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The hydrogen dilemma: An industrial site-specific case study on the transformation pathway toward renewable hydrogen

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ABSTRACT

Future renewable energy systems are expected to heavily rely on low-emission hydrogen, not least as a crucial feedstock for industry. Although there are numerous pan-European system studies exploring a cost-efficient hydrogen ramp-up, a number of issues are driving companies to develop site-specific transformation strategies, that are not always in line with the results of these large-scale studies. Addressing this gap, this study contributes a detailed analysis of a real-world chemical site in Southern Germany that depends on hydrogen as a feedstock. In doing so, insights in industry transformation options and its implications at site level are provided. Applying a cost-optimizing energy system model, several corporate strategies and extensive sensitivity analyses for the transition to renewable hydrogen are evaluated for the period 2025 to 2045. This involves considering on-site interdependencies between the production and use of hydrogen as a feedstock and the site's electricity and heat sector. The results show that under a purely rational strategy and current expectations, the transformation to renewable hydrogen will not become competitive before 2045, while neither expensive emission allowances, nor low-priced hydrogen supply on their own will result in a substantially accelerated transformation. This highlights the need for additional policy measures. Furthermore, it is demonstrated that under almost any realistic condition within the following 20 years, using hydrogen for heat generation below 200 °C is unlikely. Therefore, prioritizing the electrification of process heat supply while waiting for hydrogen imports would be a logical approach for reducing greenhouse gas emissions.

1. Introduction

There is a broad consensus that low-emission hydrogen will play a pivotal role in future Renewable Energy (RE) systems. Besides using hydrogen for energy purposes, it is and will become an even more important feedstock for a large amount of industrial products [1,2]. Aiming for a cost-efficient RE and hydrogen system, various system studies have investigated the European cost-optimal system design for meeting its energy, respective hydrogen demand [3–6]. Consistently, they find that Europe will be able to meet its future hydrogen demand in a cost-efficient manner predominantly by European-based production. However, this would lead to uneven infrastructure distributions across the continent [7]. For example, in the case of Germany, the results show that a significant amount of low-emission hydrogen should be imported, and hydrogen that is still produced within Germany itself should predominantly be produced in the northern part of the country [8,9].

Such concentration and regional imbalances in infrastructure pose challenges for companies in regions with less favorable RE potential or late infrastructure rollout in securing access to renewable hydrogen, while overconcentration in other regions may undermine social acceptance. Hence, studies such as Kendziorski et al. [10] and Neumann et al. [11] argue that additional costs of more decentralized energy system designs can be outweighed by higher social acceptance. However, additional costs also raise the threat of industrial relocations to countries or regions with higher RE availability at lower costs. As a result of such relocations, Kountouris et al. [3] warn of an overdimensioned European hydrogen grid, leading to higher hydrogen infrastructure costs for industries that were not able to relocate or had not enough reasons to do so [12].

This issue is particularly relevant for Germany, where industrial

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relocations are unlikely to be entirely avoided [13,14]. Additionally, Odenweller et al. [15] and Odenweller and Ueckerdt [16] highlight the general risk of insufficiently rapid upscaling of renewable hydrogen availability, while especially in Southern Germany a late introduction of hydrogen pipeline access is expected [17–19]. This mix of uncertainties and other sociotechnical aspects, such as for instance corporate strategies, induces companies to develop own, site-specific plans for transitioning from natural gas or gray hydrogen to renewable hydrogen. As a result, discrepancies emerge between companies' behavior and large-scale system study results. In this context, for instance, the federal state of Baden-Württemberg in Southern Germany even supports the establishment of decentral, self-sufficient hydrogen hubs [20,21].

Meanwhile, current research rarely captures these bottom-up transformation dynamics. While several studies address cost-optimal greenfield developments at the site level [22–26], research on brownfield transformation pathways for existing industrial sites remain scarce. To the authors' best knowledge, there is only one recent study considering site-specific brownfield transformation pathways: Neuwirth et al. [27] analyze the future probability of replacing fossil-based production routes by hydrogen-based production routes at 96 European heavy-industry sites. For their discrete choice decision simulation to model how industrial actors choose between hydrogen procurement options, they consider hydrogen price and CO_2 tax sensitivities, pipeline access and theoretical reinvestment cycles of existing production plants from 2022 to 2050. Their results show that for all sites considered, at least one theoretical reinvestment cycle remains to replace existing fossil-based production routes. Furthermore, their results indicate that for renewable hydrogen-based production routes to become cost-competitive, chemistry industry in particular relies on low hydrogen prices and a high CO_2 tax. However, the analysis only considers the largest European steel and basic chemical production sites and assumes purely cost-rational behavior. Smaller industry sites and potential strategic transformation approaches that go beyond such narrowly rational assumptions remain neglected, leaving the implications of alternative transformation strategies underexplored. Furthermore, potential on-site interdependencies and competition between alternative climate-neutral processes, such as hydrogen utilization versus direct electrification, stay disregarded and need further research.

This paper addresses these gaps by providing a detailed, site-specific analysis of a real-world industrial site, explicitly modeling the interdependencies between hydrogen production and use as a feedstock, and the site's electricity and heat sectors. By applying a multi-sectoral energy system optimization model, the study offers novel insights into the techno-economic and ecological implications of different transformation pathways at the site level. This approach enables a more nuanced understanding of decarbonization options beyond purely rational behavior and supports industry and policymakers in developing robust, context-sensitive hydrogen strategies. For this purpose, the following research question is to be answered:

What are potential cost-optimal transformation pathways from gray to renewable hydrogen and their techno-economic and ecological implications for a specific chemical site in Southern Germany under different corporate strategies, considering future expectations by 2045?

To answer this research question, we enhance the Life Cycle Assessment (LCA) based ENergy Decision support optimization tool LAEND [28] and apply the enhanced version to a case study in Southern Germany. The case study focuses on a real-world, mid-sized chemical site that depends on hydrogen as a feedstock. To meet Germany's climate targets [29], the site must defossilize its hydrogen and energy supply by 2045.

The outline of this paper is structured as follows. In the methods and materials section, we describe the applied modeling tool, provide relevant background information and data for the case study. Furthermore, the transformation strategies considered are described and afterwards analyzed through scenario computations and sensitivity analyses. The techno-economic and environmental results obtained are then presented and discussed in detail in the results and discussion section. Finally, conclusions and a brief outlook are presented.

2. Methods and materials

In this section, we introduce the enhanced and applied modeling tool, describe the case study and underlying model assumptions, and outline the computational scenarios explored to represent potential transformation strategies for the industrial site.

2.1. Life cycle Assessment based ENergy Decisions support tool LAEND

To answer our research question, we enhance and apply the Life cycle Assessment based ENergy Decision support tool LAEND [28,30]. LAEND is a bottom-up linear programming tool, that combines conventional cost-minimization with Life Cycle Impact Assessment (LCIA), capable of optimizing both investment and dispatch decisions. LAEND itself is based on oemof.solph [31]. Solph is the main software package of the Open Energy MOdeling Framework oemof, that was published for the first time in 2018 to provide a flexible and open source framework for energy system modelers of different kind [32]. Its underlying logic to describe energy systems is based on a bipartite graph structure consisting of nodes and directed edges [32].

Based on the available oemof architecture, Tietze et al. [28] established mainly two options within LAEND. The first option is to respect environmental attributes within oemof's originally cost oriented objective function and hence consider environmental attributes during optimization. The second option is to just report multiple environmental indicators for the optimal results, while the optimization process itself remains solely focused on cost minimization. These options are implemented by normalization and weighting approaches, resulting in following objective function consisting of economic (prefix *c*) and environmental terms (prefix *e*), subdivided by edges E and nodes N [28]:

$$\begin{aligned}
\min: & \sum_{t\in T}\left\{\sum_{(s,e)\in E}\left(\left[g_C\cdot cvar^t_{(s,e)}+\sum_{x\in X}g_x\cdot evar^{x,t}_{(s,e)}\right]\cdot wvar^t_{(s,e)}\right)\right\}\\
&+\sum_{a\in A}\left\{\sum_{(s,e)\in E}\left(\left[g_C\cdot cfi^a_{(s,e)}+\sum_{x\in X}g_x\cdot efi^{x,a}_{(s,e)}\right]\cdot wfi^a_{(s,e)}\right)\right\}\\
&+\sum_{t\in T}\left\{\sum_{n\in N}\left(\left[g_C\cdot cvar^t_n+\sum_{x\in X}g_x\cdot evar^{x,t}_n\right]\cdot vvar^t_n\right)\right\}\\
&+\sum_{a\in A}\left\{\sum_{n\in N}\left(\left[g_C\cdot cfi^a_n+\sum_{x\in X}g_x\cdot efi^{x,a}_n\right]\cdot vfi^a_n\right)\right\}
\end{aligned} \tag{1}$$

T:	set of (hourly) timesteps
A:	set of years
E:	set of edges
N:	set of nodes
X:	set of environmental impact indicators
(s,e):	start and end node of an edge
g_C:	weighting factor for costs
g_X:	weighting factor for environmental impact indicators
cvar:	(normalized) variable costs
evar:	(normalized) variable environmental impact
wvar:	flows associated with edges
cfi:	(normalized) annualized fixed costs
efi:	(normalized) capacity related environmental impact
wfi:	capacities associated with edges
vvar:	flows associated with nodes
vfi:	capacities associated with nodes

By setting the economic and ecological weighting factors g_C and g_x, the user of LAEND is free to choose whether to minimize system costs, environmental impacts or the normalized sum of both. Here, fix costs *cfi* and fix environmental impacts *efi* correlating with investments are considered as annuities. Irrespective of the chosen objective, the obtained results provide both system cost and environmental impact information for the optimized system design and its dispatch scheduling. To collect all relevant technology- and commodity-specific LCIA data that is needed before starting the optimization process, Tietze et al. [28] implemented a link to the LCA software openLCA [33]. Furthermore, LAEND is coupled with other software packages, e.g. to derive power curves of wind power plants [34] or to generate load profiles [35].

Our own enhancements to LAEND primarily involve updating it to oemof.solph v0.5.2 [36], making it possible to consider multiple investment periods. LAEND now allows for multi-period perfect foresight optimizations, a prerequisite for the adequate consideration of future expectations, as aimed for in the research question. Further enhancements include the introduction of the ability to represent both material flows and energy flows. This is introduced by predefining physical units and considering respective conversion factors. Furthermore, we established the option to model brownfield scenarios and we implemented a link to the LCA software brightway2 [37].

Eventually, in this paper we optimize for cost-minimal system designs and dispatch scheduling. Environmental impact indicators, explicitly the Global Warming Potential over 100 years (GWP100), are used for an ex-post comparison of different scenarios. That is, mathematically all environmental weighting factors g_x for $x \in X$ are set to zero, resulting in the following objective function:

$$\min:\sum_{t\in T}\left\{\sum_{(s,e)\in E}\left(cvar^{t}_{(s,e)}\cdot wvar^{t}_{(s,e)}\right)\right\}+\sum_{a\in A}\left\{\sum_{(s,e)\in E}\left(cfi^{a}_{(s,e)}\cdot wfi^{a}_{(s,e)}\right)\right\}+\sum_{t\in T}\left\{\sum_{n\in N}\left(cvar^{t}_{n}\cdot vvar^{t}_{n}\right)\right\}+\sum_{a\in A}\left\{\sum_{n\in N}\left(cfi^{a}_{n}\cdot vfi^{a}_{n}\right)\right\} \tag{2}$$

2.2. Case study and model design

To answer our research question, we conduct a case study consisting of a real-world, medium-sized chemical site in Southern Germany that depends on hydrogen as a feedstock. Fig. 1 provides a schematic of the site's current energy and hydrogen system. Today, the entire hydrogen demand of 5000 t/a is met by on-site hydrogen production through Steam Methane Reforming (SMR). Arising excess heat is utilized to partially meet the site's process heat demand (235 GWh/a), that is otherwise mostly covered by a natural gas-fired Combined Heat and Power plant (CHP). Furthermore, today's electricity demand of 86 GWh/a is also largely met by the CHP. However, the SMR and the CHP will reach their technical end of life within the next five years. Hence, reinvestments or investments into alternative technology options will become necessary while keeping in mind Germany's target to reach climate-neutrality by 2045 [29]. Yet, according to the plan of the European Hydrogen Backbone initiative, the site will not be connected to a transregional hydrogen grid at least until 2035 [18]. Besides that, the site is not affected by any policy schemes such as a mandatory Renewable Fuel of Non-Biological Origin (RFNBO) quota arising from national implementations of the EU's Renewable Energy Directives (RED II + III) [38,39].

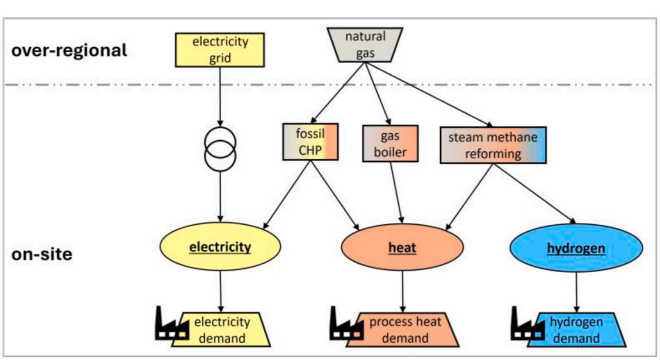

Fig. 1. Schematic of the site's current energy and hydrogen system, focusing on the key components and interfaces pertinent to the study.

At large, several future investment options are available to meet the demands at hand. Investment options range mainly from RE technologies to various fossil-based and non-fossil-based technologies to produce hydrogen and process heat. To maintain a streamlined model and ensure clarity in interpreting results, we only focus on technology options that are already adopted in industry or exhibit a high technology readiness level suggesting near-term market entry. Additionally, we group related technology options into shared technology clusters, such as for instance Polymer Exchange Membrane (PEM) electrolysis, Alkaline Electrolysis (AEL) and Anion Exchange Membrane (AEM) electrolysis under the low-temperature electrolysis cluster. Otherwise, particularly detailed techno-economic and ecological differentiation between closely related technologies would become necessary. Since no Carbon Capture and Storage (CCS) or Carbon Capture and Utilization (CCU) options are available in the site's proximity, and the mere availability and hence costs of transregional infrastructure cannot yet be foreseen [40], we exclude CCS and CCU from consideration. Furthermore, we neglect bio-based technology investments and natural gas substitution due to the limited regional availability of usable biomass [41,42, see also supplementary materials]. Consequently, in alignment with the defossilization targets, we exclude fossil-based investment options except for the already existing reference technologies.

Fig. 2 shows the model representing the analyzed industrial site with the technology options included and their fundamental interconnections. The model can be divided into three primary sectors: (1) electricity, (2) process heat and (3) hydrogen. In all three sectors, there are significant demands that need to be met both today and in the future. Additionally, all three sectors are closely interconnected. For example, electricity is a crucial energy vector for many climate-friendly technologies for both heat and hydrogen production. In turn, hydrogen or excess heat from hydrogen production can be utilized to meet process heat demands.

In our model, the demand for electricity can be met through seven pathways, including the use of an electricity storage. On the one hand, we distinguish between electricity procurement from newly installed RE plants and electricity procurement from the power grid. On the other hand, we differentiate between the spatial origin of the sourced electricity. The spatial differentiation of regional and over-regional sourcing options is handled by applying different magnitudes of grid fees, that is explained in further detail in the model assumptions section. If electricity is obtained from the outside of the industrial site, investments in an additional on-site transformer station become necessary. At the same time, electricity can be generated on-site using the existing CHP. However, as the CHP is expected to reach its end of life in 2030, reinvestment will become necessary at that time. On-site investment options furthermore include a hydrogen-based CHP and an electricity storage system, enabling the decoupling of electricity generation and demand.

Process heat supply is for technological reasons subdivided into four different temperature levels: 60 °C, 120 °C, 200 °C, and 400 °C. To meet

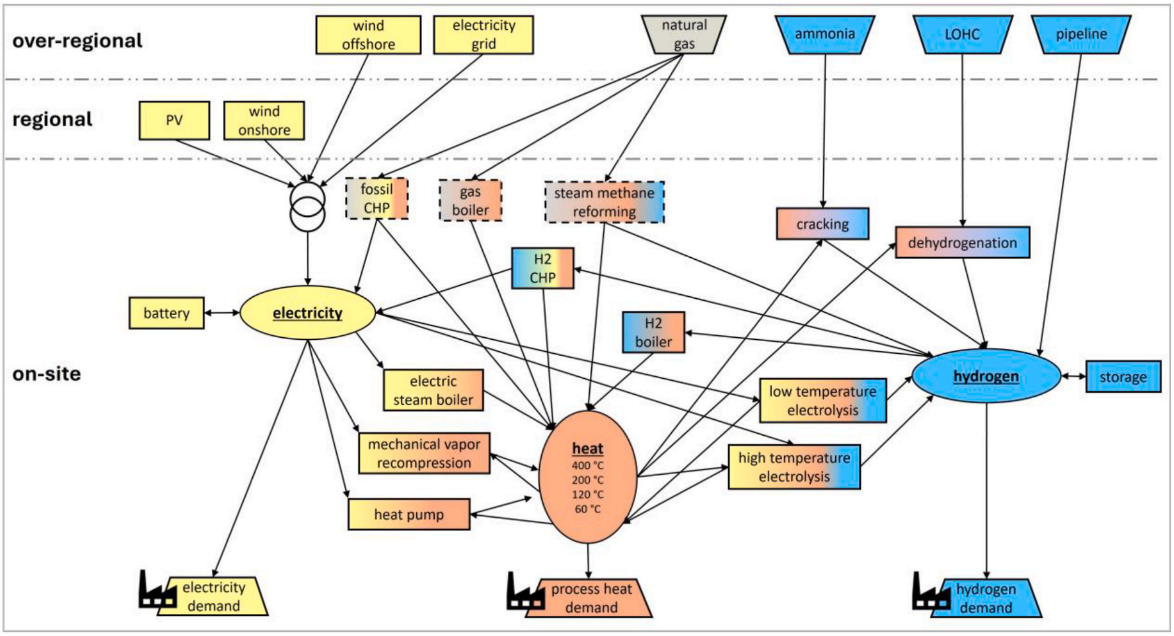

Fig. 2. Modeled system and its included technology options, differentiated by its location. Dashed squares represent technologies that are already in place nowadays. Colors represent the respective sectors of the industrial site: yellow for electricity, orange for process heat, and blue for hydrogen. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

the exogenously defined process heat demand, a temperature level of 200 °C is required. This can be achieved using the existing CHP, or by investing in new technologies. However, as the industrial site's publicly documented process heat demand cannot be met entirely by the publicly documented CHP capacity in place [43], we assume the existence of an additional natural gas-fired steam boiler. Besides reinvestments into the existing CHP and natural gas boiler, investment options include a hydrogen-based CHP, a hydrogen-based steam boiler, an electric steam boiler, or by utilizing occurring excess heat combined with a heat pump and additional Mechanical Vapor Recompression (MVR). Lower temperature levels can also be reached by all previously mentioned heat generation options. In contrast, the temperature level of 400 °C, which is needed exclusively for the decomposition of Liquid Organic Hydrogen Carriers (LOHC) and ammonia, can only be achieved by using an electric steam boiler, a hydrogen-based CHP, and a hydrogen-based steam boiler. The use of fossil fuel-fired technologies was excluded, as otherwise the obtained hydrogen could not be classified as renewable. Furthermore, heat pumps were considered not being capable of covering such temperature ranges both today and in the future [44].

In our study, hydrogen can be provided through seven pathways, including the use of a hydrogen storage. These pathways are available at different times in the future and subdivided into

- on-site hydrogen production,
- the import of hydrogen carriers and their respective on-site decomposition, and
- direct hydrogen import via pipeline.

For on-site hydrogen production we distinguish between low-temperature and high-temperature electrolysis, alongside the existing SMR that is expected to reach its end of life in 2030 and must be decommissioned or reinvested by that time. Low-temperature electrolysis is represented by a PEM electrolyzer due to its flexible operation mode, while high-temperature electrolysis is represented by a Solid Oxide Electrolysis Cell (SOEC). For imported hydrogen carriers and their respective on-site decomposition, LOHC and ammonia are considered.

2.3. *Model assumptions*

For parametrization, mostly time-step specific techno-economic and ecological data, and information about the mere availability of a technology option are collected. Due to the strategic questions at hand, the time horizon is set from 2025 to 2045, and it is necessary to model and optimize the entire time horizon up to that point. This was realized by making use of representative years, each representing a time span of five years. Hence, the data presented in this section covers every 5th year.

Since our analyses are carried out from a business perspective, our model's parameters are mainly based on techno-economic data, supplemented by ecological data for ex-post comparison of different scenarios. Techno-economic data are for instance degrees of efficiency, CAPital EXpenditure (CAPEX), OPerating EXpenditure (OPEX), technical lifetime, and procurement prices. Ecological data mainly refers to GWP100, calculated using the Environmental Footprint 3.1 impact assessment method [45] and the ecoinvent 3.9 [46] allocation cut-off database (see also supplementary materials). We focus on GWP100 as it is the highest weighted midpoint impact category in the Environmental Footprint scheme of the European Commission [47]. Furthermore, as we decided for an hourly temporal resolution within each representative year, hourly demand curves for electricity, process heat and hydrogen, as well as hourly weather data is used. While demands must be met each hour, weather data is used to determine the potential electricity output of RE plants.

The summary of general model parameters is as follows:

- Due to Germany's target of achieving Greenhouse Gas (GHG) neutrality by 2045 [29], the use of fossil fuels is prohibited at the latest by that year.
- Investment costs are incorporated into the optimization process as annuities, calculated based on CAPEX, asset lifetime, and an interest rate. As interest rate we use 7.9 %, reflecting the weighted average cost of capital for the chemical and pharmaceutical industry in 2023 [48].
- If technologies emit GHG emissions, emission permits must be purchased. Based on Germany's long-term energy scenarios ("Langfristszenarien") [9], we expect the European Emission Trading

Scheme (EU-ETS) costs to increase linearly from 75 €/$t_{CO2\text{-}Eq.}$ in 2025 to 300 €/$t_{CO2\text{-}Eq.}$ by 2040.

- Exogenously defined demands as driving variables to be met include electricity (86 GWh/a), process heat (235 GWh/a) and hydrogen (5000 t/a). With the model configured at an hourly resolution and following consultations with industry experts [43], these annual demands are evenly distributed across all 8760 h of the year for simplification. The demands remain constant throughout the entire time span from 2025 to 2045.

Within the following section, we describe all relevant time-step specific techno-economic and ecological data that is used to parametrize our model. Subsequent to the overview of general model parameters, we split this section into five sub-sections. First, we describe commodities, that are energy and hydrogen carriers. For second, RE technologies and their underlying weather data assumptions are defined. For third, all conversion technologies for hydrogen production, fourthly storages, and fifthly conversion technologies for process heat generation are parametrized. For all commodities and technologies, a more thorough description and reasoning of the chosen parameters and their ecological parametrization can be found in the supplementary materials.

2.3.1. Energy and renewable hydrogen carriers

As energy and renewable hydrogen carriers we explicitly consider natural gas, LOHC, ammonia, hydrogen imports by pipeline and electricity procurement from the power grid. To ensure consistency in our assumptions, we use results and assumptions from Germany's "Langfristszenarien" [9] wherever possible, particularly referencing the T45-electricity scenario. Precisely, data was available for natural gas, the German electricity mix, respective shadow prices, and hydrogen import prices. However, after conducting various comparisons, we found the hydrogen import prices to be overly optimistic and therefore applied own assumptions coherent with our assumptions for LOHC and ammonia import prices. Furthermore, it is necessary to keep in mind, that there is a difference between supply costs, market prices and procurement prices [1,49]. Since our study follows a business perspective, it is appropriate to use procurement prices for model parametrization. Procurement prices incorporate costs for production and delivery (supply costs), premiums due to market dynamics (market prices) plus levies and fees. However, as it is almost impossible to forecast all different procurement price components, scientific literature primarily focuses on supply costs. To address the discrepancy between supply costs and procurement prices, we base our assumptions on a conservative supply cost approach, as discussed with industry experts [43], and incorporate the necessary fees where applicable. An overview of our assumptions can be found in Table 1.

It is expected, that the analyzed industrial site will be connected to a transregional hydrogen pipeline at the earliest by 2035 [18] and that other hydrogen carriers will be available in relevant amounts at the earliest by 2030. Furthermore, we assume that except for electricity all supply contracts are terminated at a fixed supply rate for a period of at least five years. For electricity, we allow for variable grid supply combined with fixed procurement prices and grid fees. In addition, there is the potential for volatile electricity procurement from RE investments (see following sub-section).

Table 1
Applied procurement price assumptions for energy and hydrogen carriers, [9,50,51]. For further information, see supplementary materials.

	2025	2030	2035	2040	2045
Natural gas [€/kWh_{LHV}]	0.042	0.030	0.019	0.019	–
LOHC [€/kg_{H2}]	–	4.03	3.87	3.71	3.55
Ammonia [€/kg_{H2}]	–	4.08	3.85	3.63	3.34
Hydrogen by pipeline [€/kg_{H2}]	–	–	4.87	4.58	4.29
Electricity from grid [€/kWh_{el}]	0.10	0.08	0.07	0.06	0.055
Power grid fees [€/kWh_{el}]	0.04	0.04	0.04	0.04	0.04

2.3.2. Renewable energy technologies and transformer station

Our model incorporates three RE technology options for electricity generation. As RE investments are commonly not made by an industrial site itself, modeled RE investments rather represent Power Purchase Agreements (PPAs), i.e. long-term electricity supply contracts between a RE operator and a consumer for the supply of renewable electricity linked to the actual generation profile. In the model, such PPAs are reflected as on-site investments with corresponding off-site generation profiles and costs, assuming the industrial site bears the investment-like commitment while not operating the RE plants itself. This allows for assessing the economic implications of sourcing renewable electricity through PPAs. Considered RE options are regional ground-mounted PV plants, regional onshore wind power plants, and over-regional offshore wind power plants. Here, we deliberately exclude over-regional onshore wind power plants, as Sensfuβ et al. [9] indicate that the largest share of expansion is expected from offshore wind. Additionally, we assume that the lower-cost onshore wind from northern Germany is already allocated for other purposes. For consistency reasons regarding the previously described price assumptions for electricity procured from grid, we use the same weather data as [9]. Our weather data for 2010 is obtained from [52] and the New European Wind Atlas [53]. Applied economic parameters for RE technologies and the necessary on-site transformer station can be found in Table 2.

Additionally, grid fees of 4 ct/kWh apply when electricity is procured from offshore wind power plants. This equals the grid fees applied to electricity procured from the power grid (see previous sub-section). Anticipating future differentiation between regionally and transregionally sourced electricity, grid fees for electricity from regional PV and regional onshore wind power plants are set at 2 ct/kWh. However, due to the limited availability of space for wind energy in the considered region, the onshore wind power capacity accessible to the analyzed industrial site is restricted to 50 MW, representing 20 % of the region's approved wind energy potential [41].

2.3.3. Technologies for hydrogen production

Besides the SMR in place (666 kg_{H2}/h), expected to reach its technical end of life in 2030, we account for five investment options. These include PEM electrolysis representing low-temperature electrolysis, SOEC representing high-temperature electrolysis, ammonia decomposition, LOHC dehydrogenation, and conventional SMR. The information used to parametrize these technology options is obtained from a number of references [56–65]. Regarding electrolyzers, a distinction is made between the lifetime of peripheral devices and stack lifetime. For

Table 2
Applied economic assumptions for RE technologies [9], and the transformer station [54,55], plus primary data. For further information, see supplementary materials.

	2025	2030	2035	2040	2045
Ground mounted PV					
CAPEX [€/kWp]	509	430	392	369	356
fix OPEX [€/kWp/a]	10.7	10.7	10.7	10.7	10.7
Lifetime [a]	20	20	20	20	20
Wind onshore					
CAPEX [€/kW]	1453	1387	1349	1326	1311
fix OPEX [€/kW/a]	20.6	20.6	20.6	20.6	20.6
Lifetime [a]	20	20	20	20	20
Wind offshore					
CAPEX [€/kW]	3466	3438	3394	3348	3309
fix OPEX [€/kW/a]	58.9	58.9	58.9	58.9	58.9
Lifetime [a]	20	20	20	20	20
Transformer station					
CAPEX [€/kW]	300	300	300	300	300
fix OPEX [€/kW/a]	9	9	9	9	9
Lifetime [a]	40	40	40	40	40

Table 3
Applied economic assumptions for technologies producing hydrogen [56–65]. For further information, see supplementary materials.
*If permitted by a respective scenario, the existing SMR is allowed to be retrofitted by five years, incurring costs equivalent to one-fifth of its 2030 investment costs.

	2025	2030	2035	2040	2045
PEM					
CAPEX [€/kg$_{H2}$/h]	63,281	50,235	40,246	32,514	28,900
fix OPEX [€/kg$_{H2}$/h/a]	830	830	830	830	830
Lifetime [a]	20	20	20	20	20
SOEC					
CAPEX [€/kg$_{H2}$/h]	93,727	54,071	39,056	28,960	22,753
fix OPEX [€/kg$_{H2}$/h/a]	1127	1127	1127	1127	1127
Lifetime [a]	20	20	20	20	20
Ammonia Decomposition					
CAPEX [€/kg$_{H2}$/h]	43,014	40,066	37,326	34,778	32,408
fix OPEX [€/kg$_{H2}$/h/a]	1046	1046	1046	1046	1046
Lifetime [a]	25	25	25	25	25
LOHC Dehydrogenation					
CAPEX [€/kg$_{H2}$/h]	13,657	12,911	12,207	11,543	10,916
fix OPEX [€/kg$_{H2}$/h/a]	465	465	465	465	465
Lifetime [a]	20	20	20	20	20
SMR*					
CAPEX [€/kg$_{H2}$/h]	29,667	28,183	26,774	25,435	24,164
fix OPEX [€/kg$_{H2}$/h/a]	805	805	805	805	805
Lifetime [a]	25	25	25	25	25

peripheral devices a conservative constant lifetime of 20 years is assumed over time, while stack lifetimes are rising due to technological improvement [61,62]. So, if a stack has reached its end of life before the periphery has, the old stack is replaced by a new one with longer lifetime and updated CAPEX. Conversely, if the periphery reaches its end of life while the latest stack still has remaining life, the stack is sold for its residual value. By this logic we add all stack replacement costs minus its residual value to the initial investment costs of an electrolyzer, resulting in the applied parameters in Table 3. Furthermore, we define that potential electrolyzers and decomposition technologies must be operated using exclusively electricity from newly invested RE technologies, as required for labeling the produced hydrogen as renewable [66].

2.3.4. Technologies for electricity and hydrogen storage

To keep the model both as realistic and as streamlined as possible, one respective type of storage for electricity and hydrogen has been modeled. For storing electricity, we chose a Lithium Iron Phosphate (LFP) battery, and for storing hydrogen we chose a hydrogen pressure vessel. The choice of an LFP battery is reasoned in its available power density, which allows for faster charge and discharge rates compared to, for instance, vanadium redox flow batteries [67,68]. The selection of a pressure vessel for hydrogen storage is due to its suitability to be installed on-site, as there are no geological storage potentials near the considered industrial site [69]. The applied economic parameters are summarized in Table 4. Due to reasons of uncertainty, especially regarding publicly available data for hydrogen pressure vessels, the parameters are held constant throughout the entire time span from 2025 to 2045.

2.3.5. Technologies for heat generation

In addition to the existing CHP (24 MW$_{th}$) and natural gas-fired steam boiler (1 MW$_{th}$), which are expected to reach their technical end of life by 2030, we consider seven investment options for heat generation. These include a natural gas-fired CHP, a hydrogen-powered CHP, a natural gas-fired steam boiler, a hydrogen-powered steam boiler, an electric steam boiler, a heat-pump, and an MVR for additional temperature increase. Here, the heat-pump is capable of raising the temperature from 60 °C to 120 °C, while the MVR can further increase the temperature from 120 °C to 200 °C. The techno-economic parametrization is done by using a mix of primary data and publicly available secondary data from various references. An overview of the applied economic assumptions can be found in Table 5. Due to reasons of uncertainty, especially regarding publicly available data for MVR, and primarily following Thelen et al. [72], the parameters are held constant throughout the entire time span from 2025 to 2045.

Table 4
Applied economic assumptions for storage opportunities [70,71]. For further information, see supplementary materials.

	CAPEX	fix OPEX	Lifetime
LFP	500 €/kWh$_{el}$	25 €/kWh$_{el}$/a	15 a
Hydrogen pressure vessel	1000 €/kg$_{H2}$	25 €/kg$_{H2}$/a	30 a

Table 5
Applied economic assumptions for heat generation technologies [72–75], plus primary data. For further information, see supplementary materials.
*If permitted by a respective scenario, existing fossil-based technologies are allowed to be retrofitted by five years, incurring costs equivalent to one-fifth of their theoretical investment costs.

	CAPEX	fix OPEX	Lifetime
CHP$_{ng}$*	1900 €/kW$_{el, out}$	57 €/kW$_{el}$/a	25 a
CHP$_{H2}$	2280 €/kW$_{el, out}$	68 €/kW$_{el}$/a	25 a
Steam boiler$_{ng}$*	70 €/kW$_{th, out}$	1.4 €/kW$_{th}$/a	20 a
Steam boiler$_{H2}$	94 €/kW$_{th, out}$	1.9 €/kW$_{th}$/a	20 a
Electric steam boiler	160 €/kW$_{th, out}$	3 €/kW$_{th}$/a	20 a
Heat pump	1780 €/kW$_{el, in}$	53 €/kW$_{el}$/a	20 a
MVR	3780 €/kW$_{el, in}$	114 €/kW$_{el}$/a	20 a

2.4. Scenario descriptions

To answer our research question, scenario computations are conducted. In doing so, we apply and vary the previously described assumptions within four main scenarios (see Table 6). We distinguish between a (1) rational, (2) rapid, (3) hesitant, and (4) self-sufficient defossilization scenario. While they differ in their restrictions, all four scenarios are optimized for a cost-minimal system design and dispatch scheduling. In the (1) rational defossilization scenario, all parameters and constraints are applied as they are described in the model assumptions section, also allowing for refurbishments by five years of technologies already in place. Hence, it stands for a purely rational homo economicus perspective, allowing investments into all available technology options. In contrast, each of the other scenarios reflects a possible corporate strategy besides pure economic rationality. Reflecting an ecocentric strategy, the (2) rapid defossilization scenario prohibits new investments into fossil-based technologies and refurbishments. The (3) hesitant defossilization scenario represents a hybrid of the first and second scenario. Here, also new fossil-based technology investments are prohibited, but existing fossil-based technologies are allowed to be retrofitted by five years until the import of hydrogen via pipeline becomes accessible and hence more alternative technology options are available for selection. Finally, the (4) self-sufficient defossilization scenario is closely related to the second scenario. Besides the prohibition of new fossil-based investments, we enforce the continuation of self-sufficient on-site hydrogen production during the initial transformation years. That is, when the existing SMR expires in 2030, alternative hydrogen production is forced to continue taking place on-site without importing hydrogen carriers until at least 2035. This scenario reflects a resilience-oriented strategy and current aspirations in Southern Germany for the establishment of so-called decentral hydrogen hubs.

Additionally, to prove the robustness of our results and to determine conditions that change the evolved transformation pathways, we conduct a set of sensitivity analyses where we vary main input parameters. These are described separately in section 3.4.

Table 6
Overview of scenario specifications.

Scenario	Corporate focus	New fossil investments	5-yr refurbishment of existing fossil tech	Forced on-site H_2	Notes
Rational	Purely economic	Allowed	Allowed	No	Baseline, all options open
Rapid	Ecocentric	Prohibited	Prohibited	No	Fast fossil exit
Hesitant	Hybrid	Prohibited	Allowed	No	Compromise
Self-sufficient	Resilience-oriented	Prohibited	Prohibited	Yes (<2035)	Decentral H_2 hub logic

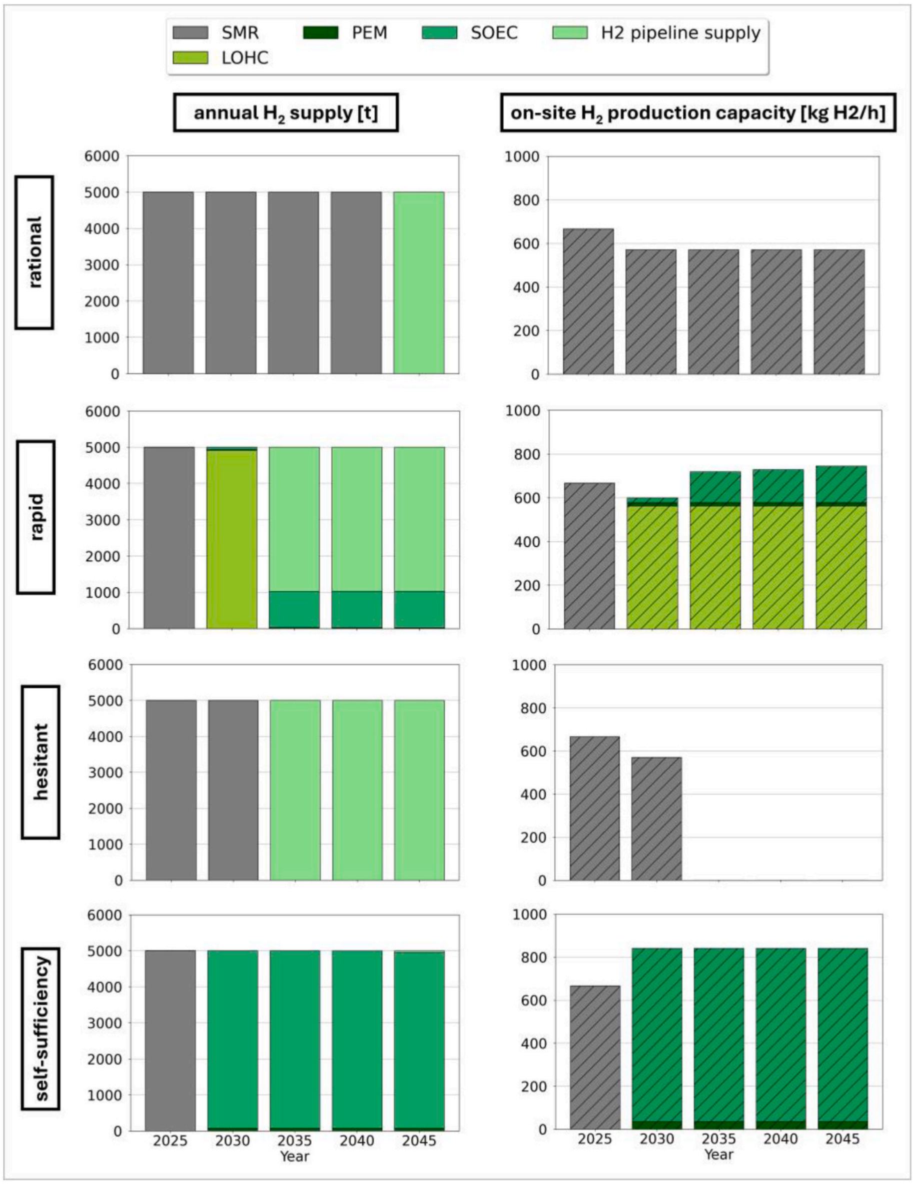

Fig. 3. Cost-optimal transformation pathways regarding hydrogen supply and on-site hydrogen production capacities. Clear bars denote values associated with flows, while hatched bars denote values associated with capacities.

3. Results and discussion

The following sub-sections present the scenario results, starting with the hydrogen supply for the industrial site, followed by an overview of the electricity and process heat supply, and concluding with the associated costs and GHG emissions. Finally, the results of a series of sensitivity analyses are presented.

3.1. Hydrogen supply

Fig. 3 summarizes the results of the analyzed transformation strategies in terms of hydrogen supply and key aspects of the underlying system design. Under the assumptions made, the economically rational transformation pathway for an industrial site is to maintain fossil-based hydrogen production until its legal prohibition in 2045. This is true even though the latest fossil-based investments will not have reached their end of life by then, which suggests that stranded assets do not necessarily indicate poor planning but may instead result from economically rational transition decisions.

Stranded assets also arise when a rapid defossilization strategy is pursued, in which case they specifically affect import infrastructure for on-site LOHC dehydrogenation. This infrastructure becomes redundant once hydrogen imports via pipeline are available. RE technologies initially installed to operate the LOHC dehydrogenation unit are then repurposed for meeting the industrial site's general electricity demand (see also sub-section Electricity and heat supply), and for on-site hydrogen production, illustrating a certain path dependency: Without prior RE investments, pipeline imports – as in the hesitant defossilization scenario – would have been the more cost-effective option.

Under the hesitant defossilization scenario, the SMR is refurbished for five years and then decommissioned, while the hydrogen demand is fully met by pipeline imports. Counterintuitively, SMR capacity is smaller after its refurbishment in 2030 than before. This is due to the underlying linear optimization approach and the fact that refurbishments are still modeled as investments with shorter lifetimes and lower investment costs. Hence, in theory the exogenously defined constant hydrogen demand of approximately 570 kg/h does not require the full SMR production capacity that was in place at the beginning.

By comparison, in the self-sufficiency scenario, on-site electrolysis is overdimensioned by about +50 % relative to the hourly demand. This, in combination with a 32 t hydrogen storage, enables flexible and cost-efficient hydrogen production in line with RE availability. Storage investment and loading occurring in 2025 before the electrolyzers' commissioning is explained by bridging scarce RE availability during the initial hours of 2030 (Fig. 4). However, the storage is not used for storing hydrogen seasonally. The results further show that, even though self-sufficiency is exogenously enforced only until 2035, it continues at least until 2045. This relates to investments made in RE technologies required for on-site renewable hydrogen production. Due to the model's scope, these were restricted from being repurposed for electricity supply beyond the modeled industrial site, resulting in the observed path dependency.

Finally, all scenarios show that hydrogen demand does not increase by time. That is, under the assumptions made, hydrogen is only used to meet the industrial site's feedstock demand, but it is not used for heat generation (see also sub-section Electricity and heat supply).

3.2. Electricity and heat supply

In Fig. 5, an overview of the industrial site's cost-optimal electricity and heat supply is shown for each scenario, examining in more detail potential interdependencies between the on-site production of hydrogen and the site's electricity and heat sector. Similar to the hydrogen supply, in the rational scenario fossil-based technologies for heat generation are utilized until its prohibition in 2045. However, the preexisting CHP is decommissioned before its actual end of life and replaced by a natural gas fired boiler in 2025. The electricity that would have been generated by the CHP is instead supplied through electricity imports. These consist of a mixture of newly constructed regional PV and wind power plants as well as grid electricity, resulting in GHG savings (see also sub-section System costs and greenhouse gas emissions).

In all other scenarios, the preexisting CHP is used until its end of life, when allowed even refurbished for five additional years (hesitant scenario), and afterwards replaced by an electric steam boiler. Partially, the electric steam boiler is supported by an MVR, upgrading excess heat from on-site technologies producing hydrogen and thereby leveraging sector coupling interdependencies. Notably, the increased heat demand in the rapid and self-sufficiency scenario is reasoned in the application of a SOEC high temperature electrolyzer and, in the case of the rapid scenario, LOHC dehydrogenation in 2025. Additionally, in all scenarios, no hydrogen-based options for heat generation are applied, demonstrating the cost advantage of electrification for this purpose.

Due to the electrification of heat supply, the site's electricity demand at least triples across all scenarios. If hydrogen is produced on-site, electricity demand even increases fivefold. Apart from the self-sufficiency scenario, electricity imports consist of approximately equal shares of unspecified grid electricity and newly constructed RE plants, indicating an optimal PPA rate of about 50 %. The higher RE share in the self-sufficiency scenario results from the constraint that renewable hydrogen production must rely on newly installed RE plants. Since on-site hydrogen production requires approximately 200 GWh of additional electricity per year, the remaining electricity demand is still met by the previously mentioned fifty-fifty share.

3.3. System costs and greenhouse gas emissions

Total costs from 2025 to 2045 show that, under the assumptions made, stranded fossil assets in the rational transformation strategy are less expensive than pursuing faster defossilization (Fig. 6a). All faster defossilization strategies incur higher total costs compared to the rational strategy, with additional costs ranging from at least +17 % in the hesitant strategy to nearly +45 % in the self-sufficiency strategy.

Furthermore, treating investment costs as annuities, annual costs across all strategies are at least 40 % higher in 2045 than in 2025 (Fig. 7a), highlighting the inherent cost increase of industrial transformation. Comparing the strategies' annual costs in 2045 shows that all but the self-sufficiency strategy result in similar expenses. In contrast, self-sufficiency incurs up to 21 % higher annual costs. However, even with comparable annual costs in 2045, the strategies' temporal development differs significantly. While the rational strategy registers constantly growing annual costs, reasoned in a rising EU-ETS price, all other strategies register an abrupt cost increase with technology switch, subsequently decreasing. The additional costs during the phase of technology switch compared to the rational strategy range from +43 % (hesitant in 2035), over +66 % (rapid in 2030), up to +76 % (self-sufficiency in 2030). For renewable hydrogen and heat generation

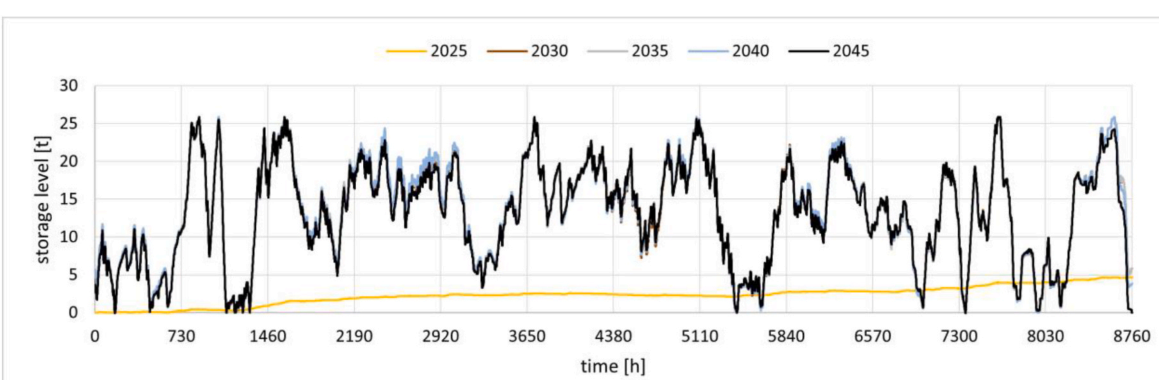

Fig. 4. Hydrogen storage level in the self-sufficiency scenario. Note: The curve of 2045 mostly overlaps the curves of 2030, 2035 and 2040.

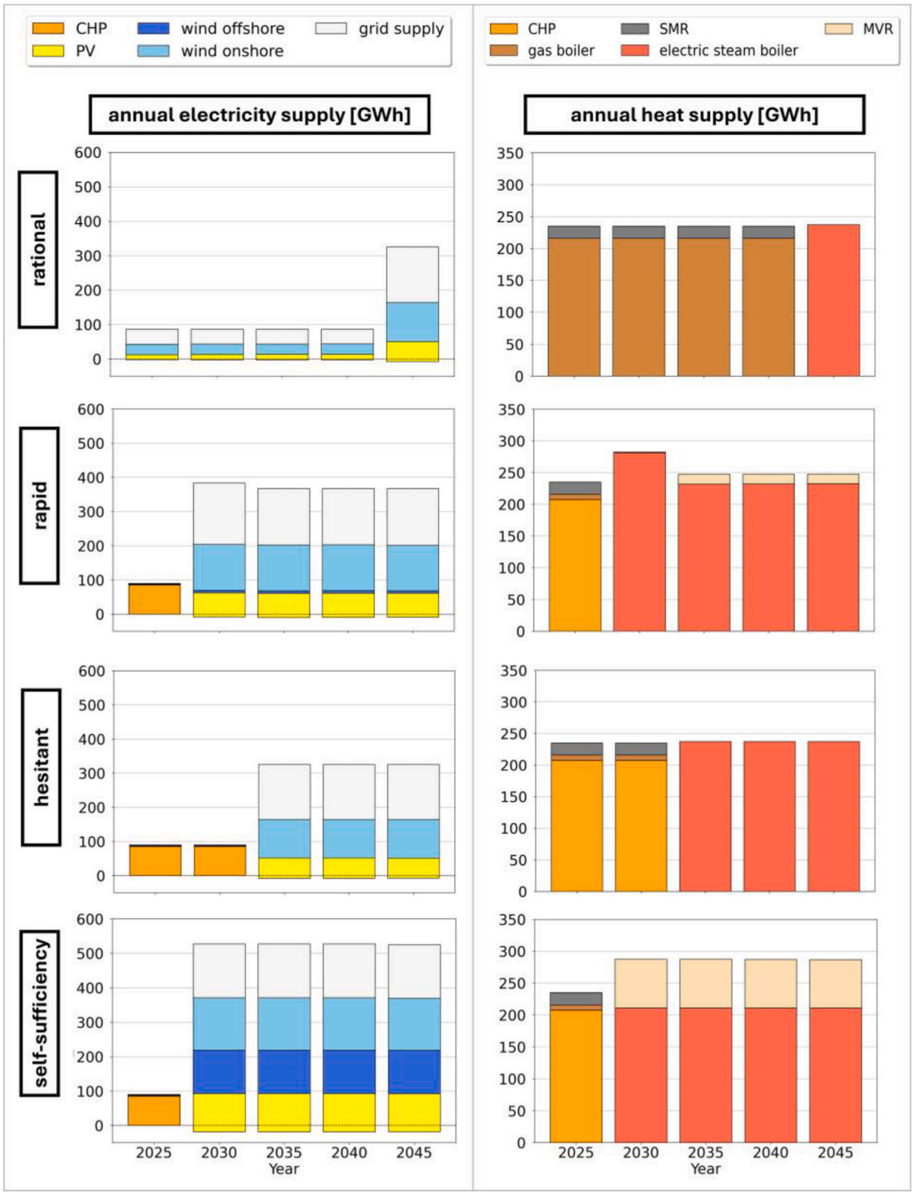

Fig. 5. Scenario results regarding the industrial site's electricity and heat supply. Note: Surplus electricity is shown negative. Although it may appear so, surplus electricity stems not necessarily from PV.

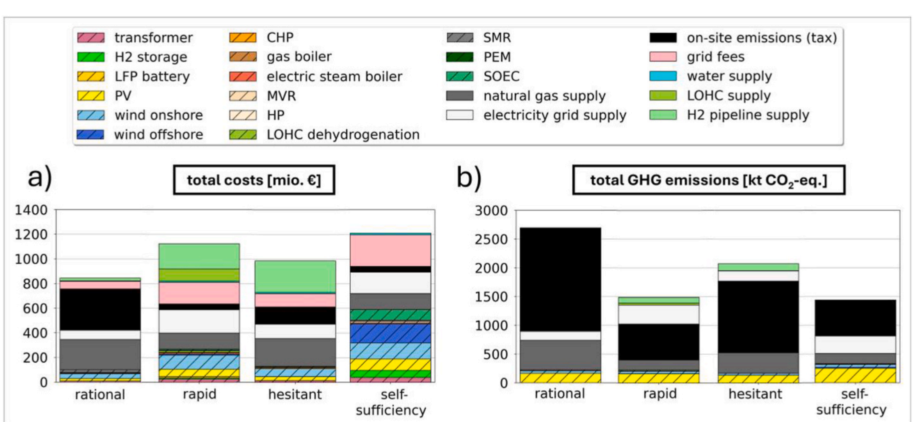

Fig. 6. Total costs and GHG emissions of defossilization strategies from 2025 to 2045. Note: Clear bars denote values associated with flows, while hatched bars denote values associated with investments; on-site emission tax is used as synonym for the EU-ETS.

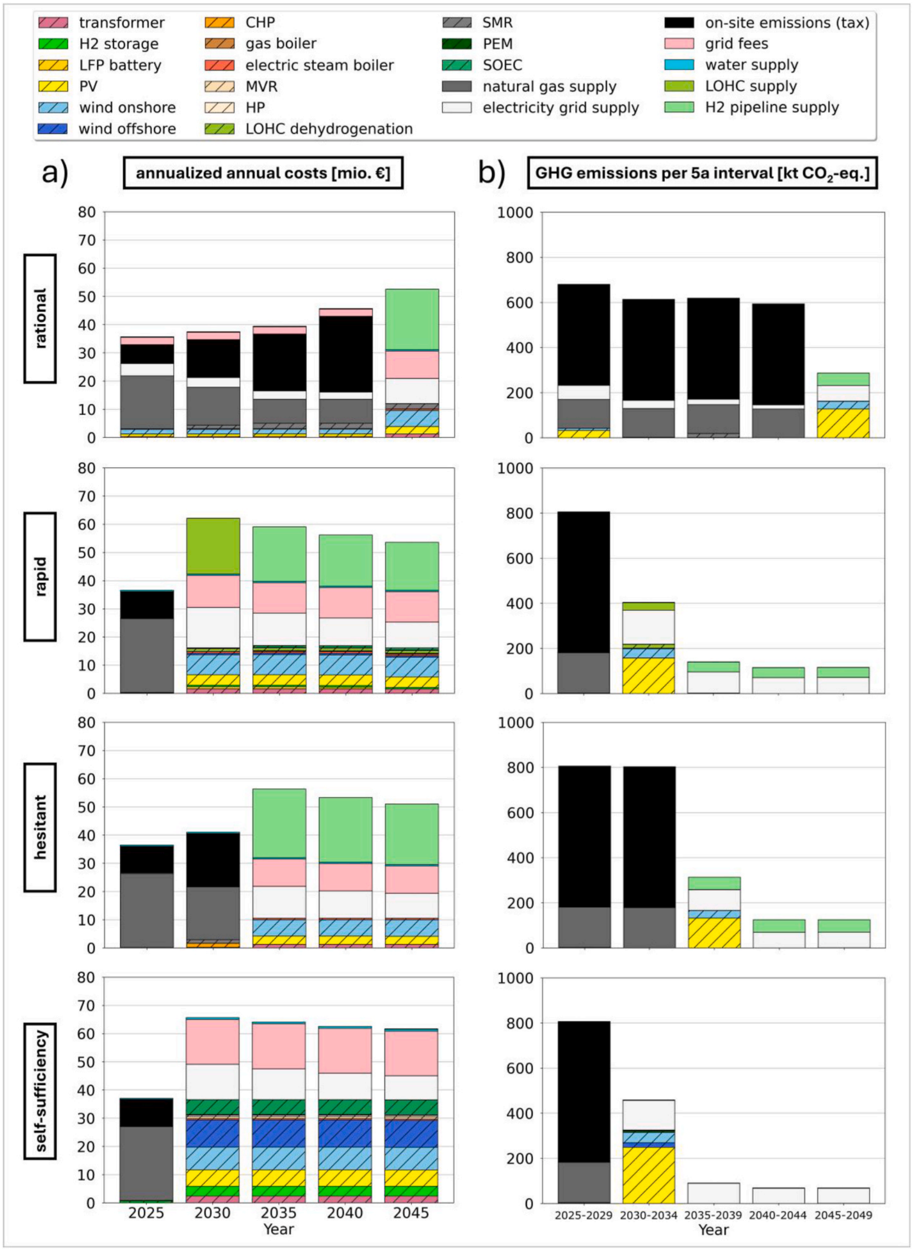

Fig. 7. Course of costs and GHG emissions of defossilization strategies. Note: Clear bars denote values associated with flows, hatched bars denote values associated with investments; on-site emission tax is used as synonym for EU-ETS; GHG emissions are displayed per five-year interval.

technologies becoming economically competitive, these cost gaps need to be closed in the short-term.

Here, investment costs have little impact on the site's cost structure, apart from RE investments that are typically not made by an industrial site itself but passed on to it. It is only in the self-sufficiency strategy that investment costs other than RE investments account for approximately 20 % of annual costs. Key cost drivers are the electricity supply including grid fees, the hydrogen supply, and the EU-ETS. Therefore, these parameters are analyzed more thoroughly in the sensitivities section.

Regarding GHG emissions, similar implications are observed (Fig. 6b). GHG emissions mainly occur from firing fossil fuels on-site, and from importing natural gas, electricity, and hydrogen, but not from new investments respectively the construction of new industry plants. Strategies with the lowest total costs come with the highest total GHG emissions and vice versa. Furthermore, our results show that as soon as there is an on-site abandonment of fossil-based technologies, annual GHG emissions decrease significantly (Fig. 7b). Nevertheless, counterintuitively, from 2025 to 2029 the lowest GHG emissions occur in the rational scenario. This is the result of decommissioning the existing CHP in a cost-efficient manner early on and replacing it with a natural gas boiler and electricity imports. That is, replacing on-site combined heat and power generation with heat-only generation and electricity import can reduce GHG emissions by up to 20 %. In all other scenarios, such new fossil-based investments were exogenously prohibited, resulting in the continued use of the existing CHP until its technical end of life.

3.4. Sensitivity analyses

To prove the robustness of our results and to determine conditions that change the evolved transformation pathways, we conduct sensitivity analyses by varying key parameters. Here, we focus on the EU-ETS, electricity procurement prices – in particular power grid fees, and hydrogen import prices. Eventually, we split the analyses into two

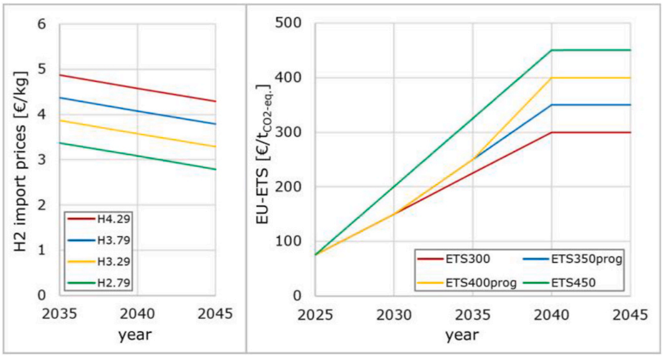

Fig. 8. Variations of hydrogen import prices (left) and EU-ETS prices (right), that are combined with each other to identify conditions for accelerated defossilization pathways.

parts. First, we investigate under which conditions an economically competitive but accelerated defossilization occurs, and secondly, we investigate conditions for economically competitive on-site hydrogen production. In the following two sub-sections, both analyses are explained in detail and their results are presented.

3.4.1. Accelerated defossilization

To identify conditions that lead to economically competitive yet accelerated defossilization pathways, we focus on the rational scenario. Here, we adjust the final EU-ETS price from 300 to 450 €/$t_{CO2\text{-}eq.}$ across four variations and reduce the initial hydrogen import price trajectory (H4.29) across four variations by 0.50 €/kg_{H2} each (Fig. 8). Combining these variations leads to 16 sensitivity analyses. To save computational effort and as our main results show distinct favor for hydrogen imports via pipeline, for hydrogen supply we solely focus on pipeline imports and on-site production.

The results of the analyses shown in Fig. 9 indicate that if hydrogen import prices (including fees and levies) follow our initial assumptions (H4.29), an EU-ETS price increase to 450 €/$t_{CO2\text{-}eq.}$ will be required to accelerate the transformation pathway by five years. If an acceleration of 10 years is desired, there are two options for achieving a technology switch in 2035. These are either an EU-ETS price exceeding 300 €/$t_{CO2\text{-}eq.}$ combined with hydrogen import prices below 4 €/kg_{H2} (Fig. 9L), or an EU-ETS price of 225 €/$t_{CO2\text{-}eq.}$ with hydrogen import prices below 3.50 €/kg_{H2} (Fig. 9M), both in 2035, and anticipating a further EU-ETS price increase and a hydrogen import price decrease. However, considering today's EEX HYDRIX Index is above 7 €/kg_{H2} [76] plus hydrogen grid fees possibly becoming higher than 1 €/kg [12], a price of 3.50 €/kg_{H2} may be overly optimistic for 2035. Hence, neither an expensive EU-ETS, nor low priced hydrogen supply on their own are expected to substantially accelerate the transformation pathway toward renewable hydrogen. This suggests that an accelerated transformation may require a sharp increase in the EU-ETS price, substantial financial support or regulatory policies.

Furthermore, under certain conditions, new fossil-based investments made in 2035 become stranded assets after just five years of use (D, G, H, J, K), highlighting the limited influence of investment costs and suggesting that stranded assets can be a rational outcome of an optimized transformation strategy. At the same time, the results show that in no case on-site renewable hydrogen production occurs, and in almost all cases hydrogen imports are only used to meet the industrial site's feedstock demand but not for process heat supply. Only in Fig. 9M and (N) hydrogen is used for process heat supply by 2045. This initially appears counterintuitive, as in the analyses (O) and (P) with the same hydrogen import prices but higher EU-ETS prices hydrogen is not used for heat generation. However, due to the faster increasing EU-ETS, in (O) and (P) the defossilization and electrification of process heat supply becomes cost-competitive while hydrogen-based heat supply still is not.

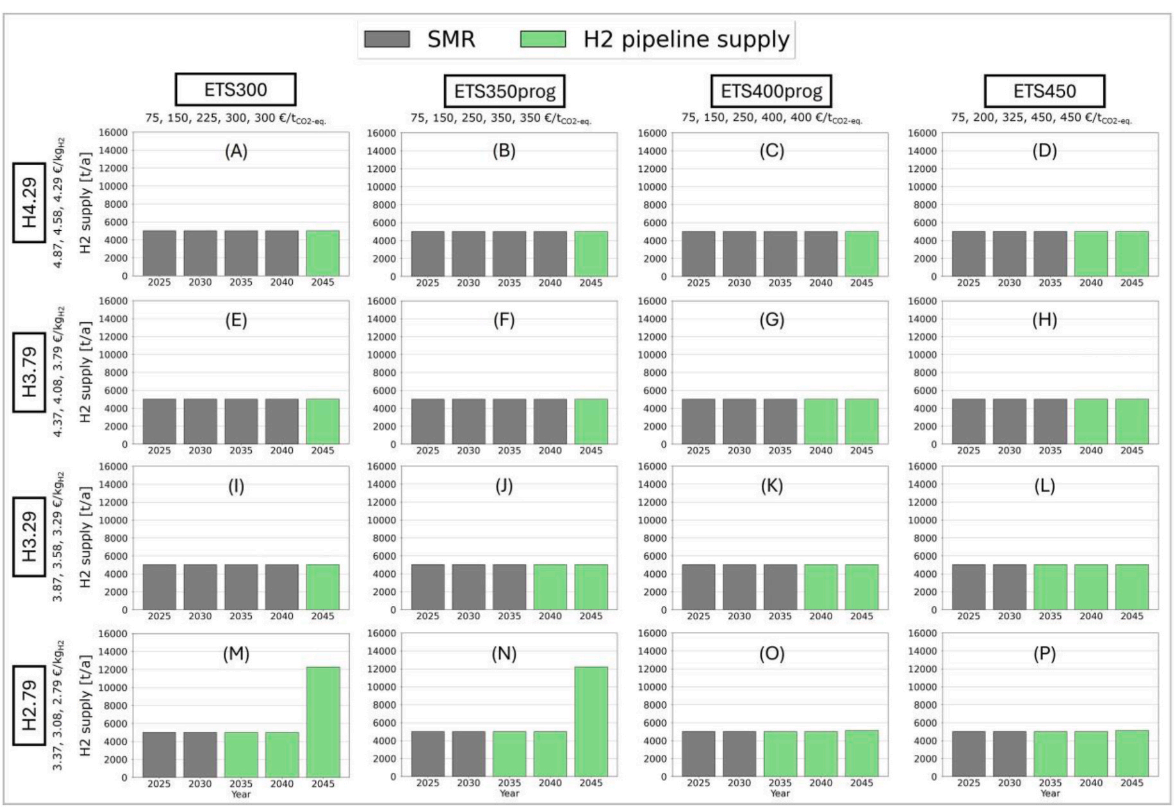

Fig. 9. Results of the sensitivity analysis on how hydrogen import prices (rows) and EU-ETS prices (columns) influence the transformation speed toward renewable hydrogen at the industrial site. Visual concept inspired by [27].

In (M) and (N), heat supply remains largely fossil-based until 2045, delaying the technology switch and eventually resulting in hydrogen-based heat generation becoming cost-competitive.

3.4.2. On-site hydrogen production

To identify conditions for cost-competitive on-site hydrogen production, we focus on the hesitant scenario. The hesitant scenario is chosen, as its main results show a relatively soon technology switch coming along with relatively limited additional costs. To save computational effort, and since our main results have shown that the years 2030 and 2035 are of the highest relevance, in this analysis we focus exclusively on the period from 2030 to 2035. Additionally, to further reduce computational effort, we concentrate solely on hydrogen supply through pipeline imports and on-site production. Varied parameters are power grid fees ranging from 2 to 6 ct/kWh, and hydrogen import prices in 2035 ranging from 2.37 to 5.87 €/kg_{H2}. Additionally, we compare hydrogen imports with a fixed supply rate to fully flexible hydrogen imports, both at a fixed price per kg. Here, the first one represents inflexible take-or-pay contracts similar to current natural gas contracts, while the second one represents complete flexibility, hence allowing for hydrogen balancing.

Fig. 10 shows the results as a function of the varied parameters. Here, hydrogen is produced on-site when the import volume (z-axis) falls below the feedstock demand of 5000 t_{H2}/a, whereas an import volume exceeding 5000 t_{H2}/a corresponds to additional hydrogen use in heat generation. Hence, the results indicate that on-site hydrogen production will only become cost-competitive with hydrogen imports when import prices exceed approximately 5.50 €/kg_{H2} and power grid fees fall below 2 ct/kWh. However, if more flexible hydrogen contracts evolve, a mix of hydrogen imports and on-site production could become a reasonable strategy, particularly when power grid fees remain on today's level of approximately 4 ct/kWh [51] and hydrogen import prices will exceed 4 €/kg_{H2}. Nevertheless, taking into account that in the long-term, i.e. by 2050, hydrogen prices are expected to range between 2 and 5 €/kg [77–80], on-site hydrogen production in Southern Germany tends to be unviable under either type of supply contract.

In addition, it is observed that hydrogen use increases significantly once import prices fall below approximately 2.50 €/kg_{H2}, due to its additional use in process heat generation. With high power grid fees, hydrogen is even used for process heat generation at import prices up to approximately 3.50 €/kg_{H2}. However, combined with the previous findings in Fig. 9 and future price assumptions for hydrogen imports, the

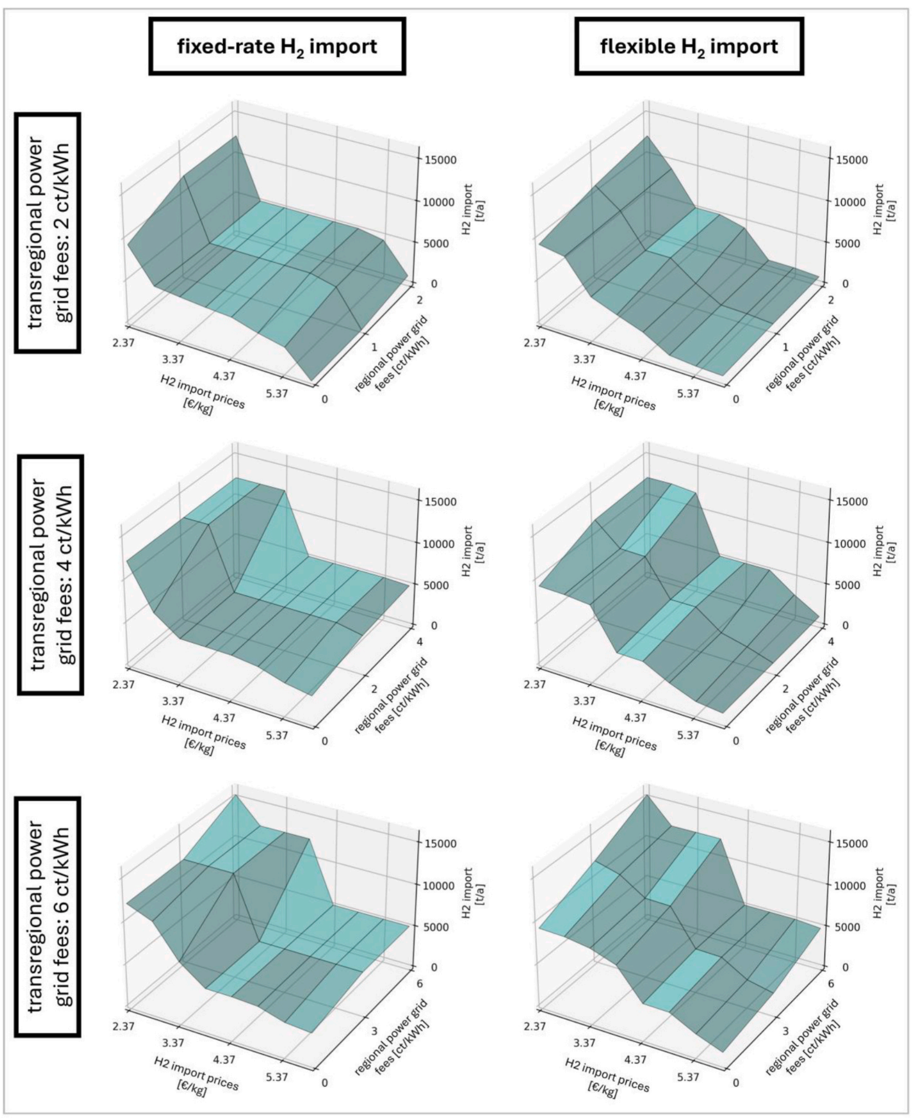

Fig. 10. Results of sensitivity analysis on how power grid fees, hydrogen import prices, and hydrogen supply contracts affect the industrial site's cost-optimal hydrogen supply. The z-axis shows the cost-optimal hydrogen import volume of the industrial site as a function of the varied parameters. Note: The industrial site's annual feedstock demand is 5000 t – lower import volumes indicate on-site production, higher import volumes indicate hydrogen utilization in heat generation.

results suggest that at least for the following 20 years, electrification of process heat supply can be considered a low-regret option.

Comparing fixed-rate hydrogen imports to flexible hydrogen imports more generally, it is observed that with costly hydrogen imports, a flexible hydrogen supply contract leads to fewer imports than with a fixed-rate contract. In contrast, with low-priced hydrogen imports, a flexible contract tends to result in higher hydrogen demand. Hence, future supply contracts will have a significant impact on the cost-optimal system design and consequently necessary infrastructure capacity.

Overall, this sensitivity analysis underscores the critical interplay of future uncertainties shaping hydrogen supply strategies. Notably, hydrogen import prices and power grid fees strongly influence whether hydrogen is primarily used for feedstock or also for process heat generation, while the design of hydrogen supply contracts significantly affects the cost-competitiveness of on-site hydrogen production versus imports. By contrast, the differentiation between regional and over-regional grid fees has only a minor impact.

3.5. Limitations

In general, models are simplified representations of reality, and their results inevitably depend on the assumptions and simplifications made. In our case, particularly policy and technology-related assumptions about future developments - including potential changes in regulatory frameworks (e.g., the EU-ETS price or quota regulations), subsidy availability, technological breakthroughs (e.g., in electrolyzer efficiency or storage systems), and supply chain volatility - are subject to significant uncertainty. All these factors could alter the relative competitiveness and timing of different technology pathways. However, as our sensitivity analyses account for a wide range of possible developments, and our findings align with other research [1,8,27], we consider the identified trends to be robust.

Nevertheless, the applicability of specific results to real-world implementation may require further detailed investigation. For instance, results indicating LOHC imports for an only five-year period may be difficult to be implemented in practice, as it can be challenging to find a supplier willing to terminate contracts for such a limited time period. Furthermore, the actual economic superiority of LOHC above ammonia as a hydrogen carrier can be contested [81–83]. Yet, due to their marginal influence on the overall findings, a more detailed comparison of LOHC and ammonia imports was beyond the scope of this study. The same applies to the accurate allocation between SOEC and PEM electrolysis in a self-sufficiency strategy. Moreover, the assumption of constant energy demand over time represents a simplification. In reality, demand profiles – particularly for hydrogen and electricity – may evolve dynamically due to efficiency measures, production shifts, or behavioral changes. Incorporating time-varying or scenario-based demand developments could influence system design and transition pathways.

Furthermore, beyond the technology options ultimately considered in our model, several more could have been included, particularly regarding process heat supply such as for instance solar collectors, geothermal heat or heat storage. Though, as our focus was on the transformation pathways toward a renewable hydrogen supply and to keep our model as streamlined as possible, we decided not to include less conventional technology options that are currently not widely adopted. Still, they may become relevant in the future.

On top of that, we deliberately focused on a single industrial site. Although the necessary new PV and wind power plants will be located in the surrounding region, we did not include the region's electricity demand. Including this demand would have expanded the limited reutilization options for RE investments, likely increasing hydrogen imports in our main scenarios that currently favor on-site hydrogen production. In addition, due to the electrification of sectors besides industry, such as mobility and residential heating, allocating 20 % of the region's approved wind energy potential to the analyzed industrial site might be challenged, potentially also leading to increased hydrogen imports. This highlights the need for political and social prioritization of RE allocation.

Besides the previously mentioned limitations, we did not account for an increased willingness to pay for renewable hydrogen. For instance, this could have further accelerated the purely rational defossilization strategy, in addition to low-cost hydrogen imports and rising EU-ETS prices. Yet, if there are no mandatory quota regulations or comparable policies, today's willingness to pay increased prices for renewable hydrogen is limited [84]. Moreover, socio-political adoption barriers, such as limited public acceptance, permitting issues, and planning constraints may slow down infrastructure deployment. Furthermore, no material flow interdependencies – such as those that occur in combination with steam crackers, where hydrogen is produced as a byproduct – were observed at the industrial site under consideration. If such interdependencies exist, they could considerably impact potential transformation pathways.

4. Conclusions and outlook

A number of issues are driving companies to develop site-specific transformation strategies toward renewable hydrogen, that are not always in line with the results of pan-European or nationwide system studies. Current research rarely captures these bottom-up transformation dynamics. Addressing this gap, we contributed a site-specific analysis of a Southern German industrial site, offering insights that complement large-scale system studies and enable a more nuanced understanding of different industrial decarbonization strategies.

First, we demonstrated that at industrial site level the transformation process toward renewable hydrogen is more of a binary decision than a gradual phase out. In addition, our results stress that fast defossilization not only of hydrogen supply but of an entire real-world chemical site leads to substantial additional total costs of at least 17 % from 2025 to 2045 compared to a purely rational defossilization strategy. Especially additional annual costs from 40 % to 75 % during the initial transformation years pose the risk that these costs cannot be compensated by rising market prices. Renewable hydrogen could only become economically competitive before 2045 if current EU-ETS prices increase by at least a factor of three by 2035, with further increases needed. At the same time, the results show that neither an expensive EU-ETS price, nor realistically low-priced hydrogen imports on their own will result in a substantially accelerated transformation toward renewable hydrogen. Hence, if an accelerated transformation is desired, policy measures such as financial support, mandatory quotas, or other regulations are recommended.

The implementation of one such measure could be to break down the RED III industry quota to the company level – comparable to the RFNBO quota for fuel suppliers under RED II – and require them to use at least 42 % and 60 % RFNBOs in hydrogen-consuming processes by 2030 and 2035, respectively. However, we also demonstrated that a premature and overly ambitious restriction to use renewable hydrogen risks creating costly path dependencies in domestic hydrogen production. This is particularly the case if RE plants installed for this purpose cannot be repurposed to supply electricity for other uses.

One way or another, society and particularly policymakers need to be aware that the transition to renewable hydrogen, and the transition to a climate-neutral industry in general, is likely to remain more expensive in the long run than today's business costs, and therefore consumer prices will rise. Still, the observed cost increase of approximately 40 % from 2025 to 2045 does not allow for conclusions on the cost increase of individual products, as these consist of multiple and possibly more cost-determining components.

Additionally, our results emphasize that even if hydrogen import prices are high, pipeline import is likely to be economically more favorable than domestic and especially on-site production, even when considering local synergies with process heat. Therefore, we recommend that infrastructure planners and policymakers – particularly in Southern Germany - prioritize the development of import corridors and international supply agreements. If self-sufficient hydrogen hubs are still pursued, for example as part of a resilience-oriented corporate strategy, decision makers should be aware of its likely up to 21 % higher costs compared to renewable hydrogen imports. Nevertheless, by providing system services – such as offering flexibility or utilizing surplus electricity from regional RE plants – these higher costs could potentially be reduced. Therefore, we recommend that project developers focus not solely on hydrogen production for industrial purposes alone, but rather on mixed business models that combine industrial hydrogen production with system-oriented services.

Furthermore, our findings highlight that hydrogen is unlikely to be used for heat generation below a temperature level of 200 °C under almost any realistic condition within the next 20 years, so that electrification of process heat supply can be considered a low-regret option. Therefore, for reducing GHG emissions, industrial actors should prioritize the electrification of process heat and policymakers should enable this shift through stable grid pricing and targeted electrification incentives.

Additionally, our extensive sensitivity analyses highlight the optimal investment timing and the critical interplay of future hydrogen and electricity prices, emphasizing the need for adaptive, scenario-based planning. The figures presented enable both companies and policymakers to assess hydrogen supply options by mapping expected import prices, power grid fees, EU-ETS prices and hydrogen supply contract flexibility. These insights support both corporate investment decisions and targeted policy design in the face of uncertainty.

To conclude, future research should explore the impacts of concrete policy measures, including the impact of the EU regulation's RE additionality criterion for renewable hydrogen production. Furthermore, as there were no on-site material flow interdependencies related to hydrogen production in our study, though such interdependencies could significantly influence potential transformation pathways, analyses should be conducted for industrial sites where such interdependencies occur. Moreover, beyond GHG emissions, other environmental impacts such as mineral resources and land use must be addressed and minimized. Optimizing for broader environmental indicators will be crucial in shaping more sustainable hydrogen systems and transformation pathways – ensuring that decarbonization not only accelerates but does so with the least environmental trade-offs.

CRediT authorship contribution statement

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

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

During the preparation of this work the authors used DeepL and ChatGPT 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.

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

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