Evaluation of the levelised cost of hydrogen based on proposed electrolyser projects in the Netherlands

Renewable Hydrogen Cost Element Evaluation Tool (RHyCEET)

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Disclaimer

The companies that contributed to this project provided data and suggestions for analysis and visualisation of results. TNO is responsible for the calculations and analyses carried out in the context of this project, and for the content of the report. However, TNO is not responsible for the quality of the data supplied by the companies.

Summary

Objective, scope, and main results and conclusions

This study intends to provide an overview, as realistic as possible, of the most important cost components and the implied levelised cost of hydrogen ($LCOH_2$) for the production of renewable hydrogen through water-electrolysis in the Netherlands. To this end, project developers were asked to reflect on the estimates of electrolysis data from the market consultation (held in 2022) for the main Dutch support scheme (SDE++), and to provide cost data of their projects. As a result, this study provides and updated view on cost data for electrolysis projects, and presents cost ranges rather than point estimates to provide a wider view on cost components in the nascent market for hydrogen production.

This cost study is unique in the sense that it is based on a significant number of electrolysis projects, which are currently under development or are already being realised, and for which not only integral project costs are available but also a breakdown of cost elements. A total of eleven parties provided data sets of fourteen projects. The data sets were analysed and processed into an anonymous data set by TNO, representing the cost characteristics of an electrolysis-based hydrogen plant with a rated electrical input capacity in the range of 100 MW_e to 200 MW_e. In addition, a tool has been developed to calculate the $LCOH_2$.

In calculating the $LCOH_2$, the production of only renewable hydrogen has been assumed. As the focus is on cost, no potential revenues from operating electrolysers or subsidies have been considered. Based on the data provided and analysed in this study, the level of investment cost faced by project developers is estimated at €3,050/kW_e and €2,630/kW_e for a 100 MW_e and a 200 MW_e project, respectively. The resulting $LCOH_2$ is in the order of €12/kg_{H2} to €14/kg_{H2}. The largest contributions to the $LCOH_2$ are the cost of electricity, the investment cost and associated capital cost, and the high-voltage electricity grid transport tariff. The contribution of the tariff for the hydrogen network is limited but could become of the same order of magnitude if utilisation lags behind expectations.

The investment costs have shown an upward trend in recent years due to increases in the cost of energy, raw materials and labour, and increased interest rates. The investment costs in this study fit in with that trend, although they appear to be slightly higher than several recent studies indicate. Including a compressor in the projects and location-specific circumstances could contribute to this. Furthermore, it should be noted that the data provided showed significant variability. The results, therefore, represent a weighted average picture of the current situation of projects under development in the Netherlands. Lower costs may apply to individual projects.

In addition to the inflationary cost increases, other price-increasing effects may also play a role in the recent cost increases for electrolyser projects, such as the still limited availability of manufacturing capacity for electrolysers, especially in Europe and the US. Therefore, caution should be exercised in generalizing the results and using them as a starting point for projections for future years. Also, the results should not simply be interpreted as an indication of the feasibility of electrolyser projects, let alone as a benchmark for market prices. The results of this research, including the calculation tool, should primarily be considered as a transparent and common basis for project developers, policymakers and

researchers to explore and discuss policy measures that can accelerate investment decisions for electrolysis projects.

Outlook and recommendations

Renewable hydrogen from water electrolysis is considered of great importance for the success of the energy transition. Significant cost savings are generally expected for future electrolyser projects. These savings require the actual realisation of projects. This will lead to development of supply chains which will enhance competition. Gaining experience will result in optimisation and standardisation of plant designs, components and systems. An increase in demand for electrolysers will drive automation of manufacturing. Also, the economies of scale will contribute to cost reduction of electrolyser projects.

However, there is currently considerable uncertainty about the costs of producing renewable hydrogen from water-electrolysis, and the development of costs. For the time being, substantial (financial) contributions from public resources appear to be necessary to kick-start realisation of projects. In this context, and in view of the scope and results of the present study, the following recommendations are made:

- The results of the current research provide an improved and more detailed insight into the current cost basis for the production of renewable hydrogen in the Netherlands through water electrolysis. It is a valuable refinement of the existing knowledge base for policy making. It is therefore advisable to incorporate the findings as much as possible in the ongoing search for a smart mix of policy instruments for effective support of renewable hydrogen.
- Regularly update the present study to continue close monitoring of market developments and to challenge cost projections. To prevent data bias, supplement the analysis with results and findings from other sources and perspectives, such as the results of project submissions for subsidy schemes and bids for tenders, and interviews with, for example, technology providers and EPC-contractors.
- Lagging domestic production (and import) of renewable hydrogen could lead to a shortfall in coverage of the cost of the hydrogen network. This could lead to an increase of the network tariff, as is currently observed for the electricity grid. This looming issue should be addressed in a timely manner by policymakers to prevent it from causing further uncertainty for investments.
- Strong public support for investments in green hydrogen offers the opportunity to gain valuable knowledge and experience regarding the realisation of projects and the performance of electrolysis-based hydrogen plants. In order to achieve a good return on these contributions from society (tax payers money), it is important that this knowledge and experiences are shared as much as possible. The frameworks for providing public support to projects need to be improved to optimize knowledge exchange. Greater transparency can contribute to better policymaking, acceleration of innovation and more efficient development of the hydrogen transition.

The results of this study provides a common basis, for project developers, interest groups, policy makers and researchers, to further improve the cost analysis, and explore options for cost reductions enabling competitive renewable hydrogen production. Suggestions for more extensive and detailed analyses include:

- Simulation of various roll-out scenarios and examining how cost drivers may evolve over time;
- Integrating dynamic aspects for better representation of real-world conditions;
- Comparison with fossil-based hydrogen production methods;

- Incorporating revenue streams and exploring the impact of supporting policy measures.

These directions for further research are expected to yield a more comprehensive and improved understanding of the factors that influence the cost and competitiveness of renewable hydrogen production. Results can contribute to design of effective policies and strategies for the efficient development of green hydrogen as a ver-satile energy vector for a sustainable net-zero energy system.

Contents

1 Introduction

Context

The focus on renewable, green hydrogen has increased significantly in recent years. There is now a broad consensus on the value of renewable hydrogen for making both the energy system and the feedstock system for the chemical industry more sustainable. It is considered essential as it provides a means to decarbonise industrial processes that require hydrogen for non-energy purposes, and processes that lack opportunities for the direct electrification of their energy (heat) demands. Production of hydrogen from water using electricity also provides an energy storage mechanism that offers the opportunity to optimally utilise the potential of energy from variable renewable energy sources and to integrate it into our energy supply, especially the large potential of offshore wind energy.

As a result, in the Netherlands, as Europe and worldwide, many projects are under development for large-scale water-electrolysis with an electrical input capacity of tens of megawatt (MW_e) up to gigawatt (GW_e) scale. Actual realisation, however, is still an exception. Apart from two MW-sized electrolyser projects, the only truly large-scale project currently under construction in the Netherlands is the 200 MW_e Shell project “Holland Hydrogen 1”.

Actual realisation and deployment of water-electrolysis based hydrogen plants is struggling to get off the ground due to high and growing cost that make financing and reaching a viable business case difficult. The cost of producing renewable hydrogen involves a wide range of cost determinants, including the price of electricity, investment costs, the number of operational hours, maintenance costs and network costs. There is ongoing debate as to whether all cost determinants are identified and well-understood, and there is still considerable uncertainty about the values of many of the cost determining factors.

A sound overview and understanding of costs is vital, not only for market parties to be able to properly assess the business case, but also for policy makers to be able to design effective and efficient policy instruments. Such instruments are very much needed to support realisation of green hydrogen production, infrastructure and utilisation projects.

Objective

The aim of this project is to provide a sound overview of the most important cost components for the production of renewable hydrogen through water-electrolysis, and as realistic a picture as possible of the current value of those components. The aim is then to use this data to provide a picture of the levelised costs of (renewable) hydrogen ($LCOH_2$) through electrolysis faced currently by parties that want to invest in the option. The study is considered a first step in a structured analysis of cost components and their impact on the $LCOH_2$, and intends to provide a shared basis for project developers, policy makers and researchers to identify and discuss enabling mechanisms for electrolysis to become a competitive option for hydrogen production.

Scope

This project focuses on calculating the $LCOH_2$ of Dutch projects for the production of hydrogen through electrolysis with renewable electricity, which are currently under development or are already being realised. This therefore concerns (estimates of) current costs insofar as these are clear in the current phase of development of the projects. The analysis covers the production up to and including feeding of the hydrogen into the national hydrogen network.

In the context of the recently revised EU Renewable Energy Directive[1] (RED), hydrogen produced by electrolysis of water using renewable electricity is a so-called renewable fuel of non-biological origin (RFNBO). Electrolysers can also be used to produce other types of hydrogen in addition to RFNBO-hydrogen if grid-mix electricity is used for the production. However, this was not considered in this study. As a consequence the number of full load hours for operation of the electrolyser projects is limited to the possible number of hours of renewable electricity supply from available renewable sources.

The study focuses exclusively on costs. The operation of electrolysers can generate revenues from the sale of RFNBO-hydrogen, low-carbon hydrogen and CO_2 emission allowances, from providing ancillary services to the electricity grid, from avoidance of CO_2 taxes and from indirect cost compensation under the EU Emission Trading System (ETS). Revenues from operating electrolysers, however, are not included in the analyses in this study.

Report structure

The report structure is straightforward. Chapter 2 describes the approach and methods followed in this study. Results and findings are discussed in Chapter 3. Chapter 4 follows with a discussion of the results and a sensitivity analysis for a number of determining cost factors. The final chapter presents the conclusions and suggests options for expanding the calculation model and additional analyses.

[1] Directive - EU - 2023/2413 - EN - EUR-Lex (europa.eu)

2 Approach and methods

Both market parties, united in the interest group NLHydrogen, and the Ministry of Economic Affairs and Climate have supported the idea of a joint exercise to determine the costs of hydrogen production through electrolysis. There is a need for an up-to-date picture of the cost-determining factors, and for an estimate of the costs based on a shared and transparent cost model. This can serve as a basis for exploring measures that lead to cost reductions and can increase the chance of industries and energy companies making final investment decisions. Because parties cannot share their project data and cost models with each other, TNO is involved in this study as an intermediary and independent party. This chapter describes the approach that was followed.

2.1 Cost data collection and processing

Data collection

As a first step in the study, a list of the cost determinants that play a role in the calculation of hydrogen production costs via electrolysis was drawn up together with developers of electrolyser projects and the ministry. A list of the identified cost determining factors can be found in Appendix a. The cost factors can be categorised as follows:

- Unit capital cost (UCC)
- Fixed operational cost
- Variable cost
- Plant performance
- Financial parameters

After establishing the list, TNO assigned starting values to the parameters. These values were mainly based on figures used in the '*Eindadvies basisbedragen SDE++ 2023*'[2] (hereafter referred to as SDE++) for the category *'Waterstof via Elektrolyse'* (Hydrogen via Electrolysis). Furthermore a brief explanation was added to ensure as much as possible an unambiguous interpretation of the scope of the parameters. For instance, parties were asked to include estimates for compression up to 60 bar for the feed-in of produced hydrogen into the national hydrogen network.

The list was then sent to all market parties who had indicated willingness to participate in the project, with the request to adjust the starting values based on data from the projects they are developing. In accordance with EU antitrust legislation, project data from individual projects have exclusively been exchanged between the relevant project developer and TNO, and not between project developers. To ensure data protection, non-disclosure agreements have been signed between TNO and the involved market parties.

Data processing

The data provided by parties is stored in a separate data space with limited access. After receipt of all data, the data were aggregated and processed with the intention to generate a

[2] Eindadvies basisbedragen SDE++ 2023 | Rapport | Rijksoverheid.nl; The SDE++ is the most important subsidy scheme in the Netherlands for support of the deployment of renewable energy technologies and technologies that lead to a reduction of greenhouse gas emissions. The values have not changed for the 2024 round of the SDE++ (Eindadvies basisbedragen SDE++ 2024 (pbl.nl))

single anonymised representative data set for a 100 MW_e electrolysis reference unit. In order to avoid possible traceability to individual projects in the case of limited data, no distinction was made between projects with alkaline and PEM electrolysers when processing the data. No data for solid oxide electrolysers was expected.

Not all projects under development are of the same rated capacity, which could enable evaluation whether there are parameters that show a clear correlation with the size of the projects. In case the data did not appear to be correlated to the rated electrical input capacity of the plant, the median value was used in the final dataset. For data that appeared to have a correlation to the total capacity, data regression was used to determine the interrelationship between parameters.

2.2 Levelised Cost of Hydrogen calculation

In parallel with the data collection, a model was created to calculate the levelised costs of hydrogen ($LCOH_2$) for production by electrolysis. The model has been kept relatively simple so that the calculation is easy to follow and transparent for everyone.

it has been assumed that a power purchase agreement (PPA)) will have to be concluded for the time being for the purchase of renewable electricity in order to demonstrate compliance with the requirements for RFNBO-hydrogen production under the RED and associated delegated acts.[3] A fixed electricity price has been assumed for the PPA. Besides, the model uses a fixed number of full load hours (FLH) to calculate the annual hydrogen production. These are choices made when defining the study, in consultation with the parties involved, in order to limit the required assumptions and the complexity of the $LCOH_2$ model.

Stack degradation has been included, which leads to an increase in power input during the lifetime of the electrolyser to keep production constant. Investment in stack replacement takes place after reaching a set maximum increase in power needed to keep the annual production constant at the fixed number of FLH. However, if the stacks haven't reached end of life in the period of the $LCOH_2$ calculation there is no compensation for the residual value of the stacks. The period for calculation of the $LCOH_2$ is set at 15 years.

The model takes into account a construction and commissioning period for the electrolysis-based hydrogen plant with an assumed curve of expenditure during this period. So, with a three year construction period starting in 2024, the plant starts operating in 2027. There is no significant production during the construction and commissioning period. It has been assumed that the plant will operate at full capacity from this period onward.

The $LCOH_2$ model has been discussed with various parties involved in the project to verify the calculations. The cost model is shared with the project partners, with which they can then perform further exploratory calculations with other data sets to compare their own insights with the dataset from this study. The model can also be used in discussions between market parties and government about support mechanisms to reduce costs far enough, so that green hydrogen can compete with conventional and low-carbon hydrogen produced with natural gas.

[3] EUR-Lex - C(2023)1086 - EN - EUR-Lex (europa.eu)

3 Results and findings

3.1 Data and analysis

Responses

Over the course of the project a total of 14 datasets were received from 11 respondents, with three respondents submitting multiple datasets. The data sets provided varied in completeness. In particular, information on financial parameters was limited. The respondents were themselves responsible for the quality of the data. In a few cases consultation with respondents took place to discuss the provided data and to verify the scope of the parameter values.

Dataset

Using the methods explained in the previous section, a dataset was constructed to represent the data submissions while ensuring anonymity. The dataset can be found in Appendix a. In Table 3.1 some of the data are compared to the values used by PBL in the 'SDE++' in order to provide some context.

Table 3.1: Notable parameters resulting from processing the submission data.

Parameter	Unit	This study	SDE++
Unit Capital Cost (UCC)	€/kW$_e$	3,050.-[4]	2,200.-
Operation and Maintenance (O&M)	€/kW$_e$/yr	75.34[4]	88.-
TSO (TenneT) EHS electricity grid tariff	€/kW$_e$/yr	143.57[5]	144.30
HNS hydrogen network tariff (entry fee)	€/kW$_e$/yr	21.13[6]	-
Total electricity consumption	kWh$_e$/kg$_{H2}$	56[7]	58
Electricity consumption electrolyser system	kWh$_e$/kg$_{H2}$	51	-
Unit cost of electricity (Offshore wind)	€/MWh$_e$	75.-	58.30
Degradation rate	%/1000 hrs	0.18	0.39[8]
Stack replacement cost	% of UCC	10[5]	10[9]
Weighted average cost of capital (WACC)	%	9.5	7.5
Full-load Hours (FLH)	hrs	4,800	5,150[10]

4 Non-constant value across capacity. The value shown represents the value at 100 MW$_e$.
5 Tarievenbesluit TenneT 2024 (acm.nl)
6 Personal communication IJmert van Muilwijk (Energie Nederland); Tariff 2023 after application of price index at a rate of €38.48/kW/yr expressed in 2020 price level (see also download Presentaties VEMW webinar Waterstof - VEMW: kenniscentrum en belangenbehartiger)
7 Assumed to include electricity consumption for compression up to 60 bar. No indication about this in the 'SDE++'.
8 SDE++ takes into account a standard 2% degradation rate per year of the electrodes which leads to a calculated degradation rate of 0.39%/1000 h at 5,150 FLH.
9 Stacks are replaced once in this study. The calculation for the 'SDE++' takes into account two replacements
10 These FLH are based on the hours that a grid-connected electrolyser is able to produce hydrogen at lower emission rates than SMR alternatives. For 100 MW$_e$ electrolyser coupled to 100 MW$_e$ onshore wind, the FLH are estimated at 2,795 hours.

Some notable differences in Table 3.1 are the significantly higher values in this study compared to the values used for the SDE++for the unit capital cost (UCC), the electricity price, and the weighted average cost of capital (WACC). The higher WACC value mainly results from a difference in ratio between loan and equity in financing of the investment. On the other hand, the value for the degradation rate is much lower in this study. This difference, however, has a much smaller effect on the final production costs than higher values for the UCC and WACC, for example. Furthermore this study takes into account a feed-in tariff for using the open access national hydrogen network (that is under construction), which is not the case for the SDE++.

Unit Capital Cost (UCC)

As shown in Table 3.1, the UCC used in the latest version of the 'SDE++' is significantly lower than the UCC found from the responses. Cost escalations during the time between these submissions and the submissions for the SDE++ 2023 could play a role here. Other than that an upward and/or downward bias in the figures provided for this study and the SDE++ market consultation could be part of the explanation of the difference. This is further explained in the discussion section.

A more detailed breakdown of the UCC can be found in Figure 3.1. The pie chart shows that the direct costs, which are based on the cost of the electrolyser system, the balance of plant[11] and the compressor, only account for about 65% of the total costs. Due to cost reductions, this share may even decrease in the coming years. An increase in the number of projects will lead to optimisation and greater standardisation of components and systems, and further automation of production. The economics of scale and numbers will also lead to cost reductions for electrolysers. At the same time, lessons from initial projects can also reduce indirect costs[12], owner costs[13] and unforeseen costs (contingency costs), which can somewhat dampen changes in the share of direct costs.

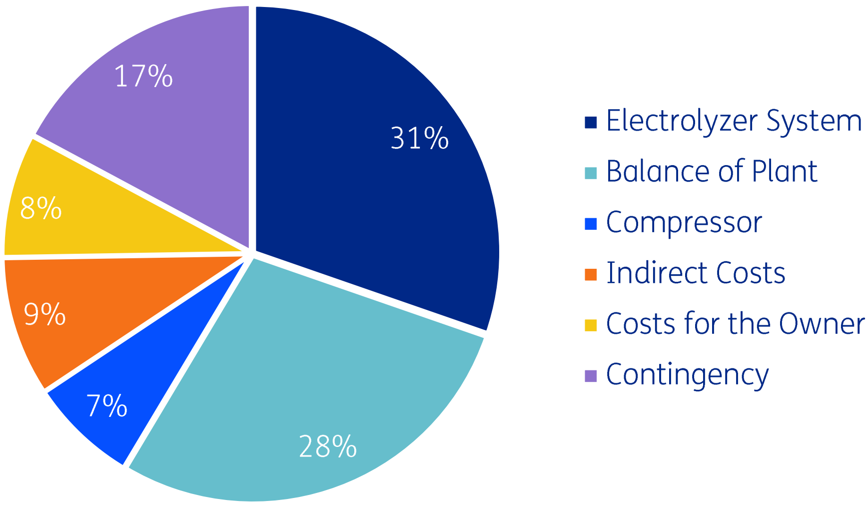

Figure 3.1: Breakdown of the UCC into its constituent parts. The direct costs consist of the Electrolyser System, Balance of Plant and the Compressor. The remaining cost components are not categorized.

[11] Includes, among others, the transformer station (High Voltage to 33 KV), utilities and civil works.
[12] Indirect cost includes, among others, management cost of engineering, procurement and construction (EPC contractor), temporary housing facilities and temporary site services and facilities
[13] Owner's costs in general are the non-EPC costs, e.g. owner's engineering and project management, and land cost and site development outside of project boundaries.

Installed capacity correlation

Some variables exhibited behaviour that suggests a correlation with the total installed capacity. In this dataset, that was only the case for the UCC and the operation and maintenance (O&M) costs. The resulting cost estimates are shown in Figure 3.2, as a function of installed capacity. Note that the reference costs are set at 100 MW_e, which is the reference case for the study. The data sets submitted covered a wide range of electrolysis capacities, but mainly focused on projects of approximately 100 MW_e to 200 MW_e and therefore only estimates within that range are provided.

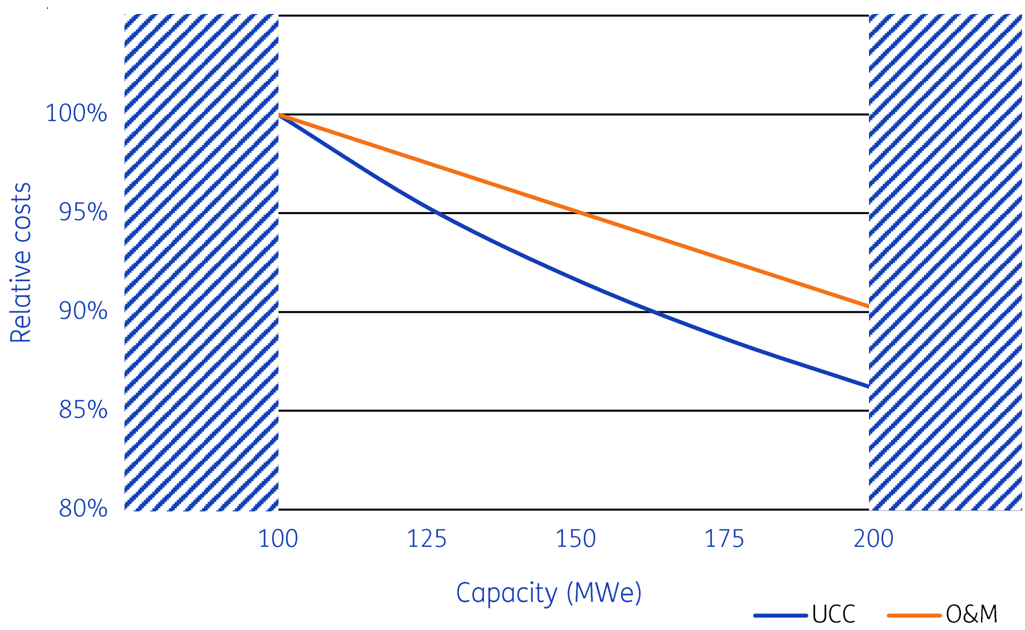

Figure 3.2: Correlation of UCC and O&M with the installed capacity (base value at 100 MW_e). Insufficient data for capacities smaller than 100 MW_e or larger than 200 MW_e.

The solid lines in the graph represent a best fit of the data provided where the value for a 100 MW_e unit as presented in Table 3.1 is set at 100%. It must be noted that while the trend in the data is clear, the R-squared value of the data fits is poor. This parameter is a measure of how well the regression model agrees with the data points, is poor. A poor fit indicates that there is a significant spread in the obtained data.

The data clearly show an effect of economies of scale, reflected in declining costs per unit with increasing unit size. A scaling factor can be derived based on the UCC for 100 MW_e and 200 MW_e that result from the regression analysis. The scaling factor turns out to be 0.79.[14] This scaling factor corresponds well with the factor 0.8 used by PBL in the context of SDE++ calculations. The scaling factor can be used to estimate investment cost for electrolyser units with another capacity. However, caution should be exercised when estimating costs outside the stated capacity range, as the regression analysis is based on a limited number of data points outside that range.

[14] A scaling factor of 0.79 means that if the investment cost for a unit of 100 MW is €305 million, then the investment cost of a 200 MW is not two times €305 million but (200/100)^0.79 times €305 million.

Distribution of parameter values

Understanding the spread and resulting uncertainty of the data is important to assess the accuracy of the results. The spread of the results is exhibited in the form of box and whisker plots. Box 3.1 elaborates briefly on the contents and intuitions of such plots.

In Figure 3.3, the spread is shown for each of the outcomes highlighted in Table 3.1. In this figure the deviation with respect to the mean is shown in order to compare multiple variables with different units, while showing the spread. It is evident from Figure 3.3 that there are significant spreads in a number of parameters. The spread in the UCC is the largest, which can be partially explained by its dependence on the capacity and the fact that there is a significant spread in the capacities of the provided data. By contrast, there does appear to be agreement with regards to the efficiency parameter.

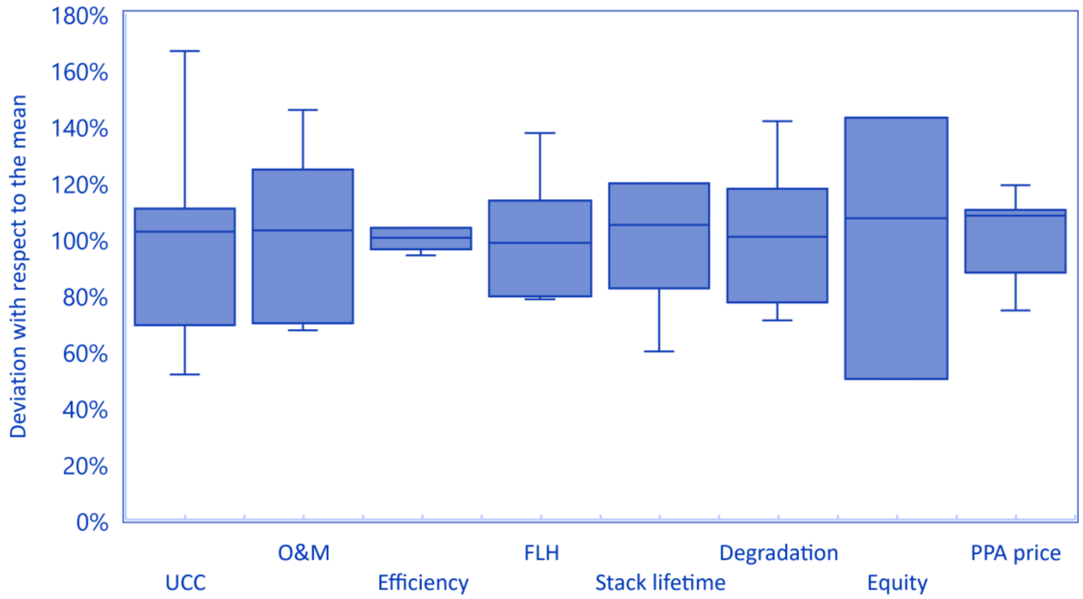

Figure 3.3: Box and Whisker plot for selected parameters as shown in Table 3.1. Quartile deviations are shown with respect to the mean (mean markers omitted). See the Box 3.1 for guidance on how to interpret this figure.

The spread of each of the constituent parts of the UCC is given in Figure 3.4. In this figure, the spread is no longer displayed in relation to the mean, but instead the absolute percentage of the total UCC is shown. This gives a more intuitive interpretation of the composition of the total UCC. The variations in project size, technology, and developer all could contribute to variations within the UCC. Also note that even though the scope for each of the constituent parts was specified, it is possible that respondents interpreted this scope differently, leading to costs falling into different categories for different respondents. This could explain part of the spread in the data.

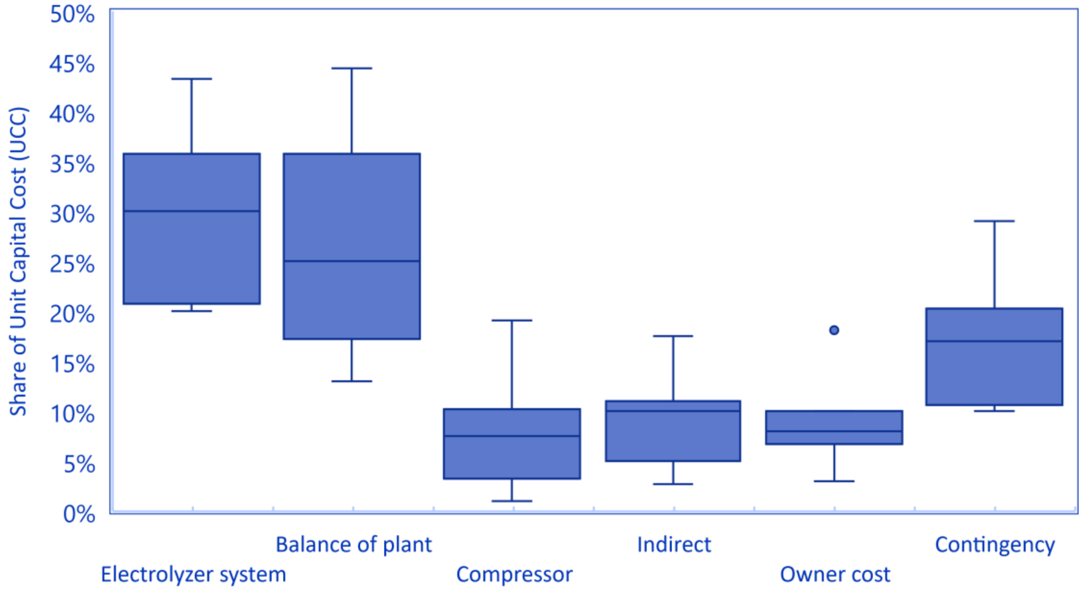

Figure 3.4: Box and Whisker plot of the constituent parts of the UCC, as shown earlier in Figure 3.1. Quartile deviations are shown with respect to the mean (mean markers omitted). See the Box 3.1 for guidance on how to interpret this graph.

Box 3.1: Box and Whisker plots

Box and Whisker plots offer a straightforward means of assessing the spread, central tendency, and potential outliers within a dataset. The central box represents the middle 50% of the data, with a line inside denoting the median of all the data. The lower border of the box represents the median of the lower 50% of the data, while the upper border represents the median of the upper 50% of the data. The "whiskers" extending from the box illustrate the range of the dataset, excluding outliers. Longer whiskers indicate greater variability in the data. Outliers, if present, are depicted as individual points.

3.2 Levelised Cost of Hydrogen Calculation

Nominal Levelised Cost of Hydrogen production

The data exhibited in the previous section are used to calculate the levelised cost of hydrogen production (LCOH$_2$). The cost model is a separate deliverable of this study and is available for general use.[15] Figure 3.5 shows the breakdown of the resulting nominal levelised cost of hydrogen production.

[15] Available as a supplementary file to the web version to this report on Energy.nl

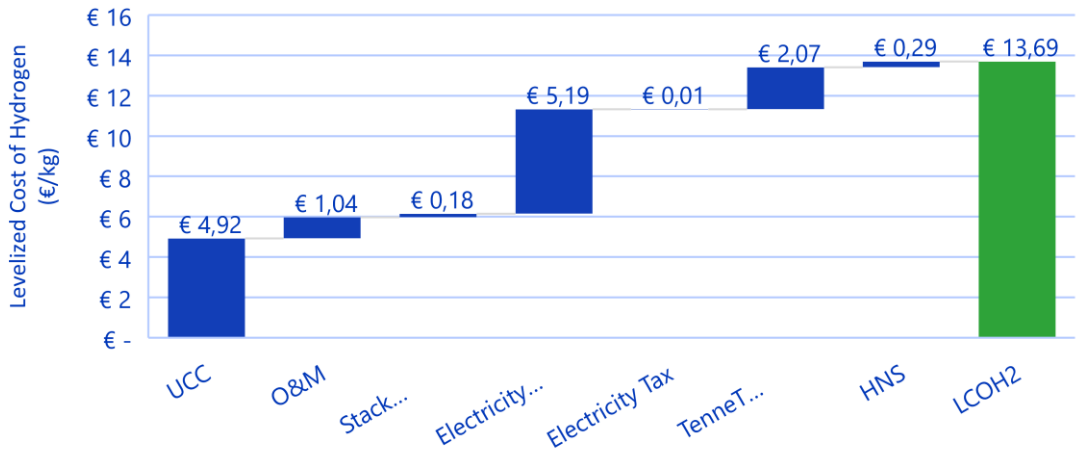

Figure 3.5: Nominal levelised cost of hydrogen production for the base case.

As expected, the UCC and electricity costs are the main cost factors, which combine for over €10/kg_{H2} already. One factor that is typically discussed less in the literature is the grid tariff for the high voltage grid. The relevant tariff for large-scale electrolysers has more than quadrupled in 2024 compared to the 2021 level, from €32.80/kW_e/yr to €143.57/kW_e/yr. It now makes a significant contribution of more than €2/kg_{H2} to the $LCOH_2$, as is shown in Figure 3.5. The exact development of the tariff is uncertain as it is partly determined by uncertain developments in energy prices. Nevertheless, it is expected that the necessary investments in expanding the high-voltage network will result in further increases in the near future. The sensitivity to the grid tariff is discussed in more detail in the following chapter. Because of the large impact of the tariff on the $LCOH_2$ ongoing discussions focus on whether it is possible to (partially) exempt electrolysers from these costs.

The contribution of the tariff for the hydrogen network is modest. At the moment, the total entry and exit tariff for the hydrogen network is approximately a quarter of the electricity grid tariff. As this study focuses on the costs of hydrogen production for the producer, up to and including feeding the hydrogen into a national hydrogen network, only half of the total tariff is included in the $LCOH_2$ calculation of the base case. This reduces the contribution of the hydrogen network in the $LCOH_2$ of the base case to approximately one-eighth of the contribution of the electricity grid tariff. However, due to possible underutilization, the impact of the hydrogen network tariff may increase in the foreseeable future and even become comparable to the electricity network tariff, as will be argued in the next chapter.

4 Discussion and sensitivity analysis

Bandwidth of levelised cost of hydrogen production

The cost of hydrogen production was calculated for each dataset submitted to provide insight into the bandwidth of the cost of hydrogen production. In case data for certain parameters were not provided by respondents, values determined for the base case were used instead for the calculations. The outcomes are shown in Figure 4.1.

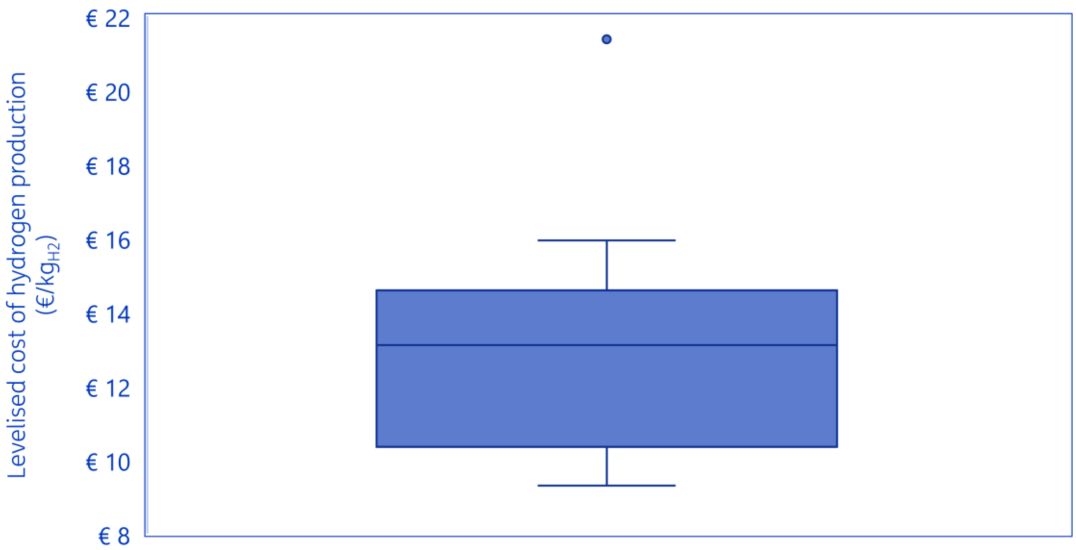

Figure 4.1: A box-and-whisker plot for the $LCOH_2$ calculated individually for each dataset received. For any missing data points, parameter values from the base case were used in the calculations.

The graph shows a significant spread in the results for the $LCOH_2$ based on the different data sets, with one clear outlier. A spread is to be expected because the data sets used relate to projects with different capacities, where large-scale projects generally tend to have a lower UCC than small-scale projects, as illustrated in Figure 3.2. However, the differences in electrolysis capacity only explains part of the spread. Other factors such as differences in electricity price, FLH and WACC also contribute. Furthermore, it is noted that in this case the lower and upper values represented by the whisker in the graph do not correspond to received datasets for projects with the largest and smallest capacities. The fact that datasets from projects with different capacities are used for the results in Figure 4.1 also explains why the $LCOH_2$, is not more central between the extreme values, as calculated for the base case for a 100 MW_e project, shown in Figure 3.5.

The results for the base case in the previous chapter represent the general or average picture for cost factors and $LCOH_2$ that emerges from the data provided by project developers in the context of this study. Figure 4.1 illustrates that individual projects can score better. These projects will potentially rise to the top in tenders for subsidy because more or larger scale projects can then be achieved with the available budget. This implies that in practice the observed $LCOH_2$ may relate more to the lower end of the bandwidth outlined in Figure 4.1 than to the base case as shown in Figure 3.5.[16]

Comparison with the existing literature

To provide context to the results highlighted in the previous sections, Table 4.1 exhibits the $LCOH_2$ calculated in various recent studies.

Table 4.1: Calculated $LCOH_2$ of various recent studies, including the key parameter values.

Source	Ref. year	UCC (€/kW$_e$)	E-price (€/MWh$_e$)	FLH (hrs)	$LCOH_2$ (€/kg$_{H2}$)
This Study (2024)	**2023**	**3,050**	**75**	**4,800**	**13.69**
EU Hydrogen Observatory (2024)	2022	1,250	86	4,120	7.87
Berenschot & TNO (2023)	2023	2,200	50	4,200	12.14
Wood Mackenzie (2023)	2023	1,820	78	4,800	6.72
Umlaut & Agora Industry (2023)	2023	1,200	70	4,000	5.98
CE Delft & TNO (2023)	2030	1,710	40	4,300	8.30

The data in the table show that the calculated $LCOH_2$ in this study is significantly higher than in most other studies (European Hydrogen Observatory, 2024), (Berenschot & TNO, 2023), (Wood Mackenzie, 2023), (Umlaut & Agora Industry, 2023), (CE Delft TNO, 2023). Based on the data included in the overview, this seems to be due to a significantly higher estimate of the UCC in this study compared to the other studies. But differences in many other cost factors, such as WACC, O&M costs, project life and included network tariffs, as well as the exact calculation method used, can also contribute to the differences in $LCOH_2$.

The difference in UCC in the studies with a similar reference year could be due to a difference in scope of the UCC. Generic studies that are not based on specific projects for which a (detailed) design and cost study has been carried out are often mainly based on estimates of direct costs. Cost factors that fall outside the direct costs, such as indirect costs, owner's costs and contingency costs, are often insufficiently included or not considered

[16] Recent results of the pilot auction for renewable hydrogen of the European Hydrogen Band (EHB) illustrate that individual projects can score better and will be the winners in tenders for RFNBO-hydrogen production projects (Competitive bidding - European Commission (europa.eu)). Unfortunately, none of the Dutch bids were among the winning projects, but the evaluation of the bids presents interesting results. The evaluation shows bids from seven Dutch projects with a total capacity of 770 MW$_e$ for which an average $LCOH_2$ is calculated of €9.8/kg. This is clearly less than the $LCOH_2$ reported for the 100 MW$_e$ reference unit in the present study. However, it coincides quite well with the lower part of results shown in Figure 4.1, although it is not clear whether the assumptions for the $LCOH_2$ calculations are entirely comparable. A nice result is that the average $LCOH_2$ of Dutch projects compare quite favourable with the average $LCOH_2$ of projects in all other Western European countries, including Germany and Belgium. This is remarkable given the discussion about the high electricity grid tariffs in the Netherlands and the exemptions for this in Germany and Belgium. However, insufficient data are available to explain and interpret this result. Another remarkable result is that the best scoring Dutch project submitted a bid for a contribution in the order of only €1/kg, and the second best a bid between €1.5/kg and €2/kg. The cost gap between RFNBO-hydrogen and fossil hydrogen is much larger. These projects may possibly have other favourable sources of income to build their business case, or the strategy was (without success this time): better ask for a limited contribution to closing the cost gap than obtain no contribution at all. The question therefore remains whether granting the requested contribution would have directly led to an FID for the projects. This also applies to the seven winning projects of the EHB pilot auction, who submitted bids between only €0.37/kg and €0.48/kg of renewable hydrogen produced. Clearly, the full picture is still missing, but these results also provide useful input for discussion between private and public stakeholders on what is needed to realise electrolyser-based sustainable hydrogen production projects.

because they are location-specific and can also depend on the development phase of a project. As shown in Figure 3.1, these costs make up a significant portion of the total costs.

The context in which data is provided can also play a role in differences between figures. In case of tenders for hydrogen projects, parties have an interest in calculating optimistically in order to win a tender. If data about UCC are derived from such information, it is possible that an overly favourable picture is assumed. The UCC in the (Berenschot & TNO, 2023) study is derived from information from the Dutch SDE++ subsidy scheme. Although this information has been obtained through a market consultation, the subsidy intensity per ton of CO_2 avoided by applying a technology is an important criterion in this subsidy instrument. This can mean that costs issued are slightly more favourable than in practice to better compare with other technologies supported by the scheme. Such possible effects do not play a role in this study. On the contrary. In this case, there is in principle no reason to be reluctant in presenting costs, as this can create a good starting position in discussions for development of new support mechanisms that should lead to the adoption of a final investment decisions. Although we have no reason to assume that the costs are on the high side for this reason, it is good to include this type of context in considerations regarding differences between figures in various data sources.

In the Global Hydrogen Review of 2023, the IEA mentions that 'the installed cost of electrolysers has increased significantly in the past few years due to increases in materials and labour costs' (IEA, 2023). The IEA reports 'a year-on-year increase of 9% compared to the UCC range observed in 2021', with UCC in 2023 being in the range of \$1,700/kW_e to \$2,000/kW_e. 'However, in Europe', the report continues, 'some project developers have observed even higher inflation values, up to 40% in certain cases'. This would indicate UCC as high as \$2,400/kW_e, which gets close to the UCC found in this study. The high value of the UCC found in this study is also supported by figures in the 'Electrolyser Price Survey 2024' from BloombergNEF (BNEF, 2024). They conclude that the cost of electrolysers for hydrogen production is rising instead of falling, and report that the average system-level costs for large-scale electrolysers made in Europe or the US are currently around \$2,500/kW_e.

Effect of UCC reduction

A change in the UCC leads to a proportional change in the UCC contribution to the $LCOH_2$, e.g. a halving of the UCC leads to a halving of the contribution of the UCC to the $LCOH_2$. Significant cost savings are generally expected for future electrolyser projects. However, these savings require the actual realisation of projects. This will lead to development of supply chains which will enhance competition. Gaining experience will result in optimisation and standardisation of plant designs, components and systems. An increase in demand for electrolysers will drive automation of manufacturing. Also, the economies of scale (see section below) will contribute to cost reduction of electrolyser projects.

The UCC is made up of several cost components (see Figure 3.1) and the rate of cost reduction over time is not necessarily the same for all components. There will be differences between the innovative parts of an electrolysis-based hydrogen plant, such as the electrolysers themselves, and more conventional parts, such as the transformer station connecting the electrolyser systems with the high voltage grid, utilities and all civil works. However, cost savings on all components seem necessary to arrive at the desired low UCC. The data provided indicate that the cost of the electrolyser system is only 30% of the UCC. A halving of the cost of the electrolyser system – with other cost components remaining the same - would thus only lead to a 15% lower contribution of the UCC to the $LCOH_2$.

As the announced expansions of manufacturing capacity of electrolyser systems have not yet been realised, especially in Europe and the US, it is possible that the recent cost increases also partly are a reflection of market tightness as the demand for these systems increases. In that case, an additional and rapid decline in the UCC could occur once the manufacturing capacity is in place, on top of the impact of the effects mentioned above. The near future will tell whether this is the case.

Regardless of technology and manufacturing capacity related effects, the effective UCC, which project developers need to deal with, will decrease if part of the investment cost is covered by an investment subsidy. The higher the share of subsidy, the lower the contribution of the UCC to the $LCOH_2$. The decrease may be more than proportional because covering a (large) part of the costs reduces uncertainty in the business case, and can lead to more favourable financing conditions, i.e. a reduction in the WACC.

Finally, the O&M costs are defined as a percentage of the direct cost in the current $LCOH_2$ calculation. This means that the O&M costs change proportionally to the direct costs. The reliability of systems will increase as the number of systems increases, which can lead to a decrease in O&M costs. However, it is doubtful whether the relation between direct costs and O&M costs remains the same if the O&M costs depend mainly on labour costs, especially with sharply declining direct costs. Therefore, this cost factor will have to be examined more closely, as soon as sufficient practical data are available.

Advantages of scaling installed capacity

Analysis of the cost data in the received data sets exhibited a decrease in the UCC and the unit O&M costs with an increase in installed electrolyser capacity, as shown in Figure 3.2. In order to examine the effects of these changes on the levelised costs, Table 4.2 outlines the effect of the capacity dependence of these cost factors on the $LCOH_2$ for electrolysers with a capacity varying between 100 MW_e and 200 MW_e. The results indicate that doubling the capacity from 100 MW_e to 200 MW_e leads to a decrease in $LCOH_2$ of approximately €1/kg_{H2}.

Table 4.2: Nominal levelised cost of hydrogen contributions for the UCC and O&M costs as the installed capacity of the facility increases.

Electrolyser capacity	UCC	O&M	$LCOH_2$
100MW	€4.92/kg_{H2}	€1.04/kg_{H2}	€13.69/kg_{H2}
150MW	€4.52/kg_{H2}	€0.91/kg_{H2}	€13.13/kg_{H2}
200MW	€4.25/kg_{H2}	€0.81/kg_{H2}	€12.75/kg_{H2}

Impact of financing aspects on the costs

Arranging financing, especially external financing, for early projects could pose a significant challenge. Various respondents raised concerns over being able to arrange any form of debt financing at all. Figure 4.2 shows the cost breakdown and resulting $LCOH_2$ if the 100 MW_e project is financed with 100% equity. The WACC grows as the equity share increases, which leads to an increase in the contribution of the initial investment costs to the $LCOH_2$. The increase in the equity share from 67% (Figure 3.5) in the base case to 100% leads to an increase of the $LCOH_2$ by €0.74/kg_{H2} hydrogen. A lower equity share of 30% and a debt share of 70%, as used in the calculations for the SDE++ scheme, would result in a decrease of the $LCOH_2$ by €0.74/kg_{H2} and an overall $LCOH_2$ just below €13/kg_{H2} hydrogen.

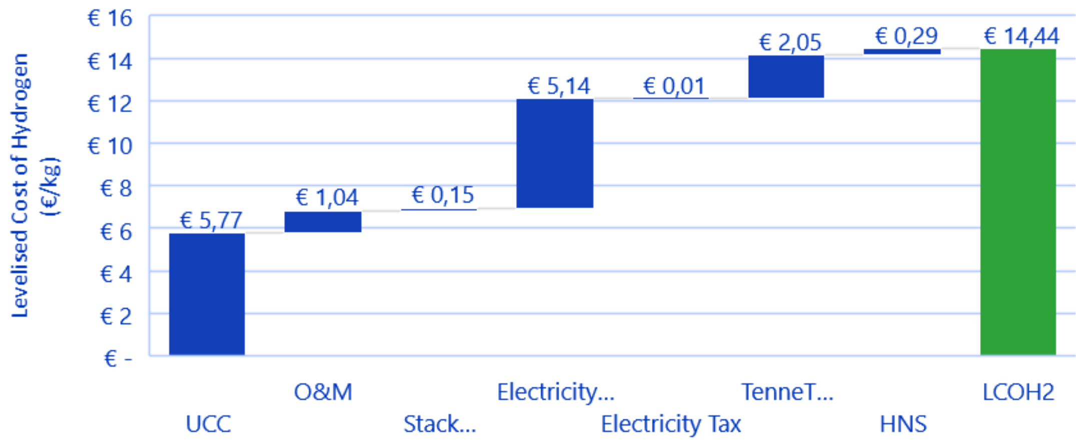

Figure 4.2: Nominal $LCOH_2$ breakdown for a project funded with 100% equity.

Impact of electricity price changes

The contribution of the electricity price to the $LCOH_2$ changes proportionally with changes in the average electricity price for production of hydrogen by water-electrolysis. The current view is that PPAs for renewable electricity are necessary to qualify the hydrogen produced as RFNBO-hydrogen and to comply with RFNBO-obligations arising from the recent revision of the RED. Currently, the PPA costs for electricity from offshore wind are estimated at €75/MWh_e, and electricity from onshore wind and solar at €80/MWh_e.

If the share of renewable electricity on the grid continues to increase, the need for having a PPA may change. The number of hours with an abundant supply of renewable electricity will then increase, resulting in longer periods of relatively low electricity prices. This will eventually make it possible to achieve additional, and possibly even sufficient, operating hours by connecting electrolysers to the grid and purchasing relatively cheap electricity on the electricity market. A recent exploratory study into the operations of a hydrogen spot market indicates that electrolysers could run with 4,200 FLH, producing renewable hydrogen at marginal costs, i.e. electricity cost and O&M costs, of approximately €3.3/kg_{H2} with assumed supply and demand figures for electricity and hydrogen in 2030 (TNO, HyXchange & Berenschot, 2024). However, it is not yet clear whether this could be part of a feasible business case, as this does not cover capital expenditure on projects.

Effect of full load hours

The base case assumes 4,800 FLH annually. This does not mean that the installation runs at 100% for 4,800 hours and is turned off the rest of the time. In principle, the installation would also run at 55% of capacity for 8,760 hours. Cumulatively this also provides 4,800 FLH. In practice, the situation will lie somewhere between these two extremes.

A higher or lower number of FLH produces more or less hydrogen production, causing the $LCOH_2$ to be lower or higher. The input from the market parties was also not homogeneous with regard to the number of FLH. To illustrate the effect of a different number of FLH on the $LCOH_2$, Figure 4.3 shows the results for a number of FLH that is 500 hours higher and 500 hours lower than in the base case.

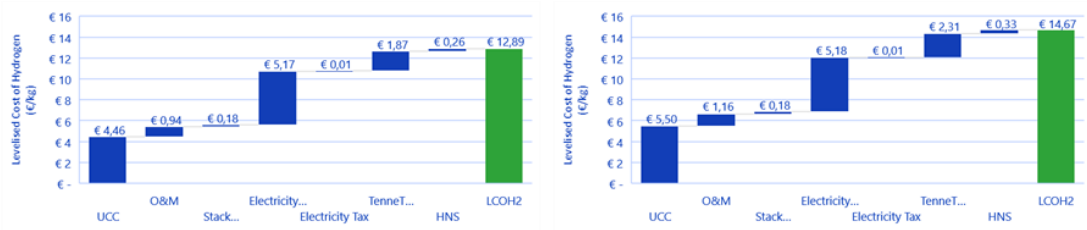

Figure 4.3: Breakdown of $LCOH_2$ for cases with 5,300 (left) and 4,300 (right) FLH, respectively.

The results show that an increase of 500 FLH compared to the base case leads to a decrease in $LCOH_2$ by approximately €0.8/kg_{H2}, whereas a decrease of 500 FLH leads to an increase in $LCOH_2$ by almost €1/kg_{H2}. Thus, the $LCOH_2$ is sensitive to the amount of operating hours. The change in FLH mainly affects the contribution of the cost factors that are expressed in electrolyser capacity (i.e. power) as each kilowatt of capacity produces more or less hydrogen. The change in FLH has little effect on cost factors based on kilowatt hours (i.e. electricity or energy) because the average electricity consumption per unit of hydrogen does not change significantly. The small variation in the contribution of the electricity price is the result of the moment of stack replacement and its effect on the average electricity consumption per unit of hydrogen.

Sensitivity of $LCOH_2$ to TSO grid tariffs for large-scale electrolysers

The extra high-voltage (Extrahoogspanning; EHS) grid tariffs of the transmission system operator (TSO) TenneT apply to large-scale electrolysers in the Netherlands. These tariffs have seen significant increases over the previous years, and further increases are expected in the near future. This increase in rates leads to a further increase in the already high $LCOH_2$ and thus to a further deterioration of the business case for renewable hydrogen from electrolysis. Applying the rate for 2024 already results in a contribution of just over €2/kg_{H2}. There is, therefore, ongoing discussion about the possibilities to reduce these costs, partly because of exemptions for electrolysers from these rates in neighbouring countries (E-Bridge, 2024), which could mean that there is no level playing field for Dutch electrolyser projects.

Table 4.3 shows the contribution to the $LCOH_2$ of two alternative scenarios for the development of grid tariffs; a pessimistic scenario with further rising tariffs and a slightly more positive development. The background of both scenarios is explained in Appendix b. If full exemption would ultimately be granted, the contribution will of course be reduced to zero. However, the $LCOH_2$ for the 100 MW electrolyser that is taken as a starting point in this study will still be more than €11.50/kg_{H2}.

Table 4.3: Contributions of the TSO grid tariff to the $LCOH_2$ for different scenarios of grid tariff development.

Scenario EHS grid tariff development	Contribution of EHS grid tariff to $LCOH_2$
Flat inflation correction	€2.07/kg_{H2}
Flat inflation correction (50% exemption)	€1.02/kg_{H2}
Pessimistic Scenario	€3.04/kg_{H2}

Sensitivity of $LCOH_2$ to hydrogen network tariffs

This study focuses on the costs of hydrogen production for the producer, up to and including feeding the hydrogen into a national hydrogen network. Initially, therefore, only the entry part of the hydrogen network tariff was included in the calculation of the $LCOH_2$. It is assumed to be half of the total tariff which means that consumers who receive hydrogen via the network have to pay the exit part of the network tariff in addition to the commodity price. Including the full tariff in the $LCOH_2$ calculation leads to doubling of the contribution from €0.29/kg_{H2} to €0.58/kg_{H2}.

The current rate is a provisional rate, determined by dividing an estimate of the operational costs of the hydrogen network by the target for installed electrolyser capacity in 2030, i.e. 4 GW_e. No contribution from hydrogen imports has been taken into account, because no concrete goal has been defined for this so far. The provisional tariff (entry and exit fee) has been set at €42.27/kW_e/yr (price level 2023). However, if the rollout of electrolysis lags behind, it can be expected that the tariff will be adjusted upwards once regulated network management with regulated network tariffs need to be in place from 2031, in line with the EU Hydrogen and decarbonised gas market regulation[17]. For example, if only 1 to 2 GW_e is installed in 2030, which is not an unrealistic scenario given the current slow progress in project realisations, and network utilisation from imports also lags behind, this could lead to an increase in the tariff by a factor of 2 to 4. It could even be slightly higher if missed income from previous years must be made up in the next period.

At the moment, the total tariff for the hydrogen network is only a quarter of the tariff for the electricity network. But with an increase as outlined above, the impact of the tariff for the hydrogen network could become of a comparable magnitude as the rate for the electricity network. This would represent an additional hurdle in arriving at a feasible business case for RFNBO-hydrogen.

The effect of stacking some favourable assumptions

Combining the 100 MW_e unit with the higher amount of FLH, an exemption from network charges and financing with 70% debt, i.e. the most favourable cases discussed above, results in an $LCOH_2$ of €10.33/kg_{H2}. The outcome of a calculation with a combination of the factors appears to be slightly less favourable than reducing the base scenario with the effect of the individual factors as shown in the above paragraphs as this leads to €10.08/kg_{H2}. The same calculation with a combination of favourable factors for a 200 MW_e unit leads to an $LCOH_2$ of €9.59/kg_{H2}. Assuming a construction period of one year instead of three years would further reduce the $LCOH_2$ to €9.16/kg_{H2}.

Although considerably lower than the base case calculation, these cost levels are still well above the costs for production of hydrogen with natural gas. This is a clear illustration of why parties are struggling to arrive at an FID for their projects, and why there have been many reports lately about projects that are temporarily put on hold or even terminated.

[17] Hydrogen and decarbonised gas market package (europa.eu)

5 Conclusions and recommendations

5.1 Conclusions

This cost study is unique in the sense that it is based on a significant number of real electrolysis projects under development for which not only integral project costs are available for a cost analysis but also a breakdown of cost elements. This report presents RFNBO-hydrogen production cost results based on cost data from fourteen electrolysis projects currently in various stages of development in the Netherlands. The results provide an overview of cost-determining factors, and a snapshot of the current size of these factors and the resulting $LCOH_2$.

The snapshot does not include the effects of available subsidies and potential income from operating electrolysers, nor has any attempt been made to optimise the results. The results should therefore not be regarded simply as a benchmark for the feasibility of electrolyser projects, let alone as a benchmark for market prices. Given the context of increasing demand for electrolyser systems, immature supply chains and evolving policymaking, caution should also be exercised when using the results as a basis for projections into the coming years. With this in mind, based on the findings, the following can be concluded:

Main contributions to the levelised cost of hydrogen

The largest contributions to the $LCOH_2$ are the cost of electricity, the investment cost and associated capital cost of a hydrogen plant based on water-electrolysis, and the tariff for a connection to the high-voltage electricity grid.

High investment costs for an electrolysis project

The unit capital cost of a hydrogen plant based on water electrolysis appears to be higher than generally assumed so far. It was already clear that project costs include more than the direct costs for an electrolyser, which is why the UCC estimate in the context of the SDE++ has already been increased to €2,200/kW_e for a 100 MW_e project. Based on data collected and analysed in this project, the level of investment cost faced by market parties again appears to be significantly higher than assumed until recently, and is estimated at €3,050/kW_e for a 100 MW_e project.

Rising electricity grid tariff considerably impacts the $LCOH_2$

The electricity grid tariffs have increased significantly in recent years. The contribution to the $LCOH_2$ of the 2024 tariff applicable to large-scale electrolysers is calculated to amount approximately €2/kg_{H2}. This is of the same order of magnitude as the integral cost of producing hydrogen based on natural gas which clearly illustrates the (negative) impact the current grid tariff has on the business case of producing green hydrogen. As the Dutch TSO TenneT expects large investments in expansion of the electricity transmission grid, including the offshore grid, it is likely that, with other elements determining the grid tariff remaining equal, the cost of grid tariffs will further increase.

Hydrogen network tariffs could become an additional hurdle for green hydrogen

The currently established combined entry and exit tariff of hydrogen for the hydrogen network amounts approximately a quarter to a third of the electricity grid tariff. But it is based on the expectation of an installed electrolyser capacity of 4 GW by 2030. If this lags behind and the tariff is adjusted to the actual installed capacity it could become of the same order of magnitude as the electricity grid tariff. Such an increase and the uncertainty about this will make it more difficult to take investment decisions.

Financing is still difficult due to uncertainties, leading to relatively high WACC

High and rising costs create uncertainties that make favourable financing of projects difficult, especially in a (hydrogen) market that has yet to take shape. The project developers, who have provided information about this, indicate that they take into account that a large share of equity is required to finance electrolyser projects, up to 100%, which leads to a relatively high value for the WACC in the calculation of the $LCOH_2$.

There is a large gap to be bridged to make green hydrogen competitive

Electrolyser projects of 100 MW_e to 200 MW_e, for which one would like to take a final investment decision and would like to start construction in 2024 in the Netherlands, face an $LCOH_2$ of the order of €12/kg_{H2} to €14/kg_{H2} without taking into account any form of subsidy, or revenues from electrolyser operations. If we include some of the more favourable cases, this range could be extended down to approximately €10/kg_{H2}. Various factors can be optimised and contribute to improvement of the $LCOH_2$. But the current analysis also shows that even with stacking of multiple favourable conditions, a significant gap still remains, which needs to be bridged to compete with fossil based hydrogen.

5.2 Recommendations

Include study findings in ongoing search for a smart mix of support instruments

Considerable reductions in unit capital cost, electricity cost and electricity grid tariffs appear to be a prerequisite for achieving competitive production cost of RFNBO-hydrogen. This insight is not completely new although the challenge seems greater than previously thought, and the issue of grid tariffs only came into focus recently. Measures to reduce costs, and create favourable (financing) conditions for investments, have therefore been subject of research and policy making for some time. This includes measures such as stimulating R&D projects, subsidies on investment or integral operating cost and the use of RFNBO hydrogen, a purchase or user obligation with tradable certificates, and full or partial exemptions from network tariffs. In the meantime, significant budgets have already been arranged. However, it appears time consuming to find the right mix of instruments to get production and use of RFNBO-hydrogen off the ground, not least because the costs continue to prove higher than expected. An obvious recommendation is therefore to include the findings of this study as much as possible in the ongoing search for the design of a smart mix of instruments for effective support of RFNBO-hydrogen.

Continue close monitoring of market developments

There are many studies that assume significant cost reductions for electrolysers and electrolyser projects in the foreseeable future. However, the substantiation for this is usually qualitative. The projections are difficult to reconcile with the theory of learning curves, which assumes that cost decrease by a certain percentage for every doubling of installed capacity of a technology. Many cost estimates require learning rates for which are unprecedented. The cost reductions could eventually become a reality, but possibly only in a slightly longer term. The speed of expanding capacity, gaining experience, and incorporating lessons learned and new solutions into next generations of technology and projects takes time. In order to properly monitor these dynamics and market developments, it is recommended to regularly update the present study. The insights from this can be used to facilitate a balanced and fact-based discussion between private and public stakeholders about the development of effective measures to reduce costs and accelerate the hydrogen transition. Because the data provided for the present type of study may not be entirely without bias, it is advisable to supplement the analysis with results and findings from other sources such as the results of project submissions for subsidy schemes and bids for tenders, and interviews with, for example, technology providers and EPC-contractors.

Provide clarity in a timely manner about future tariffs for the national hydrogen network

Too little installed electrolyser capacity is more likely than too much installed capacity. Lagging domestic production (and import) of RFNBO-hydrogen could lead to a shortfall in coverage of the cost of the hydrogen network. This could lead to an increase of the network tariff, as is currently observed for the electricity grid. This looming issue should be addressed in a timely manner to prevent it from causing further uncertainty for investments.

Ensure maximum return on public investments by sharing knowledge and experiences

The realisation of RFNBO-hydrogen production requires substantial support from public resources. These investments bring the opportunity to gain valuable knowledge and experiences with regard to the realisation of projects and the production of green hydrogen. In order to achieve a good return on this social investment, it is important that this knowledge and experiences are shared as much as possible. This can contribute to accelerating of the hydrogen transition so that costs can fall more quickly. It is recommended to investigate the possibilities for setting up a knowledge coalition, learning community, or a comparable platform for the exchange of knowledge and experiences in the field of hydrogen production by water-electrolysis.

5.3 Future research

This research can mark the beginning of more extensive and detailed analyses to jointly explore, for example, technology options to reduce the cost of green hydrogen production, or the effect of specific policy measures, with project developers, interest groups, policy makers and researchers. Suggestions for further research include:

Testing potential developments of cost parameters over the medium/long term

Further research could test potential developments of cost parameters over the medium to long term. This could cover cost projections of the UCC and electricity, and tariffs for both electricity grid and hydrogen network. A learning curve module could be included in the calculation tool for UCC cost projections. This could include a multi-component learning curve approach in combination with further cost breakdown of the components of an electrolyser system and the other parts of the project costs. In this way, the innovation potential and cost reduction possibilities of the individual components in an electrolyser and other cost elements of projects could be better taken into account. Simulation of various scenarios and examining how cost drivers evolve over time, can generate $LCOH_2$ projections that account for future uncertainties and technological advancements, which can aid strategic planning and investment decisions, providing input to further shape research agendas.

Integrating dynamic aspects for better representation of real-world conditions.

The calculations can be improved by using renewable electricity supply profiles for different sources. This can be practical data from current wind and solar farms or simulated profiles of wind and solar farms yet to be built. For the electrolyser it can then be taken into account that the efficiency of production increases as the electrolyser is operated at a lower part load level, but also that a minimum part load level must be maintained for safety reasons. The impact of different scenarios can then be explored, such as oversizing a PPA, combining PPAs for different sources, and whether or not to switch off the electrolyser if the supply of renewable electricity falls below the minimum part load level. It may also be possible to explore whether and to what extent additional production of low-carbon hydrogen can contribute to reducing the $LCOH_2$.

Comparison with fossil-based hydrogen production methods

Analysing the cost gap between electrolytic hydrogen and fossil-based production options is valuable in order to guide policy development towards a level-playing field for the various production methods. This would require integrating data on fossil-based hydrogen production, including e.g. performance characteristics of technologies, energy prices cost and emission factors. If relevant, a comparison with other renewable hydrogen production methods could also be considered.

Incorporating revenue streams and exploring the impact of supporting policy measures

The study on costs could be extended by a study on potential revenue streams of operating an electrolyser, and the impact of various supporting mechanisms to reduce the cost of hydrogen production. By considering revenues in addition to costs, a better insight into business cases of electrolyser projects can be obtained. In addition to the sale of hydrogen, revenues can, for example, be generated from the sale of oxygen, the provision of supporting services to the electricity grid and the sale of CO_2 emission allowances. Indirectly, the value of RFNBO-certificates from obligation schemes for the industry and transport sector will also contribute to revenues because they influence the price at which RFNBO-hydrogen can be sold. Finally, subsidies can also be counted as income.

In conclusion, it is expected that these research directions yield a more comprehensive and improved understanding of the factors that influence the costs of hydrogen production. This can contribute to the design of effective policies and strategies for the development of green hydrogen as a versatile energy vector for a sustainable net-zero energy system.

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Appendix A
List of base case parameter values

Table A.1: List of base case parameter values

Unit Capital Costs	Unit	Mean
Total	€/kW$_e$	3,050
Direct costs	%	65%
of which Electrolyzer system	%	30%
of which Balance of plant	%	28%
of which Compressor	%	7%
Indirect costs	%	9%
Owners costs	%	9%
Contingency	%	17%
Fixed OPEX		
Annual operating and maintenance cost	% of Direct costs	3.8%
Annual operating and maintenance cost	€/kW$_e$/yr	75.34
Grid fee (fixed)	€/kW$_e$/yr	143.57
Capacity tariff H_2 network (entry part; 50% of total tariff)	€/kW$_e$/yr	21.13
Plant performance		
Specific electricity consumption (plant level)	kWh$_e$/kg$_{H2}$	56.00
of which Electricity consumption electrolyser system	%	91%
Stack lifetime (replacement at 10% degradation)	hrs	55,556
Capacity level for stack replacement	% of rated capacity	90%
Stack degradation rate	%/1000 hrs	0.18%
Minimum part load operation	% of rated capacity	22.5%
Variable OPEX		
Contracted capacity offshore wind PPA (for 100 MW$_e$ unit)	MW$_e$	100
Annual average full load hours	hrs/yr	4,800
Electricity tax	€/MWh	1.15

Financial parameters		
WACC	%	9.5%
with Debt share of total capital required (TCR)	%	33%
with Equity share of TCR	%	6%
with Interest rate	%	67%
with Required return on equity	%	12%
Corporation tax	%	25.8%
Inflation rate	%	2%
Plant (economic) lifespan	yr	15
Term of the loan	yr	15
Design and construction period	yr	3
Curve of capital expenditure:		
with spending in year 1	% of TCR	35%
with spending in year 2	% of TCR	45%
with spending in year 3	% of TCR	20%

Appendix B
TSO grid tariff development scenarios

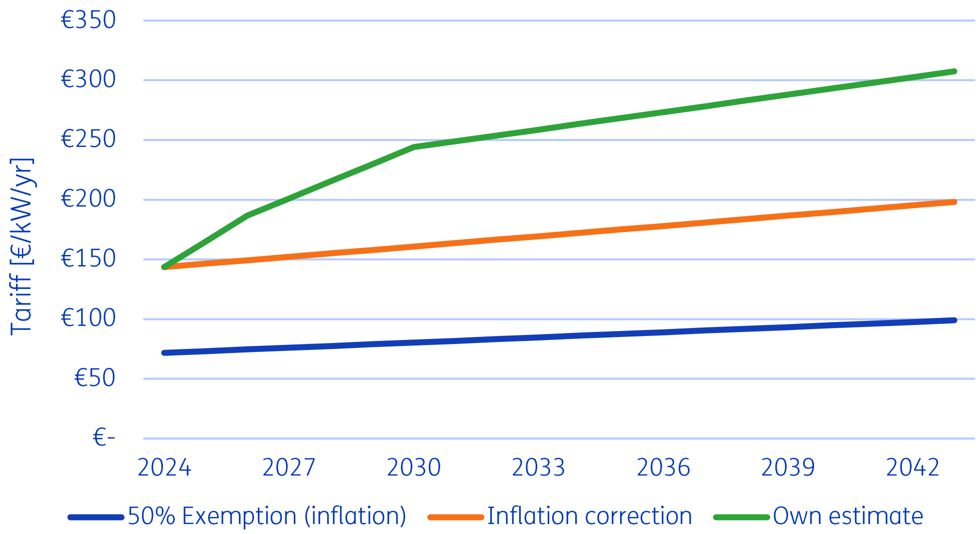

Figure B.1: TSO EHS grid tariff development scenarios

The base case for the electricity grid tariff is based on the 2024 Extra High Voltage (Extrahoogspanning; EHS) tariff to which only inflation is applied for further years. In addition two alternative cases are explored, one that includes outlooks for further cost increase, and one that includes a 50% reduction of the base case tariff:

- The upper case is constructed assuming an increase in tariff of 15% in the next two years as indicated by TenneT[18], and a potential increase of grid tariffs of 70% by 2030 as indicated by Netbeheer Nederland[19]. The grid tariff for the year in between 2026 and 2030 are the result of linear interpolation.
- The case with 50% is justified based on the proposal to introduce a time-bound transport tariff (ATR85) whereby TenneT can impose a restriction on an affiliated party 15% of the time, but in return no kW-contract tariff has to be paid. This can lead to a discount of ~50%. In the meantime, expectations about cost increases are also being adjusted slightly and a slight decrease in transport costs is even expected for 2025.[20]

[18] TenneT verwacht verdere stijging transporttarieven in 2024
[19] Investeringsprognoses tot 2030 | Netbeheer Nederland
[20] TenneT verwacht lichte daling transportkosten in 2025

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