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Impact of expected cost reduction and lifetime extension of electrolysis stacks on hydrogen production costs

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ABSTRACT

The production of green hydrogen-based chemicals using renewable energy is essential for the decarbonization of several sectors that are difficult to address through electrification. Various electrolysis technologies are often considered for sustainable green hydrogen production. They are therefore in a phase of dynamic development. Currently, hydrogen production costs are calculated on the basis of investment costs and lifetimes of the most recent components and future production costs are calculated using development targets. The impact of ongoing developments during the project lifetime is neglected. However, these ongoing developments will have an impact on the estimation of the levelized cost of hydrogen, which is expected to be non-neglectable. This paper proposes a novel methodology that incorporates the impact of evolving electrolysis technologies on the levelized cost of hydrogen. By integrating cost and lifetime development functions, the presented approach allows for precise hydrogen cost estimations tailored to individual stack replacements, adapting to varying annual operating times. Moreover, project-specific investment costs can be derived for a more accurate calculation of the hydrogen production costs. With this method, an average capital cost reduction of more than 11% is achieved for all investigated technologies compared to a cost estimation neglecting ongoing technology developments. The methodology presented provides a comprehensive understanding of ongoing technology developments that affect the economics of hydrogen production.

1. Introduction

In a climate-neutral energy system, hydrogen will play an important role in the decarbonization of several sectors that are difficult to address through electrification. Hydrogen production by water electrolysis using electrical energy - and thermal energy for high-temperature electrolysis - is expected to cover a significant part of future hydrogen demand [1]. In order to develop realistic scenarios for the energy transition, it is important to compare the cost of electrochemical hydrogen production with other production routes and with the costs of fossil energy. However, estimating the levelized cost of hydrogen ($LCOH_2$) from electrolysis is challenging because, electrolysis technologies are in a phase of dynamic development that affects the investment costs, the electrolysis efficiency, and the stack lifetime [2]. In addition, different electrolysis technologies are available at different Technology Readiness Level (TRL) and are affected by different developments. Another factor influencing the hydrogen production cost is the chosen electricity source, which defines the capacity factor and thus influences the stack replacement interval. This study is intended to be more comprehensive than previous ones and to take all these factors into account in to provide a realistic picture of the future costs of hydrogen production. Uncertainties regarding future technology developments are addressed in a sensitivity analysis that considers a wide range of key assumptions regarding electrolysis stack cost and lifetime.

Previous studies have investigated the integration of electrolysis systems with renewable energy sources for green hydrogen production. Hofrichter et al. [3], Gallardo et al. [4] and Marocco et al. [5,6] studied the impact of the intermittent behavior of renewable energy production from wind and solar on the cost of hydrogen production using low temperature electrolysis technologies. The combination of concentrated solar power (CSP) and an high-temperature electrolysis has also been studied in the past [7–13]. Depending on the renewable energy source, different capacity factors can be achieved. Thus, different operating full load hours per year can be realized, which affects the stack replacement

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scenario. Stack replacement is often considered after a fixed number of years [5,14–26], or the $LCOH_2$ has been calculated for a fixed capacity factor or stack lifetime [27–33]. Thus, the impact of stack replacement costs has not been investigated in detail. In some cases, the expected lifetime does not affect the cost because it exceeds the expected process lifetime [34]. For example, a stack lifetime of 80,000 h results in approximately 28.5 years of operation at 2800 process full load hours (capacity factor = 32%). In another case, Nguyen et al. [35] and Wolf et al. [36] considered the resulting stack replacement cost as an annual stack replacement fee. Thus, the cost impact of stack replacement at a specific point in time cannot be investigated. It also does not consider the ongoing cost reduction and lifetime improvement. Knowing the impact of stack replacement costs will help to better estimate $LCOH_2$ during project development.

Similar to the lifetime development, the cost of the electrolysis system is influenced by ongoing developments. Böhm et al. [37,38] conducted a detailed evaluation of the economy of scale effect to predict future investment costs using technological learning effects for SOEL, PEMEL and AEL. Investment cost reductions in the range of 30–75% are predicted for all three technologies. However, SOEL is most affected by the learning effect of increasing production capacity and system installation. In addition, system cost reductions of >75% were predicted for capacities above 50 MW compared to a 5 MW reference scale. The effect of electrolysis system scale has also been considered in studies on the economic assessment of hydrogen production, with a cost advantage for large scale electrolysis systems [3,31,39].

The present work presents a new approach to consider electrolysis cost and stack lifetime development in the economic evaluation of hydrogen production processes. The study evaluates and compares the three most common water electrolysis technologies, namely alkaline electrolysis (AEL), polymer electrolyte membrane electrolysis (PEMEL), and solid oxide cell electrolysis (SOEL), with a TRL of 9, 8, and 5, respectively [40,41]. Cost reduction and lifetime improvement are expected for all three technologies (AEL, PEMEL, SOEL) [42–45]. A wide range of process full load hours is studied. The process full load hours define the year of stack replacement based on the current stack lifetime. Therefore, the new stack cost for each replacement are calculated based on the cost development curve, the process full load hours, and the year reached with the lifetime of the previously installed stack. By considering constant energy prices, a detailed analysis of the impact of the stack replacement scenario as a function of process full load hours and the cost and lifetime development is performed with a sensitivity analysis.

2. Methodology

This section addresses the assumptions and methods used to calculate the levelized cost of hydrogen production ($LCOH_2$) were calculated in this study.

An important influencing factor is the determination of when an electrolysis stack needs to be replaced. The end of life of an electrolysis stack can be defined as the point during operation when the electrolysis power consumption is increased by 10% [44]. Depending on the electrolysis technology, different cell degradation rates are known. Therefore, an expected stack lifetime or degradation rate can be calculated if necessary. The European Union [44] summarizes the degradation rates for SOEL, PEMEL and AEL as 1.9%/kh, 0.19%/kh, and 0.12%/kh respectively in 2020. They expect the degradation rate to change to 0.5%, 0.12%, and 0.1% for the SOEL, PEMEL, and AEL, respectively, in 2030. Thus, the expected lifetime increases by dividing the lifetime in 2020 by the change in degradation rate. The most recent lifetime expectations of the three main electrolysis technologies are also given in other publications for 2018, 2020, and the future [31,41–43,45]. Table 1 summarizes the lifetime for different years as given by the authors. The lifetime of the three technologies differs for the assessment of the State of the Art (SoA). All authors expect a similar component specific lifetime in 2050. For example, the European Union [44] assumes a lifetime of 5500 h, while Schmidt et al. [41] estimate a lifetime of 46, 000 h. Lang et al. [46] tested a SOEL for 8000 h and measured a degradation of 0.5%/kh. Schefold et al. [47] measured a degradation of 0.4%/kh in a similar experiment, i.e. a lifetime of 20,000 or 25,000 full load hours respectively can already be achieved. In contrast, the differences in the current and future component lifetimes are smaller for AEL. Nevertheless, all three technologies are under development and lifetimes are expected to increase. Table 1 summarizes the current and potential lifetime expectations of various authors, which are used to calculate the average lifetime for each electrolysis.

Table 1
Summary of recent and future stack lifetime expectation by various authors. Values are rounded to the next 500 h.

Reference	Year	Lifetime in full load hours (FLH)[a]		
		SOEL	PEMEL	AEL
European Union [44]	2020	5500 h	50,000 h	83,500 h
	2024	10,000 h	66,500 h	91,000 h
	2030	20,000 h	83,500 h	100,000 h
IndWEDe [42]	2018	20,500 h	44,500 h	57,000 h
	2030	50,000 h	63,000 h	80,000 h
	2050	90,000 h	138,000 h	107,000 h
IRENA [43]	2020	20,000 h	65,000 h	60,000 h
	2050	80,000 h	110,000 h	100,000 h
Schmidt et al. [41]	2020	46,000 h	60,500 h	85,000 h
	2030	93,500 h	75,500 h	85,000 h
Gerloff [31]	2020	27,500 h	45,000 h	60,000 h
	2030	50,000 h	60,000 h	75,000 h
	2050	90,000 h	130,000 h	100,000 h
IEA [45]	2019	20,000 h	60,000 h	75,000 h
	2030	50,000 h	75,000 h	95,000 h
	2050	87,500 h	125,000 h	125,000 h

[a] The full load hours are rounded to the next 500 hours.

To calculate the total electrolysis investment costs, the cost development curves of SOEL, PEMEL and AEL from Böhm et al. [38] are used and adapted to the SoA and development target costs of the European Commission - SRIA [44]. The Chemical Engineering Plant Cost Index (CEPCI) is used to convert the available cost data to EUR_{2023}. A seventh-degree polynomial function was derived for each electrolysis technology. In addition, Böhm et al. [38] predict the cost share of the stack in the total system costs. Therefore, a third-degree polynomial function is used to calculate the fraction of the stack replacement cost. The cost of the electrolysis system and the individual stack costs depend on the desired cost target. However, the results are subject of uncertainty and the final costs are difficult to predict. Therefore, a range is given for the final cost targets. In addition to cost reduction, the lifetime of the electrolysis stack is also expected to be increased. Hence, a second-degree polynomial function is used to estimate the development to the targeted stack lifetime of the investigated electrolysis technologies. Therefore, the average stack lifetime of the data collected in Table 1 is calculated for the year 2020 and 2050. The functions are related to the system costs and stack lifetime in Table 2. The variation of the development targets is part of the sensitivity analysis.

The levelized cost of hydrogen is calculated to assess the economic impact of further development. Therefore, the following simplifications are made when calculating the cost of H_2 production for the three electrolysis technologies:

- H_2 compression and storage are not considered.
- Capital costs other than the electrolysis system are neglected.

Based on the selected electrolysis power P_{ELY} and the specific electrical energy demand e_{ELY} of each electrolysis the annual H_2 production m_{H_2} is calculated with Equation (1) using the achievable process full load hours t_{FLH}. Additionally, the annual capital cost (ACC) and the total operational expenditures ($OPEX_{Total}$) are calculated to determine the

Table 2
Electrolysis system state of the art and future system cost and stack lifetime for SOEL, PEMEL, and AEL.

Technology		Units	SoA (2020)	2050	Variation of 2050 targets
SOEL	System costs	€$_{2023}$/kW	2860.6	698.4	+50% −5%
	Stack lifetime	Hours	25,000	85,000	+5000 −10,000
PEMEL	System costs	€$_{2023}$/kW	1208.7	671.5	+20% −10%
	Stack lifetime	Hours	55,000	125,000	+5000 −10,000
AEL	System costs	€$_{2023}$/kW	805.8	537.2	+20% −10%
	Stack lifetime	Hours	70,000	105,000	+5000 −10,000

$LCOH_2$ using Equation (2).

$$m_{H_2} = \frac{P_{ELY}\, t_{FLH}}{e_{ELY}} \qquad \text{Equation 1}$$

$$LCOH_2 = \frac{ACC + OPEX_{Total}}{m_{H_2}} \qquad \text{Equation 2}$$

$$ACC = EC_{Total}\, WACC \qquad \text{Equation 3}$$

$$WACC = \frac{i\,(1+i)^{t_{Project}}}{(1+i)^{t_{Project}} - 1} \qquad \text{Equation 4}$$

$$EC_{Total} = EC_{System}\left(t_{System\ operation,i=0} = 0\right) + \sum EC_{Stack}\left(t_{System\ operation,i}\right) \qquad \text{Equation 5}$$

The ACC is calculated as the product of total equipment cost (EC_{Total}) and the weighted average cost of capital (WACC), Equation (3) & Equation (4). The WACC is calculated using the interest rate I and the project lifetime. The EC_{Total} is the sum of the initial investment cost for the electrolysis and the cost for each new stack replacement Equation (5). The $OPEX_{Total}$ consists of the operation and maintenance (O&M) demand with an electrolysis power specific cost factor $c_{O\&M,ELY}$ [42]. Additionally, the operating costs for energy and H_2O demand are calculated using cost factors. Thus, the $OPEX_{Total}$ is calculated as

$$OPEX_{Total} = E_{Total}\, LCOE + Q_{Total}\, LCOHeat + V_{H_2O}\, c_{H_2O} + P_{ELY}\, c_{O\&M,ELY} \qquad \text{Equation 6}$$

Table 3 summarizes the cost, energy, and other system parameters used.

The state of the art energy demand is used to calculate the electrolysis energy demand [44]. However, due to the cell degradation the electrolysis power demand increases by up to 10% at the end of life. Therefore, the last installed stack may not reach its end of life during the project lifetime $t_{Project}$. This degradation is considered to calculate the average electrical electrolysis power P_{Total} during the project lifetime as the sum of all stack lifetime specific power demands $p_{ELY,i}$ divided by the project lifetime Equation (7). Therefore, the $p_{ELY,i}$ of each installed stack i is calculated using Equation (8). Whenever a stack reaches the end of its life during the project lifetime, the averaged electrolysis power of this stack is equal to $P_{ELY} + \frac{P_{Degradation}}{2}$ over the period of its operation. Thus, it is set in relation of the process full load hour to calculate its total operating period in years. However, if the stack does not reach the end of its lifetime, the average electrolysis is less than $P_{ELY} + \frac{P_{Degradation}}{2}$. The resulting power is a function of stack lifetime, process full load hours, and remaining project lifetime. The remaining project lifetime is calculated as $t_{Project}$ minus the time the system has already been operating $t_{System\ operation,i}$ at the stack replacement i calculated with Equation (9). The annual electrical energy demand E_{ELY} is then calculated using Equation (10).

$$P_{Total} = \frac{1}{t_{Project}} \sum p_{ELY,i} \qquad \text{Equation 7}$$

$$p_{ELY,i} = \begin{cases} if\left(t_{System\ operation,i} + \frac{t_{Lifetime,i}}{t_{FLH}}\right) \le t_{Project}: \\ \left(P_{ELY} + \frac{P_{Degradation}}{2}\right)\frac{t_{Lifetime,i}}{t_{FLH}}, \\ if\left(t_{System\ operation,i} + \frac{t_{Lifetime,i}}{t_{FLH}}\right) > t_{Project}: \\ \left(P_{ELY} + \frac{P_{Degradation}}{2}\left(\frac{t_{Project} - t_{System\ operation,i}}{\frac{t_{Lifetime,i}}{t_{FLH}}}\right)\right)\frac{t_{Lifetime,i}}{t_{FLH}} \end{cases} \qquad \text{Equation 8}$$

$$t_{System\ operation,i} = t_{System\ operation,i-1} + \frac{t_{Lifetime,i-1}}{t_{FLH}}, \quad if\ i = 0 \Rightarrow t_{System\ operation,i-1} = 0 \qquad \text{Equation 9}$$

$$E_{ELY} = P_{Total}\, t_{FLH} \qquad \text{Equation 10}$$

However, the high temperature SOEL has a standby electrical energy demand $E_{ELY,SB}$ that must be considered. $E_{ELY,SB}$ is calculated using the electrolysis power and the time no operation is possible based on the process full load hours and a stand by energy demand factor $f_{ELY,SB}$ using Equation (11). The specific standby electrical energy demand for a SOEL is equal to 8.6% of the electrolysis system power [49]. For the PEMEL and the AEL no standby electrical energy demand is considered. The SOEL standby demand is needed to keep the stack in a hot state (i.e. 700-800 °C) so that the system can start operating immediately at any time. The other technologies are typically operated at temperatures below 100 °C and their startup of them is comparably simple. For the techno-economic assessment, the total electrical and thermal energy demand E_{Total} and Q_{Total} is calculated with Equation (12) & Equation (13). In addition, the volumetric water consumption in V_{H_2O} is calculated with the molar mass M of H_2O and H_2 and the density ρ of H_2O in Equation (14).

$$E_{ELY,SB} = f_{ELY,SB}\, P_{ELY}\,(8760 - t_{FLH}) \qquad \text{Equation 11}$$

$$E_{Total} = E_{ELY} + E_{ELY,SB} \qquad \text{Equation 12}$$

$$Q_{Total} = m_{H_2}\, q_{ELY} \qquad \text{Equation 13}$$

$$V_{H_2O} = m_{H_2}\frac{M_{H_2O}}{M_{H_2}\, \rho_{H_2O}} \qquad \text{Equation 14}$$

Table 3
Summary of cost, energy, and other system parameters used for the economic analysis.

Cost and Simulation Parameter		Value	Unit	Reference
Electricity Price	LCOE	50	€/MWh	
Heat Price	LCOHeat	50	€/MWh	
Water Price	c_{H_2O}	2	€/m^3	[48]
O&M Costs	$c_{O\&M,SOEL}$	32.5	€/kW/a	[42]
	$c_{O\&M,PEMEL}$	12.5	€/kW/a	
	$c_{O\&M,AEL}$	18	€/kW/a	
Electrical Energy Demand	e_{SOEL}	40	kWh/kg	[44]
	e_{PEMEL}	55	kWh/kg	
	e_{AEL}	50	kWh/kg	
Thermal Energy Demand	q_{SOEL}	10	kWh/kg	
Standby Energy Factor	$f_{SOEL,SB}$	0.086	–	[49]
Project Duration	$t_{Project}$	25	years	
Interest rate	i	8	%	
Degradation Power	$P_{Degradation}$	0.1 P_{ELY}	W	[44]

Since the achievement of the cost and degradation targets is uncertain, a sensitivity analysis is performed. This is done by considering the upper and lower bounds of the final cost and lifetime development targets. The polynomial cost and lifetime functions are fitted to the new target cost parameter. The upper and lower bounds are summarized in Table 2. Additionally, the effects of a change in interest rates and changing energy prices are examined. Furthermore, constant cost factors are used for energy prices.

3. Results and discussion

The resulting evolution of cost and lifetime is shown in Fig. 1. In addition, the system costs in 2023 €/kW and lifetime in hours of different reports and studies [31,42–45] are shown, as they are often used by different authors for techno-economic assessment and technology comparison. It can be seen that the studies [31,42–45] overestimate the cost development potential of SOEL and PEMEL in particular, with the exception of the IEA report from 2019 [45], and the lifetime estimate varies greatly in the short development range. However, all studies show similar cost and lifetime estimates that are consistent with current development functions for the long-term future. The SOEL technology has the highest cost reduction potential because it has the lowest TRL. In addition, the cost share of the SOEL stack is and will be the lowest. AEL has the lowest potential for cost reduction and lifetime improvement because it is the most mature technology. Both AEL and PEMEL will always have a higher proportion of stack cost. Therefore, stack replacement will have a greater impact on $LCOH_2$ than SOEL technology. For a better understanding, the cost composition is examined for 2023 costs. The investment cost of the electrolysis system is 2693.9 €/kW, 1176.6 €/kW and 795.8 €/kW and the lifetime is 34,500 h, 65,000 h and 74,500 h for SOEL, PEMEL and AEL, respectively. In 2030, the cost decreases to 1571.9 €/kW, 887.1 €/kW and 713.9 €/kW and the lifetime increases to 52,500 h, 85,000 h, and 83,000 h for SOEL, PEMEL and AEL, respectively. In 2040, the electrolysis system costs are further reduced to 871.8 €/kW, 713.6 €/kW and 574.0 €/kW and the lifetime is further increased to 73,500 h, 109,500 h, 95,000 h for SOEL, PEMEL and AEL, respectively.

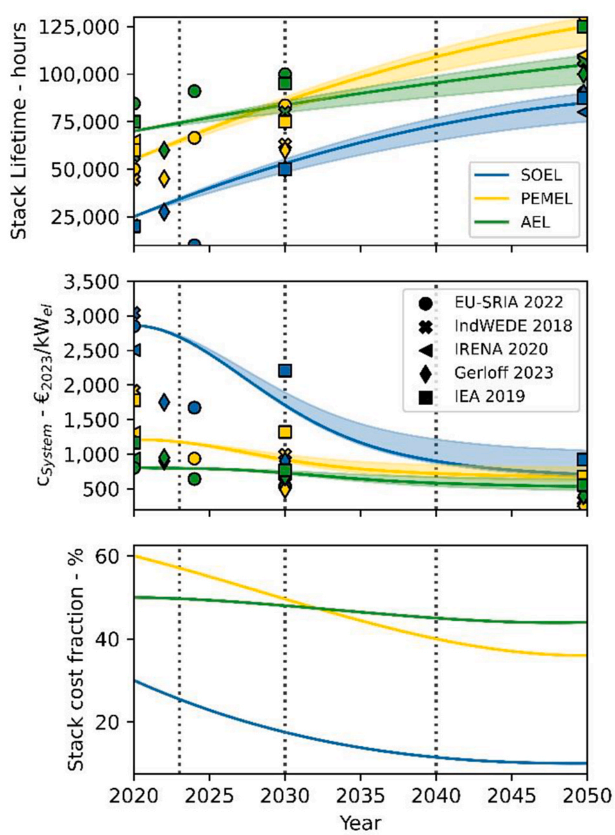

Fig. 1. Electrolysis lifetime and cost evolution behavior for a period from 2020 to 2050. The markers show the cost and lifetime estimates of different authors [31,42–45], and the colored area shows the variation of the evolution functions based on the variation of the targets.

3.1. $LCOH_2$ cost composition

Based on the initial assumptions, the $LCOH_2$ consists of operating and capital costs. The initial analysis is performed for a project scenario starting in 2023 and lasting 25 years. Energy costs are assumed to be constant as shown in Table 3. Fig. 2 shows the composition for the three technologies over a wide range of capacity factors. The capacity factor is defined as the division of the process full load hours achieved divided by the total hours in a year.

$$\text{Capacity Factor} = \frac{t_{FLH}}{8760\ \text{h}} \qquad \text{Equation 15}$$

The impact of the energy demand and the CAPEX dominate the O&M costs for all three technologies and the water purchase cost is relatively small at less than 0.02 €/kg. In general, the CAPEX impact is higher at low capacity factors. The cost impact of CAPEX is influenced by the capacity factor and the resulting number of stack replacements. Depending on the available stack lifetime, different replacement scenarios are required as an additional stack replacement is required. Therefore, the increase in CAPEX due to the additional stack replacement can be seen as a sudden increase in $LCOH_2$ for all three technologies. Thus, the visible steps are caused by each additional stack replacement and the height is defined by the stack replacement cost at the time of the last stack replacement. With the chosen project time of 25 years, the year of the last stack replacement causing the step occurs at

$$t_{\text{Last replacement}} = \left(t_{\text{Start}} + t_{\text{Project}}\right) - \frac{t_{\text{Lifetime}}}{t_{\text{FLH}}} \qquad \text{Equation 16}$$

Since the timing of the last replacement depends on the project lifetime, the development of cost reduction and lifetime improvement is the most advanced. Since the stack cost factor is the lowest for the SOEL, the spike of an additional stack replacement is the lowest compared to the PEMEL and AEL. Fig. 3 shows the individual stack replacement costs and marks the costs for each replacement at 2500, 5000, and 7500 annual process full load hours, respectively. At 2500 process full load hours, the PEMEL and AEL do not need an additional stack replacement. In 2023, the Lifetime of a PEMEL and AEL stack is about 65,000 h and 74,000 h, respectively. Therefore, at 2500 full load hours, the project ends before the end of life of the stack is reached. When the process full load hours exceed the 2500 h, an additional stack is needed to reach the 25 years of project duration.

With a project start in 2023 and a project life of 25 years, the last stack replacement may take place in 2048 at the latest and will increase the total investment cost. With the present model, the system investment costs in 2048 are calculated to be 719.6 €/kW, 678.9 €/kW and 535.1 €/kW for SOEL, PEMEL and AEL respectively. The stack cost shares are 10.0%, 36.1% and 43.9%, respectively, resulting in specific stack costs of about 72 €/kW, 245.1 €/kW and 234.9 €/kW. The peaks of the additional stack replacement costs have not been investigated in the literature. Because the impact of the additional cost was neglected or considered as an O&M cost. Nevertheless, the $LCOH_2$ over a wide range of capacity factors is comparable to the behavior investigated in other studies [7,23,39].

The lifetime of an electrolysis system is defined by its degradation and all three technologies are affected by it. Electrolysis degradation causes an increase of electrical energy demand over time. At the beginning of the stack operation, the nominal electrical energy demand for the SOEL, PEMEL and AEL is 40 kWh/kg, 55 kWh/kg and 50 kWh/

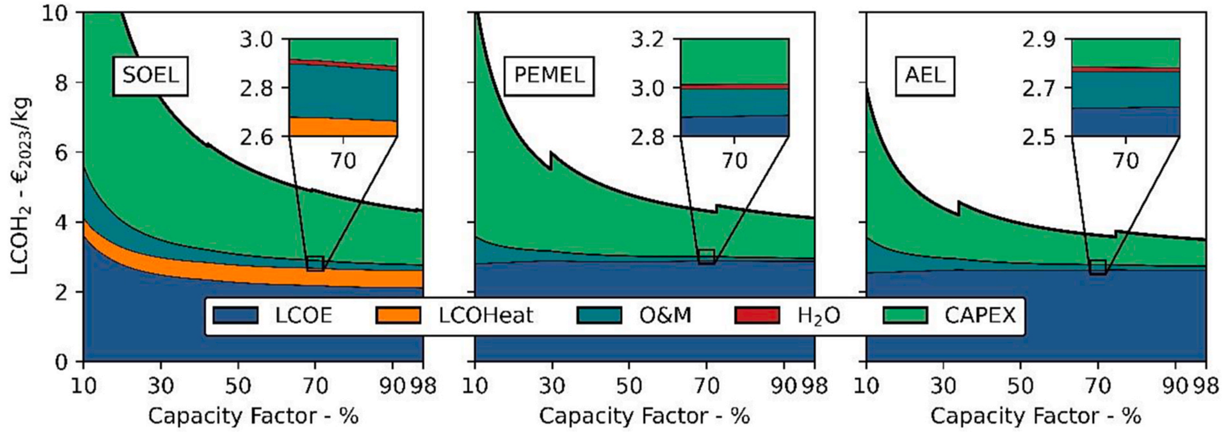

Fig. 2. Impact of the different operational and capital investment costs on the $LCOH_2$ for a project start in 2023.

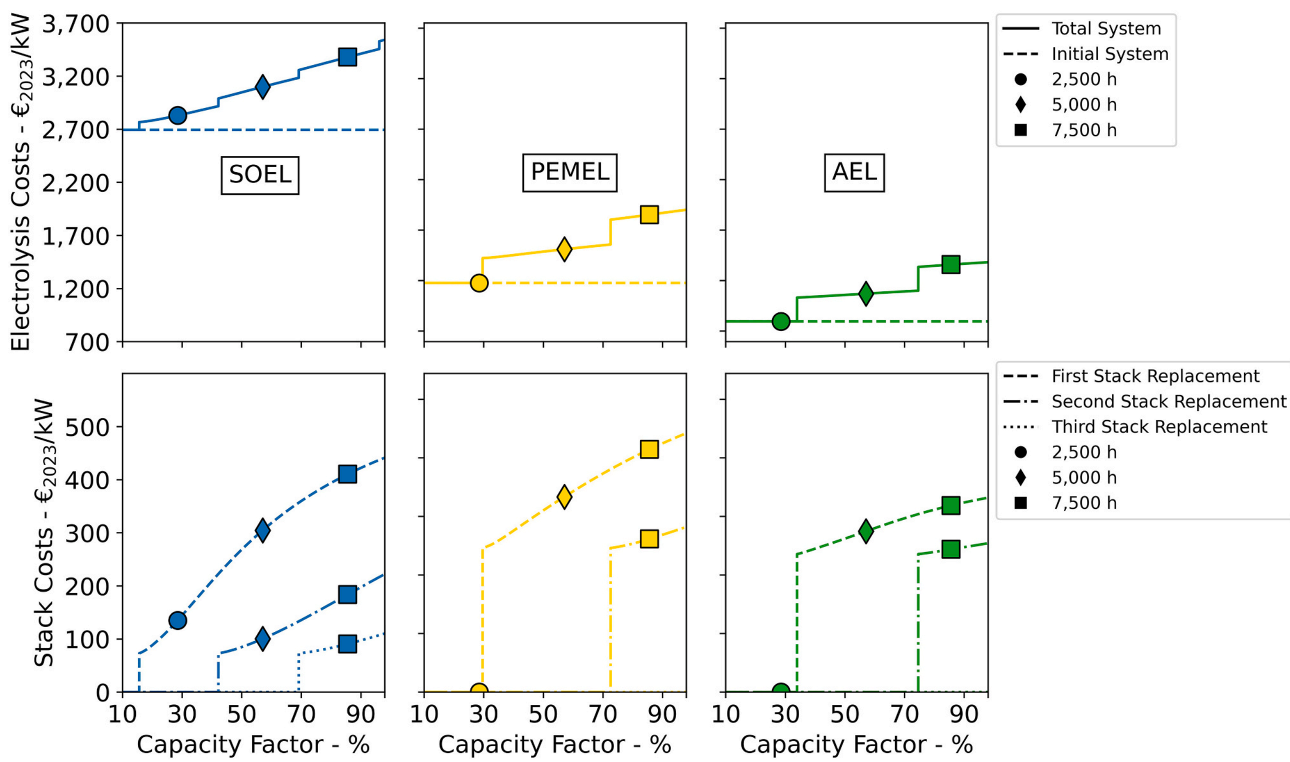

Fig. 3. Specific Electrolysis costs and individual stack replacements costs as function of the capacity factor for a project start in 2023. The markers mark the individual costs at 2500, 5000, 7500 process full load hours, respectively.

kg, respectively. Fig. 4 shows the specific electrical energy demand considering the electrolysis degradation and standby energy demand of a range of capacity factors. The figure shows peaks in the specific energy demand. These are at the same location as the peaks in Fig. 2 and indicate an additional stack replacement. At the peaks, the average electrolysis power demand is increases by 5% due to the cell degradation. At 4000 full load hours the specific electrical energy demand is increases to 45.6 kWh/kg, 57.2 kWh/kg and 52 kWh/kg for the SOEL, PEMEL and AEL, respectively. The increase for the SOEL is the highest with an increase of 14% compared to 4% for the PEMEL and AEL. Because, the SOEL requires a standby electrical energy whenever the system is not operating. Thus, an increase in the process full load hours to 8000 will result in a decrease in the specific electrical energy demand of the SOEL to 42.4 kWh/kg.

3.2. *Future H_2 production costs*

To examine the impact of the trajectories, different scenarios are compared. Fig. 5 shows the $LCOH_2$ for the base case scenario starting in 2023 compared to a project start in 2030 and 2040. It also shows a scenario with no cost reduction or lifetime improvement using the SoA cost and lifetime data shown in Table 2. The figure also shows the total electrolysis investment cost $c_{ELY,Total}$ for the different scenarios. $c_{ELY,Total}$ consists of the initial investment in the electrolysis system and the cost of each stack replacement. Besides the cost reduction, which is studied by the intensities of the step peaks, the lifetime extension is seen by the distance between the step peaks. Therefore, the case with no lifetime improvement and no cost reduction is plotted as black dotted lines in Fig. 5. We see a reduction in step height and an increase in step spacing for the SOEL and PEMEL. Only the AEL shows a small improvement because it is the most mature technology and only small improvements

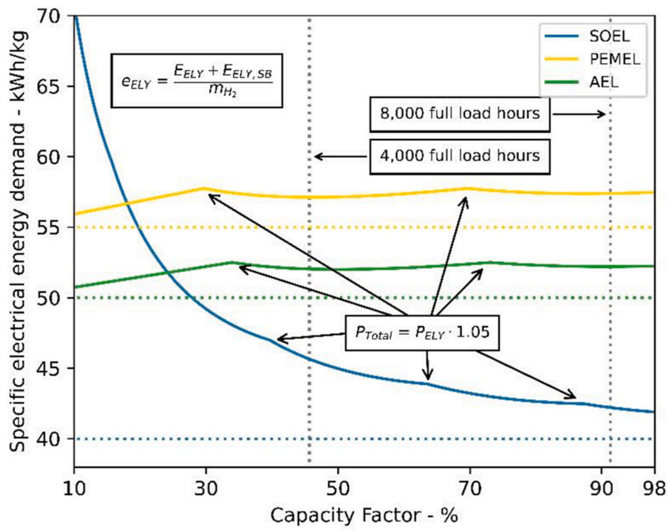

Fig. 4. Specific electrical energy demand for SOEL, PEMEL and AEL. The dotted lines show the specific electrical energy demand without degradation effects and stand by energy demand.

in cost and lifetime are expected. The differences in step height are caused by the differences in stack cost at the last stack replacement. Therefore, the system cost at that moment in time is multiplied by the cost fraction of the stack at that moment in time. In addition, it can be seen that at low capacity factors, i.e. up to 20–30%, PEMEL and AEL are not affected by any cost reduction or lifetime improvement. This is because a higher capacity factor must be achieved to cause a stack replacement during the 25-year project lifetime. For longer project lifetimes, this effect will only occur at even lower capacity factors. However, we achieve an average investment cost reduction for SOEL, PEMEL, and AEL of 37.1%, 23.2%, and 9.4%, respectively, and the reduction in $LCOH_2$ is 19.8% for SOEL, 9.5% for PEMEL, and 3.0% for AEL for the 2030 scenario compared to 2023. Table 4 summarizes the data for the 2030 and 2040 cost scenarios. Without considering the cost reduction and lifetime improvement, the $LCOH_2$ will be higher for all three technologies at higher capacity factors. Because no stack replacement is required at low capacity factors, as indicated by the overlap of the black dotted line and the colored solid line for each technology in Fig. 5. Thus, the average reduction in $LCOH_2$ in 2023 is expected to range from 3.5% to 29.9% for the technologies studied. The initial specific system costs differ by 5.8%, 2.7% and 1.2% between 2020 and 2023 for the SOEL, PEMEL and AEL, respectively.

3.3. Sensitivity analysis

The sensitivity analysis is performed for different interest rates, development scenarios and energy prices. The resulting change in $LCOH_2$ for the changing parameters is shown in a tornado diagram in Fig. 6. The analysis is performed for a project start in 2023 at 4000 full load hours for all three technologies. The 4000 full load hours correspond to a capacity factor of 45.7%. As shown in Fig. 2, the cost of energy has a large impact on the $LCOH_2$. Varying the LCOE to 25 €/MWh and 100 €/MWh causes the biggest change in $LCOH_2$ for all three technologies. However, SOEL is the least affected by a change in LCOE because its specific electrical energy demand is the lowest. Thus, PEMEL benefits the most from decreasing electricity prices while the SOEL benefits from increasing prices. Regarding energy prices in general, the LCOHeat is considerably cheaper than electricity. Thus, the $LCOH_2$ for SOEL can be lower than using PEMEL or AEL, which do not use heat for the water splitting reaction. The cost of heat will have a greater impact

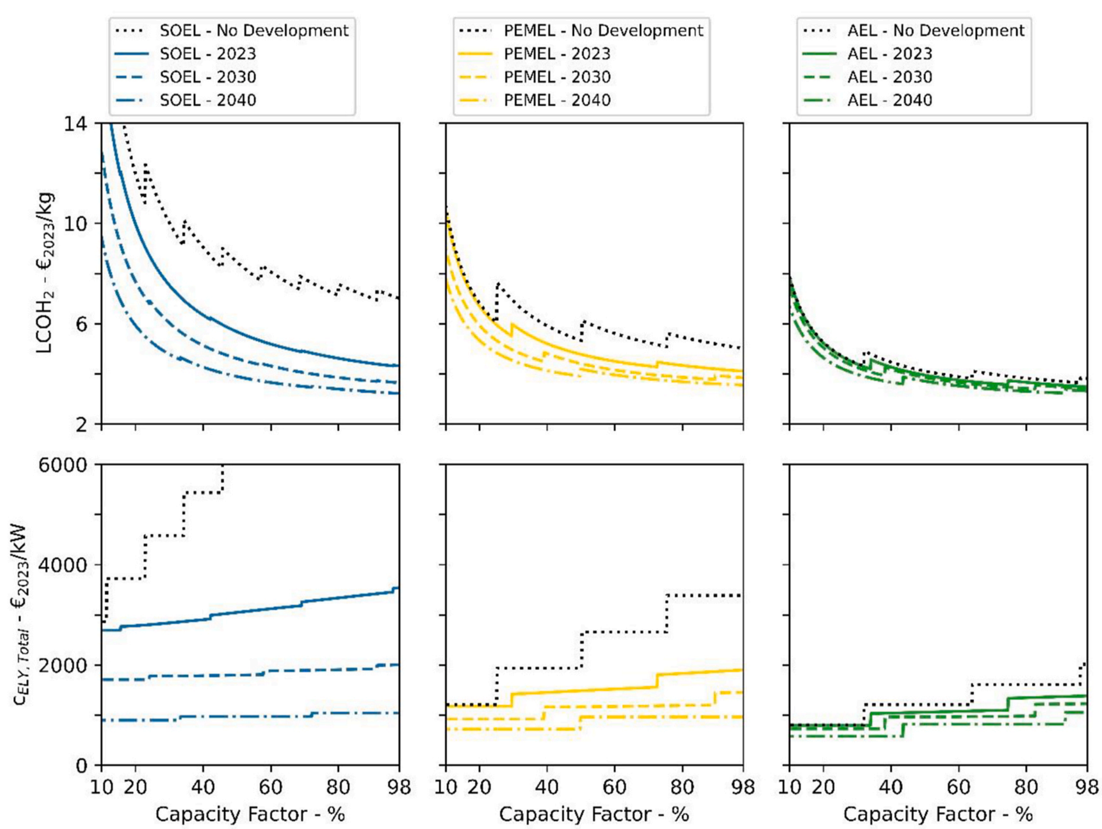

Fig. 5. Comparison of H_2 production costs using SOEL, PEMEL or AEL for an electricity and heat price of 0.05 €/kWh. Specific electrolysis investment cost comparison including the initial system and replacement costs.

Table 4
The mean value of the relative change of electrolysis investment ($c_{ELY,\ Total}$) and hydrogen production costs ($LCOH_2$) for the 2023 scenario compared to the 'No Development' scenario and for the 2030 and the 2040 scenarios compared to 2023.

Relative Cost Change to No Development scenario										
Scenario	Parameter	SOEL			PEMEL			AEL		
		mean	min	max	mean	min	max	mean	min	max
2023	$LCOH_2$	−29.9%	−4.2%	−39.9%	−13.2%	−1.6%	−22.4%	−3.5%	−0.6%	−12.9%
	$c_{ELY,\ Total}$	−44.5%	−5.8%	−60.1%	−28.4%	−2.7%	−43.7%	−11.8%	−1.2%	−34.2%
Relative Cost Change to 2023 scenario										
Scenario	Parameter	SOEL			PEMEL			AEL		
		mean	min	max	mean	min	max	mean	min	max
2030	$LCOH_2$	−19.8%	−14.9%	−26.8%	−9.5%	−5.2%	−17.4%	−3.0%	−1.4%	−11.0%
	$c_{ELY,\ Total}$	−37.1%	−34.4%	−39.8%	−23.2%	−17.8%	−37.4%	−9.4%	−6.0%	−30.5%
2040	$LCOH_2$	−35.2%	−26.4%	−48.6%	−17.1%	−9.2%	−28.9%	−8.7%	−3.9%	−17.0%
	$c_{ELY,\ Total}$	−66.1%	−61.3%	−69.3%	−42.1%	−32.3%	−52.8%	−26.8%	−17.7%	−45.1%

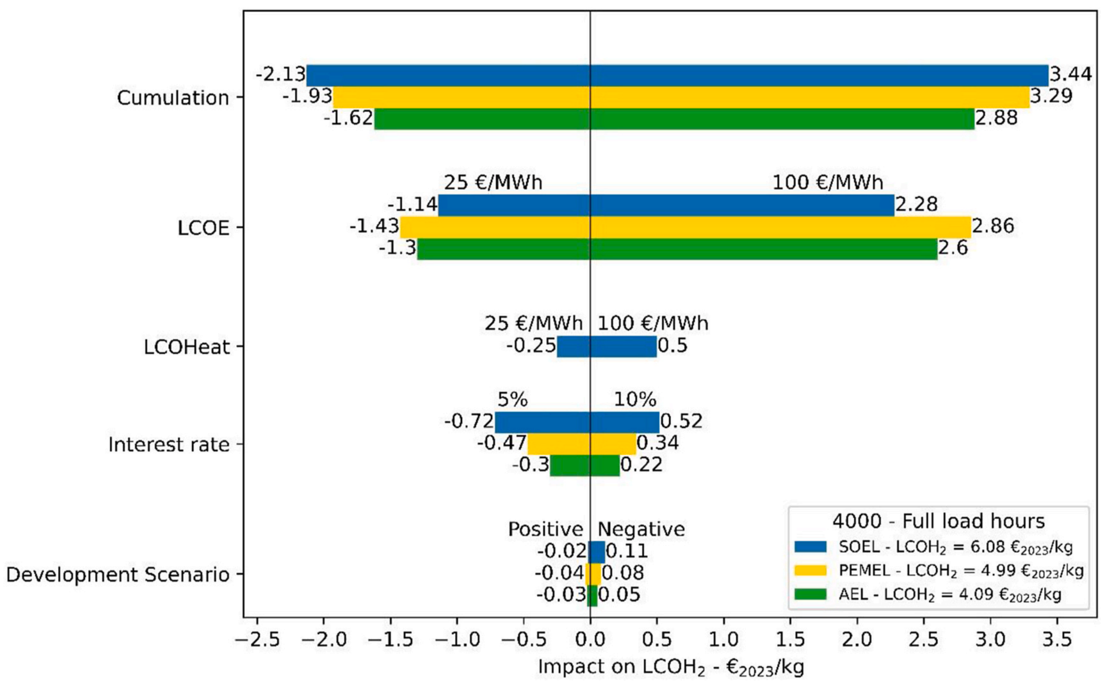

Fig. 6. H_2 cost sensitivity for SOEL, PEMEL and AEL at 4000 process full load hours.

on the $LCOH_2$ and the SOEL can be the cheapest technology for hydrogen production using electrolysis. In the 2040 future scenario, $LCOH_2$ of 4.04 €/kg, 3.99 €/kg, and 3.82 €/kg are achieved for the SOEL, PEMEL, and AEL, respectively, at 4000 full load hours. Considering a reduction of the heat cost from 0.05 €/kWh to 0.025 €/kWh, the $LCOH_2$ for the SOEL is 3.83 €/kg. Thus, the hydrogen produced with the SOEL is 0.16 €/kg cheaper than using the PEMEL and is cost neutral with the AEL.

In contrast, a small change in the interest rate also affects the hydrogen cost because it affects the CAPEX. Thus, the SOEL is most affected as it has the highest CAPEX cost share in 2023. With further progress in cost reduction and lifetime improvement, the impact of a change in the interest rate becomes less. In general, the impact is small compared to CAPEX-intensive projects because a large portion of the $LCOH_2$ cost construction is due to OPEX. However, a change in the interest rate has a greater impact on lower capacity factors because they are more CAPEX intensive than higher capacity factors. This is because, the annual hydrogen production rate is lower and the project becomes less profitable. By reducing the cost and improving the lifetime, all three technologies become less CAPEX intensive. In future scenarios, the impact of a change in the interest rate becomes smaller as the cost of the electrolysis decreases.

Since the cost and lifetime evolution is uncertain, a positive and negative development scenario are analyzed. The lowest cost development is paired with the highest stack lifetime for the positive scenario. For the negative scenario, the highest cost is paired with the shortest stack. Fig. 7 shows the cost deviation of the three technologies for the positive and negative development scenarios in 2023 compared to the neutral cost scenario shown in Fig. 5. The variation in width between scenarios is influenced by changes in stack lifetime, with the negative scenario assuming a lower stack lifetime expectation. For example, the base case scenario predicts a PEMEL stack lifetime of 125,000 h in 2040. However, in the negative development scenario, the lifetime is projected to decrease by 10% to 112,500 h, based on the assumptions in Table 2. As a result, stack replacements occur earlier, which affects the cost of additional stack replacements. The same table shows the expected cost deviation in 2050, hence the height of the deviation box is determined by the differences in stack replacement costs. In general, the different development scenarios have a greater impact on future projects because the total deviation in cost or stack life is greater in the future than it is

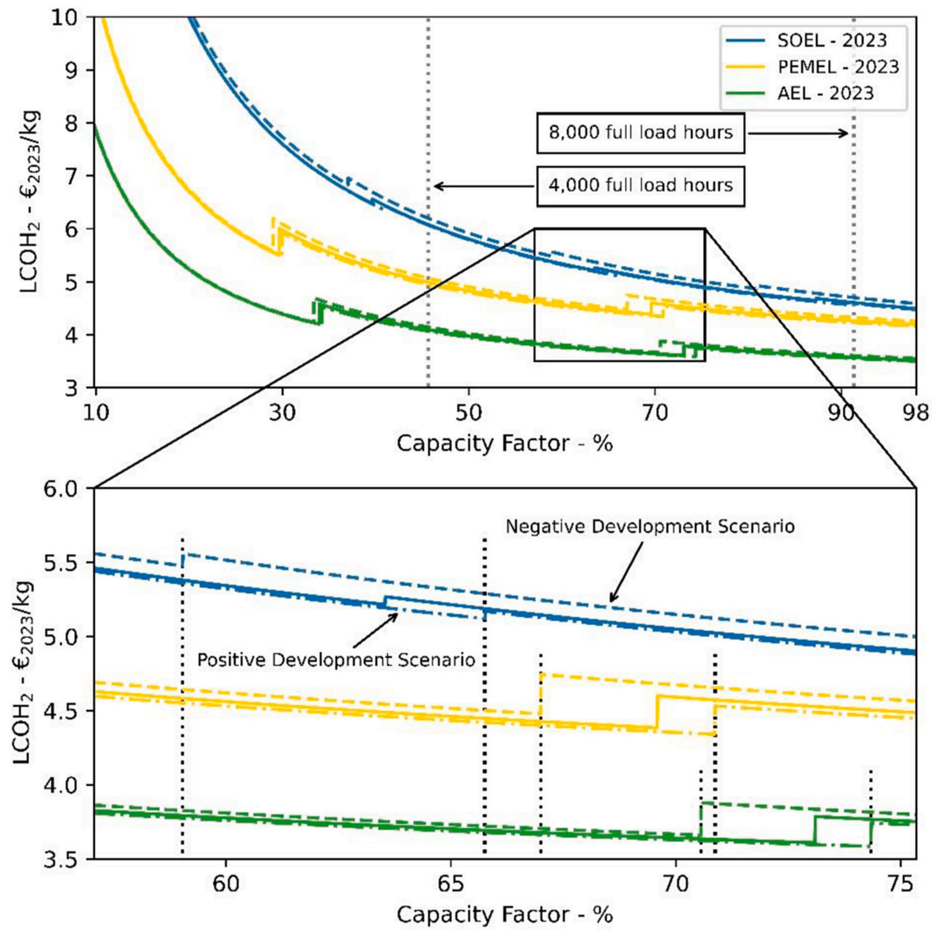

Fig. 7. H_2 production cost for 2023 projects and cost sensitivity with a change of electrolysis cost and lifetime development scenario.

today, as shown in in Fig. 2. Additionally, it can be seen that all technologies are affected by deviations from the base cost. A different expected stack lifetime leads to stack replacement at different times. Thus, there is a greater variance whenever an additional stack replacement is required. For example, the negative development scenario is associated with an additional stack replacement, while the positive development scenario is associated with less stack replacement. In a 2040 scenario, a larger cost deviation is expected. This is because the cost and lifetime predictions are different with high uncertainties. The SOEL has the lowest TRL and therefore the highest development potential. However, achieving the development goal is more uncertain and higher system costs are more likely. Nevertheless, the impact of the negative SOEL development scenario is comparable to the PEMEL and the AEL. Because, the stack cost share is the lowest and the cost impact is less.

4. Conclusion

A new approach is presented to consider electrolysis cost and stack lifetime development in the economic evaluation of H_2 production processes. As a result, project developers can improve the design and economic operation of their electrolysis system. Nevertheless, developments need to be closely monitored, as price changes and improvements in stack lifetimes have an impact on the methodology presented. Therefore, the cost and lifetime functions need to be updated as new developments occur.

The inclusion of ongoing developments provides a better representation of production costs. Furthermore, different scenarios can be explored to find better operation and stack replacement strategies. However, PEMEL and AEL in particular are less affected by the presented methodology than SOEL systems as the latter are still at the lowest TRL. All three technologies achieve similar $LCOH_2$ at high capacity factors, assuming a constant electricity price. They are also similarly affected by changes in economic parameters. SOEL is less affected by a change in LCOE than PEMEL and AEL because it replaces about 20% of the total energy demand with a thermal energy supply, reducing the electrical energy demand. Changes in CAPEX or the interest rate does have the least impact on AEL because it has the lowest specific cost. In general, the consideration of continuous cost reduction and lifetime improvement reduces the $LCOH_2$ and increases the project profitability. This makes electrolysis more cost competitive with fossil-based hydrogen production. With the presented cost calculation method, the total investment cost of electrolysis for 2023 could be reduced in average by 44.5%, 28.4% and 11.8% for SOEL, PEMEL and AEL, respectively, compared to a method that does not consider ongoing cost and lifetime development trends.

However, due to the intermittent nature of renewable energy resources, high full load hours can only be achieved with energy storage, which increases the cost of energy. The cost impact of hydrogen compression and storage have not been considered in this study, nor have variable energy prices as a function of full load hours. The impact of these factors on the $LCOH_2$ remains to be investigated with the present economic model.

CRediT authorship contribution statement

Timo Roeder: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Andreas Rosenstiel:**

Writing – review & editing, Project administration, Conceptualization. **Nathalie Monnerie:** Writing – review & editing, Supervision, Resources, Project administration, Funding acquisition, Formal analysis. **Christian Sattler:** Supervision, Resources, Funding acquisition.

Declaration of competing interest

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

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2024.08.015.

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