On the cost competitiveness of blue and green hydrogen

Falko Ueckerdt (falko.ueckerdt@pik-potsdam.de)
Potsdam Institute for Climate Impact Research

Philipp C. Verpoort
Potsdam Institute for Climate Impact Research https://orcid.org/0000-0003-1319-5006

Rahul Anantharaman
SINTEF Energy Research

Christian Bauer
Paul Scherrer Institute https://orcid.org/0000-0002-1083-9200

Fiona Beck
Australian National University https://orcid.org/0000-0001-9631-938X

Thomas Longden
Australian National University https://orcid.org/0000-0001-7593-659X

Simon Roussanaly
SINTEF Energy Research

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Abstract

Hydrogen is indispensable for climate change mitigation; yet, it is unclear to what extent blue hydrogen from natural gas with carbon capture and storage will complement green hydrogen from renewable electricity. Today, green hydrogen costs are higher than those of blue hydrogen, and, despite huge cost reduction potential, it is uncertain when cost parity will be achieved. However, by combining data on costs and life-cycle emissions, we show that hydrogen's competitiveness is increasingly determined by carbon costs associated with different life-cycle emissions across fuels. To become competitive, green hydrogen requires >90% renewable electricity input, whereas blue hydrogen requires >90% net CO2 capture rates and close-to-zero methane leakage. For a broad parameter range, we show that by 2035-40, green hydrogen can become the cheapest hydrogen option. Low-emission blue hydrogen may play a valuable role in bridging the scarcity of green hydrogen; yet, depending on regional circumstances it may have a limited window of competitiveness.

Introduction

While there is agreement that low-carbon hydrogen and derived fuels are indispensable for climate change mitigation[1], at least two controversial debates remain. First, the demand-related question: it is not yet clear in which applications and sectors hydrogen should and will be used and thus what end-use energy share hydrogen will have in comparison to other mitigation options, particularly direct electrification[2]. Second, and the focus of this paper, the supply-related question: to what extent blue hydrogen from natural gas with carbon capture and storage (CCS) can and should complement green hydrogen from renewable electricity.

Considering the entire supply chain, the production of green hydrogen is associated with lower greenhouse gas (GHG) emissions[3] if produced entirely using renewable electricity, while blue hydrogen can be produced at lower costs at least in the near future[4]. The predominant technology for producing hydrogen is steam methane reforming (SMR) of natural gas. Once coupled with CCS, this blue hydrogen concept can reduce the emissions of hydrogen production; yet, today's industrial-scale applications lead to relatively small reductions in GHG emissions due to partial CO_2 capture and often high methane leakage rates from natural gas supply chains[5,6]. Enabling higher net (i.e., plant-wide) CO_2 capture rates (>90%) in SMR plants requires post-combustion CO_2 capture from reforming furnace flue gas, which is more expensive (around 22% more expensive than partial capture)[7]. However, coupling autothermal reforming (ATR) of natural gas with CCS can more cost-efficiently produce low-carbon hydrogen, if in addition methane leakage rates are substantially reduced compared to the current industry standard[3,8].

Today, production costs of blue hydrogen are lower than those of green hydrogen[4,5]. However, increasing electrolyser sizes, establishing serial production, and plummeting renewable electricity costs could substantially reduce green hydrogen costs [4,9–12]. As these assessments differ with respect to timing and long-term floor costs, it remains uncertain if and when green hydrogen will reach cost parity with blue hydrogen.

In this paper, we analyse the cost competitiveness of blue and green hydrogen - with one another and with fossil fuels - which is not only determined by their direct costs, but also by their life-cycle GHG intensities due to expanding and increasing CO2 pricing schemes or equivalent regulation[13]. More specifically, we derive circumstances for and timing of a potential blue-to-green switching point where green hydrogen becomes the most cost-competitive option. Beyond this point, green hydrogen would be expected to attract most private investments.

We take a techno-economic perspective and develop an analysis framework that combines new and existing data for specific costs and life-cycle emissions. We do not translate the competitiveness results into scenarios or overall investment pathways, as these also depend on other aspects such as potential bottlenecks in the upscaling dynamics of green hydrogen[14] or blue hydrogen[15] as well as path dependencies[16].

Despite substantial parameter uncertainties and regional differences, this approach allows us to derive carefully considered general conclusions. Along with the paper, we publish an interactive tool (https://interactive.pik-potsdam.de/blue-green-H2, username: preview, password: preview)[17], which allows the user to reproduce all figures with their own parameter choices. While analysing regional-specific cases is out of scope of this paper, we point to regional conditions that impact results and conclusions.

Fuel-switching CO2 prices as an indicator of competitiveness

Green and blue hydrogen compete in three ways:

1. They compete with other mitigation options such as direct electrification or biofuels (not analysed in this paper).
2. They compete with fossil fuels in different applications (analysed here for natural gas, e.g. for industrial process heat, and coke for producing primary steel).
3. They compete with each other (analysed here for SMR-CCS, ATR-CCS and electrolytic hydrogen from electricity with 80% to 100% renewable share).

For the different combinations of fuels, we calculate fuel-switching CO2 prices (FSCPs) as an indicator of competitiveness. The FSCP of two different fuels is defined as the CO2 price that is required to equalise the total costs of providing the energy service. Total costs comprise both the direct cost (see explanation in methods) of providing the energy service and the carbon cost of the associated life-cycle greenhouse gas emissions.

We use our main parameter specifications (table 1 and figure 1) to introduce the core concepts and relations that are later explored for broader parameter ranges. A detailed description of all technical and economic parameters can be found in the methods section and the supplementary information. The underlying mechanics of deriving FSCPs for green hydrogen, blue hydrogen and a fossil fuel application are illustrated in Figure 2 for natural gas for process heat.

Table 1: Most important parameters and assumptions

	unit	**2025**	**2030**	**2040**	**2050**
electrolysis CAPEX (system costs)	USD/kW	900 ± 200	600 ± 200	400 ± 150	200 ± 100
electricity costs for electrolysis	USD/MWh	45 ± 10	41 ± 10	33 ± 10	25 ± 10
Capacity factor of electrolyser	%	60	55	50	50
renewable share in electricity for electrolysis	%	80	90	100	100
GHG intensity of electricity for electrolysis	g_{CO_2eq}/kWh	102±18	62±13	20±7	16±5
methane leakage rate	%	1	0.82	0.46	0.1
hydrogen transport costs	EUR/MWh	20	18	14	10

For all parameters and references see the methods section and supplementary information.

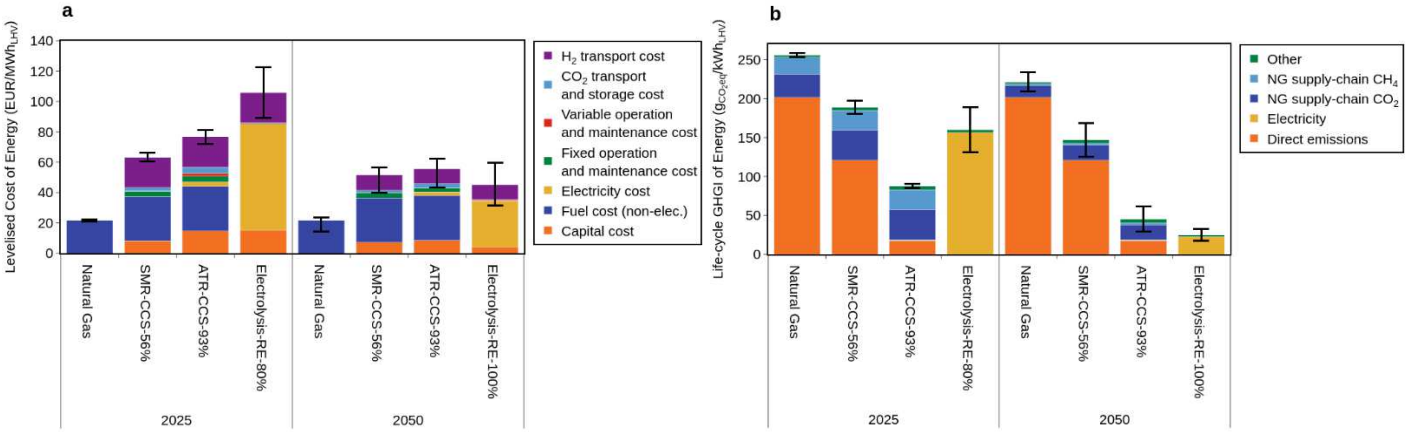

Figure 1: *a) Levelised cost and* ***b)*** *life-cycle GHG intensity of natural gas and hydrogen from different supply technologies.* ***For blue hydrogen production,*** *we distinguish two technologies. Firstly, an SMR plant with partial CO2 capture (referred as SMR-CCS-56% here), in which CO2 is captured from the syngas prior to the hydrogen purification pressure swing adsorption (PSA). A CO2 capture rate of 90% is achieved during the capture step, however this only allows for a net (i.e., plant-wide) CO2 capture of about 56% as there are additional CO2 emissions from combusting natural gas to provide process heat (in the reformer furnace). Instead of this configuration, it is possible to consider a post-combustion CO2 capture unit on the SMR flue gas to achieve net CO2 capture rates higher than 90%; yet, this option is foreseen to be a costly pathway for low-carbon blue hydrogen production. This is why we select an ATR-CCS plant as the second case that more cost-efficiently achieves high net CO2 capture rates (here: 93%). ATR technology is already used at industrial scale for methanol production (e.g. the Haldor Topsøe plant in Turkmenistan), though without CO2 capture. The first ATR-CCS hydrogen plants HyNet and H2H Saltend are announced to start operating in the United Kingdom in 2025 and ~2026/27, respectively. To account for upstream methane emissions, we summarise the wide range of region-specific methane emission rates by assuming a value of 1% in 2025 that decreases to 0.1% in 2050.* ***For green hydrogen production*** *via electrolysis, life-cycle emissions are mainly determined by their electricity input. As renewable electricity capacity is scarce and their supply fluctuating, we assume that in 2025 a representative electrolysis plant operates flexible with an annual capacity factor of 60% using 80% renewable electricity (referred to as "RE-80%") and 20% grid electricity. Note that this specification leads to "green" hydrogen having higher emissions than ATR-CCS-93% in the short term (Figure 1b). From 2035 on, our representative electrolysis plant runs on a renewable electricity share of 100% (referred to as "RE-80-to-100%") at the expense of full-load hours as the capacity factor decreases to 50%. For the main analyses and figures below, we also show an off-grid electrolysis case that uses 100% renewable electricity already in the short term ("RE-100%") as several such projects are planned to export green hydrogen[4].*

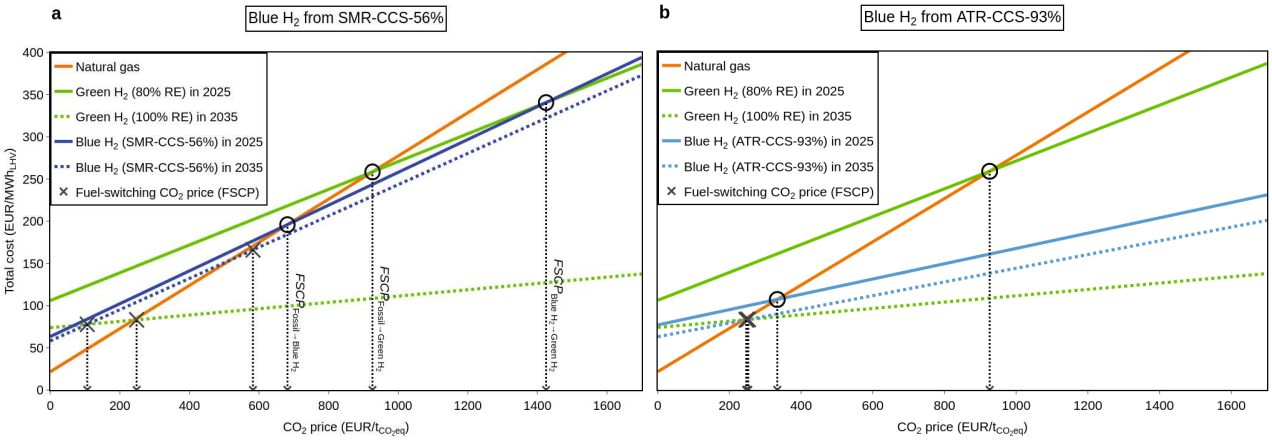

Figure 2: *Total levelized costs as a function of CO2 prices for green and blue hydrogen as well as for natural gas for 2025 (solid lines) and 2035 (dotted lines). We distinguish two technology options for blue hydrogen production:* ***a)*** *SMR-CCS technology with net CO2 capture rates of 56% and* ***b)*** *based on ATR-CCS technology with net CO2 capture rates of 93%. The fuel's life-cycle GHG intensity defines the slope of the respective lines. The y-intercepts equal the direct costs for each fuel. For any given CO2 price there is one fuel that provides the selected energy service at the lowest cost. FSCPs emerge from the intersections of two cost lines and mark the CO2 price at which a low-carbon fuel with higher direct costs becomes cheaper, and thus competitive, compared to a more carbon-intensive fuel.*

Three different FSCPs can be derived corresponding to the switching between the three fuels:

1. switching from natural gas to blue hydrogen: $FSCP_{Fossil->Blue\ H_2}$

2. switching from natural gas to green hydrogen: $FSCP_{Fossil->Green\ H_2}$

3. switching from blue to green hydrogen: $FSCP_{Blue\ H2->Green\ H_2}$ (also "*blue-to-green FSCP*")

In the short term, these FSCP typically line up in a specific order irrespective of the choice of a hydrogen application (compare solid lines and circular markers in figure 2a): $FSCP_{Fossil->Blue\ H_2} < FSCP_{Fossil->Green\ H_2} < FSCP_{Blue\ H_2->Green\ H_2}$. In 2025, $FSCP_{Fossil->Blue\ H2}$ of SMR-CCS-56% is ~700 €/tCO2eq, while $FSCP_{Fossil->Green\ H2}$ ("RE-80%") is 900 €/tCO2eq, both due to relatively small emission reductions (<50%) compared to natural gas. As a result, the slopes of the total cost curves are similar and the intersections and FSCPs are thus highly sensitive to small changes of life-cycle emissions or costs, and $FSCP_{Blue\ H2->Green\ H2}$ can thus become very high (~1400 €/tCO2eq). By contrast, the substantial emission reduction through ATR-CCS-93% can lead to much lower $FSCP_{Fossil->Blue\ H2}$ of 300 €/tCO2eq in the short term (figure 2b). This demonstrates how crucial high capture rates are for blue hydrogen production. Similarly, the competitiveness of green hydrogen drastically improves when the renewable share in the input electricity increases to 100% in 2035 (low slope of the dotted green line).

The mid to long-term competitiveness of low-emission blue hydrogen and green hydrogen then depends on the future direct costs and residual life-cycle emissions of the hydrogen supply options. For the emission-intensive SMR-CCS-56% hydrogen, the relation of FSCPs inverts once green hydrogen becomes cheap and clean enough: $FSCP_{Fossil->Blue\ H2} > FSCP_{Fossil->Green\ H2} > FSCP_{Blue\ H2->Green\ H2}$, which can be seen for 2035 costs and lifecycle emissions, and is indicated by the geometric inversion of the triangle of x-shaped markers in figure 2a. Green hydrogen can then abate more emissions at a lower specific mitigation cost of ~200 €/tCO2eq, which would exclude the emission-intensive SMR-CCS-56% option (~600 €/tCO2eq) from a cost-efficient marginal abatement cost curve (MACC).

As a consequence, in the mid- to long-term, producing blue hydrogen with high net CO2 capture rates is a necessary condition for cost competitiveness with green hydrogen in the presence of CO2 pricing. For low-emission blue hydrogen from ATR-CCS, all FSCPs in 2035 are close to 300 €/tCO2eq (figure 2b). This suggests further analyses of i) broader cost and emission data ranges and ii) the temporal development of parameters, which we will provide in figure 3 to 5.

Expanding competitiveness of low-carbon hydrogen

With innovation and scale, the costs of producing low-carbon hydrogen and associated FSCPs will decrease for all hydrogen supply pathways and applications. We demonstrate this for the hydrogen production technologies introduced above and for two hydrogen applications: process heat (in competition with natural gas, figure 3 top) and primary steel production (direct reduction process in competition with the conventional coke oven, figure 3 bottom), by plotting FSCPs against time. We further differentiate SMR-CCS-56% (left) and ATR-CCS-93% (right). Over time, CO2 prices, or equivalent regulation, will likely increase and expand across regions and end-use sectors. The corridor of CO2 price trajectories in Figure 3 is derived from several model-based scenarios that achieve the EU climate targets[18]. We make a general assumption that explicit or implicit CO2 prices of this magnitude are required for all countries that aim at climate neutrality in 2050.

The expanding competitiveness is marked by the intersection of CO2 prices and FSCPs of green and blue hydrogen with a fossil reference application (milestones 2 and 3 in figure 3). One striking result is that blue hydrogen from SMR-CCS-56%, unlike ATR-CCS-93% and green hydrogen, cannot compete with natural gas; yet, if used to replace an emission-intensive coke-fueled blast furnace, its competitiveness is similar to those of ATR-CCS-93% and green hydrogen. Replacing coke-based steel production could create early markets for low-carbon hydrogen solely based on CO2 prices before 2030.

1) Before milestones 2 and 3 are reached, there is a transition period starting from the current situation. As long as CO2 prices are below FSCPs, low-carbon hydrogen is not yet competitive as using fossil fuel is still cheaper. Investments in green or blue hydrogen require either an investors' anticipation of high future CO2 prices, complementary policy measures (regulation and subsidies) or lead markets with a high willingness to pay (e.g. climate-neutral steel for car manufacturing). The expected short-term reduction of this competitiveness gap is

indicated by the decreasing difference of carbon prices and FSCPs. This gap highly depends on the hydrogen application and the hydrogen supply option.

2) Once increasing CO2 prices cross $FSCP_{Fossil->Blue\ H2}$, the switch from a fossil to a blue hydrogen application is incentivized. The timing highly depends on the application and hydrogen supply option. For a process heat application, it is substantially later (~2050 or later for SMR-CCS-56%, ~2035-2040 for ATR-CCS-93%) than for primary steel production (~2025-2030 for both SMR-CCS-56% and ATR-CCS-93%).

3) Once the CO2 price reaches $FSCP_{Fossil->Green\ H2}$, the use of green hydrogen becomes also competitive with the fossil fuel application. This occurs ~2035-2040 for heating applications and ~2025-2035 for primary steel production.

Irrespective of the competition with fossil fuels, the competitiveness relations within the hydrogen supply options may invert, such that green hydrogen would become the cheapest supply option. In fact, there are *three* blue-to-green switching points (milestones 4, 5, and 6) with different characteristics. Note that the order of 2-5 can invert with higher residual emissions of blue hydrogen (figure 3a), faster cost reductions of green hydrogen or a less ambitious increase of CO2 prices. We discuss this potential blue-to-green supply transition in the next section.

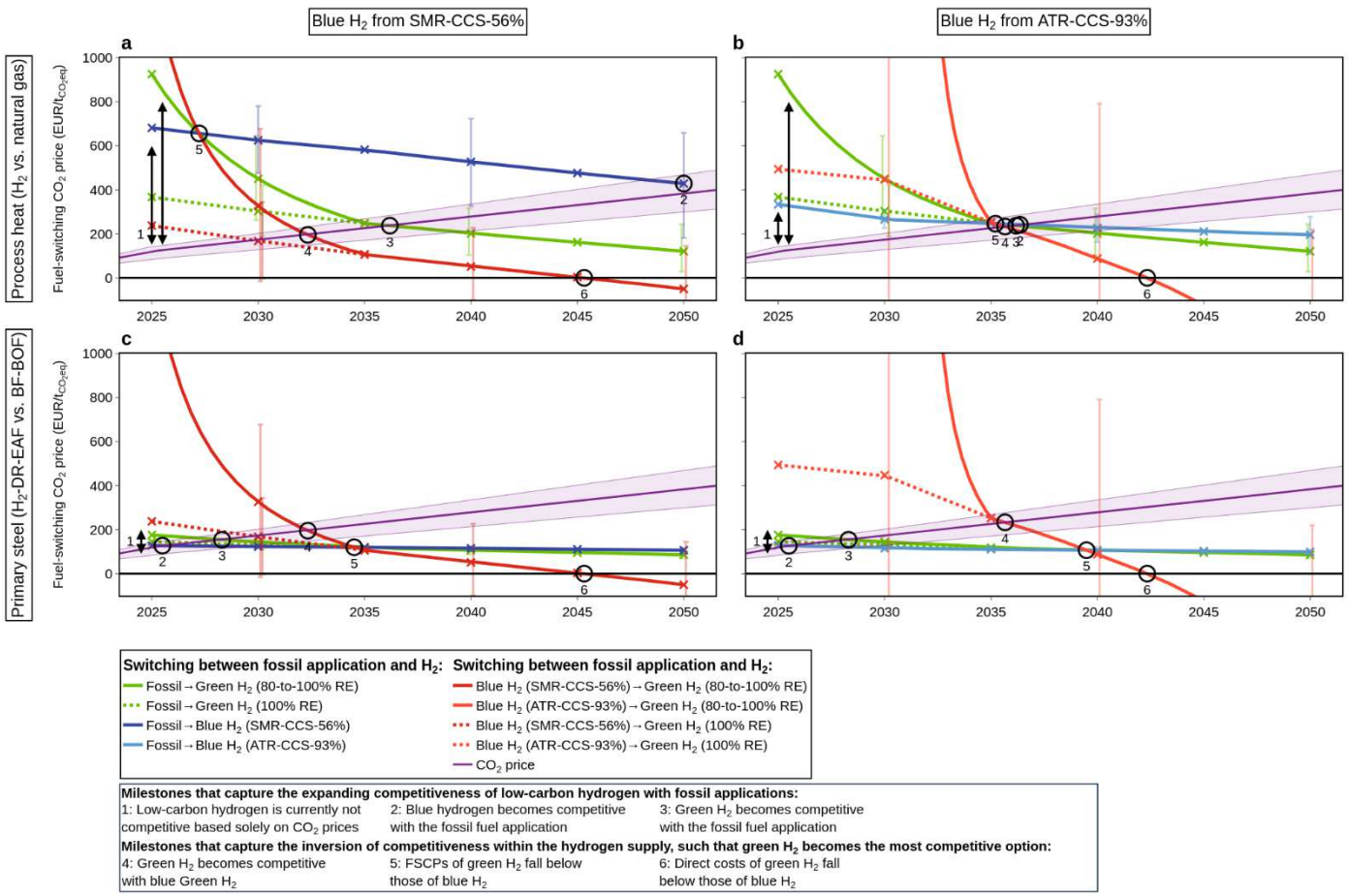

Figure 3: *Decreasing FSCPs in time for blue hydrogen from SMR-CCS-56% technology (**left: b, d**) and ATR-CCS-93% technology (**right: a, c**), and for green hydrogen from 100% renewable electricity (dotted) and for a 80-to-100% renewable electricity transition case (solid), for two applications, hydrogen replacing natural gas for process heat (**top: a, b**) and hydrogen replacing coke in primary steel production (**bottom: c, d**).*

To better understand the competitiveness with fossil applications, we show a contour plot of FSCPs (figure 4) again for a) process heating and b) primary steel production. The trade-off between emissions intensity (x axis) and costs of hydrogen (or resulting costs for hydrogen-based steel, y axis) leads to diagonal zones of similar competitiveness level, which are marked with diagonal contour lines of identical FSCPs. The relative position of the different hydrogen supply options (in figure 4 a and b) as well as the blue-to-green FSCP (red lines in figure 3, discussed in the next section) are invariant to the choice of hydrogen application. However, the fossil-to-hydrogen FSCP levels and the slope of the contour lines highly

depend on the hydrogen application, or more specifically on the additional costs and emission savings relative to the conventional process. As a consequence, the relative competitiveness of hydrogen supply options change with the respective conventional process. For example, the three hydrogen supply options are mainly located in the same FSCP zone (100-150 €/t/CO2) for steel making (figure 4b), as the relative emission and cost differences among both options are small compared to the conventional steel making emissions and costs. By contrast, the emission and cost differences of hydrogen supply options are higher relative to natural gas, as it is lower-cost and lower-emission than steel making (figure 4a) leading to a stronger differentiation of the various hydrogen FSCPs.

To become competitive with natural gas process heating, hydrogen needs to be both clean and cheap. While SMR-CCS-56% hydrogen lacks competitiveness due to its high emissions (dark blue markers), green hydrogen (green markers) struggles due to high short-term costs, and in the 80-to100%-RE case (solid green lines), due to its short-term emissions. SMR-CCS-56% and 80-to100%-RE hydrogen thus require high short-term CO2 prices of 600-750 €/tCO2eq and 700-1300 €/tCO2eq, respectively. Lower-emission and lower-cost ATR-CCS-93% hydrogen could replace natural gas at short-term FSCPs of only about 350 €/tCO2eq for methane leakage rates of ~1%, once industrial scale projects are available (~2026/27). Despite falling FSCPs of green and blue (ATR) hydrogen, expected CO2 prices in most countries will only reach sufficient levels after 2035 (figure 3). Hydrogen from SMR-CCS-56% remains uncompetitive with FSCPs of >300 €/tCO2eq also in the long term. By contrast, steel applications could become early markets for low-carbon hydrogen based solely on CO2 prices, as the FSCPs are much lower already before 2030.

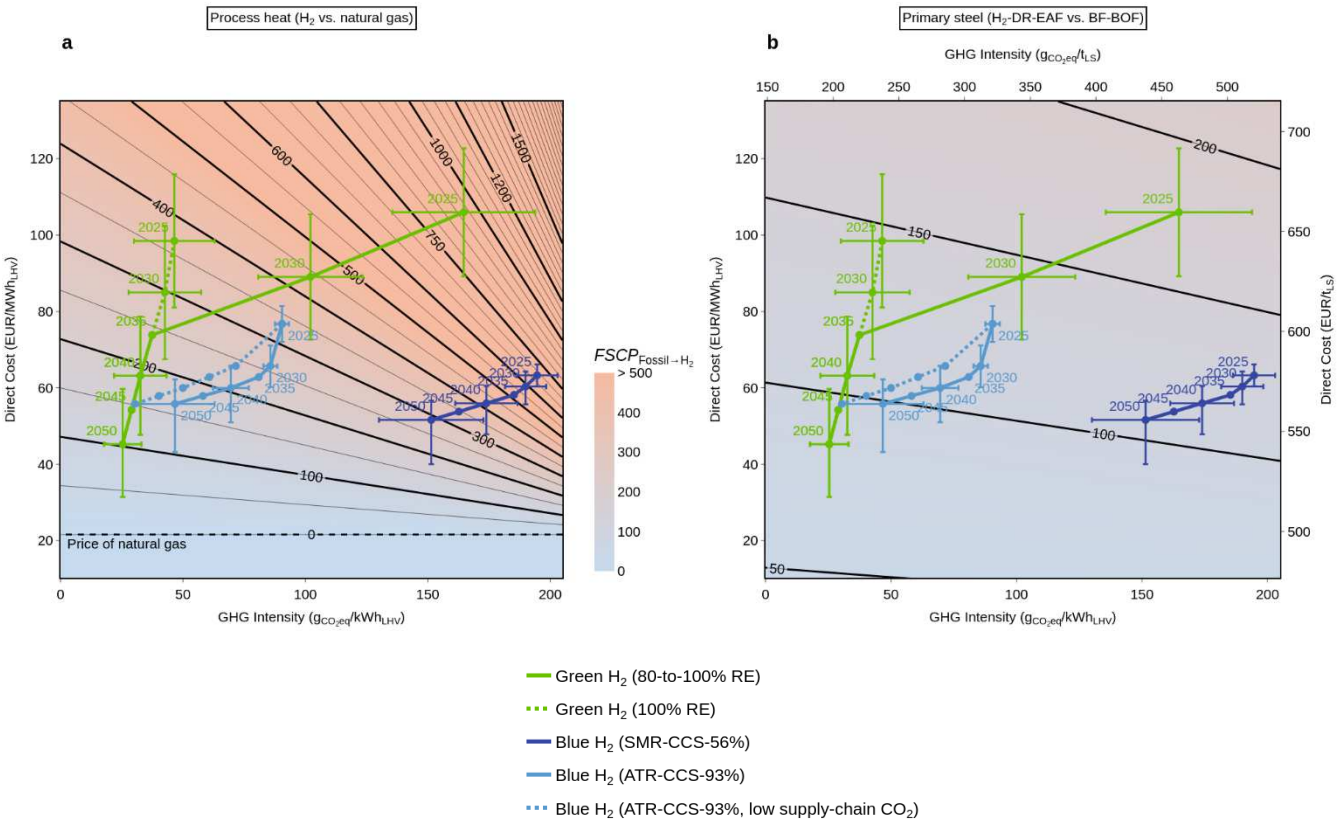

Figure 4: *Emission intensities and direct costs of different hydrogen fuel options (scatter plot for several years), along with FSCP estimates (contour plot) required to make hydrogen competitive with* ***(a)*** *natural gas for heating and* ***(b)*** *conventional steel production (2nd y axis shows resulting costs of hydrogen-based liquid steel). The hydrogen production cases shown are i) a high-emissions blue hydrogen based on SMR-CCS-56% technology with net CO2 capture rates of ~56%, ii) a low-emissions blue hydrogen based on ATR-CCS technology with net CO2 capture rates of ~93% (here we include a sensitivity case with very high upstream CO2 emission reductions, which reflects the high ambitions of the oil and gas industry in Norway[19], dotted), and iii) green hydrogen produced with a renewable electricity share increasing from 80% (2025) to 100% (>2035). Green hydrogen produced with 100% renewable electricity from 2025-2035 is indicated with a dotted green line. Methane emission rates along the natural gas supply chains are assumed to reduce from ~1% to ~0.1% in 2025-2050. The trade-off between emission intensity and costs of hydrogen (or resulting costs for hydrogen-based steel) leads to diagonal zones of similar competitiveness level, which are marked with diagonal contour lines of identical FSCPs. The relative position of the different hydrogen supply options (in a and b) as well as the blue-to-green FSCP (red lines in figure 3, discussed in the next section) are invariant to the choice of hydrogen application. However, the fossil-to-hydrogen FSCP levels and the slope of the contour lines highly depend on the hydrogen application, or more specifically on the additional costs and emission savings relative to the conventional process.*

To better understand the competitiveness with fossil applications, we show a contour plot of FSCPs (figure 4). The relative competitiveness of hydrogen supply options change with the hydrogen application. For steel production (figure 4b), the three hydrogen supply options are mainly located in the same FSCP zone (100-150 €/t/CO2), as the relative emission and cost differences among both options are small compared to the conventional steel making emissions and costs. By contrast, replacing natural gas in heating (figure 4a) leads to a stronger differentiation of the various hydrogen FSCPs.

Competitiveness of blue with green hydrogen

Blue hydrogen (SMR-CCS-56% and ATR-CCS-93%) have lower direct costs and lower FSCPs than green hydrogen in the short- to mid-term. However, there are *three* potential blue-to-green switching points (4-6 in figure 3) that are determined by different drivers and vary depending on the hydrogen application.

4) Once the CO2 price reaches $FSCP_{Blue\ H2->Green\ H2}$, green hydrogen total costs (including carbon costs) become cheaper than those of blue hydrogen. Higher CO2 costs are associated with higher residual emissions of blue hydrogen, creating a cost advantage for green hydrogen irrespective of the hydrogen application. The timing of this switching point thus depends on climate mitigation ambition and the associated national or regional CO2 price level. For the CO2 price corridor shown in figure 3, total cost parity is reached 2030-35 for SMR-CCS-56% and 2035-40 for ATR-CCS-93%. However, if green hydrogen remains scarce by that time, blue hydrogen could still secure parts of the hydrogen markets.

5) Another blue-to-green switching point is potentially reached where all three FSCPs intersect and fossil-to-hydrogen FSCPs of green hydrogen fall below those of blue hydrogen: $FSCP_{Fossil->Blue\ H2} = FSCP_{Fossil->Green\ H2} = FSCP_{Blue\ H2->Green\ H2} = P_{CO2,*}$ (please find an analytical derivation in the supplementary information). Hereafter the FSCP relation will invert and green hydrogen is the cheapest mitigation option: $FSCP_{Fossil->Blue\ H2} > FSCP_{Fossil->Green\ H2} > FSCP_{Blue\ H2->Green\ H2}$, which corresponds to the inversion observed in figure 2a. This switching point varies with the hydrogen application and the replaced conventional fuel, and is enabled by lower GHG emissions (compared to blue hydrogen) and cost reductions of green hydrogen. In contrast to switching point 4, the timing of this switching point is independent of CO2 prices; yet, it requires CO2 prices of at least $P_{CO2,*}$ or equivalent regulation to unmask these new competitiveness relations. For green hydrogen competing with SMR-CCS-56% (figure 3, left) for process heat applications (primary steel production) this point is reached by 2025-30 (~2035), while for green hydrogen competing with ATR-CCS-93% (figure 3, right) will take until 2035-40 (~2040).

6) Finally, irrespective of GHG emission intensities and CO2 prices, the direct production costs of green hydrogen might fall below those of blue hydrogen in the mid- to long-term. This will likely happen later than the milestones above, and is most relevant for regions without CO2 pricing or equivalent regulation in the long term. This point is marked by blue-green FSCPs becoming negative (figure 3), which happens 2040-2045.

In the competition of green hydrogen with ATR-CCS-93%, blue-to-green switching points are reached ~2035-40 for both heating and primary steel making. For SMR-CCS-56% the competitive window is narrower and is reached already before 2030 for process heating and before 2035 for primary steel making. If hydrogen is produced in or imported to a region with ambitious CO2 pricing, the switching point 4) is likely reached earlier than point 5). If CO2 prices increase less ambitiously, point 5) is likely reached earlier than point 4). Both points depend on the *blue-to-green FSCP*, which we analyse in greater detail in figure 5.

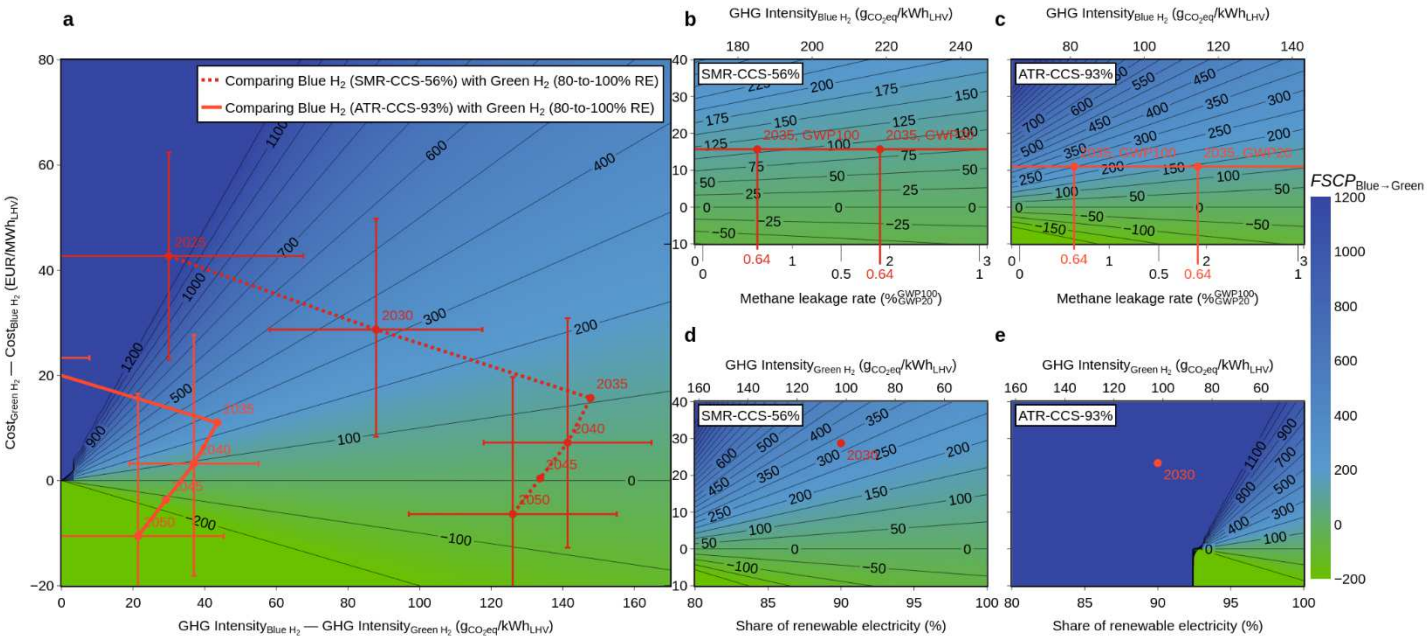

Figure 5: *Blue-to- green $FSCP_{Blue\ H2->Green\ H2}$ as a function of additional specific costs of green compared to blue hydrogen (y axis in all panels) and* ***a)*** *additional life-cycle emissions of blue compared to green hydrogen,* ***b)*** *methane leakage rates (two x axes: GWP100 and GWP20) for SMR-CCS-56% and* ***c)*** *for ATR-CCS-93%,* ***d)*** *share of renewable electricity (for green hydrogen) compared to SMR-CCS-56% and* ***e)*** *to ATR-CCS-93%. In contrast to figure 4, we show cost and emission differences here to capture the substantial changes for all four absolute values: costs and emissions for green and blue hydrogen. For the colour scheme of the heat map, we select a FSCP of 200 €/tCO2eq to be a central value where the colours transition from green to blue. While this choice does not affect any numeric values, it reflects that CO2 prices or equivalent regulation will likely cross this level (200 €/tCO2eq) in many regions in the next 1-2 decades. Blue-to-green FSCP of below 200 €/tCO2eq are thus shown with increasing green hue (likely to favour investment in green hydrogen), while blue-to-green FSCP of above 200 €/tCO2eq are shown with increasing blue hue (likely to favour investment in blue hydrogen).*

The blue-to-green FSCP trajectories (red lines, figure 5a) are mainly driven by a continuous decrease in the costs of green hydrogen, as well as by a reduction of GHG intensity of green hydrogen until 2035 due to the transition from 80% to 100% renewable electricity input for electrolysers. As a result, the blue-to-green FSCPs decrease from very high levels (>600 €/tCO2) in 2025-2030 to very low levels (<100 €/tCO2) in 2040-45. After 2045, FSCPs can be negative indicating that the direct costs of green hydrogen have fallen below those of blue hydrogen. Importantly, blue-to-green FSCPs for SMR-CCS-56% hydrogen cross the 200 €/tCO2eq contour line between 2030 and 2035, and FSCPs for ATR-CCS-93% follow about 5 years later.

We show sensitivity analyses for the methane leakage rate and the choice of global warming potential (GWP) metric (figure 5b, c), and the share of renewables in electricity (figure 5d, e). Increasing the methane leakage by 1% for ATR-CCS-93%, for direct cost differences of ~10 euro/MWh as projected for 2035, (figure 5c), with our default choice of a GWP100 metric, translates into decreasing the FSCP by ~100 €/tCO2eq, which moves the blue-to-green switching point forward by ~5 years, assuming CO2 price trajectories shown in figure 3. Similarly, applying a GWP20 metric instead of GWP100 at a constant leakage rate has a comparable effect of decreasing blue-to-green FSCPs and highlights the need to substantially reduce methane leakage to close-to-zero values. Likewise, green hydrogen's competitiveness with ATR-CCS-93% relies on renewable electricity shares of at least ~90-95% (figure 5d), at cost parity, and close to 100% when green hydrogen costs are higher.

Conclusions and discussion

Scientists, stakeholders and policy makers agree that low-carbon hydrogen is indispensable for sustainable energy transitions. Here, we study the cost competitiveness of blue and green hydrogen, based on a techno-economic analysis framework that combines new and existing data for specific costs and life-cycle GHG emissions. As the core indicator for

competitiveness, we estimate fuel-switching CO2 prices (FSCPs) that would be required for reaching cost parity of respective fuels and applications.

In 2025, we estimate FSCPs of low-carbon hydrogen (green or blue) with fossil fuels to be in the range of 130 to 1000 €/tCO2eq. Low-carbon hydrogen is thus not competitive based solely on CO2 prices in most countries in the next few years. With innovation, scale and deployment, the costs and GHG emissions of low-carbon hydrogen and associated FSCPs will substantially decrease, while CO2 prices, or equivalent regulation, will likely increase and expand across regions and end-use sectors. As a result of both developments, low-carbon hydrogen will become competitive for more and more applications and regions. An early market-driven entry point is replacing emission-intensive coke-based blast furnaces with hydrogen-based steel in regions with substantial CO2 pricing (e.g. the EU), as these steel-related FSCPs can decrease to ~110 €/tCO2eq in 2030, while EU ETS CO2 prices are already at ~100 €/tCO2eq today. By contrast, the competitiveness with relatively low-emission natural gas (e.g. for industrial process heat) will not occur before 2035-40, when FSCPs decrease to ~200 €/tCO2eq. As a consequence, hydrogen will compete in those heating applications for which direct electrification faces high barriers such as selected high-temperature industrial processes[20].

The competitiveness of hydrogen hinges on its life-cycle emissions and thus relies on reducing GHG emissions along its supply chains.

1. Green hydrogen needs to be produced from electricity with renewable shares of >90% to compete with natural gas and low-emission blue hydrogen. In addition, as hydrogen applications are less efficient than using renewable electricity for electrification or to replace today's fossil electricity, there is a debate about additionality criteria for renewable electricity used to produce green hydrogen[21]. Achieving both conditions is challenging for grid-connected electrolysers in most regions, but achievable for off-grid electrolysis projects with dedicated renewable power.

2. Blue hydrogen has to be produced with >90% net CO2 capture rates to compete with natural gas and with green hydrogen from >90% renewable electricity. Combining SMR, today's predominant technology for producing hydrogen, with CCS, by capturing ~90% of CO2 from the syngas after the reactors, only leads to a net CO2 capture rate of ~56%. The SMR-CCS-56% competitiveness window with green hydrogen can thus narrow to less than a decade, and SMR-CCS-56% hydrogen cannot compete with natural gas. Net CO2 capture rates above 90% can most cost efficiently be realised with ATR-CCS plants, which are becoming the focus of planned blue hydrogen investments[4].

3. The competitiveness of blue hydrogen also relies on low methane leakage rates along the natural-gas supply chain. In some countries (e.g., Norway, Netherlands, UK) the natural gas industry demonstrates that near-zero leakage rates are possible; yet, huge regional differences remain with some countries having average leakage rates of 1.5%-2% (e.g., USA, Russia) and higher (e.g., Algeria, Libya)[22]. The IEA recently showed that official statistics substantially underreport methane leakage compared to satellite data, while >100 countries seek to reduce global methane emissions at least 30 percent from 2020 levels by 2030[23] and the EU commission has proposed regulation on monitoring and third-party verification of life-cycle methane emissions[24]. This could translate into a clear differentiation and competition among blue hydrogen suppliers and the incentive to quickly reduce methane leakage rates.

4. In case of high net CO2 capture and low methane leakage, the largest remaining impact of blue hydrogen are CO2 emissions from various sources along the natural gas supply chain (see methods: e.g., native CO2 emissions, on-site electricity generation for compressors, emissions embodied in materials). There are several technical measures that can reduce these CO2 emissions (e.g., on-site renewable electricity generation or CCS[25,26]).

In the mid- to long-term, we show that for a broad parameter range, green hydrogen from 100% renewable electricity becomes the cheapest hydrogen option, if CO2 prices surpass 0-200 €/tCO2eq. While green hydrogen costs get close to those of blue hydrogen, life-cycle emissions of green hydrogen (from 100% renewables) likely stay lower than those of low-emission blue hydrogen. Blue-to-green switching points occur in 2035-40 (irrespective of the hydrogen application), while direct costs of green hydrogen fall below those of blue hydrogen only after 2040. These numbers are based on our

main parameter specification for ATR-CCS-93% with methane leakage rates decreasing to 0.6% by 2035, natural gas costs at 20 €/MWh and green hydrogen costs (with transport) decreasing to 80 €/MWh by 2035.

While a pure cost perspective suggests a limited competitiveness window for low-emission blue hydrogen (ATR-CCS-93%), investments in blue hydrogen can also be spurred by the short- to mid-term scarcity of green hydrogen due to scaling limits of additional renewable power and electrolysis capacity. While these bottlenecks highly depend on dedicated near-term policy instruments for green hydrogen innovation and deployment, scarcity is anticipated until at least 2030-35[14]. If policy incentives improve, CCS investment risks decrease,[15] and large-scale blue hydrogen plants and associated carbon dioxide transport and storage infrastructure can be built within a decade, this would allow for a more substantial build-up of required hydrogen infrastructures and an earlier transformation towards hydrogen end-uses. However, an uncertain beginning and the risk of a potentially early end of blue hydrogen competitiveness might impede investments.

The length and width of a competitive bridge of blue hydrogen is determined by several uncertain future developments and regional circumstances.

1. *Future natural gas and electricity prices* could drastically increase when scarcities occur. An unprecedented gas price shock (up to 180€/MWh in December 2021) caused an energy crisis with the risk of continued high gas prices[27], even before the Russian invasion of the Ukraine, which is driving continued uncertainty and scarcity. Our sensitivity analysis (Extended data figure 1) shows that increasing natural gas prices from 20 to 40 EUR/MWh makes green hydrogen competitive with natural gas and ATR-CCS-93% hydrogen much sooner, at ~2030. On the other hand, renewable electricity prices could also experience substantial scarcity and concurrent price increases. Increasing electricity prices by 20 EUR/MWh would shift green hydrogen competitiveness to ~2040 (for natural gas) and ~2050 (for ATR-CCS-93% hydrogen).

2. *Climate change mitigation ambition and the overall role of hydrogen.* If ambitious climate targets such as those set by the EU[28] are translated into stringent CO2 pricing schemes or equivalent regulation, this would not only immediately close the competitiveness window for higher-emissions blue hydrogen, but narrow the window of any bridging technology with substantial residual GHG emissions. For countries with earlier climate neutrality targets such as Germany (2045) or Austria (2040), short-term emission reduction requirements might not leave time for even a low-emission blue hydrogen bridge. However, this requires a rapid expansion of renewable electricity and direct electrification, while scarce green hydrogen needs to be prioritised for hard-to-abate sectors. In contrast, for countries with later climate neutrality targets, such as China or India, there could be an extended competitiveness window for blue hydrogen.

3. *Regional availability of green and blue hydrogen, and hydrogen transport costs.* It is uncertain if long-distance hydrogen shipping will become cheap enough to create a global hydrogen market. If transport costs remain high, markets will be regional and competitiveness of blue and green hydrogen will be shaped by the regional availability of low-cost renewable electricity, geological CO2 storage reservoirs, natural gas supply with low methane leakage and existing pipelines. For example, if natural gas pipelines can be repurposed to hydrogen, and if natural gas reservoirs are co-located with geological CO2 storage sites, transporting natural-gas-based hydrogen instead of natural gas can lead to transport cost advantages for blue hydrogen that extend its competitiveness. On the other hand, if hydrogen shipping costs become low enough for global markets to emerge, blue-green competitiveness will be increasingly determined by low-cost green hydrogen exports from renewable-rich countries to meet growing demand in regional markets.

4. *The importance of methane emissions.* The relative importance of short-lived methane emissions increases if the focus of climate change mitigation shifts from long-term stabilisation to shaving the global temperature peak. Reflecting this by evaluating blue hydrogen based on the GWP20 metric instead of GWP100 would shorten the competitiveness window of blue hydrogen. We show that for ATR-CCS-93% and a methane leakage rate of 0.6% in 2035, the change of metrics translates into decreasing the blue-to-green switching price by 100 €/tCO2eq, which is roughly equivalent to decreasing the blue hydrogen competitiveness window by 5 years.

5. *CCS synergies and competition.* There is an additional incentive to develop blue hydrogen as an entry point to CCS technology innovations and building CO2 transport and storage infrastructure, which will be required for unavoidable process emissions (e.g. from cement production) as well as for CO2 removal options (e.g. direct air capture with permanent storage, and bio-energy use with CCS), which are increasingly in demand for offsetting.

On the other hand, blue hydrogen production will then partially compete for geological storage reservoirs. This might impose additional scarcity costs for CO2 storage, in regions where overall storage or injection capacity is scarce.

Our objective for this paper is to share an analysis framework that allows for an unbiased assessment of hydrogen competitiveness, identifying the associated drivers, dynamics and uncertainties, as well as deriving rough estimates based on broad and generic parameter ranges. A promising future research direction could be to specify these findings for regional cases.

Methods and data

We briefly describe the life-cycle GHG emission and cost assessment. For a comprehensive overview of all input data see the Supplementary information.

Life-cycle Greenhouse Gas (GHG) emissions

Greenhouse gas emissions quantified in this analysis represent – unless otherwise stated – life-cycle emissions, for hydrogen from both water electrolysis and methane reforming. These emissions have been quantified applying the well-established Life Cycle Assessment (LCA) methodology [29–31]. Therefore, all processes along the value chains from extraction of resources, manufacturing of infrastructure components, transport activities and energy supply chains to the hydrogen production itself are included and their direct and indirect GHG emissions contribute to the GHG intensities of all hydrogen production pathways. Attributional LCA has been performed using the ecoinvent database with its system model “allocation, cut-off by classification” as source of background inventory data [32]. Per default, we use Global Warming Potentials (GWP) for a time horizon of 100 years (“GWP100”) to quantify climate impacts of all individual greenhouse gases according to IPCC AR5 [33] and as implemented in the ecoinvent database [34]. We perform sensitivity analysis applying GWP20 factors according to the same sources (figure 5b and c). The most notable difference lies in the equivalence factors of methane, which are around 29 (GWP100) and 85 (GWP20), respectively. The choice of metric applied is especially relevant for systems with comparatively high methane emissions [35,36].

Life-cycle GHG emissions of blue hydrogen

For blue hydrogen production, we distinguish two technologies. Firstly, an SMR plant with partial CO2 capture (referred to as SMR-CCS-56% here), in which CO2 is captured from the syngas prior to the hydrogen purification pressure swing adsorption (PSA). A CO2 capture ratio of 90% is considered during the capture step, however this only allows for a net (i.e., plant-wide) CO2 capture of about 56% as there are additional CO2 emissions from combusting natural gas to provide process heat (in the reformer furnace). Instead of this configuration, it is possible to consider a post-combustion CO2 capture unit on the SMR flue gas to achieve net CO2 capture rates higher than 90%; yet, this option is foreseen to be a costly pathway for low-carbon blue hydrogen production. This is why we select an ATR-CCS plant as the second case that more cost-efficiently achieves high net CO2 capture rates (here: 93%, with a capture rate of 98% at the capture step), due to high overall plant efficiency with CO2 capture. ATR technology is already used at industrial scale for methanol production (e.g. the Haldor Topsøe plant in Turkmenistan), though without CO2 capture. The first ATR-CCS hydrogen plants HyNet and H2H Saltend are announced to start operating in the United Kingdom in 2025 and ~2026/27, respectively. In addition, for the main parameter specification, we summarize the wide range of region-specific methane emission rates by assuming a value of 1% in 2025 that decreases to 0.1% in 2050.

The quantification of GHG emissions of both cases builds upon the integrated process simulation/LCA of natural gas reforming with CCS as performed by Antonini et al. [37]: the SMR configuration corresponds to “SMR with CCS, HT, MDEA 90”; the ATR to “ATR with CCS, HTLT, MDEA 98” [37]. Both include CO2 capture from the synthesis gas using methyl diethanolamine (MDEA) as absorbent. The acronyms HT and HTLT represent the use of high-temperature water gas-shift only and the use of a low- and high-temperature water gas-shift, respectively. CO2 capture rates from the produced syngas are indicated by the figures “90” and “98”, respectively. Plant-wide, overall net CO2 removal rates amount to 56% for the SMR and 93% for the ATR. The substantially lower overall removal rate of the SMR is due to the fact that of the two CO2 emissions streams present, applying capture to syngas only does not affect the CO2 emissions from the natural gas combustion in the reformer furnace. As the ATR is driven by heat produced in the reformer itself, it does not include a reformer furnace – which allows to remove the majority of the CO2 directly from the syngas. Some remaining CO2 is

emitted from a small natural gas fired heater usually part of an ATR, which results in an overall CO_2 removal rate of 93% at 98% CO_2 capture from the syngas [37].

The SMR technology configuration can be considered as representative for currently operating “first-of-a-kind” hydrogen plants with CO_2 capture; however, currently planned facilities in Europe and the US are expected to correspond to our ATR configuration [35]. Reducing CO_2 emissions of blue hydrogen further than our ATR case by increasing the overall CO_2 removal rate beyond 93% is feasible: first, a CO_2 capture unit could be installed to capture the CO_2 emissions of the small natural gas fired heater; second, the capture rate could be increased to almost 100% as demonstrated by Anonini et al. [37] with a novel vacuum pressure swing adsorption (VPSA) process, that combines hydrogen purification and CO_2 separation in one cycle. The latter one slightly increases electricity demand and decreases the efficiency of the hydrogen production process to a very minor extent [37] and therefore, it is unclear whether it will decrease or increase the life-cycle GHG emissions of the process; either way, this effect will be minor. Cost data for this VPSA process are not (yet) available. An additional CO_2 capture unit would certainly increase both CAPEX and OPEX and was not considered here.

The crucial role of methane emissions along natural gas supply chains regarding the climate impacts of blue hydrogen has been demonstrated [35,36]. Methane emissions mainly originate from venting natural gas at extraction wells and natural gas leaks or releases during pipeline transport. These sources and emitted quantities reflect common procedures of the natural gas industry and the status of its infrastructure – both exhibit high geographical variability, in which so-called “super-emitters” play an important role [38]. In some countries (e.g., Norway, Netherlands, UK) the natural gas industry demonstrates that near-zero leakage rates are possible; yet, huge regional differences remain with some countries having average leakage rates of 1.5%-2.5% (e.g., USA, Russia) and higher (e.g., Algeria, Libya) [39]. On average, natural gas supply chains for European supply today exhibit a methane emission rate of around 1.3% [35,39–41]. In the main specification in this paper, methane leakage rates linearly reduce from 1% in 2025 to 0.1% in 2050. The short-term value represents a rough average across production regions, while the long-term value reflects that minimizing methane emissions is technically possible and that industry and policy makers have set corresponding targets [42].

The relative importance of methane leakage depends on the choice of GHG emission metric used to compare short-lived methane emissions to CO_2 emissions. The most prominent metric is the global warming potential (GWP) that compares the future global warming caused by an idealized emission pulse of different greenhouse gases [43]. It is defined in multiplicative terms compared to CO_2 such that the GWP of CO_2 is 1. Importantly, the GWP is a metric that aggregates impact over time such that its estimation requires the specification of a time horizon until which future warming shall be captured and compared (e.g. 100 years in GWP100). Given the short atmospheric lifetime of methane of roughly 12 years [43], the choice of time horizon has a strong impact on its GWP.

This choice should rely on the context of the metric’s application, and there is no single right choice [43]. Our default choice is GWP100 as this is the established metric in UNFCCC context when assessing long-term stabilization scenarios [44]. However, if the focus of climate change mitigation shifts from long-term stabilization to shaving the global temperature peak (in order to reduce short- to mid-term climate impacts and tipping elements). Reflecting this, we show a sensitivity case for a GWP20 metric (figure 5b and c).

In addition to methane leakage, supply of natural gas also causes direct and indirect CO_2 emissions – main sources for those are native CO_2 emissions, flaring of natural gas at the extraction wells, natural gas combustion for compression along the transport chain, other electricity generation on offshore gas platforms, which is often supplied by on-site gas turbines and CO_2 emissions embodied in materials used for the infrastructure such as steel and concrete for pipelines and other infrastructure. Regarding the current average natural gas supply to the European market, these emissions account for about two thirds of the GWP100 related climate impacts of natural gas supply chain [35,40,41]. Reducing these CO_2 emissions is technically feasible: CO_2 emissions directly originating from natural gas wells can be captured at moderate costs, as implemented at the Norwegian gas fields Sleipner and Snøhvit [25]; energy supply on site can also be decarbonized, for example via electrification or application of CCS [26]; and also GHG emissions embodied in steel and concrete are supposed to be lower than today in the future due to new low-carbon production processes and the application of CCS [45,46]. Implementing all these measures at a global scale is likely to take time. To the best of our knowledge, there is no published life-cycle analysis that comprehensively modeled these measures and derived a residual GHG emission estimate for blue hydrogen or natural gas supply chains. We thus have to assume an overarching reduction and calculated sensitivities to account for the associated uncertainty. For our main specification, we assume a reduction of these CO_2 emissions of 50% until 2050 (with respect to 2025 values), with a linear phase-in period between

2035 and 2050. In a sensitivity case, we assume a stronger reduction of 90% until 2050, with 35% reduction already by 2030 (compared to 2025), which reflects the high ambitions of the oil and gas industry in Norway[19].

Further, reducing natural gas transport distances would result in lower energy and thus natural gas demand for compression, but natural gas reserves are often not available close to consumers. Blue hydrogen could be generated close to the natural gas extraction sites and transported instead of natural gas. However, long-distance hydrogen transport comes with its own issues and requires infrastructure adaptation; furthermore, leaking hydrogen also acts as greenhouse gas, and it has been demonstrated that only “if the leakage of hydrogen from all stages in the production, distribution, storage and utilization of hydrogen is efficiently curtailed, then hydrogen-based energy systems appear to be an attractive proposition in providing a future replacement for fossil-fuel based energy systems” [47].

Life-cycle GHG emissions of green hydrogen

A rich body of literature has shown that life-cycle GHG emissions of hydrogen production via electrolysis primarily depend on the GHG-intensity of electricity needed for water splitting; additional GHG emissions are caused by potentially required water desalination, subsequent compression of hydrogen and by the construction and end-of-life of the electrolysis infrastructure [48]. That holds especially true for alkaline and PEM electroysers. We consider PEM electrolysis in our analysis, as this is the technology that can better deal with intermittent renewable electricity supply as it allows for more flexible operation. We build our quantification of GHG emissions upon the LCA of a PEM electrolyzer by Zhang et al. [49] who calculated indirect GHG emissions of the construction and end-of-life phases of a PEM electrolyzer of 0.12 kg CO2eq per kg of hydrogen, which we use as default value. This fixed contribution is added to the GHG emissions associated with electricity supply to operate the electrolysis and further compress hydrogen to a reference pressure of 200 bar. This electricity consumption amounts to 55 kWh per kg of hydrogen in 2025 and 50 kWh per kg of hydrogen in 2050 [48,50]. Further, we use GHG intensities of power generation with wind turbines and PV panels, which evolve over time until 2050. Representing good, but not best conditions in terms of wind and solar resources, those GHG intensities are 13 g CO2eq/kWh and 40 g CO2eq/kWh for wind and solar power, respectively, in 2025 and 8 g CO2eq/kWh and 24 g CO2eq/kWh, respectively, in 2050 [51]. Linear interpolation is performed for years in between. The above-mentioned infrastructure related GHG emissions are likely to decrease in the future in line with international decarbonization of economic activities such as steel and concrete production. Decreasing ore concentrations might, however, result in increasing indirect GHG emissions in other processes being part of the value chain. Overall, these effects are hard to quantify – a reduction by 50% seems plausible by 2050, but due to lack of evidence and the very minor impact on our overall results, we refrain from adjusting this “fixed” emission factor of 0.12 kg CO2eq per kg of hydrogen.

Cost data

Direct costs for energy services include fuel production costs, transport and distribution costs and end-use costs, which occur if the process or appliance needs to change to accommodate a new fuel. For example, when calculating FSCP for primary steel production we include the levelised capital costs of the coke-based blast furnace and basic oxygen furnace route (BF-BOF) and the hydrogen-based direct reduction and electric arc furnace route (EAF). When comparing fuels that are (almost) perfect substitutes such as green and blue hydrogen, or synthetic fuels and their fossil counterparts, end-use cost differences are small such that FSCPs can be calculated solely based on fuel costs. We also neglect end-use costs in the case of simple heating applications such as steam generation for industrial processes, as the levelized investment cost difference of hydrogen and natural gas boilers is small compared to fuel costs. Costs and GHG emissions (efficiency losses) associated with transporting hydrogen highly depend on region-specific supply chains, transport distances and transport modes[52,53]. We use a generic parameterization of a newly built hydrogen pipeline of 2000 km. We calculate FSCPs without considering region-specific taxes, regulation or subsidies.

Electrolysis costs in table 1 represent electrolyser plant (or system) costs and not only the costs of the electrolysis stack. The ranges represent both uncertainty and regional as well as technological heterogeneity. The median values aim to represent the bulk of production. The parameters are based on IRENA 2020[9], while Vartianen et al 2021[11] present lower estimates, and reviews of older literature used to synthesise higher costs[51,54]. The short- to mid-term cost reduction reflects that the industry is at the verge of a transition from small, "hand crafted" and first-of-a-kind electrolysis plants to serial production with increasingly larger stacks and plants.

Electricity costs (as paid by the electrolyser operator) are calculated without taxes and levies and based on recent and projected cost reductions for wind and solar PV[55–57]. For the main specification, we take a cost perspective that translates renewable generation costs into prices and hereby assuming no scarcity prices on renewable electricity. This assumption is valid for off-grid electrolysis projects with dedicated renewable power, while grid-connected electrolysis plants might have to pay a higher (scarcity) price. However, grid-connected electrolysis plants have the benefit of flexibly charging during low-price high-renewable hours (at the expense of utilisation), which compensates potential scarcity prices.

Costs for SMR blue hydrogen plants are taken from the IEA GHG report[7]. The 2030-2050 costs for ATR blue hydrogen plants are based on the Hydrogen4EU report[58]. The <2030 costs are higher (1200 €/kW in 2025). We have used a learning rate approach to back-calculate it from future costs using a learning rate of 10%. The data was also confirmed by data from the "HyNet Low Carbon Hydrogen Plant" from BEIS, which reported CAPEX of 1170€/kWH_2 for the 100kNm^3/h plant.

Data availability

The codes and input data needed for reproducing all plots presented in this article and the supplementary material are openly available on GitHub (https://github.com/PhilippVerpoort/blue-green-H2) and may be interactively explored in the associated interactive web app:
Cost competitiveness of blue and green H_2, P.C. Verpoort, et al 2022[17]. Accessible online: https://interactive.pik-potsdam.de/blue-green-H2, (restricted access during review. username: preview, password: preview).

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Author contributions

F.U. designed the study, coordinated the work, and wrote the paper. P.V. curated the data, conducted the overarching analysis, produced the associated figures and developed the interactive web application. C.B. carried out the life-cycle GHG analyses. F.B. and T.L. provided data and insights on green hydrogen technology. S.R. and R.A. provided data and insights on blue hydrogen technology. All co-authors discussed the results and conclusions, reviewed the analysis and manuscript text.

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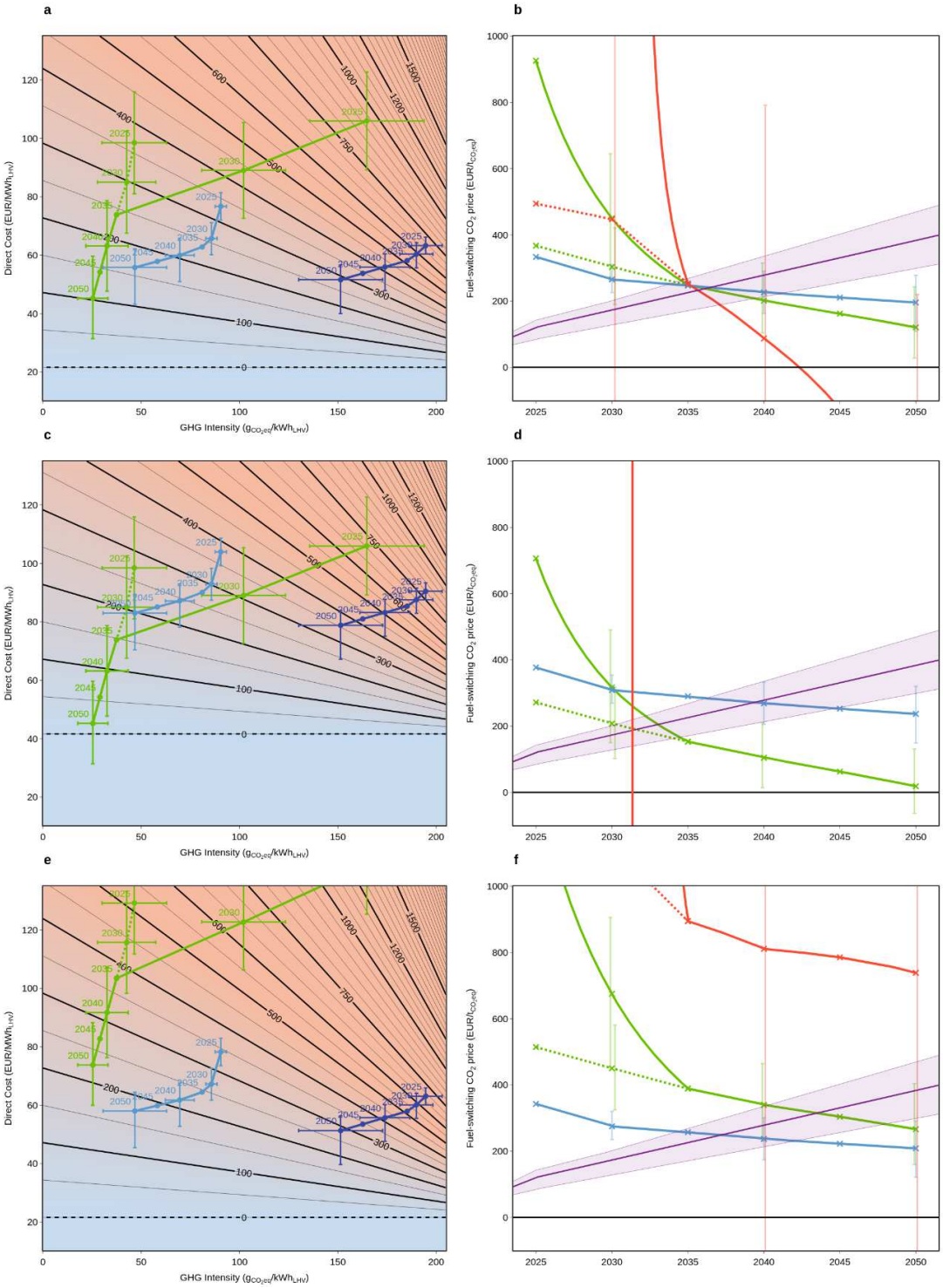
Extended data figures



Extended Data Figure 1: *Three sensitivity cases for figure 3b and figure 4a with i) main specification (a, b), ii) 20 EUR/MWh natural gas price increase (c, d) and iii) 20 EUR/MWh electricity price increase (e, f). Left (b, d, f):* Emission intensities and direct costs of different hydrogen fuel options (scatter plot for several years), along with FSCP estimates (contour plot and black lines) required to make hydrogen competitive with natural gas for process heat. The hydrogen production cases shown are a high-emissions blue hydrogen based on SMR-CCS-56% technology with net CO2 capture rates of ~56%, a low-emissions blue hydrogen based on ATR-CCS technology with net CO2 capture rates of ~93%, and green hydrogen produced with a renewable electricity share increasing from 80% (2025) to 100% (>2035). Methane emission rates along the natural gas supply chains are assumed to reduce from ~1% to ~0.1% in 2025-2050. Right *(a, c, e)*: *Decreasing FSCPs in time for blue hydrogen from ATR-CCS-93% technology, and for green hydrogen from 100% renewable electricity (dotted) and for a 80-to-100% renewable electricity transition case (solid), for hydrogen replacing natural gas for process heat.*

Supplementary Files

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