International Journal of Hydrogen Energy 256 (2026) 156089

Contents lists available at ScienceDirect

International Journal of Hydrogen Energy

journal homepage: www.elsevier.com/locate/he

Projected levelized cost of hydrogen for on-site supply technologies in Germany

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ARTICLE INFO

Keywords:
Levelized costs of hydrogen (LCOH)
On-site hydrogen supply
Hydrogen production technologies
Technology readiness level
Hydrogen technology forecast

ABSTRACT

To comply with German emission targets and support the transition to green hydrogen, this study assesses the future development of the Levelized Cost of Hydrogen (LCOH) for various supply technologies in Germany, assuming an industrial demand of 10,000 t_{H2}/a between 2030 and 2045. Steam Methane Reforming remains the most cost-effective option until 2030, with costs of 2.70 €/kg_{H2}, although emission-intensive technologies become increasingly expensive due to rising EU-ETS prices. Plasma pyrolysis could serve as a bridging technology if successfully commercialized, potentially reaching 2.14 €/kg_{H2} by 2040. From 2045 onward, high-temperature electrolysis becomes competitive when waste heat is utilized, achieving 2.78 €/kg_{H2} (3.10 €/kg_{H2} without waste heat). Declining electricity prices reduce LCOH for PEM and AEL electrolysis by about 30% by 2045, while power purchase agreements enable an additional 12.5% reduction by 2030. Despite these improvements, hydrogen costs in Germany remain above current levels in all scenarios through 2045.

1. Introduction

1.1. Background & motivation

A transition towards renewable energies is required to fulfil the emission targets of the EU and Germany [1]. As renewable energies such as wind and solar are volatile, hydrogen has become a focal point as an energy storage medium in recent years. To date, the largest share of hydrogen production originates from fossil fuels. In Germany, gray hydrogen production based on natural gas accounts for 95% of the annual hydrogen volume [2].

However, hydrogen can also be produced in a more sustainable and climate friendly way. In this context, hydrogen can be used as (i) a long-term energy storage medium within the energy system, (ii) as an energy carrier in energy-intensive processes, where direct electrification is not feasible [3–5] and (iii) as a basic feedstock in industry, particularly in the chemical sectors [6]. Despite these advantages, the transition to green hydrogen faces several challenges, including high production costs, limited availability of renewable energy, infrastructure requirements for storage and transport, as well as public acceptance issues. In addition, supportive policy frameworks and financial incentives are required to enable large-scale deployment [7].

To archive the desired transition, fossil-based hydrogen should successively be replaced by green hydrogen. As the preferred technology for the German government [8], green hydrogen is defined as hydrogen produced by water electrolysis based on renewable energies [9]. Additionally, and under certain conditions, hydrogen imports in the form of derivatives with on-site hydrogen release represents another viable option to meet domestic green hydrogen demand. The German government assumes a hydrogen demand of 95-130 TWh/a by 2030 [10] and an even higher demand of 350 TWh/a between 2030 and 2045 [11]. In comparison, today's demand is 55 TWh/a [11].

The success of transforming hydrogen feedstock from fossil-based to green production routes depends primarily on how companies adopt new technologies and to what extent investment decisions include sustainability criteria alongside economic considerations. However, such evaluations are constrained by limited data, which varies by hydrogen production technology, its level of maturity, and is particularly scarce when it comes to a timeframe up to the year 2045.

Existing studies on hydrogen production differ significantly in their

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https://doi.org/10.1016/j.ijhydene.2026.156089
Received 18 February 2026; Received in revised form 12 June 2026; Accepted 14 June 2026
Available online 8 July 2026

scope and methodology. Meta-analyses such as Merten and Scholz [12] provide a broad system-level perspective on hydrogen production costs and demand in Germany, enabling the comparison of multiple literature sources. However, their approach is based on heterogeneous data without a consistent techno-economic framework, which limits the direct comparability of different technologies.

At the same time, detailed techno-economic studies have focused on specific hydrogen production pathways. For example, Oni et al. [13] presents a comprehensive assessment of gas-based hydrogen technologies, integrating cost analysis with life cycle assessment and considering scale effects and uncertainties. While such approaches provide a high level of detail, they are limited to a narrow set of technologies, thereby excluding alternative pathways such as water electrolysis and hydrogen derivatives.

In contrast, policy- and roadmap-oriented studies such as the IndWEDe study [14] focus on the industrialization and large-scale deployment of water electrolysis in Germany, offering valuable insights into infrastructure requirements and future capacity expansion. However, these studies generally do not provide a consistent economic comparison across different hydrogen supply pathways.

Overall, existing literature either emphasizes system-level perspectives, detailed analyses of individual technologies, or policy-driven development pathways. Comprehensive comparisons of medium-scale hydrogen supply options—particularly relevant for applications without direct access to large-scale infrastructure such as the European Hydrogen Backbone ([15]) —remain scarce.

To address these gaps, this study focuses on medium-scale, on-site hydrogen supply with a capacity of 10,000 t_{H2}/a and evaluates cost developments from 2030 to 2045. A broad range of technologies is considered, including gas-based processes, water electrolysis, and hydrogen derivatives. The analysis is based on a harmonized techno-economic framework under consistent boundary conditions for Germany, supported by a structured literature review and expert assessments, enabling a consistent comparison of levelized costs of hydrogen (LCOH) across all technologies.

The main contributions of this study can be summarized as follows:

- A unified techno-economic framework for the calculation of the LCOH across a broad range of hydrogen supply technologies, including gas-based production, water electrolysis, and hydrogen derivatives.
- A focus on medium-scale, on-site systems (10,000 t_{H2}/a), addressing a gap in existing literature, which often neglects this application range.
- A consistent comparison of technologies under harmonized assumptions, including system boundaries, economic parameters, and operating conditions, ensuring a high level of comparability.
- Integration of technological maturity (TRL), cost development, and temporal dynamics, allowing an assessment of technology competitiveness from 2030 to 2045.
- Inclusion of both production and supply pathways, including hydrogen derivatives, enabling a more comprehensive evaluation than studies focused on single technology classes.
- Identification of key cost drivers and economic levers, particularly electricity prices, CO_2 costs, and system scale, providing insights relevant for industrial decision-making.
- A structured sensitivity analysis and a scenario-based uncertainty quantification addressing key uncertainties in future hydrogen production costs, contributing to a more robust interpretation of results

The paper's structure is outlined as follows. The study commences with a description of the technological landscape of hydrogen production. This is followed by a description of the calculation methods and, a presentation of techno-economic data from literature and expert discussions, ending with the values assumed in the calculations. Subsequent to the presentation of the results and discussion, the conclusion and outlook are presented.

1.2. Technological landscape of hydrogen systems

1.2.1. Overview

Hydrogen can be produced from various resources. On the one hand, fossil raw materials such as natural gas is used; on the other hand, hydrogen production based on renewable resources such as biomass and water with an energy supply from renewable energies can be used. Besides their greatly differing technical processes these technologies are also in different stages of their development. Each process offers unique opportunities, advantages and challenges. The choice of technology is influenced by the local availability of resources, the maturity of the technology, political regulations and the economy, among other factors [2].

This study analyzes, the four gas-based technologies Steam Methane Reforming (SMR), Steam Methane Reforming with Biogas (SMR Bio), Autothermal Reforming with Biogas (ATR Bio) and Plasma Pyrolysis (PP), the three electrolysis technologies Alkaline Electrolysis (AEL), Proton Exchange Membrane Electrolysis (PEM) and High Temperature Electrolysis respectively Solid Oxide Electrolyzer Cell (SOEC) (with and without waste heat use) as well as the provision of the two hydrogen derivatives H12-BT in a Liquid Organic Hydrogen Carrier Dehydrogenation route (LOHC) and NH_3 in an Ammonia Decomposition route (NH_3) by its LCOH development from 2030 to 2045. The assessment of their maturity is shown in Fig. 1.

The technologies considered are expected to reach TRL 9 by 2045. The TRL is a methodology for the assessment of product maturity and its correlation with market dynamics. The scale ranges from 1, basic principles observed to 9, actual system proven in operational environment [16].

The technologies are analyzed as process units i.e., for the SMR a pressure swing adsorption (PSA) is added to the actual reactor. For the derivative-based supply routes, the dehydrogenation (LOHC) or decomposition (NH_3) plant are considered as process units, while the imported derivatives are considered as commodities. Each process unit has input and output flows, which in turn are associated with specific costs. The input and output flows are illustrated in Fig. 2.

1.2.2. Gas-based technologies

Hydrogen that is produced by processes using fossil fuels is described as gray hydrogen. During the production of gray hydrogen, CO_2 is usually emitted into the atmosphere [2].

SMR describes the process of endothermal catalytic conversion of natural gas with water vapor into hydrogen and carbon monoxide, known as synthesis gas. The SMR usually occurs at temperatures between 700°C and 850°C and pressures between 3 and 25 bar [17]. This syngas could be used directly as building blocks for various syntheses in chemical industry. With the aim of producing pure hydrogen, the CO is converted with water via the water gas shift equilibrium to H_2 and CO_2 in an additional step. The hydrogen is then separated in a purification stage. The choice of cleaning stage depends on the required purity, although according to the state of the art a PSA system is predominantly used. In 2019, the worldwide share of SMR for hydrogen production was around 96% [18].

SMR can also be used with biogas if the biomethane is separated from the CO_2 before. For this separation a membrane can be used [19].

ATR combines the SMR and partial oxidation. The entire reaction is exothermic with a process temperature between 950°C and 1100°C and at a gas pressure of up to 100 bar [17]. For the avoidance of nitrogen in the product, pure oxygen can be injected into the process using an air separation unit at industrial plants [20]. When biogas is used a sulfurization plant for the filtration of hydrogen can be used [21].

Methane pyrolysis describes the decomposition of natural gas into the products hydrogen and carbon black. If the decomposition occurs at temperatures >1000°C, it is referred to as thermal pyrolysis [2]. In the

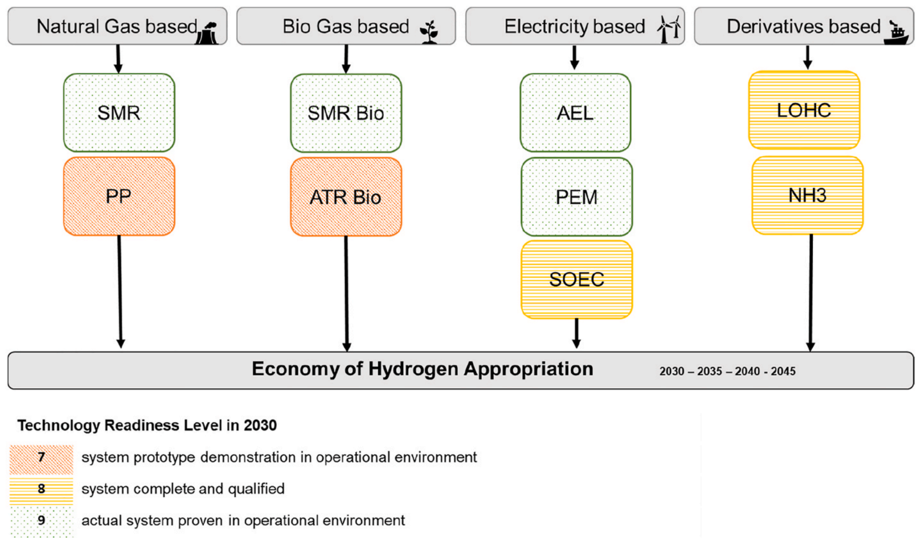

Fig. 1. On-site technologies for hydrogen appropriation.

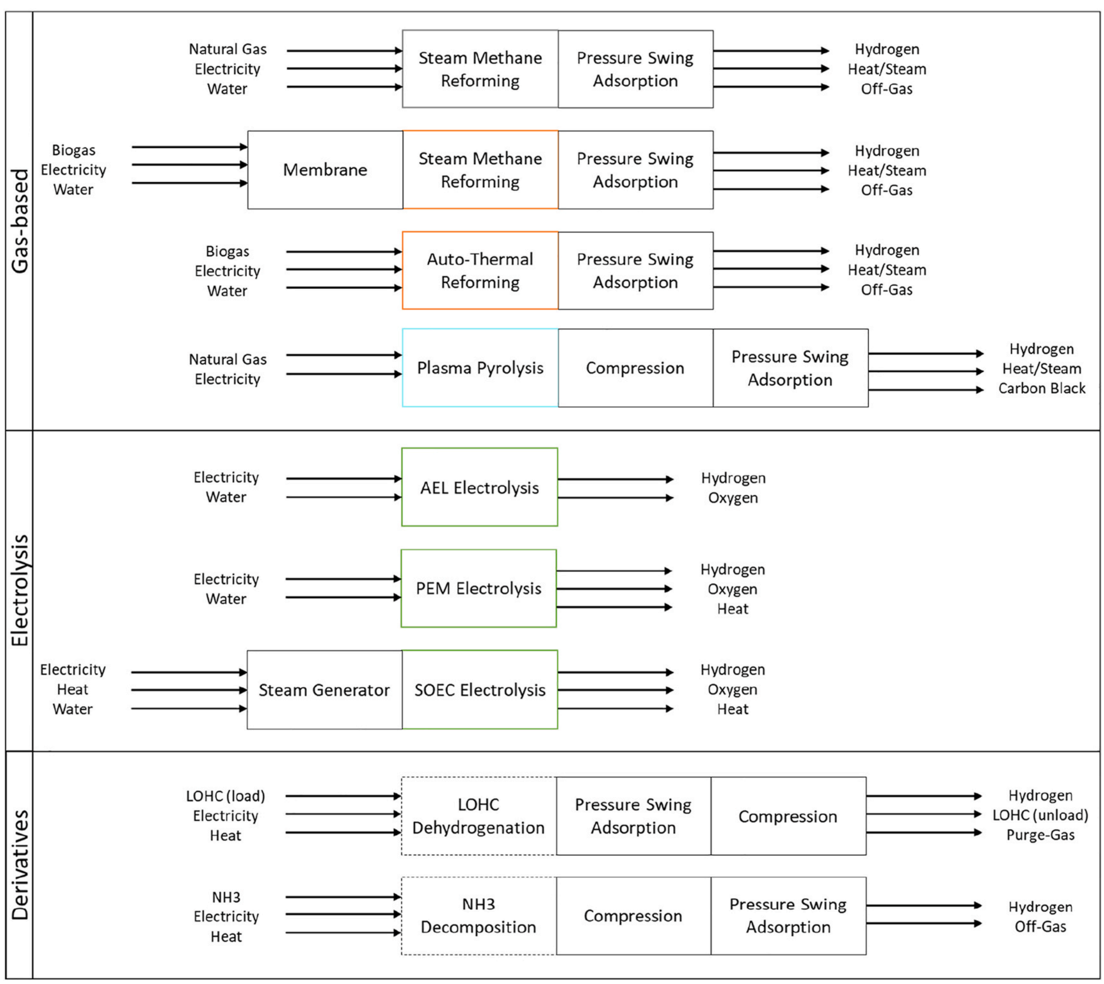

Fig. 2. Process units of technologies considered.

lower temperature range (<1000°C), catalysts enable the thermo-chemical reaction (catalytic pyrolysis). The third category of methane pyrolysis is plasma pyrolysis. This uses plasma, the fourth state of matter, which describes ionized gas, for the reaction to split methane at temperatures up to 2000°C [22]. Energy is supplied via electrical current. In the past, PP was used to produce carbon black, with hydrogen as a by-product. Methane pyrolysis is considered to be a bridging technology for the transition to renewable hydrogen production, as it is based on natural gas [23], but emits less CO_2 than SMR. The advantages as a bridging technology are comparatively low CO_2 emissions and the sale of carbon black.

1.2.3. Electrolysis technologies

Hydrogen can be produced by decomposing water through various processes such as water electrolysis, and high temperature water decomposition [17]. Of the technologies presented here, water electrolysis is the most mature and relevant in this domain and describes the process of decomposing of water into hydrogen and oxygen using an electric current.

Currently, AEL is the most mature electrolysis technology with 60% of the installed capacity worldwide by the end of 2022 [24]. The electrolyte is mostly a highly concentrated potassium hydroxide solution transporting the anions OH- between the electrodes. Electrodes and produced gases are separated through a separator permeable to the potassium hydroxide solution [25].

In PEM electrolysis, the electrodes are separated by a thin solid polymer membrane that is only permeable to protons [26]. As the medium is acid and corrosive, noble metals like Platin, Iridium, or Ruthenium are required. Due to the use of noble metals, the PEM electrolysis is more expensive than other electrolysis technologies. The advantages in comparison to alkaline electrolysis are shorter start-up time and a higher flexibility by production rate [27]. Reducing critical material loads is crucial for the development of PEM [24].

The SOEC is carried out at approximately 800°C, as at this point thermodynamics require less electrical energy for water splitting [28]. In comparison to the aforementioned electrolysis technologies, the SOEC does not necessitate the use of noble metals. Furthermore, the implementation of the SOEC in other processes involving waste heat has the potential to enhance its efficiency in comparison to alternative electrolysis technologies [29].

1.2.4. Hydrogen derivatives

The import of derivatives is a subject of particular interest in regions characterized by either limited energy availability or elevated energy costs.

Hydrogen may be imported using hydrogen derivatives such as LOHC. For this purpose, hydrogen, ideally produced using an electrolysis process with electricity from renewable energies, is bound to a carrier, such as benzyl toluene and dibenzyl toluene, in a hydrogenation plant and transported to its destination. On-site, the hydrogen is released from the carrier and the discharged carrier is reused. The separation occurs endothermal in a dehydrogenation plant [30,31].

In contrast, the synthetic production of NH_3 has already been practiced for more than 100 years using the Haber-Bosch-Process. In this process, hydrogen and nitrogen react with each other to NH_3. NH_3 is transported in liquid form and its transportation is comparable to liquid gas. At the hydrogen point of use, ammonia can be decomposed into hydrogen and nitrogen with the use of energy. Large-scale ammonia decomposition plants with the aim of decentralized hydrogen supply are currently less well known and not yet in use [32,33].

As it is assumed that the loaded LOHC and NH_3 are transported to their destination by trailers on a regular basis, on-site storage facilities must be included for both hydrogen carrier. The conversion then takes place successively. For the storage of LOHC, an above ground tank [34] or a conventional oil storage tank [30,35] can be used. For the NH_3 a low temperature storage can be used [36].

Table 1 summarizes the key advantages and disadvantages of the considered hydrogen production and transport technologies. Overall, established processes such as SMR and AEL stand out due to their high technological maturity and cost-efficiency but show clear limitations in terms of dependence on natural gas. In contrast, emerging and renewable-based options (e.g., SOEC, ATR Bio, or LOHC/NH_3 pathways) offer significant environmental benefits but are associated with higher costs, lower maturity levels, or infrastructure challenges. This highlights the fundamental trade-off between technological readiness, economic feasibility, and environmental sustainability across the assessed

Table 1
Advantages and disadvantages of the compared technologies, Sources based on previous chapter.

	Advantages	Disadvantages	TRL (2030)
SMR	Cost-effective and well-established technology.	Relies on natural gas and is therefore not sustainable in terms of CO_2 emissions and climate impact; strong dependency on imports; additional emissions from methane leakages during transport as well as from the reforming process itself.	9
SMR Bio	Utilizes renewable gas sources; established technology, as only an additional membrane unit is required upstream.	Higher costs due to additional gas cleaning and high biogas prices; limited availability of biogas in Germany, which is already integrated into existing processes; minimal expansion potential due to limited land availability.	8-9
ATR Bio	Based on renewable energy sources; technology concept is not new when using natural gas.	See SMR Bio.	7
PP	Low CO_2 emissions, as carbon is captured in solid form; potential additional revenue from carbon black sales.	Technological challenges due to soot formation; limited technological progress over the past two decades; unclear path to market maturity; considered a bridging technology but unlikely to reach industrial deployment in time for climate neutrality targets by 2045.	6-7
PEM	Fast start-up times and high operational flexibility (e.g., compared to AEL); low CO_2 emissions when powered by renewable energy.	Requires expensive noble metals; when using the current electricity mix, CO_2 emissions can exceed those of SMR.	9
AEL	Most mature electrolysis technology, uses non-precious, abundant catalysts such as nickel, resulting in cost-effective production (e.g., compared to PEM).	Limited operational flexibility due to long ramp up times, making it less suitable for fluctuating renewable energy sources.	9
SOEC	No noble metals required, high efficiency especially when integrated with processes utilizing waste heat.	Lower TRL; requires operation at very high temperatures.	7-8
LOHC Dehy.	Can be produced sustainably in regions with surplus renewable energy and low environmental impact.	Requires long-distance transport; may introduce dependencies on exporting countries; additional infrastructure needed (e.g., storage tanks).	8
NH3 Decomp.	Established process in small scale, can be produced in regions with renewable energy surplus with low environmental impact.	Significant environmental and safety risks in case of leakage during transport; additional infrastructure required (e.g., storage tanks).	8

technologies.

In this study, an optimistic technology development pathway is assumed for the assessment of TRL levels as seen in Table 1. The assigned TRLs are primarily based on literature sources and supported by expert interviews, with a tendency toward the higher end of reported ranges. Furthermore, calculations were limited to technologies with a TRL of at least 8, enabling an early-stage comparison of near-market-ready options.

2. Methods

2.1. Overall modeling framework

To ensure transparency and reproducibility of the analysis, a structured workflow as shown in Fig. 3 was developed linking technology selection, data harmonization, cost scaling, and LCOH calculation.

In a first step, a comprehensive literature review combined with expert discussions was conducted to identify relevant hydrogen production and supply technologies. Only technologies with a minimum TRL of 7 and an expected maturity of 9 by 2045 were considered for further analysis.

In the second step, techno-economic data were collected from the literature following defined criteria: (i) preference for peer-reviewed sources, (ii) availability of CAPEX and OPEX data, (iii) recency and relevance of the data, and (iv) geographical relevance, prioritizing studies conducted in Germany and Europe. Where necessary, data were cross-checked with expert assessments.

Subsequently, investment costs were harmonized by applying technology-specific scaling factors to a uniform plant capacity of 10,000 t_{H2}/a. Future cost developments were incorporated using technology price development (see also supplementary material), resulting in time-dependent CAPEX for the years 2030, 2035, 2040, and 2045.

Operational assumptions were standardized across all technologies to ensure comparability. A plant availability up to 8760 full-load hours per year was assumed, corresponding to continuous industrial operation. A weighted average cost of capital (WACC) of 7.9% was applied, and technology-specific lifetimes were considered.

Based on technology-specific input streams (e.g., electricity, natural gas, biogas, water, heat, and hydrogen carriers) and associated costs, as well as potential revenues from by-products (e.g., oxygen, heat, steam, carbon black), annualized costs were calculated. Finally, these were converted into LCOH in €/kg_{H2} using the standardized annuity-based cost model described in Section 2.3 The system boundaries applied in this modeling framework are described in Section 2.2.

2.2. System boundaries

To verify consistency and comparability across all hydrogen supply pathways, clearly defined system boundaries were applied.

The analysis focuses on on-site hydrogen supply systems with a standardized production capacity of 10,000 t_{H2}/a. The system boundaries include all process steps required to produce hydrogen at the point of use, including feedstock preparation (e.g., gas conditioning or carrier unloading), the core conversion process (e.g., reforming, electrolysis, or decomposition), downstream purification (e.g., PSA), as well as auxiliary systems such as compressors and gas treatment units.

All technologies are assumed to deliver hydrogen at a standardized pressure (20 bar) and purity level suitable for industrial applications, ensuring comparability across different production routes.

For electrolysis-based technologies, the system includes electricity supply and compression. For gas-based technologies, natural gas or biogas supply is included together with direct CO_2 emissions, which are monetized via the EU-ETS framework. Indirect emissions, particularly from electricity generation, are not explicitly modeled but are reflected in electricity price assumptions.

For hydrogen derivatives (LOHC and NH_3), the system boundary includes on-site storage, dehydrogenation or decomposition units, and associated auxiliary processes. The import of hydrogen carriers is treated as an exogenous cost parameter, meaning that upstream production, international transport, and logistics are not explicitly modeled but included implicitly via market-based import prices.

For SOEC, cases with and without external waste heat integration are

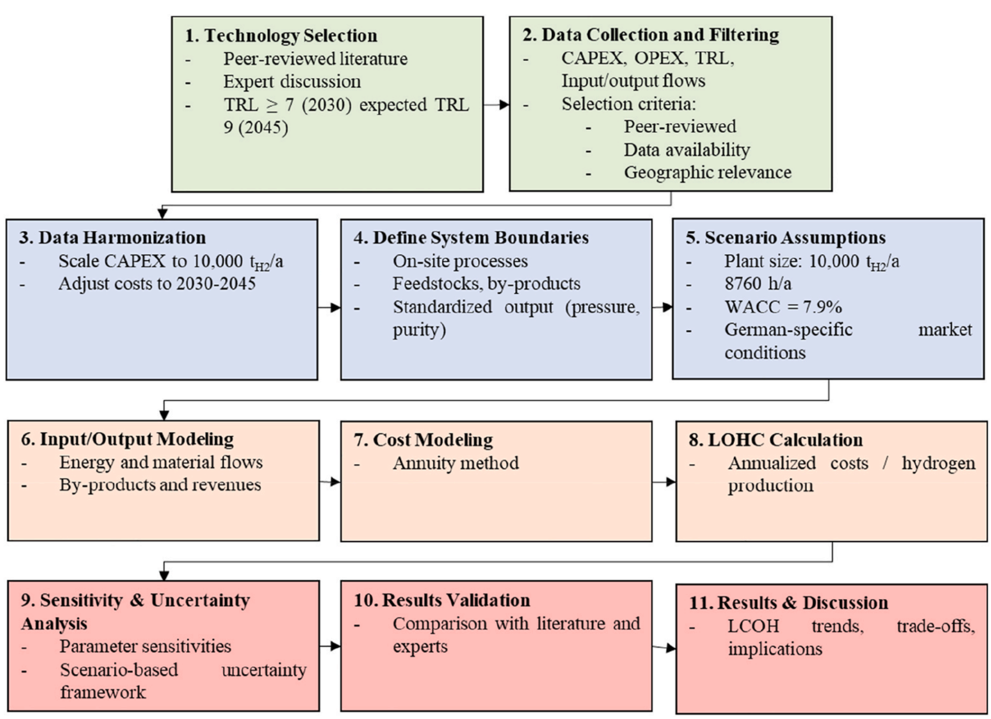

Fig. 3. Workflow of the techno-economic modeling framework applied in this study; green: data/input, blue: harmonization/processing, orange: modeling, red: output. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

considered. In the waste heat case, industrial excess heat is assumed to be available without additional infrastructure costs.

All systems are evaluated under steady-state conditions for each considered year (2030, 3035, 2040, 2045), assuming constant operating conditions and full-load operation of up to 8760 h/a. By applying harmonized system boundaries and assumptions, a consistent techno-economic comparison across all technologies is ensured.

2.3. Cost modeling and LCOH formulation

The economic evaluation is based on standardized investment calculation methods for process plants as defined in VDI Guideline 6025 [37] and 2067 [38], enabling a consistent comparison of different technological concepts. Investment profitability is assessed using dynamic, multi-periodic evaluation methods that account for the time value of money over the full lifetime.

To ensure comparability, capital expenditure (CAPEX) and operational expenditure (OPEX) are converted into equivalent annual costs using the annuity method. The corresponding annuity factor a, is defined as:

$$a = \frac{(1+r)^n * r}{(1+r)^n - 1} \tag{1}$$

where r denotes the WACC and n the evaluation period in years. For the WACC, we follow an empirically determined value collected by Schoniger et al. [39] for the chemical and pharmaceutical sector of 7.9%.

To harmonize cost data across different literature sources, investment costs are scaled to a uniform plant capacity of 10,000 t_{H2}/a using a technology-specific scaling approach:

$$CAPEX_{scaled} = CAPEX_{refernce} * \left(\frac{c_{scaled}}{C_{reference}}\right)^{sf} \tag{2}$$

where sf denotes the technology-specific scale factor. In addition, it is assumed that the price of the respective technologies will undergo changes over time. This effect is implemented as an exogenously defined relative price decrease over time. (See supplementary material)

Based on these harmonized inputs, the LCOH is calculated as the ratio of total annualized costs to the annual hydrogen production:

$$LCOH = \frac{AN_{\mathrm{CAPEX}} + AN_{\mathrm{fixOPEX}} + AN_{\mathrm{varOPEX}} - AN_{\mathrm{income}}}{\dot{m}_{\mathrm{hydrogen}} \cdot t} \tag{3}$$

The annualized cost components are defined as follows. Capital-related annuities are derived from the investment cost:

$$AN_{\mathrm{CAPEX,j}} = A_{\mathrm{CAPEX,j}} \cdot a \tag{4}$$

Fixed OPEX are estimated as a fraction of investment costs:

$$AN_{\mathrm{fixOPEX,j}} = A_{\mathrm{CAPEX,j}} \cdot f_{\mathrm{fixOPEX,j}} \cdot a \tag{5}$$

Variable OPEX include all consumption-based expenditures, such as electricity, natural gas, biogas, water, heat at different temperature levels, hydrogen carrier imports (LOHC and NH_3), and CO_2 emission costs. These are aggregated a

$$AN_{\mathrm{varOPEX,j}} = \sum A_{\mathrm{varOPEX,i,j}} \cdot a \tag{6}$$

In addition, potential revenues from by-products—including oxygen, steam, heat at different temperature levels, and carbon black—are accounted for as:

$$AN_{\mathrm{income,j}} = \sum A_{\mathrm{income,i,j}} \cdot a \tag{7}$$

This harmonized cost structure ensures a consistent and transparent evaluation of all hydrogen production pathways considered in this study.

2.4. Data selection and harmonization

Techno-economic data for all technologies were collected from the literature following a structured selection methodology. Preference was given to peer-reviewed publications with transparent reporting of CAPEX and OPEX values.

The selection of representative cost values was based on the following criteria:

(i) availability of detailed cost breakdowns,
(ii) recency and technological relevance,
(iii) comparability of plant size, and
(iv) geographical relevance, prioritizing studies conducted in Germany and Europe.

In cases where multiple values were available, representative values were derived based on consistency with other studies and expert validation. Due to large variability in reported costs, especially for emerging technologies the selected data points were primarily chosen from the mid-range of available options.

All cost data were harmonized to a common reference plant capacity of 10,000 t_{H2}/a using scaling factors. Furthermore, costs were adjusted to a consistent price level and converted where necessary.

This harmonization ensures that all technologies are evaluated on a consistent and comparable basis.

2.5. Scenario assumptions

The techno-economic analysis is based on a set of consistent scenario assumptions for the period 2030 to 2045. Key assumptions include:

- Electricity prices: Derived from national energy system models, with values ranging from 0,03 to 0,135 €/kWh.
- CO_2 emission prices: Based on EU-ETS projections, increasing to 300 €/t_{CO2} by 2040.
- Fuel prices: Assumptions for natural gas and biogas based on literature and market reports.
- Technology cost development: Future CAPEX reductions were modeled using learning rate assumptions and literature projections.
- Financial parameters: A WACC of 7.9% and technology-specific lifetimes were assumed.
- Operation: Continuous operation with up to 8760 full-load hours per year was assumed for all technologies.

These assumptions represent a conservative baseline scenario for Germany.

3. Economic assumptions

As described in the previous section, several parameters are used for the calculation of LCOH. The main parameters can be divided into technology-related data and consumption-related data.

3.1. Technology-related data

Technology-related cost data described in the following sections are the CAPEX and fixed OPEX as well as the additional technologies used in the process units. Furthermore, the system lifetime was considered.

3.1.1. Gas-based technologies

In the subsequent section, a comprehensive summary of the four gas-based technologies SMR, SMR Bio, ATR Bio, and PP examined in this study is provided.

There is a fluctuation of system costs of the SMR depending on the publication and region. Khojasteh Salkuyeh et al. [40] assume 58 million USD (2016) for the reformer, 7 million USD for the Water Gas

Shift Reactor and 81 million USD for the PSA with a capacity of 18.9 t_{H2}/h and 8760 h annual operating hours. The CAPEX for regions with natural gas deposits is assumed to be 397 million CAD for a capacity of 607 t_{H2}/day [13]. SMR is used worldwide on an industrial scale and has a lifespan between 25 [13,30] years [40].

Two cost calculations are possible for the SMR using biogas. The initial step involves estimating the price of biomethane and incorporating it into the SMR. The second option involves the utilization of an upstream technology, such as a membrane, for the purpose of separating biogas into CO_2 and CH_4. This study chose the additional pre-treatment of biogas via a membrane technology. A limited amount of studies on this topic is available, e.g., Marcoberardino et al. [41]. They analyzed an auto-thermal fluidized bed catalytic membrane reactor with a capacity of 100 kg_{H2}/day with a pressure of 20 bar and determined LCOH of 5 €/kg_{H2}. The technology has an estimated lifespan of 25 years.

In general, natural gas is used for this technology but to produce low-carbon hydrogen by the gas-based ATR technology, plants that use biogas as a feedstock are tested [42]. Montenegro et al. [42] state the costs for an ATR process based on biogas and a capacity of 100 Nm^3_{H2}/h at 872,000 €. This includes all direct costs, such as the PSA and the compressor, as well as indirect costs. The OPEX amount to 3% of the CAPEX. The operating costs amount to 93,000 €/a.

Assumptions from a case study from the Netherlands expect an economic lifetime of 20 years for a production of 500,000 t_{H2}/a with 8322 annual operating hours [43]. The same values are assumed for the SMR. The operation and maintenance costs are stated at 4% of CAPEX [43]. This value also applies to the SMR. With a capacity of 18.9 tH_2/h and 8760 h of annual operation, Salkuyeh et al. [40] estimate the total cost of the ATR at 326 million USD. The Canadian study from Oni et al. [13] quotes CAPEX of 1090 million CAD for a large-scale plant. The OPEX is indicated at 75 million CAD/a. The lifespan varies greatly depending on the literature source. In their techno-economic analysis, Montenegro et al. expect the small-scale facility to have an average lifespan of 10 years [42]. For commercial plants, lifespans vary between 25 [13,20,43]and 30 years [40].

Jensen et al. [44] consider the PP process to be the pyrolysis process closest to commercialization. The advantage of this gas-based technology is the 4 to 5 times lower electricity costs compared to water electrolysis. The costs range from 4000 to 5000 USD/t_{H2} a year. To achieve this price, the pyrolysis plant must be at least of commercial size with a minimum capacity of 25,000 t_{H2}/a [44]. Machhammer et al. [45] expect a specific investment of 2500 €/t_{H2} produced per year. Timmerberg et al. [46] compared the costs for PP from literature values and determined investment costs of 27,750 €/kg_{H2} produced per hour. The range varies between 3331 and 151,914 €. Operation and maintenance costs are assumed to be 3% of the total investment [46]. PP may be used as a temporary transition technology for hydrogen production with lower CO_2 emissions [2]. According to Monolith Materials, Olive Creek I was demonstrated at a commercial scale in 2020 [47].

The lifetime of the plasma system varies between 20 [48] and 30 years [46].

3.1.2. Electrolysis technologies

As highlighted in recent review studies on electrolysis investment costs, cost estimations are strongly influenced by the specific electrolysis technology and system capacity considered [49]. For each technology examined, this section describes all aspects of their investment costs. Fixed OPEX are uniformly assumed to be 3% of the CAPEX across all electrolysis technologies, similar to the technologies based on natural gas and biogas.

For AEL, the literature consistently indicates a substantial decline in CAPEX over the coming decades. Smolinka et al. [14] estimated CAPEX for AEL systems with capacities ranging from 1 to 100 MW at 4100 €/Nm^3/h in 2020, projecting a decrease to 2100 €/Nm^3/h by 2050. Complementary findings are reported by Koj et al. [50], who identified CAPEX values of 1097 €/kW_{el} for a 5 MW system and expect a reduction to 521 €/kW_{el} for a 50 MW system by 2050. Böhm et al. [49] provide similar estimates, assuming initial investment costs of 1100 €/kW_{el} for a 5 MW system and a decline to 511 €/kW_{el} by 2050. In this study, the initial investment costs are derived from the values reported by Koj et al. and scaled to the reference system size of 10,000 t_{H2}/a. AEL is mature [18] and has a lifespan of 20 years.

A comparable long-term cost trend is observed for PEM electrolysis. Smolinka et al. [14] estimated CAPEX at 7100 €/Nm^3/h in 2020, with a projected reduction to 2200 €/Nm^3/h by 2050. Koj et al. [50] reported CAPEX of 1188 €/kW_{el} and anticipate a decline to 314 €/kW_{el} by 2050. Similarly, Ausfelder et al. [51] assumed an initial CAPEX of 1150 €/kW_{el}, decreasing to 400 €/kW_{el} by 2050. The technology is on the verge of entering the commercial market [18] with a lifespan of 20 years.

For SOEC, the range of reported CAPEX values is notably wider, reflecting the limited empirical evidence available for early installations. Smolinka et al. [14] estimated CAPEX at 9000 €/Nm^3_{H2}/h in 2020, falling sharply to 1000 €/Nm^3_{H2}/h by 2050. In contrast, Koj et al. [50] reported CAPEX of 5733 €/kW_{el} in 2020, with a projected decrease to 491 €/kW_{el} by 2050. Böhm et al. [49] assumed initial costs of 2250 €/kW_{el}, decreasing to 508 €/kW_{el} by 2050. The substantial variation in CAPEX estimates for 2020 can be attributed primarily to the small number of installations implemented, given the limited number of SOEC installations at that time. SOEC has not reached commercialization yet [18].

3.1.3. Hydrogen derivatives

In the subsequent section, the two derivatives LOHC dehydrogenation and NH_3 decomposition are summarized.

An EU-funded project [52] has estimated CAPEX for a dehydrogenation system that includes the PSA for stationary tanks at 3.5 million Euro for 1 t_{H2}/day. In addition to this, approx. 42,000 € must be allocated for each storage tank and the costs for the carrier material, in this case LOHC. The LOHC is circulated and replaced after 750 loading and unloading cycles [52]. Jorschick [53] assumes an investment of 30 million Euro for dehydrogenation with a capacity of 12,500 kg_{H2}/h. For the required compression, Jorschick assumed 1.2 million Euro for 250 kg_{H2}/h and for LOHC storage 50 € for 1 kg_{H2} storage capacity [53]. According to Niermann et al. [30] the estimated costs of a dehydrogenation plant that operates 20 years with a capacity of 30 kg_{H2}/h is 282,000 €. Reuβ et al. [34] describe the costs of a large-scale release plant with a capacity of 300 t_{H2}/day at 30 million Euro with a depreciation period of 20 years. The operation and maintenance costs are given as 3 to [34] 4% [30,35,36].

Anderson [54] quotes costs of 140 million Euro for a capacity of 500 t_{H2}/day for the dehydrogenation and separation of H12-BT to H_2.

Reuβ et al. estimate the costs of LOHC storage at 50 €/kg_{H2}, which includes the LOHC carrier material and two tanks with 5 €/kg_{H2} [34]. The costs for the LOHC are 4 €/kg_{DBT} [35].

Ishimoto et al. [32] calculate the costs for ammonia decomposition of 51 million Euro for a capacity of 390 t_{H2}/day. When comparing transportation options for hydrogen and its derivatives, the German Research Center for Energy Economics (FfE) [55] specifies CAPEX of 460 million USD for the reconversion plant with a capacity of 1500 kt_{NH3}/a. The annual fixed OPEX is assumed to be 3% to [32] 4% [56] of the CAPEX.

A lifetime of 25 years for the decomposition system is assumed based on [32,57]. A storage tank operating at a temperature of −33°C is employed for the storage of NH_3. The estimated cost of such a storage tank is 350 €/t_{NH3} [36]. The utilization of large-scale NH_3 crackers is not a prevalent practice [32].

3.2. Data selection of CAPEX and OPEX values

The values finally used in the calculations can be found in Table 2. The data presented herein is already adjusted to the assumed technological price development and scaling to the capacity of 10,000 t_{H2}/a

Table 2
Cost basis for calculations after taking into account technology-related scaling factors and price developments. All costs are expressed in t€/10,000 t_{H2}/a.

	2030	2035	2040	2045	Initial source
SMR	25,635	24,354	23,136	21,979	[13]
SMR Bio	40,714	38,679	36,745	34,907	[13,58]
ATR Bio			18,784	17,553	[42,58]
PP			65,191	60,640	[44]
AEL	62,336	58,747	55,359	39,807	[50]
PEM	60,008	49,915	41,451	34,360	[50]
SOEC waste heat		52,372	33,744	24,410	[49]
SOEC		55,305	36,530	27,057	[49,58]

considered in the study. The future price development depends on different parameter such as the technology learning rate, which describes the hypothesis that the costs of a technology decrease by a constant amount for every doubling of installed capacity [59,60]. Several other mechanisms explain the decline in costs [61] naming the following five: Learning-by-doing, learning-by-researching, learning-by-using, learning-by-interacting and economies of scale. Comprehensive information can be found in the supplementary material.

The fixed OPEX are assumed to be 3% of the CAPEX for each technology, except for LOHC for which it is 4%. Fixed OPEX for storage (LOHC and NH_3) are assumed to be 2%.

3.3. Consumption-related data

3.3.1. Electricity

The assumptions about the future grid electricity costs are based on several studies and summarized in Fig. 4. One of them are the German long-term scenarios ([63]). The results of these scenarios contain future German electricity prices [64] for representative years. Hereof an arithmetic means and a median shadow price is calculated for each representative year. Furthermore, Prognos [65] model the future German electricity system and publish resulting wholesale prices while FfE [66] publishes projections of the German electricity wholesale price for 2040.

Especially in the mid-term results of Prognos [65], Sensfuβ et al. [63] and FfE [66] are comparable. Based on these studies and electricity futures [67] our electricity price assumptions follow Sensfuβ et al.'s median shadow prices. Moreover, no grid fees or taxes are considered, as industrial companies often have several possibilities of relief [68].

Furthermore, we consider Power Purchase Agreement (PPA) as an option to procure electricity from renewable sources. PPAs are individual negotiated long-term agreements for renewable energy between companies and energy suppliers. The advantages for companies are the lower price of the electricity supply and the guaranteed green energy from renewable energy sources. The main disadvantage for companies is the long-term contract while long-term contracts are a necessary component for energy suppliers, as they facilitate the utilization of substantial capital for the expansion of renewable energies. In this study the PPA price is directly coupled with the assumed grid electricity price (85% in 2030 to 100% in 2045) as seen in Table 3.

3.3.2. Gaseous feedstock and CO_2 emission price

As a plant that is producing 10,000 t_{H2}/a is falling under the EU-ETS [69], it becomes necessary to include the costs of CO_2 emission allowances in addition to pure fuel prices when calculating the LCOH. Due to consistency reasons with previous assumptions, our assumptions concerning the future natural gas fuel prices and EU-ETS prices follow Sensfuβ et al. [63] (Table 4).

However, as natural gas fuel prices are predicted to decrease [63], even the combination with CO_2 emission prices would lead to decreasing prices from 2030 to 2035. Sensfuβ et al.'s CO_2 emission price assumptions are adjusted for 2035 from 200 €/t_{CO2} to 225 €/t_{CO2}, leading to continuously increasing natural gas prices (Table 3). The emission price reaches a platform at 300 €/t_{CO2} as of 2040. In this study, fuel and CO_2 prices were calculated separately due to the PP technology, since the process uses natural gas as a feedstock but does not directly emit CO_2.

Regarding the parametrization of biogas, an examination of several marked monitoring reports [70–73] and other surveys [74,75] was performed. In all reports, biomethane and not biogas is considered. However, biogas prices should be cheaper than biomethane prices, as the methane separation step is omitted. Guidehouse and Gas for Climate [73] number this separation step with about 12% of the total biomethane production costs. All in all, the monitoring reports give average biomethane prices of 0.05 to 0.08 €/kWh, depending on the primary raw material. Nevertheless, due to an anticipated market shortage, we finally expect biomethane prices >0.1 €/kWh and derive for our computations

Table 3
Chosen parameters for grid electricity's purchase prices and PPA prices in [€/kWh].

	2030 – 2034	2035 – 2039	2040 – 2044	2045 – 2050
Grid electricity's purchase price	0.080	0.070	0.060	0.055
PPA price coupled to grid price	0.068	0.063	0.057	0.055

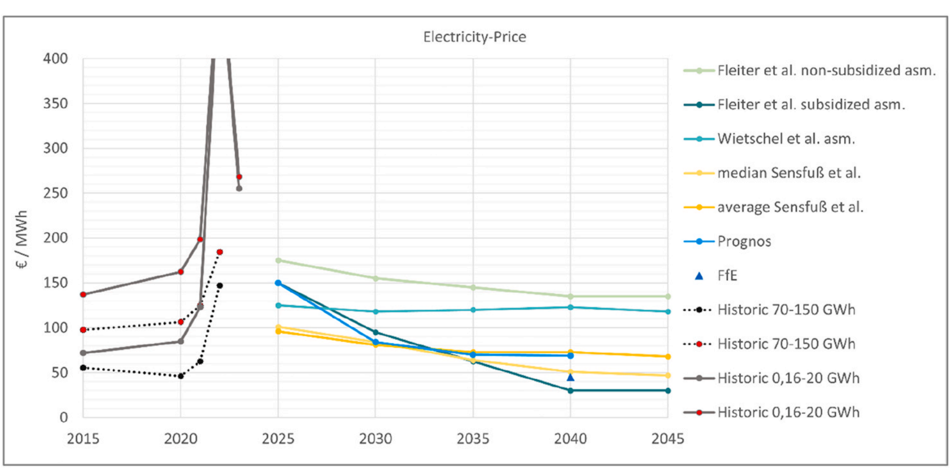

Fig. 4. Future German electricity prices, based on different studies. Be aware that Fleiter et al.'s values are industrial pur-chase prices, while Sensfuβ et al. are shadow prices and Prognos and FfE are wholesale prices [62].

Table 4
Chosen parameters for natural gas fuel prices, CO_2 emission prices and resulting purchase prices.

	2030 - 2034	2035 - 2039	2040 - 2044	2045 - 2049
Fuel Price (LHV) €/kWh]	0.025	0.014	0.014	0.015
CO2 Price [€/t_{CO2}]	150	225	300	300
Biogas [€/kWh]	0.09	0.09	0.09	0.09

biogas prices of 0.09 €/kWh and an energy density of 5.0 kWh/kg (LHV) [76].

3.3.3. Hydrogen derivative supply

Multiple surveys were analyzed to assume the future development of hydrogen carriers' import costs e.g., Refs. [5,31,35,55,77–81]. However, there are at least two challenges for adequate future assumptions. Firstly, it is still uncertain, from which countries the hydrogen carriers will be imported to Germany and secondly, it is challenging to recognize the respective differences of the applied exogenous parameters within the analyzed studies and thus the reasons for their differing results.

As Genge et al. [82] faced the same challenges as we did, they explored a dataset of more than 1000 datapoints coming from 30 studies. These data show that NH_3 and LOHC are the cheapest hydrogen carriers, while the supply costs are mostly dependent on the WACC and CAPEX. Furthermore, the average supply costs for hydrogen, bound in NH_3 and LOHC, are close to each other.

Finally, we build on Genge et al.'s [82] upper quartile NH_3 and LOHC import prices (see Table 5), because of anticipated additional taxes, fees and at least in the short-term market shortages of green hydrogen [83] and thus higher prices.

Regarding the derivatives' technical properties, we apply an NH_3 energy density of 5.2 kWh/kg (LHV) [31,84], and a LOHC and based on that an LOHC energy density of 2.0 kWh/kg (LHV) (loading density of 6.2 wt.-%).

4. Results and discussion

In the following sections, the results of the calculations are presented and discussed. Section 4.1 presents the calculated LCOH from 2030 to 2045. In Section 4.2, we conduct sensitivity analyses to evaluate the impact of key parameters on the LCOH, while Section 4.3 examines economic saving potentials.

4.1. LCOH - results

The calculations were conducted for a hydrogen supply in Germany from 2030 to 2045, with a demand of 10,000 t_{H2}/a. The analysis includes only technologies projected to reach a TRL of 9. By 2030, these comprise SMR, SMR Bio, AEL, and PEM, as shown in Fig. 5 while Table 6 compares the LCOH for all analyzed technologies over time.

The figure indicates that consumption-related costs, such as gas and electricity, account for the majority of hydrogen production costs (85% AEL to 90% SMR Bio). This is followed by CAPEX (8% SMR Bio to 13% AEL) and, to a minor extent, fixed OPEX (2% AEL, PEM – 3% SMR, SMR Bio). Furthermore, Fig. 5 shows that the most cost-efficient technology in 2030 is the SMR. The LCOH from SMR is 2.70 €/kg_{H2}, after accounting for 0.23 €/kg_{H2} in revenue from selling generated steam. It is noteworthy that by 2030, approximately 50% of LCOH will be attributable to the EU-ETS. In absence of this condition, the costs for SMR in 2030 would amount to 1.34 €/kg_{H2}.

However, due to the global ambitions to reduce CO_2-emissions, green technologies will become of greater interest. For this purpose, the SMR can also be operated with biogas as an eco-friendlier alternative. The additional investment of the membrane technology, the electrical energy required for compressing the biogas upstream of the membrane plant and the higher gas price for biogas lead to LCOH of 5.71 €/kg_{H2}. In addition, the potential for expanding biogas production in Germany is limited, since most available resources are already used for other purposes.

Concerning the AEL, the LCOH results in 5.14 €/kg_{H2} while for the PEM it is 5.32 €/kg_{H2}. The major price difference between the two electrolysis technologies results from the consumption-related costs (4.18 €/kg_{H2} AEL, 4.31 €/kg_{H2} PEM). In comparison to the gas-based PP, no revenues for by-products are considered. In addition, both available electrolysis technologies do have higher shares of CAPEX related to the overall LCOH (12% PEM and 13% AEL compared to 8% SMR). Based on the assumed service lives of electrolysis stacks (for further information see supplementary material) the stacks are to be replaced for all technologies within the assumed service life of 20 years. For simplicity, no pro-rata allocation of stacks was calculated. So, in the case of the AEL technology, the use of three stacks was considered in the calculation, despite the fact that the third stack was intended to be used for less than two years. In addition to the higher CAPEX, electrolysis prices are also higher compared to gas-based technologies due to its electricity demand and costs.

Future changes in raw material prices, CO_2 prices, and technological progress are expected to affect the LCOH. Consequently, the LCOH for a capacity of 10,000 t_{H2}/a varies over time.

Under the made assumptions, the electrolysis technologies are economically not competitive with the SMR in 2030 and 2035. However, it is important to emphasize that SMR represents a fossil-based hydrogen production pathway associated with significant CO_2 emissions (see also 4.3). The observed cost advantage is therefore primarily a short-term economic effect and does not reflect environmental sustainability or alignment with long-term decarbonization targets.

Consequently, the identification of SMR as the most cost-effective option in the early years should not be interpreted as a preferred long-term solution, but rather as a reference benchmark under current market conditions. With increasing CO_2-prices and stricter climate policies, gas-based technologies are expected to become less competitive, while low-carbon alternatives such as electrolysis gain importance over time.

This economical advantage of SMR changes in 2040, when the SOEC electrolysis becomes more competitive, especially when waste heat is used for the process. Due to the SOEC cost development on the one hand and increasing emission prices for the SMR on the other hand, SOEC with waste heat seems to achieve the lowest LCOH for water-electrolysis from the year 2040 on. In the SOEC case, it is assumed that 908 kW of heat at 200°C comes from industrial waste heat what leads to a LCOH of 3.11 €/kg_{H2}. If this heat is substituted by electric heating, SOEC is still the cheapest electrolysis technology in 2040 with a LCOH of 3.46 €/kg_{H2} as well as in 2045 with a LCOH of 3.10 €/kg_{H2}.

Besides that, the biogas-based ATR turns out to be not economically viable, mainly due to the high assumed biogas price. In contrast, PP seems to be highly competitive when it reaches the industrial maturity between 2035 and 2040. However, the available data for this technology must be interpreted with caution, as one company currently claims to have achieved commercial deployment. Most existing projects are still located in the mid-range of the TRL scale. Moreover, PP relies on natural gas as a feedstock, which contrasts with the long-term abandoning of fossil fuels strategies pursued by Germany and the European Union. Nevertheless, with regard to CO_2 emissions and projected production

Table 5
Chosen parameters for NH_3 and LOHC import prices, following Genge et al. [82] in [€/kg].

	LOHC import price	NH_3 import price
2030 – 2034	0.25	0.72
2035 – 2039	0.24	0.68
2040 – 2044	0.23	0.64
2045 – 2050	0.22	0.59

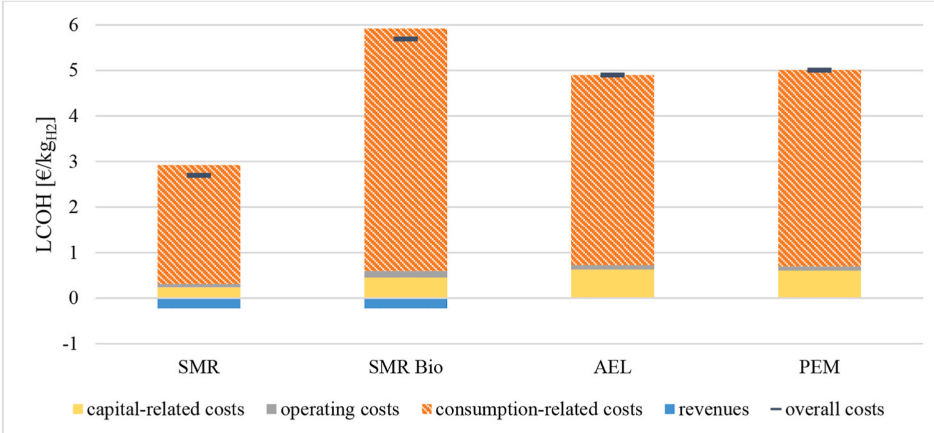

Fig. 5. Cost distribution within the hydrogen production costs in 2030.

Table 6
LCOH [€/kg$_{H2}$] of different technologies in variation of time with a capacity of 10,000 t_{H2}/a. The different colors indicate if the price is high (red), rather high (orange), medium (yellow), rather low (light green), or low (green) compared to the other technologies within this year. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

	2030	2035	2040	2045
SMR	2.70	2.86	3.56	3.60
SMR Bio	5.59	5.60	5.59	5.57
LOHC	5.17*	4.88	4.59	4.36
NH_3	5.20*	4.86	4.53	4.18
PEM	5.01	4.36	3.73	3.38
AEL	4.90	4.35	3.80	3.38
SOEC w waste heat	4.69*	3.77	3.11	2.78
SOEC w/o waste heat	4.99*	4.17	3.46	3.10
ATR Bio		4.45*	4.45	4.45
PP		2.30*	2.14	2.09

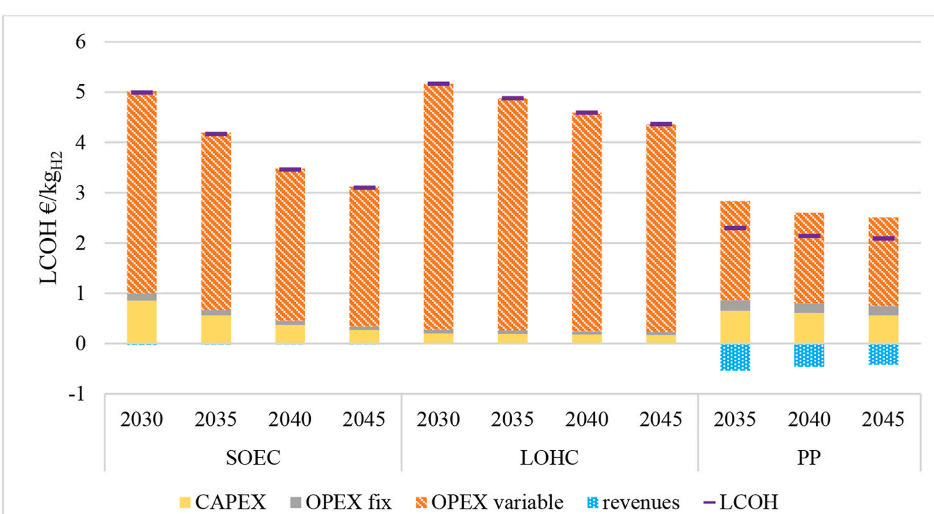

Fig. 6. Price development of cost distribution of selected technologies from 2030 to 2045.

costs, PP exhibits considerable potential to serve at least as a transitional technology, provided that ongoing scale-up and commercialization efforts are successful.

In the following, one technology from each of the clusters (1) water-electrolysis, (2) derivatives and (3) gas-based will be compared in terms of cost development and cost breakdown. Fig. 6 shows the breakdown of costs from 2030 to 2045. All analyzed technologies exhibit a continuous decline in the LCOH over time, with demand-related costs constituting the largest share of total costs, largely independent of the specific technology. The highest cost decrease is archived by the SOEC technology (without waste heat). The underlying factors contributing to this phenomenon include an expected doubling of the stack lifetime, a nearly 50% reduction in stack costs, and an anticipated decline in electricity costs, and due to the dependance between electricity and heat price, also heat price development.

The financial expense of LOHC is predicted to decline of approximately 15% between the years 2030 and 2045. This is due to the high share (above 94%) of demand-related costs, in this case the import costs and the electricity for the energy intensive hydrogen release, which are assumed to decline by appr. 12% between 2030 and 2045. However, especially the LOHC and NH_3 technologies are highly dependent from the respective import country.

The LCOH of PP is comparatively low relative to the other technologies. The economic viability of this technology is supported by two main factors. First, a 40% reduction in natural gas prices is expected between 2030 and 2035. Second, instead of producing CO_2 in gaseous form—which would incur costs under the EU-ETS—the process yields solid carbon black that can be sold at a profit, although no specific market price was assumed in this study. Furthermore, the waste heat is available at an elevated temperature of approximately 400°C, facilitating its use in additional industrial processes and the generation of supplementary revenue streams.

The calculated LCOH values for electrolysis and SMR in 2030–35 are slightly lower than those reported in the literature but align with the ranges projected for 2045 in Ref. [85]. While the present results indicate higher costs for 2030 compared to a meta-study [86], the 2045 estimates fall within the European price range specified in the study. The results are consistent with existing studies, with deviations arising from differences in system boundaries and input assumptions.

4.2. Sensitivity analysis

In order to assess the robustness of the calculated LCOH, a sensitivity analysis was conducted by varying key economic and market-related parameters. The analysis focuses on factors that are subject to significant uncertainty or policy influence, including the EU-ETS price, electricity price assumptions, electricity procurement strategies, and system scale. Each parameter was varied within a defined range based on literature values and market projections, while all other variables were held constant. This approach allows for the identification of key cost drivers and provides insights into the conditions under which cost reductions can be achieved.

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4.2.1. Impact of electricity price assumptions

As one OPEX variable in this study, the cost of electricity exerts the greatest influence on the LCOH, particularly given the high demand for electricity. Consequently, electricity costs are of paramount importance, especially for water electrolysis and the derivative technologies.

The divergence in electricity price forecasts derived from disparate national energy system models (including [66], [63], and [65]) can be attributed to the inherent uncertainty of future forecasts (see Fig. 4).

In order to demonstrate the effects of the inherent uncertain future electricity price, a sensitivity analysis was performed using five different prices based on various sources and assumptions ranging between 0.03 €/kWh and 0.135 €/kWh. The corresponding results are presented in the following Fig. 7.

The results show a significant spread of LCOH with increases of 260% within both SOEC approaches, 250% within PEM and 225% within AEL. While the production of H_2 via on-site water electrolysis is heavily dependent on local electricity costs, derivatives demonstrate a reduced degree of sensitivity. As the derivatives are expected to be imported to Germany, only their unloading is affected by local electricity price sensitivities. Consequently, the local electricity price in Germany has a smaller impact on the LCOH. However, there are notable fluctuations, reaching up to 10% for the NH_3 technology and up to 26% for LOHC technology.

4.2.2. Impact of EU-ETS price variation

A further measure of accelerating the transition to green hydrogen technologies within the European Union, and consequently in Germany, is to limit the EU-ETS emission allowances at a faster rate and hence increase the EU-ETS price. A faster increase will lead to higher LCOH for SMR, making it less economically attractive. Fig. 8 illustrates that prices escalate more rapidly in a scenario in which prices are predicted to rise five years earlier than expected. While the EU-ETS has been found to account for 50% of the LCOH in the baseline scenario, it is projected to reach 60% by 2030 in the ambitious scenario.

The cost disparity between hydrogen produced by SMR and hydrogen produced by electrolysis and derivatives is a key factor in the decision-making process. It is hypothesized that the cost discrepancy with fast increasing EU-ETS price will decrease more quickly, allowing electrolysis and derivative technologies to be introduced earlier. This, in turn, could lead to an accelerated green transformation in the hydrogen sector. However, the EU-ETS's influence on pricing is constrained to the European Union, and it is plausible that hydrogen production in Europe may become uneconomical in comparison to the rest of the world, potentially leading to corporate relocations.

4.2.3. Grid electricity versus PPA

Given the presumed significant differences between the LCOH of SMR and water electrolysis plus related technologies in 2030, additional calculations were conducted. Instead of the previously utilized grid price, PPA prices were posited. This calculation used coupled PPA prices based on the assumed electricity prices. In 2030, the PPA price is expected to be 85% of the grid price and to adjust to 100% by 2045, as we assume that the grid will then consist of 100% renewable energies.

The price fluctuations between the grid and the PPA are illustrated Fig. 9. In the field of water electrolysis technologies, the LCOH can be reduced by up to 12.5% for the AEL, 12.8% for the PEM, 10% to 11.9% for the SOEC (with and without waste heat), and by between 2.5% (LOHC) and 3.4% (NH_3) for the derivative technologies. In terms of the potential savings resulting from reduced electricity prices, the PEM technology offers the greatest opportunity.

4.2.4. Effects of system scale-up

Although CAPEX constitutes less than 20% of the LCOH, it can nevertheless serve to reduce the costs of hydrogen production. The reduction in CAPEX is attributable to the respective scaling factors of the technologies, which posit that a doubling of capacity does not result in a doubling of CAPEX. The results of the analysis demonstrate a decrease in the specific CAPEX per t_{H2} between 17% (SOEC) to 31% (LOHC). However, this decrease only results in a reduction of 1.6% to 4.9% in LCOH when scaling from 10,000 to 25,000 t_{H2}/a.

For instance, scaling up the AEL from 10,000 to 25,000 t_{H2}/a has the potential to reduce its LCOH by 3%, Consequently, if the companies demand is set at 10,000 t_{H2}/a but regional demand is higher, introducing a higher capacity and selling surplus hydrogen becomes a viable option. A capacity of 25,000 t_{H2}/a, would lead to annual cost saving of 1.5 million Euro. A similar analysis for the PEM technology would yield to a cost reduction of over 1.4 million Euro per year.

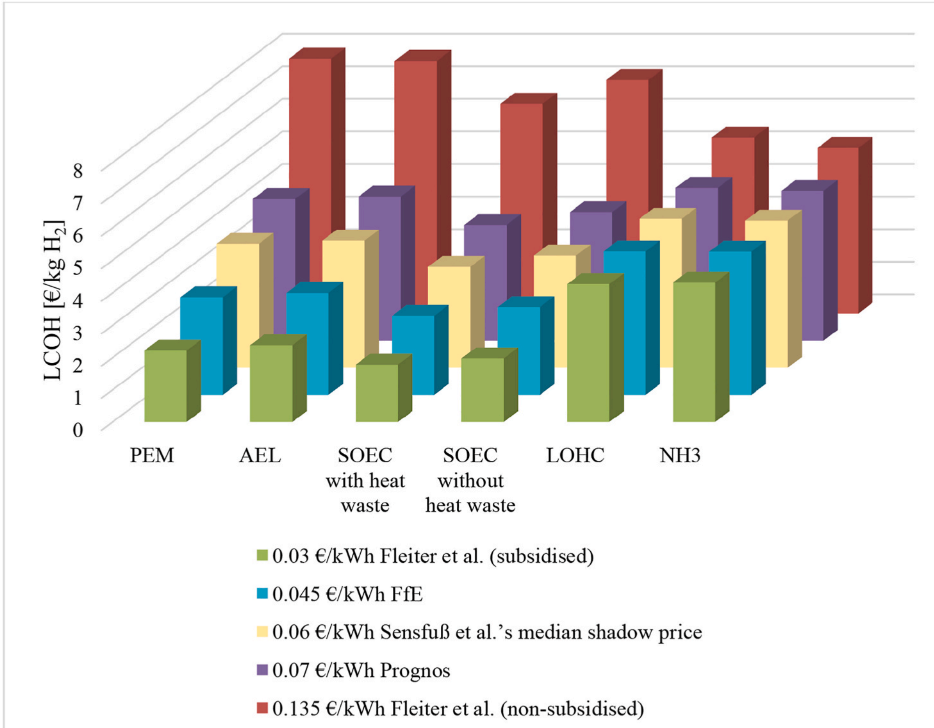

Fig. 7. LCOH of water electrolysis and derivative technologies with different electricity prices in the year 2040 [63,65,66,87]. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

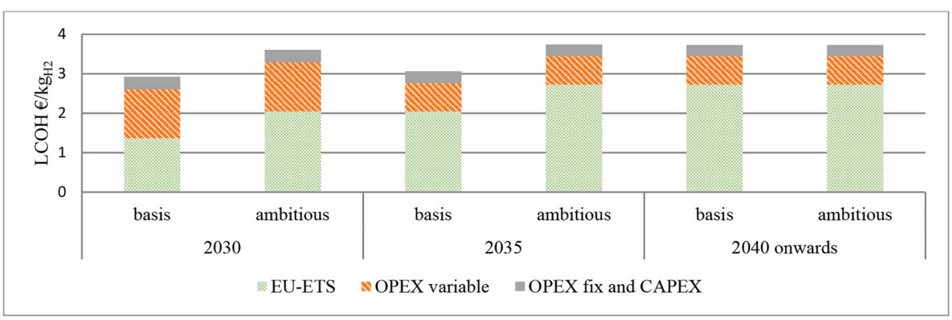

Fig. 8. Comparison of LCOH for SMR between the assumed EU ETS prices and the prices projected five years hence.

4.3. Economic–environmental trade-off analysis

The integration of CO_2 emission intensities (kg_{CO2e}/kg_{H2}) enable a clearer differentiation of the analyzed hydrogen pathways beyond purely economic metrics. The results show a disparity between fossil-based, low-carbon, and renewable-based technologies as seen especially in Fig. 10 above, where all technologies are shown in 2030 and Fig. 11 where all technologies are shown in for 2045.

Fossil-based SMR exhibits by far the highest emissions, with values of approximately 10.1 kg_{CO2e}/kg_{H2}, with 22 g_{CO2}/kWh for gas supply [88]) clearly marking the upper bound across all options. The use of biogenic inputs (SMR Bio and ATR Bio with 130 g_{CO2}/kWh [89]) significantly reduces emissions to around 2.66 kg_{CO2e}/kg_{H2} for SMR Bio and 1.3 kg_{CO2e}/kg_{H2} for ATR Bio, but at substantially higher costs (~5.6 €/kg_{H2} for SMR Bio and ~4.5 €/kg_{H2} for ATR Bio).

Electricity-based technologies show the lowest emission levels as seen in detail in Fig. 10 below, particularly when supplied with wind power (approximate 10 g_{CO2e}/kWh for wind [90]). SOEC achieves the best overall environmental performance with 0.42 kg_{CO2e}/kg_{H2} (wind) and 1.29 kg_{CO2e}/kg_{H2} (photovoltaic (PV) with 30-35 g_{CO2e}/kWh PV generation [91]), followed by AEL (0.54/1.66 kg_{CO2e}/kg_{H2}) and PEM (0.57/1.73 kg_{CO2e}/kg_{H2}). The results highlight not only the advantage of electrolysis, but also the strong influence of the electricity source as seen in detail in Fig. 10 below. The SOEC variant without waste heat utilization shows higher emissions (0.64/1.95 kg_{CO2e}/kg_{H2}).

Intermediate pathways such as LOHC and NH_3 (with 3.5 $kg_{CO2e}/kg_{H2}$for LOHC import and 3.05 kg_{CO2e}/kg_{H2} for NH_3 [92]) exhibit emission levels between approximate 3.1-3.6 kg_{CO2e}/kg_{H2}, placing them clearly above electrolysis but below fossil SMR. Their environmental performance depends on system boundaries, particularly on the importing country's electricity supply, as well as on the mode of transport and the distance to the point of hydrogen use. While these carriers enable flexible hydrogen transport, they do not reach the low emission levels of electrolysis technologies under renewable electricity assumptions.

The PP pathway combines relatively low costs (around 2.09 €/kg_{H2} in 2045) with low to moderate emissions of approximately 1.4-1.8 kg_{CO2e}/kg_{H2}. However, as previously indicated, a continued reliance on fossil fuels is not considered a long-term objective.

Overall, a ranking emerges: electrolysis pathways (especially SOEC)

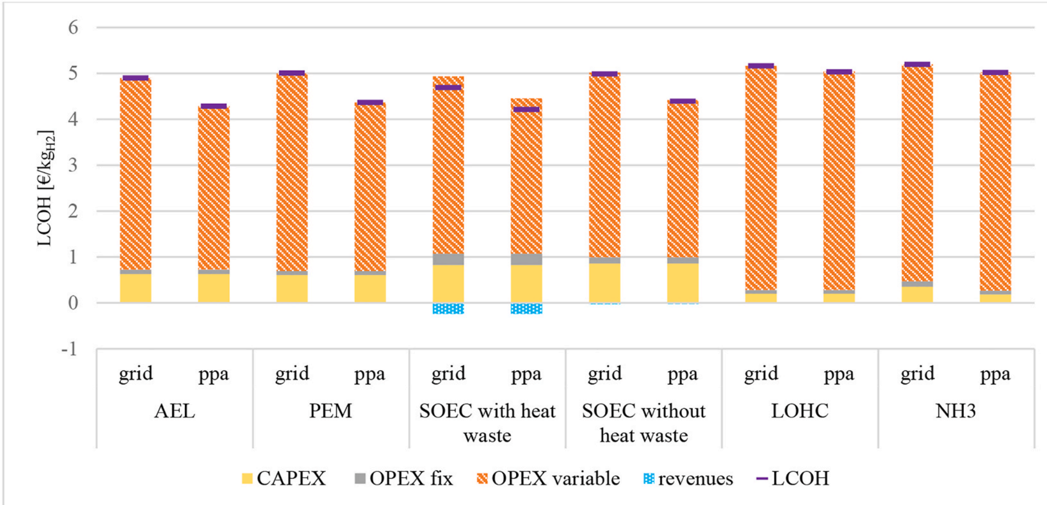

Fig. 9. LCOH comparison of different electricity-based technologies with grid electricity price compared to an assumed PPA price in 2030.

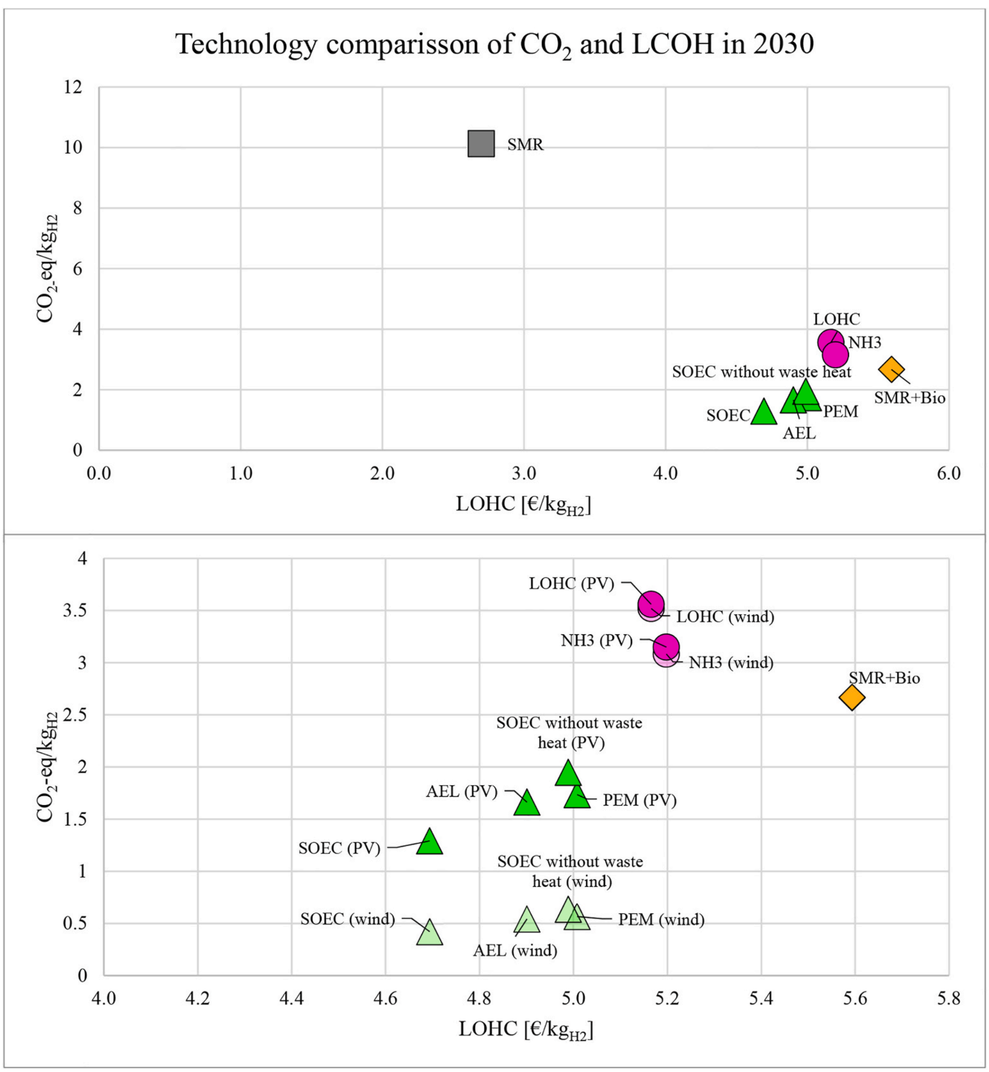

Fig. 10. Economical and ecological overview of technologies in 2030. Above: All technologies with TRL of 8 and 9; below: All technologies without SMR and distinguished by wind and PV as electricity sources; gray rectangle: natural gas-based technology; orange diamond: bio gas-based technologies; green triangle: electrolysis technologies using PV electricity; light green triangle: electrolysis technologies using wind electricity; purple circle: derivative technologies using PV electricity; light purple: derivative technologies using wind electricity. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

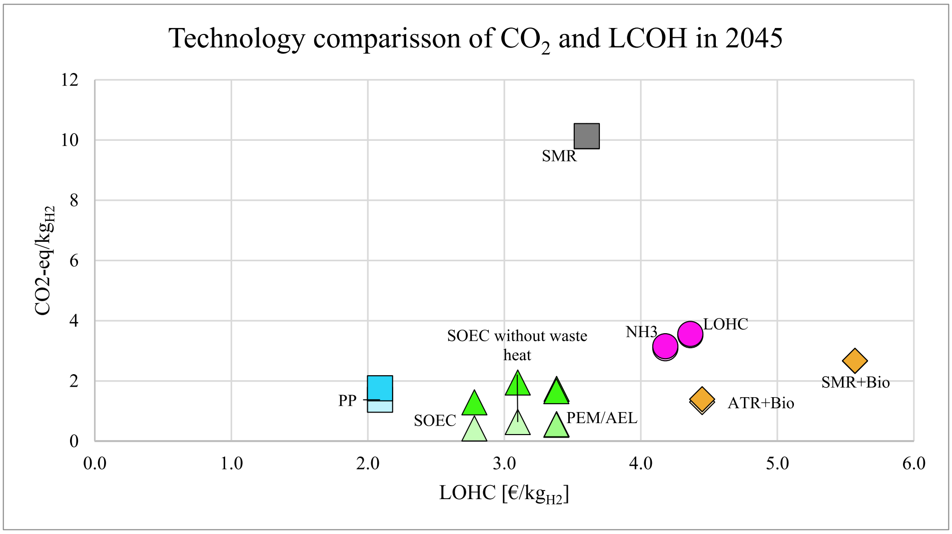

Fig. 11. Economical and ecological overview of technologies in 2045 distinguished by wind and PV as electricity sources; gray rectangle: natural gas based technology; orange diamond: bio gas based technologies; blue rectangle: natural gas-based technology with low CO_2 emissions using PV electricity; light blue rectangle: natural gas-based technology with low CO_2 emissions using wind electricity; green triangle: electrolysis technologies using PV electricity; light green triangle: electrolysis technologies using wind electricity; purple circle: derivative technologies using PV electricity; light purple circle: derivative technologies using wind electricity. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

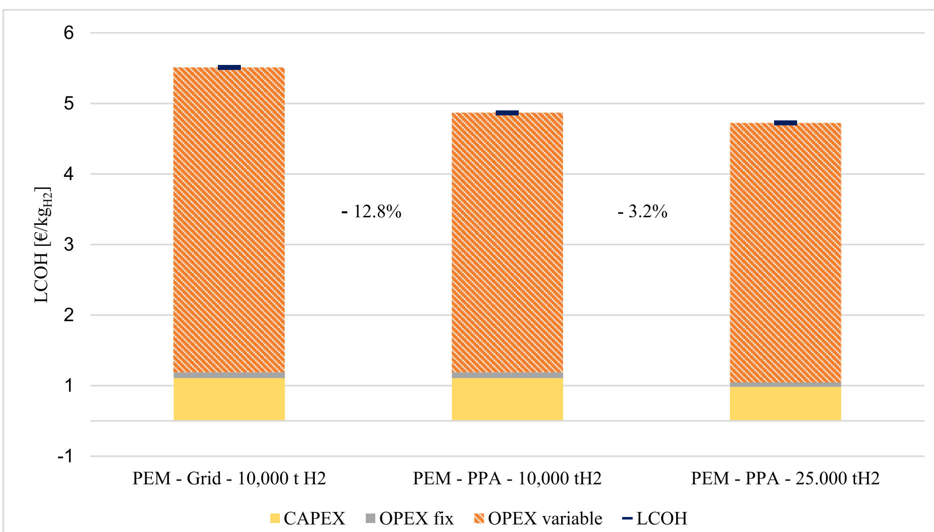

Fig. 12. Economic saving potentials through PPA and up-scaling.

provide the lowest emissions, followed by biogenic gas technologies and hydrogen carrier-based options, while the natural gas route remains the most emission-intensive. The trade-off between cost and emissions is still visible, but increasingly weakens in 2045, as low-emission technologies simultaneously achieve competitive cost levels.

4.4. Economic saving potential

In the preceding chapter, two potential avenues for cost reduction were presented. Thus, a combination of PPA and up-scaling could result in even greater cost savings and facilitate a more rapid transition to environmentally friendly hydrogen production technologies and the transformation to a hydrogen economy in Germany. Fig. 12 shows this calculation exemplary on the PEM technology case. In this instance, a reduction in LCOH from 5.01 €/kg_{H2} to 4.37 €/kg_{H2} to 4.22 €/kg_{H2} can be achieved. In the first step annual costs of appr. 50 million Euro can be reduced to appr. 43.6 million Euro, so 12.8% per year can be saved by using PPAs. The next cost reduction through scale-up leads to annual costs of approx. 42.2 million Euro and additional saving amounting up to 1.4 million Euro per year. In combination it is possible to achieve annual savings of up to 7.8 million Euro respectively 15.6%.

Table 7
LCOH sensitivity overview of selected technologies 2040 in €/kg_{H2}.

Technology	Parameter	Low	Base	High	Impact (Δmax)
PP	Gas	1.91	2.14	2.37	0.46
	CAPEX	1.90	2.14	2.38	0.48
	Electricity	1.97	2.14	2.31	0.34
	Full-load hours	2.14	2.22	2.34	0.2
PEM	CAPEX	3.48	3.73	3.81	0.33
	Electricity	2.77	3.73	4.69	1.92
	Full-load hours	3.73	3.78	3.85	0.12
LOHC	CAPEX	4.52	4.59	4.66	0.14
	Electricity	4.40	4.59	4.79	0.39
	Full-load hours	4.59	4.61	4.65	0.06
	LOHC price	3.48	4.59	3.48	2.22

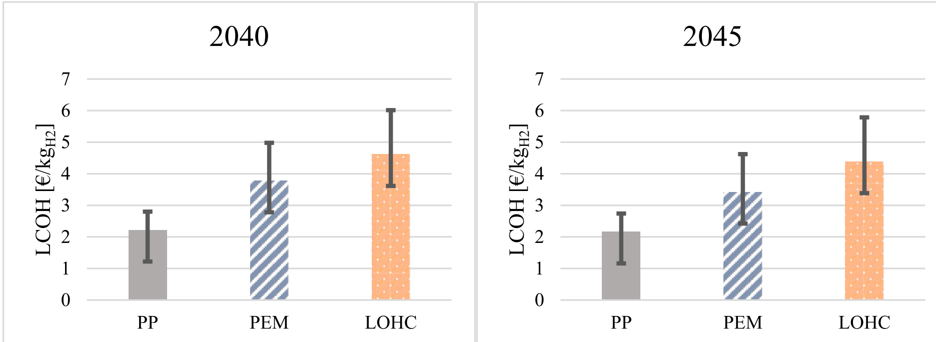

Fig. 13. LCOH uncertainty ranges for selected technologies.

4.5. *Scenario-based uncertainty quantification*

In addition to the deterministic sensitivity analysis, a scenario-based uncertainty analysis was performed to assess the robustness of the results. Key input parameters—including electricity prices, fuel prices, LOHC import prices, and investment costs—were simultaneously varied within defined ranges (Table 7). Three scenarios were considered: an optimistic scenario (low) with favorable cost assumptions (-30%) and 8760 full-load hours, a baseline scenario (base) reflecting the central assumptions of this study with 8000 full-load hours, and a pessimistic scenario (high) representing adverse market conditions with −30% and 7000 full-load hours. This approach enables the evaluation of the potential LCOH range and provides insights into the robustness of technology competitiveness under uncertain future conditions.

While parameter-specific ranges for the sensitivity analysis were derived from the literature, a generalized ±30% variation was applied in the uncertainty analysis to capture the combined effect of multiple uncertain parameters in a consistent and transparent manner. This method allows for the estimation of plausible cost ranges without assuming specific probability distributions.

As can be seen in Fig. 13, the LCOH of PP fluctuates the least of all three technologies within the range of approximately 1.6–3 €/kg H_2. This is due to the impact of variations in CAPEX and gas prices, each with a Δmax of 0.5. (Table 7).

For PEM, electricity prices are the critical factor with a Δmax of 1.92, resulting in prices ranging from 2.6 to 4.9 €/kg$_{H2}$ (2040) and 2.4–4.4 €/kg$_{H2}$ (2045).

For LOHC, costs varied the most. This is primarily due to the LOHC import price, with a Δmax of 2.22, followed by the electricity price (Δmax of 0,39). Thus, the LCOH ranges from approximately 3.2–6.1 €/kg$_{H2}$ (2040) and 3.1–5.8 €/kg$_{H2}$ (2045).

The scenario-based uncertainty analysis highlights the significant influence of input parameters such as electricity prices, CAPEX, and LOHC import costs on the LCOH across all technologies. These findings underscore the importance of addressing key cost drivers and market uncertainties to enhance the economic viability and competitiveness of hydrogen production technologies in future energy systems.

4.6. *Limitations*

A main uncertainty of our study is the lack of data and reliable information about hydrogen production technologies at early development stages. Therefore, different scientific research is introduced in the first chapter. Further uncertainty arises from the future assumptions to vary considerably, contingent on the specific models, regions, and experts involved. So, in this study, a rather conservative future regarding the price development is supposed. Also, demand-based prices, such as natural gas, biogas, electricity etc. and LOHC or NH_3 import are highly fluctuating and depend on several assumptions. Additionally, export countries for LOHC or NH_3 have not yet been finally contracted, so costs can change depending on the distance and the transportation route. Moreover, disparate scale factors were employed for the purpose of comparison between technologies, with a focus on the hydrogen production capacity of 10,000 t_{H2}/a. Depending on the available data, major scaling has been undertaken.

Due to the long-term horizon until 2045, results are subject to considerable uncertainty. This is addressed through the scenario-based uncertainty analysis, although probabilistic approaches are beyond the scope of this study.

Further uncertainty regarding future developments is introduced by factors such as legal requirements and unexpected technological developments. Such developments could facilitate the accelerated and efficient advancement of a given technology to a higher TRL. Furthermore, this may result in cost reductions that are more rapid than previously assumed. Consequently, the development of other technologies may be impeded or occur at a slower pace.

5. Conclusions and outlook

The increasing hydrogen demand in Germany, together with binding climate targets, necessitates a transformation of hydrogen supply systems, in which cost constitutes a central driver alongside CO_2 reduction. Accordingly, this paper focuses on hydrogen economics at industrial scale in Germany by integrating all relevant production technologies, their TRL, and consistent electricity and import price assumptions into a long-term LCOH analysis for 2030 to 2045, identifying significant cost-reduction potentials. By jointly assessing technological maturity, long-term cost trajectories, key economic levers and ecological impact across a broad portfolio of hydrogen supply pathways, this study provides a level of comparability that is rarely achieved in existing hydrogen cost analyses.

The conclusion of our study can be summarized as follows:

While the LCOH of SMR increases steadily over time, all other technologies exhibit declining cost trajectories. Nevertheless, compared to today's hydrogen production costs, absolute LCOH levels are in general expected to remain higher over the coming decades. Despite this increase, the SMR is expected to be economically competitive in the near term, while PP potentially becomes the most cost-efficient option around 2040.

In the long term, electrolysis-based technologies, particularly SOEC, emerge as key options for sustainable hydrogen production, offering alignment with EU and German greenhouse gas reduction targets and enable the abandonment of fossil fuels. AEL and PEM remain more costly in comparison.

Across all technologies, variable OPEX accounts for the largest share of LCOH. Particularly for electrolysis-based technologies, but also for the energy-intensive release of hydrogen from derivatives, electricity prices decisively determine the LCOH. Compared to other cost-reduction options, the largest economic saving potential is therefore associated with electricity price levels. In this context, PPAs represent a viable option for companies to decouple hydrogen production costs from general electricity market prices.

For technologies with higher CO_2 emissions, policy instruments such as an accelerated EU-ETS can further incentivize a shift toward low-emission hydrogen production. However, as the EU-ETS applies exclusively within the European Union, EU-based CO_2-intensive technologies face a growing competitive disadvantage on international markets.

While this study provides a generic, system-level assessment of hydrogen supply economics, site-specific implementation requires the consideration of additional factors beyond the scope of a purely techno-economic analysis. Beyond financial competitiveness, regional conditions, resource availability, and additional material and energy flows, such as heat and oxygen, are crucial for identifying optimal location-specific technology pathways. Furthermore, multi-stakeholder approaches, including hydrogen hubs with shared infrastructure, offer potential to leverage economies of scale and reduce both costs and emissions. Integrating regulatory frameworks, public acceptance, and broader socio-economic aspects is therefore essential for achieving a sustainable hydrogen transition.

Declaration of generative AI and AI-assisted technologies in the writing process

During the preparation of this work the authors used DeepL, ChatGPT, Copilot and Vibe in order to improve the language. After using these tools, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

CRediT authorship contribution statement

Maike-Katharina Senk: Conceptualization, Data curation, Investigation, Methodology, Validation, Visualization, Writing – original draft, Writing – review & editing. **Holger Jorschick:** Conceptualization, Data curation, Validation, Writing – review & editing. **Marco Schmid:** Data curation, Validation, Writing – review & editing. **Mélanie Apitzsch-Delavault:** Data curation, Validation, Writing – review & editing. **Mario Schmidt:** Funding acquisition, Project administration, Writing – review & editing.

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.

Acknowledgements of funding sources

This work was partially supported by the Ministry for Environment, Climate Protection and the Energy Sector Baden-Württemberg [grant number: BWZPH222133].

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2026.156089.

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