase, reaching over 5,000 hours by 2035. After 2030, average wholesale prices of approximately 40-45 EUR/MWh are estimated for these periods (Figure 6).

Figure 6: Prices on Germany's wholesale market based on modelling from the 2024 Projection Report for hours below the emission threshold between 2027 and 2035



Source: Authors' own calculations based on UBA (2024)

The operating times of electrolysers for producing low-carbon hydrogen, as determined by the hourly carbon load of Germany's electricity system, are significantly longer than the periods defined by the certification rules for renewable hydrogen as set out in the 37th Immission Control Act and based on hourly wholesale prices. The current drafts of the delegated act (as of 29 April 2025) generally provide for an hourly evaluation of the average or marginal carbon load of the electricity system as an option, which is sensible given the above-mentioned calculations. However, a more detailed analysis of the differences between the average annual and hourly average or marginal carbon loads of electricity generation is still required (the hourly options being the decisive evaluation criteria in the draft).

Overall, modelling of the electricity market for hydrogen production that can be certified as low-carbon or renewable shows that, from 2028 onwards, the envisaged rules to closely link certification options to additionality and PPAs for electricity generation, as well as the close temporal correlation between green electricity and hydrogen production from 2030 onwards, are relevant for a transitional period of substantially less than 10 years at most. In order to finance the ramp-up of hydrogen production in a pragmatic way, these can (and should) certainly be called into question. However, it should also be noted that these processes involved in decarbonising the electricity system in the context of Europe's rapid transition to climate neutrality cannot simply be transferred elsewhere, particularly outside Europe.

However, it should be noted that, in addition to wholesale prices, costs for structuring (e.g. via battery storage), grid utilisation fees, taxes, levies and charges must also be considered when calculating the costs of electricity input.

5 Analyses of the ranges of costs and reference values and their influence on cost determinants

5.1 Introduction

As the analyses in previous chapters have shown, the costs of hydrogen depend decisively on a comparatively small number of parameters. Given the considerable uncertainties and substantial differences in terms of, for example, the sites, it makes little sense to carry out cost analyses based on averages or only a small range of values, or to draw conclusions about the design of the regulatory framework from such analyses.

Against this background, sensitivity analyses are presented below that vary the two decisive cost determinants with a view to the three time horizons considered (current, medium and long term). The ranges analysed are possible for production sites in Germany, Europe and other regions of the world. These sensitivity analyses are presented in the form of heat maps. Reference values are also identified for the decisive cost determinants, based on which the ranges of hydrogen production costs can be narrowed down. Finally, in the context of the sensitivity analyses, reference values are also identified that can be used for a quick (and highly simplified) assessment of the cost impacts of changes to the regulatory framework.

It should be noted that these analyses only consider the production costs of hydrogen. Costs relating to transport, distribution, and provision of delivery volumes demanded by consumers are not included.

5.2 Electrolytic hydrogen

The most important cost factors for hydrogen production from water electrolysis are electricity input costs and the utilisation of electrolysis capacity.

The first relevant factors for electricity input costs are electricity generation and wholesale electricity costs:

- Under the current regulatory framework for certifying renewable hydrogen, electricity can only be purchased from the grid for bidding zones with an almost entirely green electricity supply. In all other cases, PPAs must be made, and from 2028 they must be with new power plants. PPAs must cover the full costs of renewable electricity generation.

- Current PPA market indicators (e.g. HexaQuote, Level10, Enervis) and other cost estimates show current cost levels in Germany of around 40-90 EUR/MWh for new projects, with the former value being relevant for solar power and the latter for wind power (Fraunhofer ISE 2024; Lazard 2024).

- PPAs of up to 30 EUR/MWh for solar power have been reported in Spain in the past (LevelTen Energy 2023). PPAs currently stand at around 45 EUR/MWh. Similar values are also estimated for generation sites in the Middle East.

- Based on the electricity market data, the requirements for qualifying as renewable hydrogen (see Chapter 3) will lead to electricity input costs (excluding grid usage fees and structuring) of 35-45 EUR/MWh in the period after 2030, according to current modelling. The corresponding periods of utilisation are between 1,500 and 2,500 hours per year (see Chapter 4).

- For low-carbon hydrogen, modelling shown in Chapter 4 would result in an electrolysis utilisation rate of between 3,000 and 5,000 hours per year after 2030, provided that the carbon load of the German electricity system were billed hourly. During these periods, electricity could be purchased at an average price of around 40-45 EUR/MWh.
- A special situation exists in the context of 'use-instead-of-curtail' mechanisms (Section 13k of the German Energy Industry Act). In this context, price ranges of 30-40 EUR/MWh are estimated; the current price is 40 EUR/MWh (Frontier Economics 2024; 50Hertz; Amprion; TenneT; TransnetBW 2025).

In addition to the wholesale prices, however, other costs must also be taken into account when categorising electricity input costs:

- The grid utilisation fees for electrolysers are particularly important in this context. Without the current blanket exemption from these fees (which applies until 2029 under Section 118(6) of the Energy Industry Act), a surcharge of up to 30 EUR/MWh would have to be added to the wholesale prices.
- The above figures for electricity generation costs are usually pay-as-produced values, which must be structured accordingly (e.g. implementation of portfolios for renewable electricity generation plants and incorporation of storage) to create capacity that can be used by consumers. Based on costs for large PV battery storage systems, structuring costs can be estimated at between 20 EUR/kWh and 40 EUR/kWh (Fraunhofer ISE, 2024). The cost components incurred here vary greatly and are largely project-specific. However, it should be noted that cost and price surcharges for structuring can generally be used to realise capacity that enable substantially higher utilisation of electrolysis systems, and that the net effects of the two opposing parameters must therefore always be considered when discussing the cost impacts.

Figure 7 shows the levelised costs of hydrogen expected in the current period and in the medium and long term, as a function of the two cost determinants of electricity input costs and utilisation of electrolysis capacity, as well as the values of the other parameters shown in Chapter 2.2.[6] The expected values for electrolytic production of renewable or low-carbon hydrogen in Germany (solid lines) and regions outside north-western Europe under favourable production conditions (dashed lines) are provided here as examples. It should be explicitly pointed out that these are example costs based on the currently conceivable framework conditions and that these do not exclude other scenarios.

[6] Average values were used for the calculations, for which the ranges are provided in Section 2.2. for these technological and economic parameters.

Figure 7: Levelised costs of hydrogen depending on electricity input costs and utilisation of electrolyser capacity

a) Short-term situation

Capacity utilisation of electrolyser - annual operating hours [h/a]

Electricity input costs [EUR2023/MWh]	500	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000	5,500	6,000	6,500	7,000	7,500
0	21.8	10.9	7.3	5.5	4.4	3.6	3.3	2.9	2.6	2.4	2.2	2.0	1.9	1.8	1.7
10	22.3	11.4	7.8	6.0	4.9	4.2	3.8	3.4	3.1	2.9	2.7	2.5	2.5	2.3	2.3
20	22.9	12.0	8.4	6.6	5.5	4.7	4.4	4.0	3.7	3.4	3.2	3.1	3.0	2.9	2.8
30	23.4	12.5	8.9	7.1	6.0	5.3	4.9	4.5	4.2	4.0	3.8	3.6	3.6	3.4	3.3
40	24.0	13.1	9.5	7.7	6.6	5.8	5.5	5.1	4.8	4.5	4.3	4.2	4.1	4.0	3.9
50	24.5	13.6	10.0	8.2	7.1	6.4	6.0	5.6	5.3	5.1	4.9	4.7	4.6	4.5	4.4
60	25.1	14.2	10.6	8.7	7.7	6.9	6.5	6.2	5.9	5.6	5.4	5.3	5.2	5.1	5.0
70	25.6	14.7	11.1	9.3	8.2	7.5	7.1	6.7	6.4	6.2	6.0	5.8	5.7	5.6	5.5
80	26.2	15.3	11.7	9.8	8.8	8.0	7.6	7.3	7.0	6.7	6.5	6.4	6.3	6.2	6.1
90	26.7	15.8	12.2	10.4	9.3	8.6	8.2	7.8	7.5	7.3	7.1	6.9	6.8	6.7	6.6
100	27.3	16.4	12.8	10.9	9.9	9.1	8.7	8.4	8.1	7.8	7.6	7.5	7.4	7.3	7.2

Cell values: hydrogen costs [EUR/kg H_2]

b) Medium-term situation

Capacity utilisation of electrolyser - annual operating hours [h/a]

Electricity input costs [EUR2023/MWh]	500	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000	5,500	6,000	6,500	7,000	7,500
0	10.2	5.1	3.4	2.6	2.0	1.7	1.5	1.3	1.2	1.1	1.0	0.9	0.9	0.8	0.8
10	10.7	5.6	3.9	3.1	2.6	2.2	2.0	1.9	1.7	1.6	1.5	1.4	1.4	1.3	1.3
20	11.2	6.1	4.4	3.6	3.1	2.7	2.5	2.4	2.2	2.1	2.0	1.9	1.9	1.9	1.8
30	11.7	6.6	4.9	4.1	3.6	3.2	3.0	2.9	2.7	2.6	2.5	2.5	2.4	2.4	2.3
40	12.2	7.1	5.4	4.6	4.1	3.7	3.6	3.4	3.2	3.1	3.0	3.0	2.9	2.9	2.8
50	12.7	7.6	5.9	5.1	4.6	4.3	4.1	3.9	3.8	3.6	3.6	3.5	3.4	3.4	3.3
60	13.2	8.1	6.5	5.6	5.1	4.8	4.6	4.4	4.3	4.2	4.1	4.0	3.9	3.9	3.8
70	13.7	8.7	7.0	6.1	5.6	5.3	5.1	4.9	4.8	4.7	4.6	4.5	4.4	4.4	4.4
80	14.2	9.2	7.5	6.6	6.1	5.8	5.6	5.4	5.3	5.2	5.1	5.0	4.9	4.9	4.9
90	14.7	9.7	8.0	7.1	6.6	6.3	6.1	5.9	5.8	5.7	5.6	5.5	5.4	5.4	5.4
100	15.2	10.2	8.5	7.6	7.1	6.8	6.6	6.4	6.3	6.2	6.1	6.0	6.0	5.9	5.9

Cell values: hydrogen costs [EUR/kg H_2]

c) Long-term situation

Capacity utilisation of electrolyser - annual operating hours [h/a]

Electricity input costs [EUR2023/MWh]	500	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000	5,500	6,000	6,500	7,000	7,500
0	4.6	2.3	1.5	1.2	0.9	0.8	0.7	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.4
10	5.1	2.8	2.0	1.6	1.4	1.3	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.8	0.8
20	5.5	3.3	2.5	2.1	1.9	1.7	1.6	1.6	1.5	1.4	1.4	1.4	1.3	1.3	1.3
30	6.0	3.7	3.0	2.6	2.3	2.2	2.1	2.0	2.0	1.9	1.9	1.8	1.8	1.8	1.8
40	6.5	4.2	3.4	3.0	2.8	2.7	2.6	2.5	2.4	2.4	2.3	2.3	2.3	2.3	2.2
50	7.0	4.7	3.9	3.5	3.3	3.1	3.0	3.0	2.9	2.9	2.8	2.8	2.8	2.7	2.7
60	7.4	5.1	4.4	4.0	3.8	3.6	3.5	3.4	3.4	3.3	3.3	3.3	3.2	3.2	3.2
70	7.9	5.6	4.8	4.5	4.2	4.1	4.0	3.9	3.8	3.8	3.8	3.7	3.7	3.7	3.6
80	8.4	6.1	5.3	4.9	4.7	4.5	4.4	4.4	4.3	4.3	4.2	4.2	4.2	4.1	4.1
90	8.8	6.5	5.8	5.4	5.2	5.0	4.9	4.8	4.8	4.7	4.7	4.7	4.6	4.6	4.6
100	9.3	7.0	6.3	5.9	5.6	5.5	5.4	5.3	5.3	5.2	5.2	5.1	5.1	5.1	5.1

Cell values: hydrogen costs [EUR/kg H_2]

Notes: The boxes with solid lines show the expected values for Germany, which are provided as examples. The boxes with dashed lines show the range for favourable locations internationally.

Source: Authors' own calculations

The constellations of parameters also serve to illustrate fundamental correlations. For domestic production sites, higher utilisation rates of electrolysers typically correspond to higher electricity input costs. Due to the wide range of production conditions internationally, there is a much greater variety of parameter combinations. Overall, it can be expected that the correlation between electricity input costs and the capacity utilisation of electrolysis systems will be much lower.

The following conclusions can be drawn from the sensitivity analyses and the assumptions used as an example:

- For domestic generation projects, costs of 7.5 to 10 EUR/kg H_2 could currently arise under the (example) assumptions used. For projects in regions with more favourable production conditions, the corresponding range is between approx. 3.5 and 8.5 EUR/kg H_2.
- In the medium term, the expected parameter configurations for domestic generation result in cost ranges of around 4.5 to 6 EUR/kg H_2, or 2 to 5 EUR/kg in regions with optimal generation conditions. The decline in investment costs for electrolysis systems, combined with the downward trend in generation costs for renewable electricity (especially PV) and significantly falling structuring costs (driven in particular by substantially falling electricity storage costs), has led to the development of the example cost levels (see above). It was also assumed for Germany that grid utilisation fees would continue to be waived if electrolysis systems were operated in line with the system's needs. Without this assumption, generation costs would increase accordingly (see below).
- In the long term, the corresponding ranges could be around 2.5 to around 4 EUR/kg H_2 for domestic production. In addition to the technological and cost-related developments for renewable electricity generation and electricity storage, the lower bandwidth values are based on the assumption that electrolysis systems will incur minimal or zero costs for grid utilisation, levies or surcharges (e.g. dynamic grid fee and surcharge systems) if operated in a manner compatible with the electricity system. This applies even in the event of a high proportion of renewables in the German electricity grid and correspondingly higher utilisation rates. In regions with favourable production conditions, cost levels of 1.5-3.5 EUR/kg H_2 could be achieved in line with the above developments in renewable electricity generation and relevant structuring options, especially electricity storage.

The following reference values can be used to categorise the cost impacts of changes to the energy sector or regulatory environment:

- Over time, a reduction in electricity costs of 10 EUR/MWh results in a reduction in hydrogen production costs of around 0.5 EUR/kg H_2;
- In the short and medium term, increasing electrolysis runtimes by 500 hours per year will reduce hydrogen costs by approx. 0.3 to 0.4 EUR/kg H_2.
- In the medium and long term, reducing investment costs by 100 EUR/kW at a capacity utilisation of 4,000 hours per year results in a reduction in the levelised costs of hydrogen of around 0.1 EUR/kg H_2.

- In the short and medium term, a reduction in the WACC by 1 percentage point results in a reduction in hydrogen production costs of around 0.15 to 0.20 EUR/kg H_2;
- In the short and medium term, a 20 % reduction in other operating costs leads to a decrease in hydrogen production costs of approx. 0.05-0.15 EUR/kg H_2;
- In the short and medium term, increasing the service life of the electrolyser by 5 years reduces the levelised costs by up to 0.15 EUR/kg H_2;
- In the short and medium term, increasing the stack lifetime by 2 years results in a reduction in hydrogen production costs of approx. 0.05 to 0.15 EUR/kg H_2.

These results highlight the crucial role of electricity input costs, utilisation of capacity, investment and capital costs, and demonstrate that other cost factors can also contribute significantly to reducing costs.

5.3 Hydrogen from steam reforming

The decisive cost determinants for producing hydrogen through steam reforming are gas input costs and the costs associated with transporting and safely storing the captured CO_2.

Gas input costs largely depend on wholesale natural gas prices:

- Wholesale prices for natural gas are currently in the range of 35 to 40 EUR/MWh (GCV);
- The projections for the medium and long term vary greatly, depending on the development of the global natural gas market. In the medium and long term, mainstream projections (IEA 2023b; 2024) anticipate a slight decrease to between 30 and 35 EUR/MWh (GCV) in the medium term, and between 15 and 30 EUR/MWh (GCV) by mid-century.

Reliable (market) data on the long-term costs of transporting and safely storing captured CO_2 (transfer and storage, or T&S) is not yet available:

- The cost assumption for the cost indicators for blue hydrogen, as provided by the market data provider Argus, increased significantly in mid-2024, rising from 20 USD/t CO_2 to 60 USD/t CO_2 for north-western Europe. The comparative values for the USA and the Middle East are USD 40, and for Japan and South Korea, 110 USD/t CO_2 (Argus 2025).
- The costs for transporting and storing CO_2 were converted from 35 to 90.60 EUR/t CO_2 in July 2024, based on reference projects and market information, in order to determine the HydexPlus Blue indicator of the analysis company E-Bridge (E-Bridge).
- In the planning of the Porthos storage project in the Netherlands, a CCS tariff of 51-53 EUR/t CO_2 was estimated in 2020, while an evaluation of international projects produced a range of 20-100 EUR/t CO_2 (mean value: 47 EUR/t CO_2) (Xodus 2020). However, a new assessment of the project in September 2023 showed a total cost increase of 53 % (83 % for investments, with operating costs remaining almost unchanged). Consequently, a substantial subsidy is required to maintain the above-mentioned tariff (NLCA 2024). Extrapolating these costs to a subsidy-free tariff for transport and storage would result in a price level of 81.30 EUR/t CO_2.
- In the consultation for tenders for the Danish CCS fund, costs of 340 DKK/t CO_2 for onshore storage and 500 DKK/t CO_2 (i.e. 45 EUR/t CO_2 and 67 EUR/t CO_2 respectively) for transport and storage were estimated in mid-2024. The cost basis and inclusion of ancillary costs for monitoring, etc., were not clearly specified (DEA 2024).
- The current cost estimates for the Aramis storage project in the Netherlands range from 90.60 to 112.80 EUR/tCO_2 (Xodus 2024).

Overall, costs or prices of around 100 EUR/t CO_2 (or potentially more, given the current cost increases in plant construction, etc.) must be estimated for transporting and storing the CO_2 produced during natural gas reforming. Although there is potential to reduce costs at certain points in the T&S process chain, it is likely to be rather low given the largely mature technologies, or will be offset by opposing trends (e.g. higher costs for storage sites further from the coast).

Figure 8 provides an overview of the results of the corresponding sensitivity analyses and the expected levelised costs for blue hydrogen production, based on currently available information and depending on the two key cost factors: procurement costs of gas and the costs of transportation and long-term storage of the CO_2. The values shown in Chapter 2.3 were used for the other parameters in these calculations.[7]

- Currently, production costs of between 3.5 and 4 EUR/kg H_2 are expected for the current parameter constellations.
- In the medium term, the cost range is very similar, from around 3 to 4 EUR/kg H_2.
- In the long term, the range is expected to be around 2.5-4 EUR/kg H_2.

The following reference values can be used to categorise the cost effects of changes to the energy industry environment and regulatory framework for blue hydrogen:

- A change in natural gas costs of 5 EUR/MWh (GCV) leads to a change in levelised hydrogen costs amounting to around 0.25 EUR/kg H_2.
- A change in the costs of CO_2 disposal of 10 EUR/t results in a corresponding change in production costs of around 0.10 EUR/kg H_2.
- A change in the carbon price (for the residual emissions) of 10 EUR/t results in a change in the levelised costs of around 0.02 EUR/kg H_2.
- A reduction in the WACC of 1 percentage point would reduce hydrogen production costs by around 0.05 EUR/kg H_2.
- An increase in carbon capture rates of 5 percentage points leads to a reduction in the levelised costs of approx. 0.10 EUR/kg H_2 with low costs of CO_2 disposal; With high CO_2 disposal costs and high carbon costs, the costs would be reduced by approx. 0.05 - 0.10 EUR/kg H_2;
- A reduction in other operating costs of 20% would result in a cost reduction of around 0.05 EUR/kg H_2.

Sensitivity analyses show that changes in cost determinants beyond natural gas prices and the costs of transporting and safely storing captured CO_2 only have a very small impact on the production of low-carbon (blue) hydrogen from natural gas.

7 Average values were used in the calculations for which ranges were provided for these technological and economic parameters in Section 2.3.

Figure 8: Levelised costs of hydrogen depending on costs of natural gas input and CCS

a) Short-term situation

Costs for CO_2 transport and storage [EUR2023/t CO_2]	Natural gas input costs (GCV) [EUR2023/MWh]														
	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80
15	2.0	2.2	2.5	2.8	3.0	3.3	3.6	3.8	4.1	4.4	4.6	4.9	5.1	5.4	5.7
30	2.1	2.3	2.6	2.9	3.1	3.4	3.7	3.9	4.2	4.5	4.7	5.0	5.3	5.5	5.8
45	2.2	2.5	2.7	3.0	3.3	3.5	3.8	4.0	4.3	4.6	4.8	5.1	5.4	5.6	5.9
60	2.3	2.6	2.8	3.1	3.4	3.6	3.9	4.2	4.4	4.7	5.0	5.2	5.5	5.8	6.0
75	2.4	2.7	3.0	3.2	3.5	3.7	4.0	4.3	4.5	4.8	5.1	5.3	5.6	5.9	6.1
90	2.5	2.8	3.1	3.3	3.6	3.9	4.1	4.4	4.7	4.9	5.2	5.5	5.7	6.0	6.2
105	2.7	2.9	3.2	3.4	3.7	4.0	4.2	4.5	4.8	5.0	5.3	5.6	5.8	6.1	6.4
120	2.8	3.0	3.3	3.6	3.8	4.1	4.4	4.6	4.9	5.1	5.4	5.7	5.9	6.2	6.5
135	2.9	3.1	3.4	3.7	3.9	4.2	4.5	4.7	5.0	5.3	5.5	5.8	6.1	6.3	6.6
150	3.0	3.3	3.5	3.8	4.1	4.3	4.6	4.8	5.1	5.4	5.6	5.9	6.2	6.4	6.7
165	3.1	3.4	3.6	3.9	4.2	4.4	4.7	5.0	5.2	5.5	5.8	6.0	6.3	6.6	6.8

Cell values: hydrogen costs [EUR/kg H_2]

b) Medium-term situation

Costs for CO_2 transport and storage [EUR2023/t CO_2]	Natural gas input costs (GCV) [EUR2023/MWh]														
	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80
15	1.9	2.2	2.5	2.7	3.0	3.3	3.5	3.8	4.1	4.3	4.6	4.9	5.1	5.4	5.7
30	2.0	2.3	2.6	2.8	3.1	3.4	3.6	3.9	4.2	4.5	4.7	5.0	5.3	5.5	5.8
45	2.2	2.4	2.7	3.0	3.2	3.5	3.8	4.0	4.3	4.6	4.8	5.1	5.4	5.6	5.9
60	2.3	2.5	2.8	3.1	3.4	3.6	3.9	4.2	4.4	4.7	5.0	5.2	5.5	5.8	6.0
75	2.4	2.7	2.9	3.2	3.5	3.7	4.0	4.3	4.5	4.8	5.1	5.4	5.6	5.9	6.2
90	2.5	2.8	3.1	3.3	3.6	3.9	4.1	4.4	4.7	4.9	5.2	5.5	5.7	6.0	6.3
105	2.6	2.9	3.2	3.4	3.7	4.0	4.3	4.5	4.8	5.1	5.3	5.6	5.9	6.1	6.4
120	2.8	3.0	3.3	3.6	3.8	4.1	4.4	4.6	4.9	5.2	5.4	5.7	6.0	6.3	6.5
135	2.9	3.2	3.4	3.7	4.0	4.2	4.5	4.8	5.0	5.3	5.6	5.8	6.1	6.4	6.6
150	3.0	3.3	3.5	3.8	4.1	4.3	4.6	4.9	5.2	5.4	5.7	6.0	6.2	6.5	6.8
165	3.1	3.4	3.7	3.9	4.2	4.5	4.7	5.0	5.3	5.5	5.8	6.1	6.3	6.6	6.9

Cell values: hydrogen costs [EUR/kg H_2]

c) Long-term situation

Costs for CO_2 transport and storage [EUR2023/t CO_2]	Natural gas input costs (GCV) [EUR2023/MWh]														
	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80
15	1.8	2.1	2.4	2.7	2.9	3.2	3.5	3.7	4.0	4.3	4.6	4.8	5.1	5.4	5.6
30	2.0	2.2	2.5	2.8	3.1	3.3	3.6	3.9	4.1	4.4	4.7	5.0	5.2	5.5	5.8
45	2.1	2.4	2.6	2.9	3.2	3.5	3.7	4.0	4.3	4.5	4.8	5.1	5.4	5.6	5.9
60	2.2	2.5	2.8	3.0	3.3	3.6	3.9	4.1	4.4	4.7	4.9	5.2	5.5	5.8	6.0
75	2.3	2.6	2.9	3.2	3.4	3.7	4.0	4.3	4.5	4.8	5.1	5.3	5.6	5.9	6.2
90	2.5	2.8	3.0	3.3	3.6	3.8	4.1	4.4	4.7	4.9	5.2	5.5	5.7	6.0	6.3
105	2.6	2.9	3.2	3.4	3.7	4.0	4.2	4.5	4.8	5.1	5.3	5.6	5.9	6.1	6.4
120	2.7	3.0	3.3	3.6	3.8	4.1	4.4	4.6	4.9	5.2	5.5	5.7	6.0	6.3	6.5
135	2.9	3.1	3.4	3.7	4.0	4.2	4.5	4.8	5.0	5.3	5.6	5.9	6.1	6.4	6.7
150	3.0	3.3	3.5	3.8	4.1	4.4	4.6	4.9	5.2	5.4	5.7	6.0	6.3	6.5	6.8
165	3.1	3.4	3.7	3.9	4.2	4.5	4.8	5.0	5.3	5.6	5.8	6.1	6.4	6.7	6.9

Cell values: hydrogen costs [EUR/kg H_2]

Note: Boxes with solid lines: expected values for Germany, north-western and northern Europe.

Source: Authors' own calculations

6 Overview of the most important market observation indicators and comparison with the first market results

Major (energy) market providers and specialised companies are now publishing a number of cost assessments for hydrogen and some of its derivatives that are updated relatively frequently. As a rule, various production routes, technologies and production regions are taken into account. The methodological documentation of determining the indicators and the historical revisions provides insight into the development of individual cost components (Platts 2024; Argus 2025; E-Bridge). Additionally, since 2023, the EEX energy exchange has calculated a transaction-based price indicator for green hydrogen (EEX 2025). MIBGAS, the Iberian gas market operator, also publishes a hydrogen cost index (MIBGAS 2025).

Figure 9 shows a selection of these market indicators for the beginning of 2023 onwards. The indicators shown are for Germany, the Netherlands, the United Kingdom and Saudi Arabia, the latter of which is included referentially as a potentially high-volume export region. This initial overview highlights the following aspects:

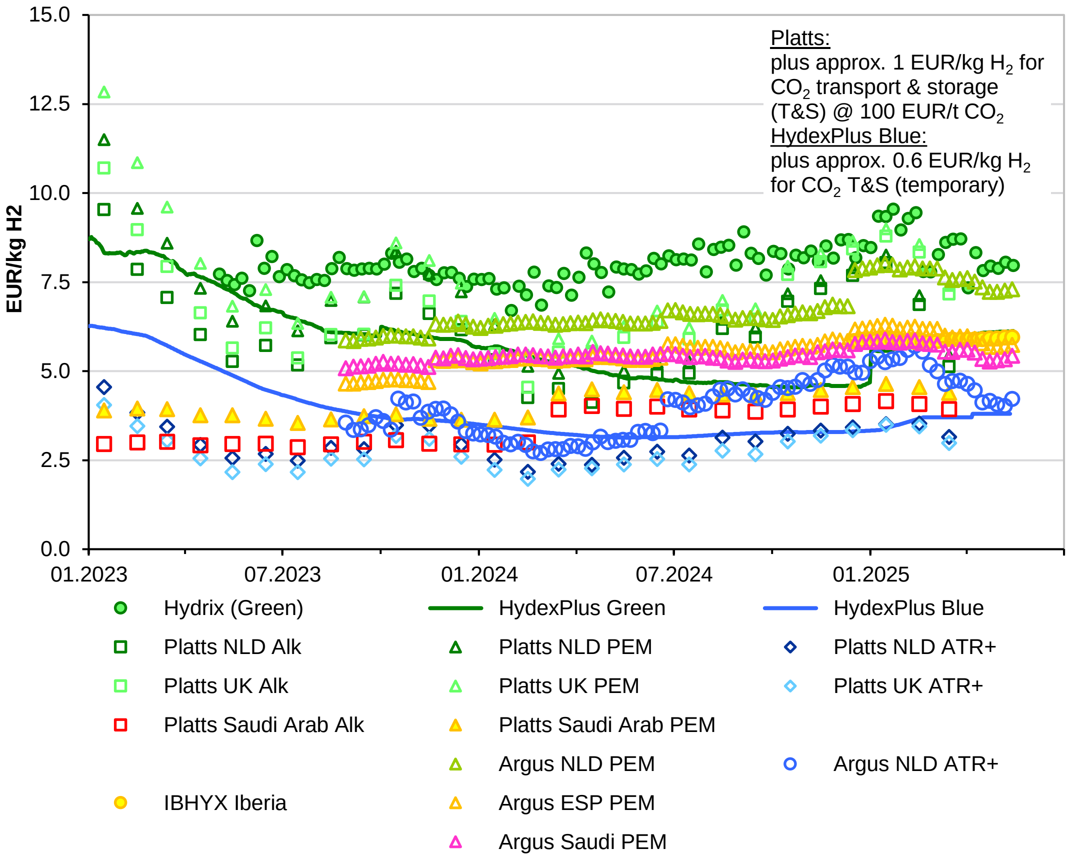
- The cost-oriented indicators for (north-western) European production regions in the field of green hydrogen demonstrate significant variability and fluctuations. In 2025, the range was between 7.50 and 8.50 EUR/kg H_2. Most recently, there has been a tendency towards cost levels of approximately 7.50 EUR/kg H_2.

- The cost estimates for blue hydrogen (in the Netherlands and the United Kingdom) demonstrate inconsistent trends, yet these are observed at notably reduced levels and with a divergent dynamic, predominantly influenced by natural gas prices. However, it should be noted that the Platts/S&P cost calculations take into account the carbon capture costs, but not the transport and storage costs. Furthermore, the cost estimates for determining the HydexPlus Blue index have been significantly increased since July 2024. When these aspects are considered, the cost indicators for blue hydrogen should be adjusted to include a surcharge of approx. 1.00 EUR/kg H_2 (Platts/S&P) and 0.60 EUR/kg H_2, bringing the total costs to around 4.50 EUR/kg H_2.

- In contrast to the cost-orientated indicators of Platts/S&P and E-Bridge, the transaction-based indicator Hydrix of the EEX (for Germany) stagnates at a level of more than 7.50 EUR/kg H_2 with some fluctuations.

- The comparative figures for the Iberian Peninsula and Saudi Arabia, which serve as exemplary cases of regions with favourable production conditions for renewable electricity generation and comparatively good investment security (and thus low financing costs), also demonstrate relatively stable levels in principle, even when they increase to values of 5 to 6 EUR/kg. This is primarily attributable to adjustments made to the assumptions about electrolysis costs. However, it should be noted that considerable differences in costs would be incurred for transport from the Iberian Peninsula (via a pipeline) and the Middle East (by ship, with the necessary conversion and reconversion of derivatives). Consequently, the disparities in production costs would be substantially mitigated.

Figure 9: Cost- and transaction-based indicators for hydrogen by Argus, E-Bridge, MIBGAS, S&P/Platts and EEX



Source: Platts Hydrogen Assessment, Argus Hydrogen & Future Fuels, E-Bridge (HydexPlus), EEX (Hydrix), MIBGAS (IBHYX Iberea), authors' own compilation and calculations

The Argus cost assessment provides an interesting differentiation by distinguishing between various production routes, technology options and regions. Furthermore, the costs are also shown with and without the capital cost shares.

The data summarised in Figure 10 provides further insights:

- With operating cost shares fluctuating only slightly overall, revisions to the capital cost estimates for green hydrogen are clearly visible, leading to a substantial increase in hydrogen production costs at the end of 2023 and mid-2024 (by a total of 0.70–1.00 EUR/kg H_2).

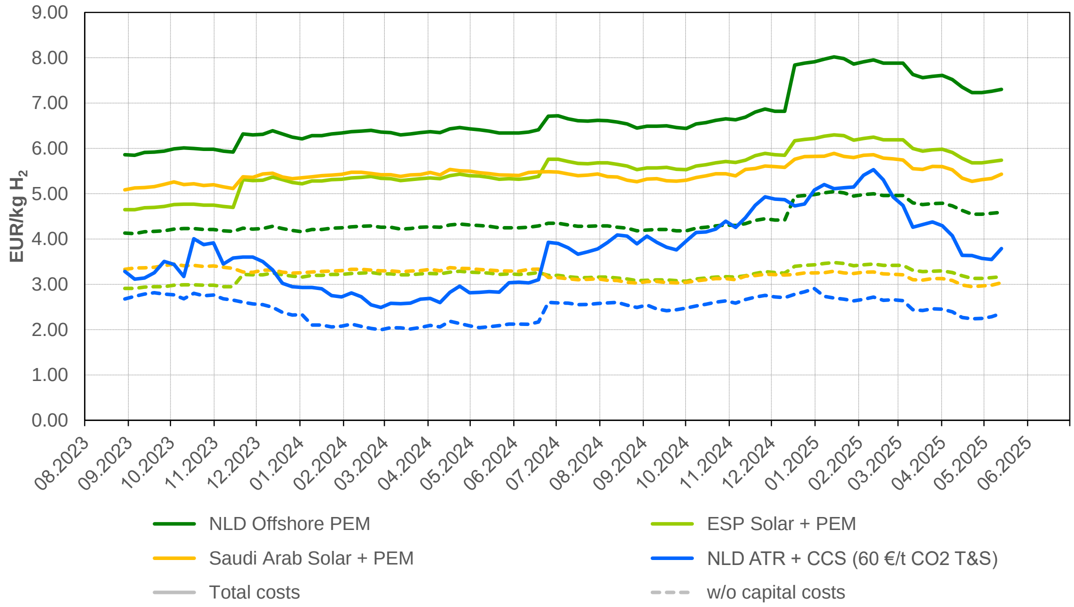
- The comparison of different regions of origin shows cost differences of around 1.50-2.00 EUR/kg H_2 between production sites in north-western Europe and the Iberian Peninsula, for example.

- It should also be noted that, the costs for the example of the Saudi Arabian production site (see above) are similar to those for the Iberian Peninsula. The Argus calculations show lower cost differences between north-western European locations and Saudi Arabia (approx. 2 EUR/kg H_2) than the Platts/S&P calculations (up to 4 EUR/kg H_2).

- In the Argus analyses, the capital costs account for a significant proportion of green hydrogen production costs, amounting to around 2.50 EUR/kg H_2.

- The costs determined by Argus for blue hydrogen are largely dependent on the cost of the natural gas used. Capital costs are estimated at around 1 EUR/kg H2 at the current margin. It should also be noted that transporting and storing the captured CO_2 is comparatively inexpensive at 60 EUR/t CO_2. Using a value of 100 EUR/t CO_2 instead of 60 EUR/t CO_2 would increase the cost of blue hydrogen by around 0.40 EUR/kg H_2.

Figure 10: Cost indicators for hydrogen by Argus (with and without the capital costs)

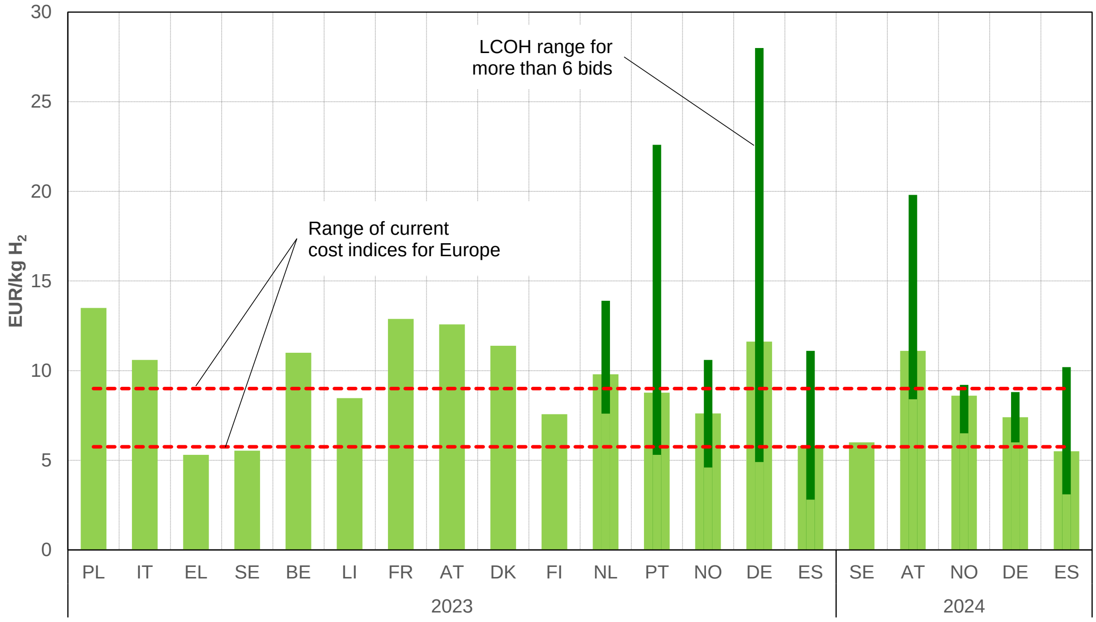


Source: Argus Hydrogen & Future Fuels, authors' own compilation and calculations

Although there are numerous regularly updated cost estimates for Europe and the most important potential export regions, questions arise as to the real-world robustness of these calculations and research, particularly with a view to market prices. The results of the two hydrogen auctions organised by the European Hydrogen Bank (EC 2024; 2025) provide an initial, very preliminary indication.

The criterion in this auction was not the hydrogen cost or price levels, but the cost gap between production and the willingness to pay among the competing combinations of hydrogen suppliers and consumers. The bidders also had to provide information on the total costs of the hydrogen used in their bids. Even if the auction results should be regarded as very preliminary, both in terms of the binding nature of implementation and the purely information-based determination and transmission of hydrogen costs or prices, the information obtained in this context provides an initial insight into the reliability of the cost determinations made to date.

Figure 11: Classification of the results of previous auctions by the European Hydrogen Bank



Source: European Hydrogen Bank, authors' own compilation and calculations

Figure 11 shows the hydrogen costs and prices submitted during the two previous auctions on average for the respective countries (with two or more bids), the corresponding cost and price ranges (for countries with several bids) and the cost and transaction-based indicators for the European countries referred to in the above analyses.

- Taking into account the available data and the ranges of costs and bids, the bids are at least partially within the expected ranges (of the large regions) Greece, Sweden, Finland, Portugal, Norway, Germany and Spain.
- Germany, Austria, Portugal, partly Spain, the Netherlands and partly Norway show very high upward outliers.
- For all other countries, there are still deviations or uncertainties that cannot (yet) be categorised based on the available data.

Taking this data into account, cost levels of 5.00–7.50 EUR/kg H_2 seem feasible for European sites of hydrogen production in the years ahead.

7 Categorisation of hydrogen costs

Irrespective of the various factors influencing hydrogen costs and prices, it is necessary to categorise the absolute level of costs and prices.

Pragmatic categorisation enables the costs of fuel switching to be analysed and expressed in terms of the required carbon price. Figure 12 shows the range of fuel switch prices based on switching from natural gas to hydrogen. It demonstrates the (effective) carbon prices necessary to equalise the cost differences between various hydrogen costs and prices (vertical axis) and cost or price levels for natural gas (horizontal axis). Switching from natural gas to hydrogen is the ideal fuel switch that will take place in electricity generation, centralised heat generation, and process heat generation.

Figure 12: Fuel switch costs from natural gas to hydrogen

Hydrogen costs and prices [EUR/kg H_2] \ Natural gas costs and prices [EUR/MWh(GCV)]	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80
1.0	112	84	56	28	0	-28	-56	-84	-112	-140	-168	-196	-224	-252	-280
1.5	196	168	140	112	84	56	28	0	-28	-56	-84	-112	-140	-168	-196
2.0	280	252	224	196	168	140	112	84	56	28	0	-28	-56	-84	-112
2.5	364	336	308	280	252	224	196	168	140	112	84	56	28	0	-28
3.0	448	420	392	364	336	308	280	252	224	196	168	140	112	84	56
3.5	532	504	476	448	420	392	364	336	308	280	252	224	196	168	140
4.0	616	588	560	532	504	476	448	420	392	364	336	308	280	252	224
4.5	700	672	644	616	588	560	532	504	476	448	420	392	364	336	308
5.0	783	755	727	700	672	644	616	588	560	532	504	476	448	420	392
5.5	867	839	811	783	755	727	700	672	644	616	588	560	532	504	476
6.0	951	923	895	867	839	811	783	755	727	700	672	644	616	588	560
6.5	1,035	1,007	979	951	923	895	867	839	811	783	755	727	700	672	644
7.0	1,119	1,091	1,063	1,035	1,007	979	951	923	895	867	839	811	783	755	727
7.5	1,203	1,175	1,147	1,119	1,091	1,063	1,035	1,007	979	951	923	895	867	839	811
8.0	1,287	1,259	1,231	1,203	1,175	1,147	1,119	1,091	1,063	1,035	1,007	979	951	923	895

Cell values: fuel switch costs from natural gas to hydrogen [EUR/t CO_2]

Source: Authors' own calculations

With natural gas prices at around 40 EUR/MWh (GCV) and hydrogen prices at approx. 3 EUR/kg H_2, carbon prices of around 280 EUR/t CO_2 would be required to offset the cost difference. If hydrogen prices were 7.50 EUR/kg H_2, more than 1,000 EUR/t CO_2 would be necessary. Higher or lower natural gas prices would change these values accordingly. For reference, a 10 EUR/MWh (GCV) change in natural gas prices results in an opposite change in the carbon price required for cost parity of around 50 EUR/t CO_2.

While this ideal fuel switch is a useful reference for important hydrogen applications, it is rather conservative for others, as it does not consider that less energy may be needed when switching to hydrogen for technical or physico-chemical reasons. For example, the values shown for using hydrogen for the direct reduction of iron ore could be reduced by up to a third. This applies to an even greater extent to the substitution of more CO_2-intensive fuels, especially if hydrogen applications involve substantially more efficient conversion technologies (e.g. fuel cells). Nevertheless, costs associated with switching from natural gas to hydrogen provide a useful reference point for categorising costs and prices of hydrogen.

The overview clearly shows that, even when assuming less conservative variants of fuel switching, values of no more than approx. 3 EUR/kg H_2 must be achieved in the medium and long term if cost parity is to be reached given the currently foreseeable or conceivable prices of fossil fuels and emission allowances.

8 Conclusions and recommendations

A detailed analysis of hydrogen costs and prices and their determinants shows that hydrogen is currently a comparatively expensive source of energy. This applies in particular to renewable hydrogen produced in Germany (typically costing more than 7.50 EUR/kg H_2) and to low-carbon and renewable hydrogen produced outside of Germany under favourable conditions for producing renewable electricity (typically costing more than 4 EUR/kg H_2). Given the current price of natural gas, carbon prices of more than 450 EUR/t CO_2 (for blue hydrogen or renewable hydrogen produced abroad) or more than 1,000 EUR/t CO_2 (for producing renewable hydrogen domestically) would be required to achieve cost parity for hydrogen and natural gas.

An analysis of the determinants of hydrogen costs indicates that considerable reductions are feasible in the medium and long term, particularly for renewable hydrogen. This relates to the input costs of renewable electricity and the investment and financing costs of electrolysis plants. For low-carbon hydrogen produced by water electrolysis, the transition of the electricity system towards renewable energy sources could enable production at relatively favourable costs. However, the cost reduction options for (blue) hydrogen produced from natural gas in combination with CCS are significantly lower. However, the future costs of natural gas and the transport and storage of captured CO_2 remain significant sources of uncertainty (in both directions).

In the medium to long term, hydrogen will only be able to reach its full potential in the transition to climate neutrality if the cost per kilogramme of hydrogen is reduced to 3 EUR/kg H_2 or less.

Such cost reductions could largely be driven by policy measures that finance them.

With a view to renewable hydrogen, the following is of primary concern:

- Ancillary electricity costs, such as grid utilisation fees, taxes, levies and surcharges, are a very significant factor, particularly for producing domestic hydrogen. Without an effective exemption from these costs, it will be difficult to achieve the above-mentioned targets for the costs of producing hydrogen in Germany. Additional costs of 1.50 EUR/kg H_2 or more could be incurred through the ancillary electricity costs alone. These exemptions could be granted directly, as is currently the case, or electrolysis could be integrated into the introduction of dynamic grid utilisation fees for electricity-intensive industries, as is currently being pursued by the German Federal Network Agency.

- The electricity quantities available via the 'use-instead-of-curtail' mechanism (Section 13k of the Federal Energy Industry Act) should be priced very low. The difference between the currently estimated prices of approx. 30 to 40 EUR/MWh and the static threshold of 20 EUR/MWh for green electricity under the 37th Federal Immission Control Act could lead to additional costs of 0.50 to 1 EUR/kg H_2 for producing electrolytic hydrogen.

- The obligation to purchase electricity from new renewable electricity generation plants via PPAs from 2028 (EK 2023a, Art. 11) will require the procurement of renewable electricity at full cost. However, the obligation to correlate electricity generation and hydrogen production on an hourly basis, which will apply from 2030, will require considerable overbuilding and overcontracting of electricity purchases to achieve a suitable utilisation of electrolysis capacity. Regardless of the fundamental question of the appropriateness and reasonableness of project-related additionality requirements[8], this will result in significant additional costs for hydrogen production. A more electricity market-related or flexible rule, such as monthly billing, should be considered. However, the tension between more pragmatic certification regulations and the market uncertainties associated with renewed negotiation processes must also be considered. In this context, it should be noted that the comparatively restrictive additionality regulations (from 2028, see EC 2023a, Art. 11) and temporal correlation regulations (from 2030, see EC 2023a, Art. 6) are relevant for a transitional period of less than 10 years at best (because the share of renewable energy in the electricity mix of the relevant price zones will exceed the 90 % threshold by then). These regulations could therefore certainly be called into question in order to pragmatically finance the hydrogen ramp-up. Therefore, a fundamental redesign of the certification rules appears less expedient than, for example, extending the relevant transitional periods to 2035. However, both redesigning the certification requirements and extending transitional regulations must consider the tension arising from applying the regulations to intra-European hydrogen production and imports from other regions. While hydrogen production in Europe is ultimately safeguarded by a robust framework of regulations, including renewable policy and emissions trading, the same cannot be readily assumed for other regions in the world.

- The expansion of offshore wind energy and hybrid concepts (wind/solar) and the integration of battery storage are crucial to the utilisation of electrolyser capacity. An increase in capacity utilisation by 3,000 hours could result in a cost reduction potential of more than 2 EUR/kg H_2 in the medium term.

- The issue of storing green electricity in batteries to extend the operating times of electrolysers in the various control areas requires clear and robust clarification. The cost levers potentially influenced by this could amount to more than 1 EUR/kg H_2 in the medium term.

- With a view to the investment costs of producing electrolytic hydrogen, a considerable cost reduction potential can still be realised (amounting to at least

8 It should be noted that the actual additionality of the renewable electricity generated to produce hydrogen is not usually determined by PPAs at project level. Additionality can only ever be determined by examining the relationship between total electricity consumption (including that used in electrolysis systems) and total renewable electricity generation, regardless of whether the renewable generation plants are financed via a PPA or an accompanying mechanism (such as the German Renewable Energy Sources Act or Contracts for Difference). The European Union's governance system safeguards this additionality through consumption-related renewable energy targets and overarching emission reduction targets (implemented via the EU Emissions Trading System). Therefore, linking the issue of additionality with the contracting of electricity via PPAs reflects a preference in electricity market design, which increases the cost of ramping up hydrogen production, rather than a regulation that ensures additionality. It should also be noted that there are valid reasons why no comparable additionality requirements are set for other electrification options, such as electromobility and heat pumps.

1-2 EUR/kg H_2). A reliable and steady market ramp-up on the production side (in Germany and elsewhere) could help to exploit corresponding learning curve effects. These learning curve effects can be achieved by industrialising electrolyser production (upnumbering) and increasing system sizes (upscaling). While upnumbering is an indispensable strategy for the hydrogen ramp-up, there is considerable room for manoeuvre with regard to upscaling (the expansion of large electrolysis systems), which should not be overlooked.

- The reduction in financing costs (i.e. the WACC) is an important influencing factor, particularly with a view to international hydrogen production, especially in regions with higher risk profiles. Although it does not play the same role as the cost of electricity, it dominates the other cost determinants. Instruments to support project financing are thus of paramount importance.

Although renewable hydrogen is important from the perspectives of sustainability and cost reduction potentials, the potential of low-carbon hydrogen should be considered, particularly during the transition period over the next one to two decades. The following aspects should take centre stage, particularly in terms of cost:

- The regulatory framework for low-carbon hydrogen is currently being finalised. In the relevant legislative procedures, targeted regulations should be established in two areas in particular. For low-carbon hydrogen produced by electrolysis, consideration should be given to determining the operating time of the electrolysis process based on the hourly carbon load in the relevant bidding zone. Regarding the production of low-carbon hydrogen from natural gas, efforts could be taken to prevent the emission reduction requirements from being circumvented by using default values, even in the short term. This should be feasible given the provisions of the EU’s Carbon Border Adjustment Mechanism (CBAM, EU 2023b) and the EU Methane Regulation (EU 2024).

- In view of the substantial cost of transporting and safely storing CO_2 in geological formations, the greatest possible market transparency should be established as soon as possible. As part of promoting CCS measures or the use of blue hydrogen, transparency regulations could be introduced based on the European Hydrogen Bank auctions (requiring the disclosure of LCOH data) or the Carbon Contracts for Difference scheme (requiring the disclosure of the conditions of hydrogen procurement).

The cost analyses presented here relate to the production costs of hydrogen. Transport costs are also a considerably important factor in the cost of producing hydrogen in Germany. Any cost advantages of producing hydrogen abroad must outweigh the transport costs to Germany. For all pipeline supply regions to Germany (i.e. those with transport costs of 0.50 EUR/kg H_2 or less), the aforementioned (decisive and important) cost determinants prevail. If hydrogen (in the form of pure hydrogen or various carrier substances) is to be transported to Germany or Europe by ship, production-side cost advantages of 1 to 1.5 EUR/kg H_2 must be realised abroad at the time of production. However, this order of magnitude roughly corresponds to the cost disadvantages that can arise due to higher financing costs in countries with higher risk profiles.

In addition to production, transport and distribution costs, structuring costs for hydrogen deliveries should also be considered when determining the purchase prices of hydrogen for various consumers. The need for hydrogen storage and the relevant business models also play a significant role in this context and require much more consideration when designing the regulatory framework for scaling up the hydrogen economy. In-depth analyses in this area are still lacking.

Finally, it should be noted that the relationships and interactions identified in this study are not only relevant for pure (molecular) hydrogen, but also for hydrogen derivatives, albeit with different (and predominantly additional) influencing factors. Categorisations aimed at sensitivities and different time horizons would also be useful in this respect.

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Appendix

Table A-1: References and explanations of the cost determinants of producing electrolytic hydrogen

		Values/ ranges	References/explanations
Electricity input costs		variable	see Chapter 5.2
Utilisation of electrolysis		variable	see Chapter 5.2
Investment costs of the electrolyser	a)	1,200 – 1,700 EUR_{2023}/kW	upper value *Argus (2024)* lower value E-Bridge (2025)
	b)	750 - 850 EUR_{2023}/kW	upper value IEA (2019) lower value IEA (2019)
	c)	350 - 500 EUR_{2023}/kW	Upper value IEA (2019); DEA (2024) Lower value IEA (2019) *;* DEA (2024)
Efficiency (NCV)	a)	57 - 62 %	Argus (2024)
	b)	65 - 70 %	IEA (2019)
	c)	67 - 75 %	IEA (2019)
Financing costs / WACC	a)	8 - 10 %	IRENA (2020)
	b)	8 %	IRENA (2020)
	c)	6 - 8 %	IRENA (2020)
Service life of the electrolysis stack	a)	60,000 - 80,000h	DEA (2025)
	b)	80,000 - 90,000h	DEA (2025)
	c)	90,000 - 120,000h	DEA (2025)
Costs of replacing the electrolysis stack		25 - 35 %	Fraunhofer ISE (2021); NREL (2024)
Other operating costs		2 - 4 % of investment costs	IEA (2020a); DEA (2025)

Costs for water		0.02 EUR_{2023}/kg H_2	TH Cologne (2023)
Service life	a)	20 - 25 years	DEA (2025), assumption initially in upper range
	b)	25 years	DEA (2025), average
	c)	25-30 years	DEA (2025), assumption long-term in upper range

Notes: The data points were determined using benchmarks from various sources. The listed references indicate the order of magnitude of the values given, but not necessarily their exact values, and refer to the key data used in each case.

Source: Authors' own compilation and assumptions

Table A-2: References and explanations of the cost determinants of hydrogen from steam reforming

		Values/ ranges	References/explanations
Natural gas input costs (GCV)		variable	see Chapter 5.3
Costs for carbon transport and storage		variable	see Chapter 5.3
Carbon price (CO_2 costs under EU ETS)	a)	70 - 80 $EUR_{2023}/t\ CO_2$	current spot and futures prices on the European energy exchanges
	b)	130 - 180 $EUR_{2023}/t\ CO_2$	based on IEA (2023b)
	c)	200 - 250 $EUR_{2023}/t\ CO_2$	based on IEA (2023b)
Financing costs / WACC		10 - 13 %	IEA (2020b), including consideration of the current key interest rates
Investment costs SMR & CCS	a)	1,300 - 1,700 EUR_{2023}/kW	IEA (2020a), DOE (2023)
	b)	1,200 - 1,600 EUR_{2023}/kW	IEA (2020a), DOE (2023)
	c)	1,100 – 1,500 EUR_{2023}/kW	IEA (2020a), DOE (2023)
Carbon capture rate	a)	80 %	WI (2023)
	b)	85 %	IEA (2020a), taking into account the ramp-up
	c)	90 %	IEA (2020a)
Direct emissions before capture		9 - 10 kg CO_2/kg H_2	IEA (2020a)
Other operating costs		2 - 4 % of the investment costs	IEA (2020a)
Service life		20 - 25 years	IEA (2020a)
Natural gas utilisation (NCV)	a)	47 MWh/kg H_2	IEA (2023a), taking into account the carbon capture rate
	b)	48 MWh/kg H_2	IEA (2023a), taking into account the carbon capture rate
	c)	49 MWh/kg H_2	IEA (2023a)

Electricity input costs SMR & CCS		1.4 kWh/kg H_2	IEA (2023a)
Utilisation		85 - 95 %	IEA (2020a)

Notes: The data points were determined using benchmarks from various sources. The listed references indicate the order of magnitude of the values given, but not necessarily their exact values, and refer to the key data used in each case.

Source: Authors' own compilation and assumptions