Hydrogen Europe

CLEAN HYDROGEN PRODUCTION PATHWAYS

REPORT 2024

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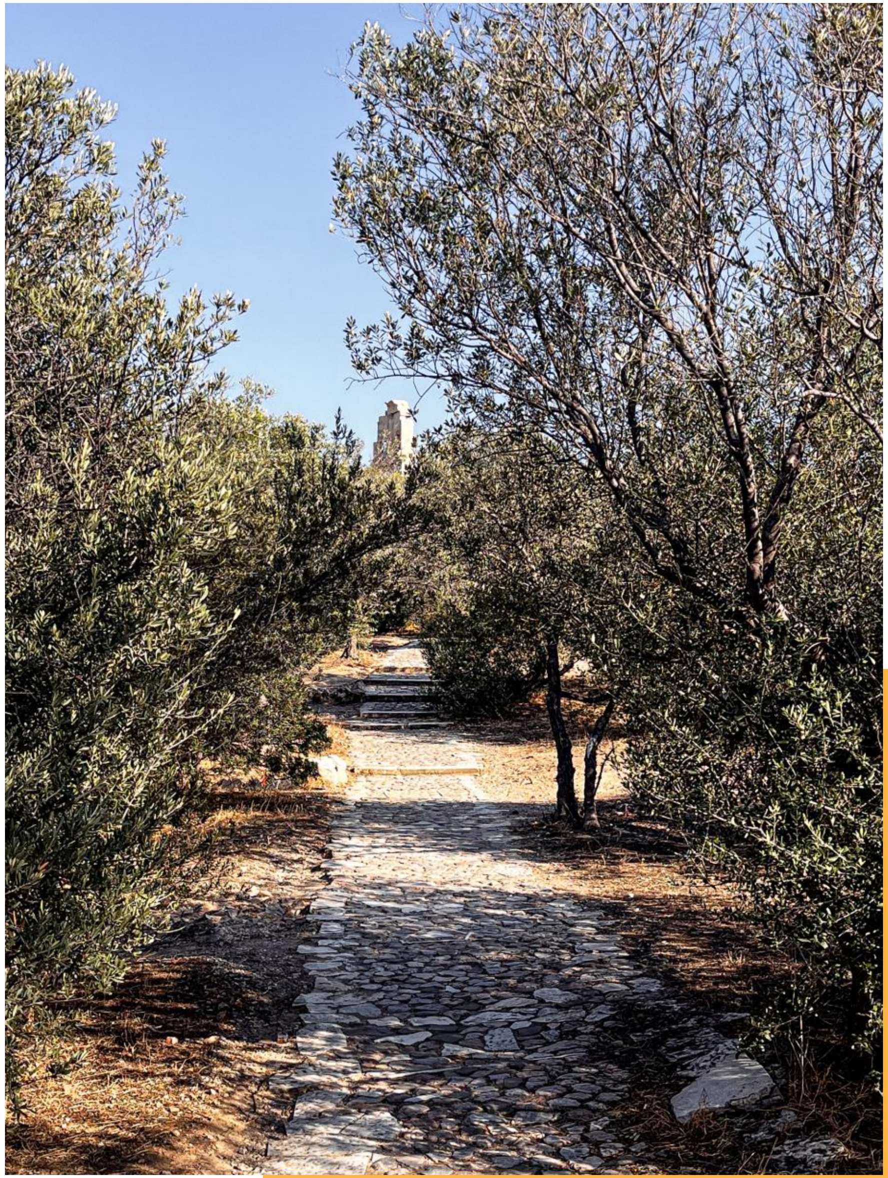

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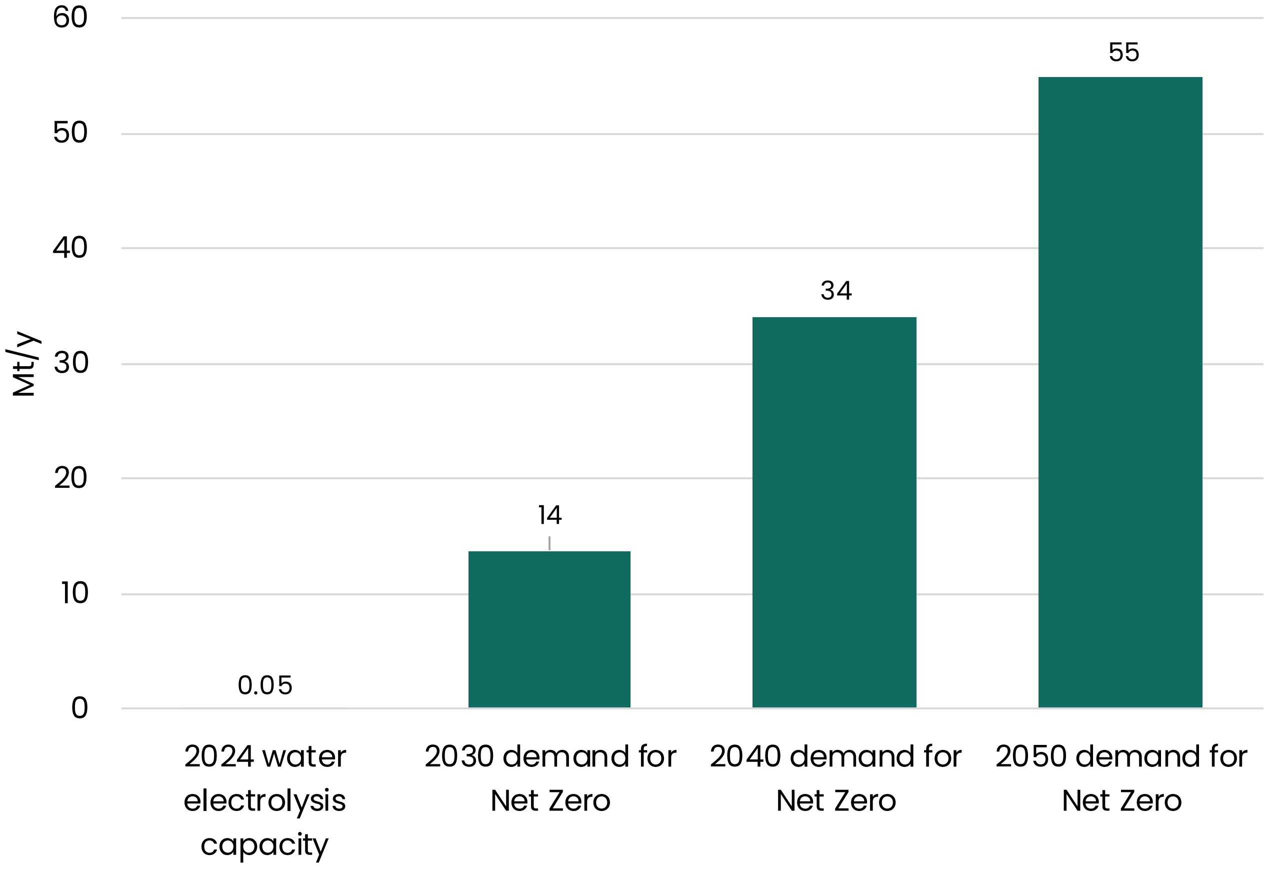
EXECUTIVE SUMMARY

Various clean hydrogen production technologies will be needed for sufficient volumes for Net Zero by 2050

- BNEF's New Energy Outlook estimates **34 Mt and 54 Mt of clean hydrogen by 2040 and 2050 respectively to achieve Net Zero in Europe by 2050**.
- Achieving those volumes requires a massive scale up from around **0.05 Mt of clean hydrogen production capacity via water electrolysys in operation currently** (June 2024).
- While water electrolysis has a significant cost reduction potential and offers important benefits from a wider energy system perspective – including the possiblity for coupling of the gas and electricity sectors - thus supporting an increased penetration of renewable energy in the energy system, **other technologies besides water electrolysis can also produce clean hydrogen and contribute to achieving Net Zero by 2050 in Europe**. This is especially crucial for regions were supply of renewable energy is either scarce or expensive.
- These include reforming with carbon capture, methane splitting, biowaste-to-hydrogen, and non-biological waste-to-hydrogen.
- Each clean hydrogen production pathways has its unique benefits and challenges related to scale, feedstock, GHG intensity, costs, infrastructure requirements, and regulatory treatment.

Figure A: Hydrogen consumption required for Europe to achieve Net Zero by 2050 vs 2024 European water electrolysis capacity



Source: Hydrogen Europe, BNEF

Different production pathways offer unique benefits from sector coupling to locally based decarbonisation

Figure B: Unique technology benefits of the five clean hydrogen production pathways included in the report

	Water electrolysis	**Reforming with carbon capture**	**Methane splitting**	**Biowaste-to-hydrogen**	**Non-biological waste-to-hydrogen**
Main feedstock or energy input	Electricity	Natural gas	Natural gas	Biowaste	Non-biowaste
Technology	Water electrolysis	Reforming with carbon capture	Pyrolysis	Gasification/pyrolysis	Gasification/pyrolysis
Unique technology benefits	- Coupling electricity and gas sectors - Grid flexibility - Delivering renewable electricity to hard to electrify sectors - Unleashing stranded renewable energy and transport it between regions	- Large scale - Available feedstock supply - Mature technology allows rapid delivery of low-carbon hydrogen for decarbonisation	- Large scale potential; - Available feedstock supply - Zero direct emissions without need for additional infrastructure - Supply of solid carbon.	- Utilising available local biowaste feedstocks; -Abating otherwise unabated emissions; - Carbon removal potential; - Promoting locally based decarbonisation	- Availability of local non-recyclable waste; - Promoting locally based decarbonisation - Contribution to waste management

Most of the assessed production technologies are available and at or close to commercialisation

Figure C: Technology readiness level and deployment of the five clean hydrogen production pathways included in the report

	Water electrolysis	**Reforming with carbon capture**	**Methane splitting**	**Biowaste-to-hydrogen**	**Non-biological waste-to-hydrogen**
Technology readiness level	Low temperature: 9 High temperature: 8	6-9	8	6-8	6-8
Current global deployment	Low temperature: ~2.5 GWel; High temperature: <50 MWel	No large-scale ATR with high carbon capture rate has been deployed	Commercial plant in the US and demonstration plants in Europe, Australia, etc.	Demonstration plants scaling up to commercial sizes	Demonstration plants scaling up to commercial sizes
Global projects and deployment	LT: 440 GWel announced by 2030 HT: 3 GWel announced by 2030	14 Mt/year announced globally by 2030	Various commercial plans but well below 100,000 tonnes/y per plant	Commercial projects in development	Commercial projects in developments

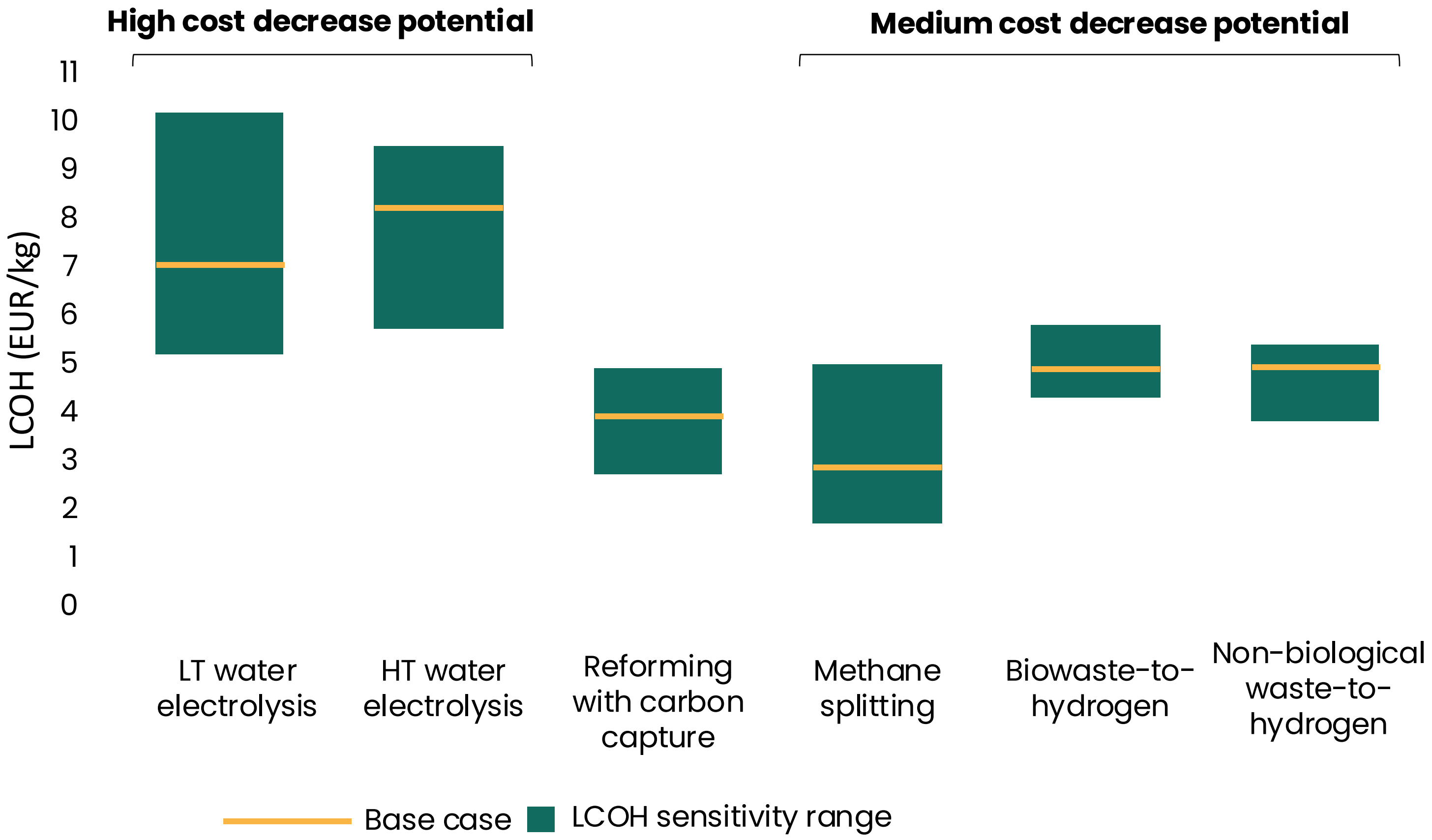
Technology readiness levels: TRL 6 – Pilot demonstration , TRL 7 – Full scale system demonstration in operational environment, TRL 8 - Experimented in deployment conditions and system complete, TRL 9 - Commercial

Clean hydrogen production costs are between 1.7 and 10.2 EUR/kg. Water electrolysis is most expensive pathway today but presents largest cost reduction potential

- **Water electrolysis** – while best locations with access to low-cost electricity can present a strong business case, in most cases, costs are too high and FID's are often conditional on the project receiveing subsidies. However, since costs are mostly driven by renewable electricity costs and CAPEX – both of which are expected to fall, water electrolysis also has the largest cost reduction potential among the analysed technologies.
- **Reforming with carbon capture** is among the most cost competitive, and with natural gas costs (the largest cost driver) still above pre-war levels, its cost could fall further. There is however significant uncertainty over CO2 storage and transportation costs. Since gas reforming is a relatively mature technology CAPEX is unlikely to fall down.
- For **methane splitting**, natural gas costs are also the largest cost driver, but solid carbon by-product revenues allow to reduce the final LCOH by 34%.
- In case of both **waste-to-hydrogen** technologies CAPEX is the largest cost driver and has significant potential to decrease. The business case is also driven by feedstock type cost/revenue, by-product revenues, and CO2 transportation and storage costs, all of which are very project specific. However, limited deployment so far creates cost uncertainty.

Note: LCOH stands for Levelized Cost of Hydrogen

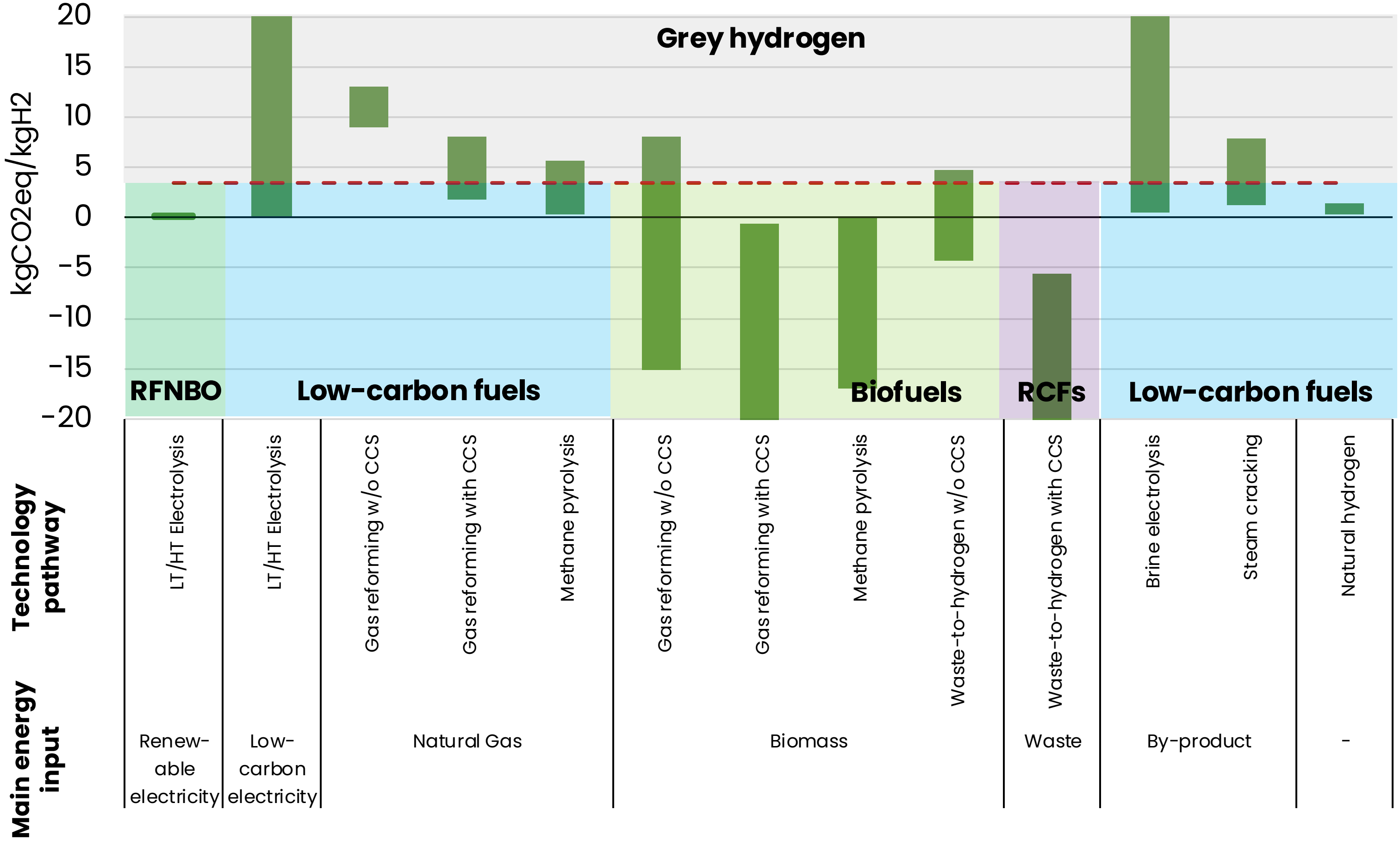
Figure D: Range of LCOH shown in the report using sensitivity assumptions



All analysed production pathways can have a substantial positive contribution towards climate change mitigation

- **All of the pathways can produce hydrogen with a carbon intensity below 3.4 kgCO2/kgH2** – in line with EU sustainable finance taxonomy and the Fit-for-55 package definitions of low carbon fuels.
- In cases **where the feedstock is either waste or biomass**, the carbon footprint can even be negative resulting in **net carbon removal**.
- On the other hand however, for some pathways the emission intensity can be significant – even exceeding emissions from unabated natural gas reforming (i.e. grey hydrogen). Example of this include water electrolysis using fossil-fuel-based electricity or reforming of natural gas without achieving a high-enough carbon capture rate, or when using natual gas source with high upstream emissions (e.g. imported LNG). **It is therefore of utmost importance to design a strong regulatory framework, which would promote sustainable solutions, while, at the same time, not create unnecessary investment barriers** – as has happened with renewable electrolytic hydrogen.
- **Unfortunately, for low-carbon hydrogen, which will be an essential part of the emerging hydrogen economy, the GHG accounting framework is still missing.**

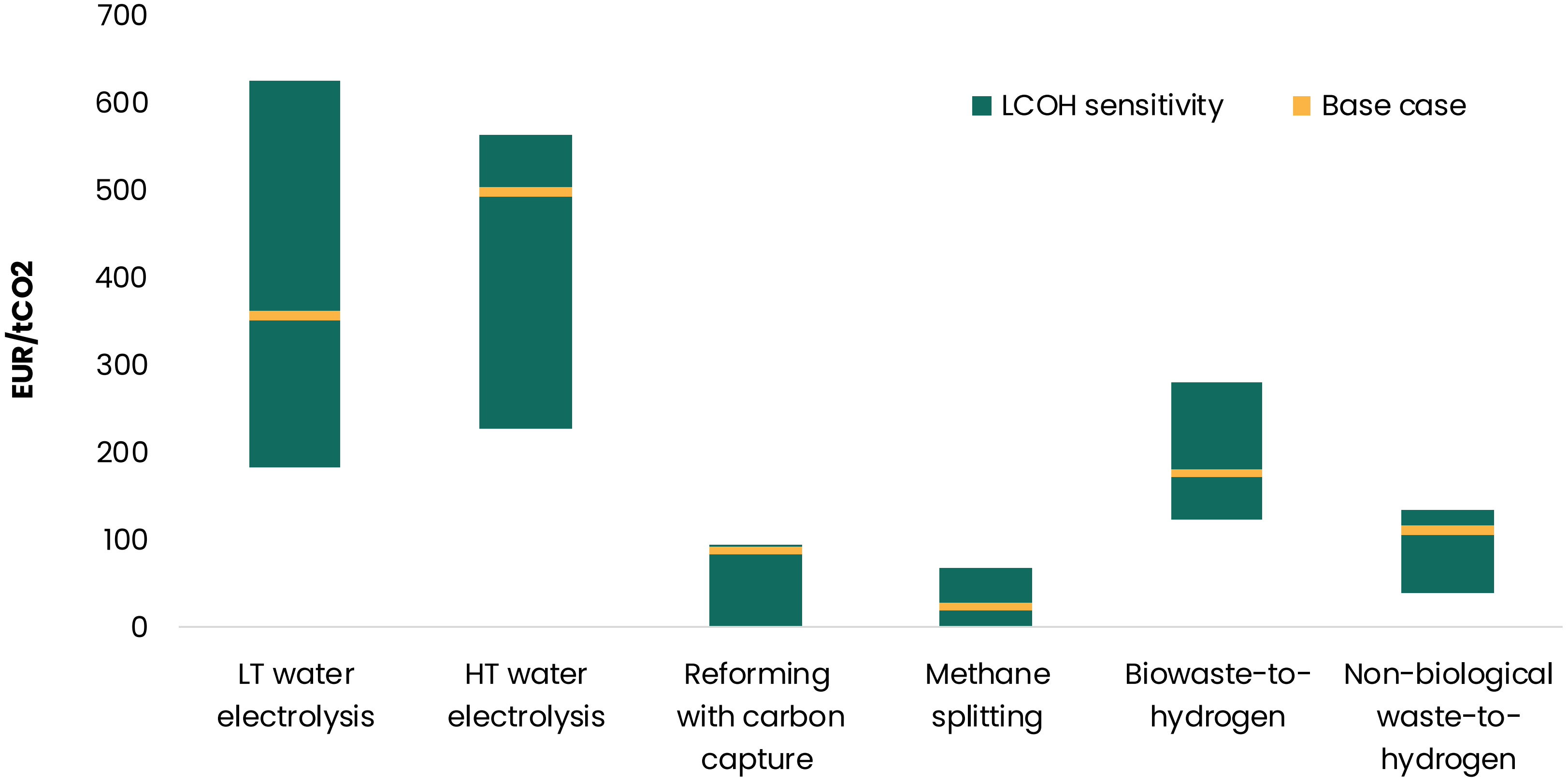
Figure E: Emission intensity range for analysed technologies (kgCO2eq/kgH2)



At the current state of market and technology development, hydrogen production pathways based on natural gas offer the lowest cost of decarbonisation

- Assuming hydrogen would be used to **replace grey hydrogen, each kg would displace around 11.3 kg of CO2** (94.2 gCO2/MJ), the estimated costs of producing low-carbon hydrogen through various pathways combined with the carbon intensity of those production patwhays allows to estimate **the cost of decarbonisation**.
- With the current grey hydrogen production costs at around 3.3 EUR/kg, and EUA prices at around 80 EUR/t, **the pathway with the lowest break-even point is methane splitting, which would require only additional 20 EUR/tCO2, followed by reforming of natural gas with CCS at around 80 EUR/tCO2**. In other words, if the ETS market prices would double, both of these technologies would be financially profitable without any subsidies.
- **Waste-to-hydrogen technologies present decarbonisation costs of around 120-180 EUR/tCO2**. The most expensive pathways at the moment are water electrolysis with CO2 abatement costs from 180 EUR/tCO2 up to more than 600 EUR/tCO2.
- **If hydrogen would be used as a tranport fuel, the GHG savings would be similar to those resulting from replacing grey hydrogen** (94 gCO2/MJ as defined in RED). However in some applications, the potential emission savings could be even higher, for example **replacing coke in conventional steel making would allow to displace around 26 kg CO2 for each kg of hydrogen.**

Figure F: Cost of decarbonisation (replacement of grey hydrogen) via analysed hydrogen technologies (in EUR/tCO2)



Note: the cost of decarbonisation has been estimated assuming the following emission intensities: 0 gCO2/MJ for RFNBO, 25.5 gCO2/MJ (~3.06 kgCO2/kgH2) for reforming with carbon capture - assuming 95% CO2 capture rate and gas upstream emission factor of 9.7 gCO2/MJ, 19.2 gCO2/MJ (~2.3 kgCO2/kgH2) for methane splitting, 15 gCO2/MJ (~1.8 kgCO2/kgH2) for biowaste-to-hydrogen without CCS and -45.8 gCO2/MJ (~ -5.5kgCO2/kgH2) for non-biological waste-to-hydrogen with CCS. Detailed caclulations are presented throughout the report. Source: Hydrogen Europe

In order to unlock the needed economies of scale, RFNBO hydrogen is currently prioritised by EU policy and funding schemes

- **RFNBO hydrogen is clearly prioritised** under the Fit-for-55 package with a number of multipliers put in place to increase RFNBO attractiveness to investors versus other options. It is eligible for compliance with all sustainability targets put in place by the Green Deal, with several targets designed exclusively for RFNBOs.
- **Bio-based hydrogen,** which could be classified as an advanced biofuel (i.e. produced from waste bio-feedstock), is also included in the 5.5% transport target for 2030 of the RED3 (together with RFNBOs). Otherwise, there are no other policy measures targeting explicitly the supply of bio-hydrogen. Hydrogen produced from crop-based biomass feedstock, is excluded from the policies targeting decarbonisation of the aviation and maritime transport sectors.
- **Other types of sustainable hydrogen**, while eligible for reaching general decarbonisation targets across all policies, **do not enjoy any explicit targets** – putting them at a disadvantage compared to RFNBOs. The only exception is the low-carbon and non-fossil hydrogen, which is eligible for synthetic aviation fuels target under RefuelEU Aviation.
- By-product hydrogen use is exempted from having to be replaced by RFNBOs if used in industrial applications (as defined in the RED3 industry target).

Figure G: Categories of hydrogen and their compatibility with various regulatory targets defined in the Fit-for-55 package

	RED transport targets				RED industry targets	RefuelEU Aviation targets		FuelEU Maritime targets	
	1% RFNBO target	5.5% sub-target with advanced biofuels	Overall RES target (29%)	GHG reduction target	42% RFNBO target	Synthetic aviation fuels (1.2% by 2030)	SAF (6% by 2030)	RFNBO (1% by 2030)	GHG reduction target
RFNBO	x2 multiplier x1.5 multiplier for aviation and maritime			YES	YES	YES	YES	YES	X2 multiplier until 2033
Bio-hydrogen (advanced)	NO	YES	YES	YES	NO	NO	YES	NO	YES
Bio-hydrogen (1st gen)	NO	NO	YES (limited)	YES	NO	NO	NO	NO	NO
Low-carbon	NO	NO	NO	NO	NO	NO	NO	NO	YES
Low-carbon non-fossil	NO	NO	NO	NO	NO (but can reduce the target)	YES	YES	NO	YES
RCF	NO	NO	YES (if the MS choses to do so)	YES (if the MS choses to do so	NO	NO	YES	NO	YES
By-product	NO	NO	NO	YES (if low-carbon)	NO (but reduces the target)	NO	YES (if low-carbon)	NO	YES (if low-carbon)

Different pathways can be complementary as they encounter different challenges

Figure H: Key challenges associated to each production pathway

		Feedstock/ energy availability	Infrastructure	Technology readiness	Scalability	LCOH
Water electrolysis	Limited by available renewable electricity and is grappling with cost competitiveness at this deployment stage	🟧	🟧	🟩	🟩	🟪
Reforming with carbon capture	Reliance on natural gas supply and CO2 infrastructure (transport and storage) limiting its geographical potential	🟩	🟪	🟩	🟩	🟩
Methane splitting	Low LCOH depends on solid carbon revenues and availability and use of gas infrastructure could contribute to a fossil lock in	🟩	🟩	🟧	🟧	🟧
Biowaste-to-hydrogen	Despite modularity, issues to scale to industrial size (100,000 t/year) due to local biomass availability. Potential future comparison with other future biomass uses	🟧	🟩	🟧	🟪	🟧
Non-biological waste-to-hydrogen	Reliance on CO2 transport and storage infrastructure; despite modularity, issues to scale to industrial size (100,000 t/year)	🟩	🟧	🟧	🟪	🟧

🟩 No significant challenge

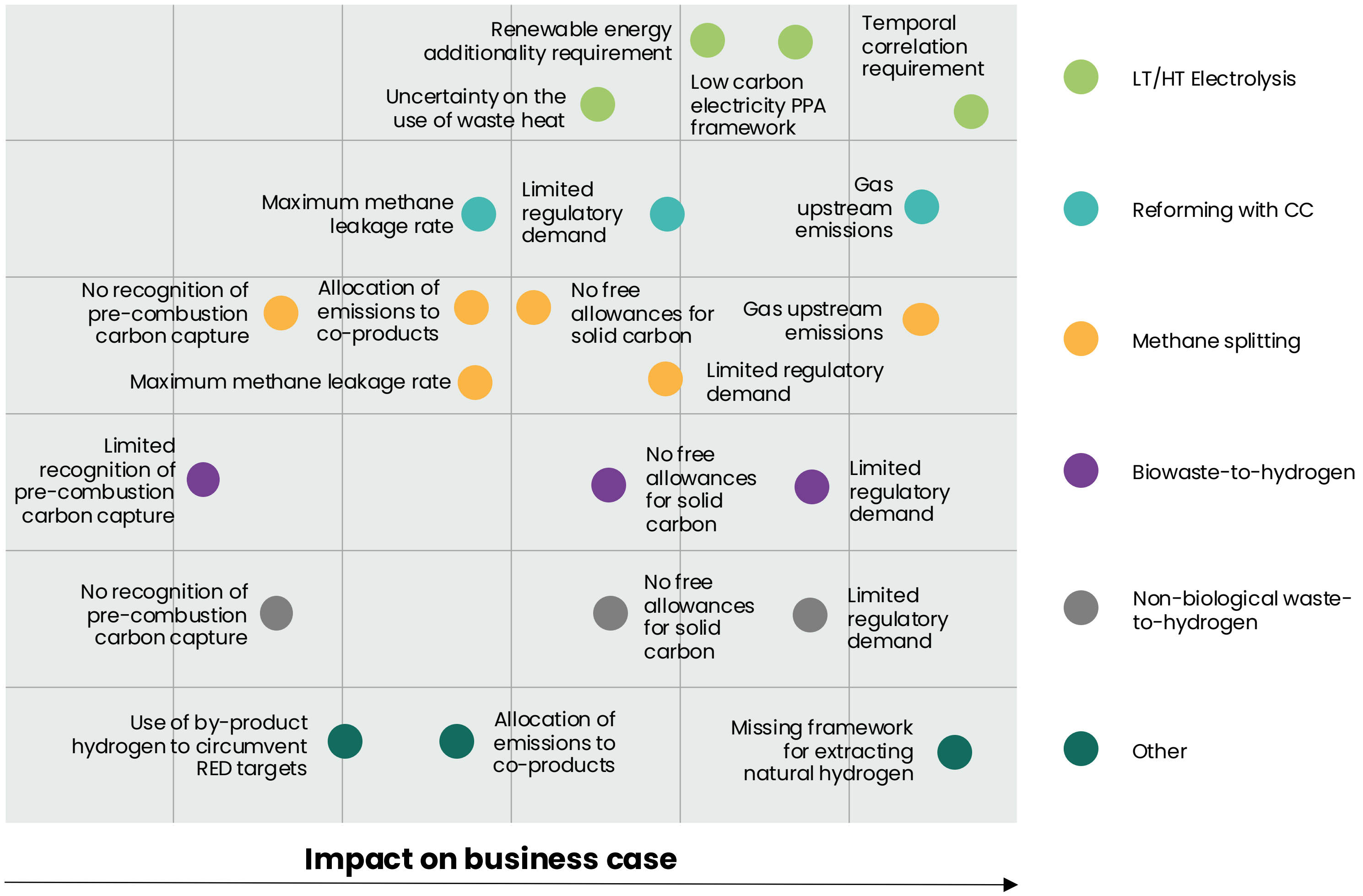
🟧 Minor challenge

🟪 Challenge

The deployment of clean hydrogen technologies is held back by persisting regulatory barriers and the lack of a framework for calculating GHG emissions

- All technologies can have a significant positive contribution towards climate change mitigation, but **significant regulatory barriers are delaying their deployment**.
- **One of the most pressing issues is the lack of GHG calculation rules for low-carbon hydrogen, which is a cross-cutting issue impacting most pathways**.
- Uncertainty regarding the possibility of sourcing low-carbon electricity for water electrolysis as well accounting for gas upstream emissions are two key issues requiring urgent clarification. Methane splitting in particular, faces a number of regulatory challenges and risks, both linked to the uncertainty about low-carbon fuels DA and also to the treatment of the solid carbon by-product.
- Hence, the new GHG accounting rules, contained in the upcoming Delegated Act (DA) are crucial, and their **simplicity and speedy adoption is essential for the entire hydrogen sector** – as is ensuring their consistency with existing rules for RFNBO and RCFs.
- For **RFNBO production, the strict temporal correlation and additionality rules continue to be a significant cost obstacle limiting its uptake**.

Figure I: Most pressing regulatory issues affecting hydrogen production technologies



There are many other pathways for sustainable hydrogen production, with solar thermochemical cycles and natural hydrogen among the most promising

Figure J: key features of other hydrogen production pathways

Solar thermochemical

- Solar thermochemical processes are currently at a relatively early stage of technological readiness level – however, by allowing to use the full spectrum of solar radiation, these technologies could deliver abundant and low-cost renewable hydrogen in the future.
- Reduction of the amount of electrical power required compared to water electrolysis together with cost reduction of solar technologies is expected to reduce the LCOH to 2-3 USD/kg.
- Concentrated solar thermal system have comparatively low greenhouse gas emissions over their entire life cycle compared to other non-fossil energy provision technologies.

LPG pyrolysis

- Outside of natural gas, propane can also be used as the raw material for obtaining CO2-free hydrogen via catalytic pyrolysis.
- LPG is especially attractive as a feedstock in areas without access to natural gas network.
- The yield of valuable solid-carbon by-product is also significantly higher, with a C:H ratio of 4.5 compared to 3.0 for methane splitting.
- Even using fossil LPG (obtained from natural gas extraction process) the estimated emission intensity of hydrogen would be below the required low-carbon emission threshold. This could be further reduced if a more sustainable feedstock would be used, e.g. bio-LPG or e-LPG.

Natural hydrogen

- Hydrogen formed by natural processes could be a breakthrough renewable resource.
- Unlike fossil energies, natural H2 is a sustainable source of energy, with a constant replenishment of the water percolating and reacting with rock.
- A recent study from United States Geological Survey estimates that 10's of millions of tonnes of natural hydrogen are generated worldwide.
- Its attractiveness lies also with both very competitive extraction costs (0.5-2.5 EUR/kg) as well as very low environmental footprint (0.4-1.5 tCO2/tH2).
- The full potential still needs to be evaluated and the necessary regulatory framework for its extraction is mostly missing.

By-product

- Hydrogen produced as a by-product of other industrial processes is an important source of hydrogen in the current economy, supplying around a third of all hydrogen used by the European industry.
- While by-product hydrogen from some sources can be considered low-carbon, any environmental benefits from its use would be lost if it would be replaced by natural gas or other fossil fuels in its existing applications.
- Furthermore, as by-product hydrogen is exempted from the RED industry targets, special effort should be made to avoid it is used to decrease investments into RFNBOs.

INTRODUCTION AND METHODOLOGY

Objectives and scope

Why?

- Bring attention to a range of different hydrogen production pathways and the drivers for their costs and emissions
- Provide public points of reference for costs and emissions assumptions
- Support the policy debate regarding low-carbon hydrogen delegated act

Technological scope

- Electrolysis (low and high-temperature)
- Reforming with carbon capture (SMR/ATR with CCS)
- Methane splitting (pyrolysis of methane)
- Biowaste-to-hydrogen (pyrolysis/gasification of woody biowaste)
- Non-biological waste-to-hydrogen (pyrolysis/gasification of non-recyclable plastic waste)

Each chapter's contents

- Technology readiness and current deployment
- Productions costs and cost drivers
- Emissions intensity of the produced hydrogen
- Scalability challenges
- Policy and regulatory issues

Cost analysis is based on the Levelized Cost of Hydrogen (LCOH) approach with a uniform set of assumptions to ensure comparability

Levelised cost approach: The production cost analysis for various technologies is based on a levelized cost approach, where all expenditures (both CAPEX and OPEX) as well as revenues from co-products and ETS (if applicable) are discounted using a discount rate reflecting the average risk of hydrogen production projects, using the following formula:

$$\frac{I_0 + \sum_{t=1}^{n} \frac{I_t + E_t + M_t - CO2_t - R_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{H2_t}{(1+r)^t}}$$

Where: Where, I_0 - investment expenditure in year 0; I_t – replacement investments (e.g. stack replacement costs); E_t – energy inputs costs, M_t - other operational and maintenance costs; $CO2_t$ – balance or revenues and costs from participation in the ETS system and captured CO2 transport and storage costs, R_t – revenues from sales of by-products; $H2_t$ – hydrogen production; r - Discount rate; n - Lifetime of the system in years.

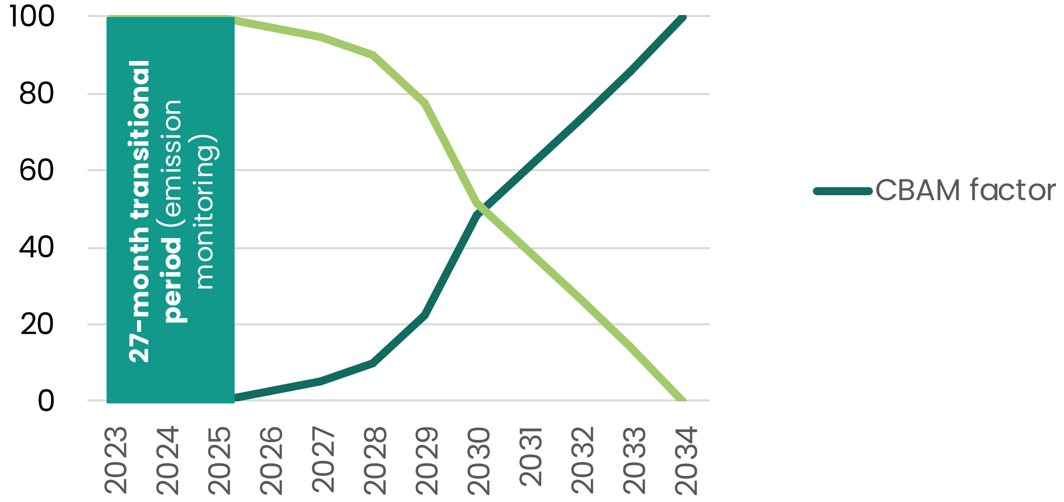
Important caveats: In order to allow a comparative analysis, all technologies were evaluated under a similar set of assumptions with regards to boundary conditions and commodity price assumptions (see table on the right). **All commodity prices have been adopted at their recent levels without making any forecasts on their future development** – hence the presented cost data does not fully reflect expected changes in costs of some pathways. **The costs include only costs of production (well-to-gate) and exclude additional expenses related to hydrogen storage and/or delivery of hydrogen to final consumers**, which in some cases might obscure the ultimate cost competitiveness of various pathways (e.g. off grid electrolysis in remote locations might require additional h2 transportation and storage costs which would not be present in case of on-site natural gas reforming with CCS). For all technologies we use **a single before-tax WACC** which is appropriate for large scale energy investments but might not always properly reflect all the risks – especially for upcoming low-TRL technologies and for countries suffering from high internal risk. Analysis has been done assuming fixed costs (i.e. without taking into account inflation).

Impact of the carbon market reform: One of the consequences of reforming the EU carbon markets will be the broadening of the scope of hydrogen manufacturing covered by the ETS, which will now include all installations producing more than 5 tpd of hydrogen. All installations would also be eligible to receive free allowances. However, a consequence of including hydrogen in the CBAM will be a gradual phase-out of free allowances until 2034.

Figure K: Assumed prices of key commodities in 2024

Key item	Unit	Value
Natural gas price	EUR/MWh	40.0
Biogas price	EUR/MWh	67.7
Wholesale electricity price	EUR/MWh	80.0
Renewable PPA (15 years)	EUR/MWh	60.0
Nuclear PPA	EUR/MWh	80.0
Power network fees and taxes	EUR/MWh	29.3
ETS EUA	EUR/t	80.0
CO2 transportation and storage	EUR/t	100.0

Figure L: Phasing in/out of CBAM and free allowances for hydrogen



As emissions from fuel transport and distribution are project- and not technology specific, the GHG emissions analysis covers only well-to-gate emissions

Scope of the analysis: The emission intensity analysis for each technology pathways has been done on a **well-to-gate basis** – i.e. the emissions cover scope 1 and 2 emissions stemming from the supply of inputs to the hydrogen production process as well as the direct process emissions, including credits from CO2 capture and storage. **Emissions** further downstream from the production process, i.e. **related to hydrogen compression, storage or transportation to end markets** are highly project specific and not linked to production technology and **are therefore not considered in the analysis**. **Emissions from the manufacturing of equipment and the investment process are excluded** – which is an approach consistent with the EU methodologies (for RFNBOs as well as in the EU taxonomy).

Emissions were divided into direct and indirect with indirect emissions covering GHG emissions related to supply of inputs (including electricity for water electrolysis) while direct emissions cover CO2 emissions stemming directly from the processing step.

The required GHG emissions threshold: From EU point of view the most relevant emissions threshold is the emission intensity limit set out by the RED III for RFNBOs and RCFs and by the Gas Package for low-carbon fuels. In all of those cases the emissions threshold has been set at **70% below the fossil fuel benchmark of 94 gCO2/MJ – i.e. 28.2 gCO2/MJ (3.4 kgCO2eq/kgH2)**. However, the emission limit set by these regulations needs to be met at the point of consumption. Therefore, as emissions calculated in the report have a more limited scope (well-to-gate), in order to accommodate additional emissions related to fuel distribution and still qualify for being certified as sustainable, the GHG emissions at production point would effectively need to be lower.

Uncertainty regarding GHG emissions calculation methodology for low-carbon hydrogen: In case of low-carbon hydrogen (and low-carbon fuels in general), while the overall emission limit is defined, **the detailed methodology for GHG emission calculation will only be defined in the upcoming low-carbon delegated act**. Since the detailed methodology is not known, for the purpose of this paper the GHG emission intensity of low-carbon options was calculated using the same principles as for the RFNBOs (where applicable) or the ISO 19870:2023.

Figure M: Boundaries of the GHG emission analysis

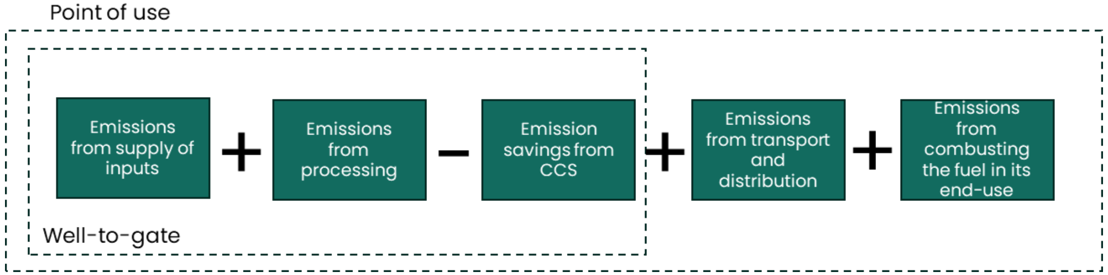
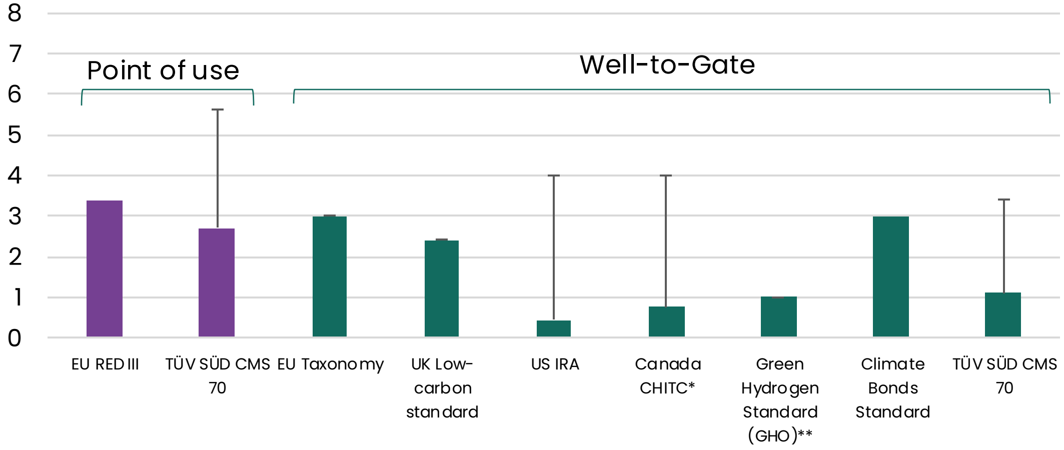


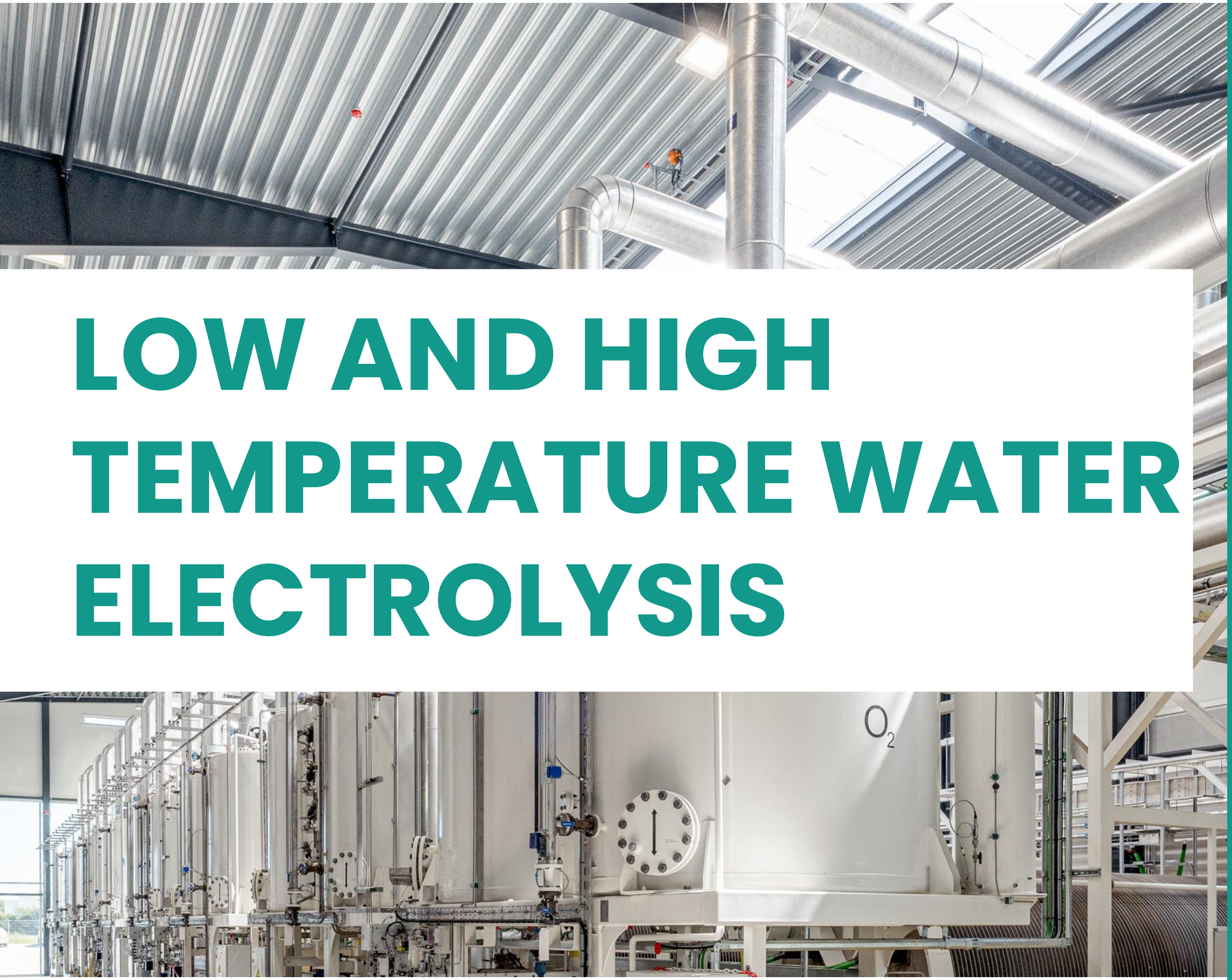
Figure N: GHG emission threshold under various regulatory and voluntary regimes (in kgCO2e/kgH2)



Note: the bars show the most strict emission criteria applicable under various emission accounting schemes, while the black line indicates the highest possible emission level which allows to achieve low carbon classigfication

* - Clean Hydrogen Investment Tax Credit, ** - Global Hydrogen Organisation

Source: Hydrogen Europe



LOW AND HIGH TEMPERATURE WATER ELECTROLYSIS

- **Water electrolysis** refers to using electricity to split water (H_2O) to produce hydrogen.
- **Unique technology benefits** - Water electrolysis provides energy system benefits as it allows converting (surplus) renewable electricity into storable molecules necessary for seasonal storage while also offering flexibility services for the electrical grid.
- **Technology** - While low-temperature water electrolysis is a commercially mature technology, it is encountering scaling challenges as it is being deployed from MW to GW scale. On the other hand, high-temperature electrolysis is entering its pilot and demonstration stage with commercial deployment several years away but advancing towards commercial maturity.
- **Costs** - LCOH is around 6-7 EUR/kg under basic modelled conditions. Key cost drivers for water electrolysis are electricity costs which, including grid fees, can constitute 60% of the hydrogen production cost per kg and CAPEX that is expected to decrease, but it has yet to benefit from economies of scale.
- **Emissions** - GHG emission intensity of electrolytic hydrogen only depends on GHG intensity of the supplied electricity. It can be very low or even zero emission if from renewable electricity, but using average EU GHG emission intensity would produce electrolytic hydrogen with GHG emission intensity of 13.7 tCO2eq/tH2, far above unabated SMR.
- **Scalability challenges** - While there are further technological improvements to be had in water electrolysis, the main limitation for the technology is with the inadequate buildout of renewables, resulting lack of availability of renewable electricity as well as electrical grid bottlenecks.

LOW-TEMPERATURE ELECTROLYSIS

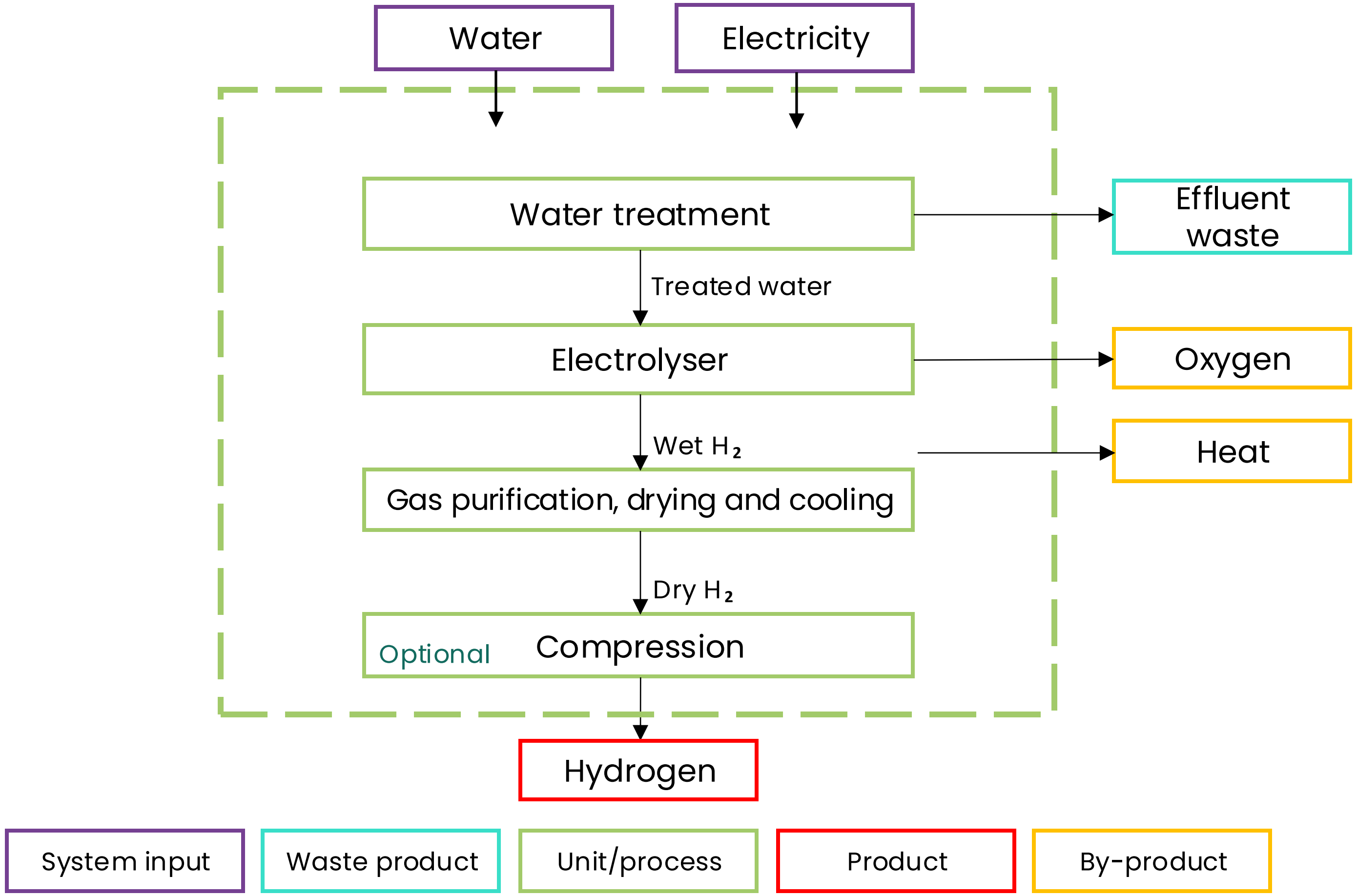
Water electrolysis is an electrochemical process that splits water (H_2O) into hydrogen (H_2) and oxygen (O_2), by passing an electric current through the water

Water electrolysis is an electrochemical process that splits water (H2O) into its component gases, hydrogen (H2) and oxygen (O2), by passing an electric current through the water.

The process: The process begins with water treatment which depends on a water source. These include processes such as sand filtration, UF/UV filtration, desalination, softening, demineralization, degassing, and others. The purified water flows into the electrolyser where electric current passes through water to separate it into hydrogen and oxygen gases. As electricity is applied, hydrogen gas forms at the cathode, and oxygen gas at the anode, enabled by the movement of ions in the electrolyte. Low-temperature water electrolysis typically operates at temperatures below 100°C and includes two main types: alkaline electrolysis and proton exchange membrane (PEM) electrolysis while additional technologies such as anion exchange membrane are also being commercialized, at smaller scale for now.

In alkaline electrolysis, an aqueous alkaline solution serves as the electrolyte, allowing ion transport between electrodes. PEM electrolysis uses a solid polymer electrolyte and operates at slightly higher efficiencies and current densities than alkaline. **After the hydrogen is produced, it needs to be dried, purified, cooled, and potentially compressed.** By-product oxygen and heat can be vented/released or valorised.

Figure 1.1: Low temperature electrolysis – process diagram



Source: Hydrogen Europe; ISO/TC 197/SC 1/WG

Low-temperature water electrolysis is a mature technology, but developers are encountering challenges as it scales from MWs to GWs

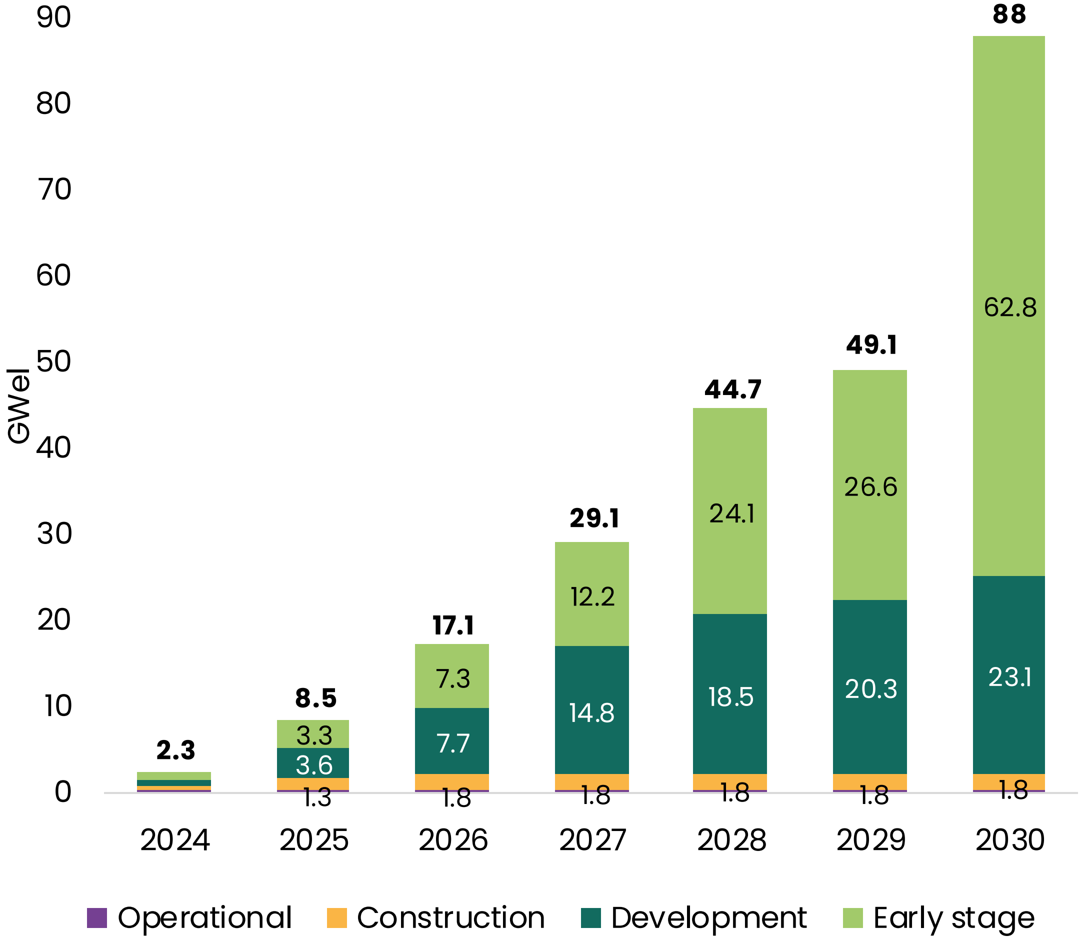
Water electrolysis for hydrogen production is not a new technology as industrial sized 100+ MWel units were installed in the first half of the 20th century. According to the International Energy Agency (IEA), total deployed capacity globally was around 1.3 GWel in 2023 with the largest commissioned installation of 260 MWel being completed in 2023 in China.

Technology readiness: Based on IEA's data, ~71% of the global operational capacity is alkaline compared to 20% for PEM. In Europe, the split is more even with alkaline at 44% and PEM at 53% due to several larger recently commissioned PEM installations. **Both are mature technologies rated at TRL 9 having achieved commercial operation in a relevant environment according to the IEA.** The Anion Exchange Membrane (AEM) technology is also already being commercially deployed, albeit at lower volumes for now.

Deployment: While technologically mature, the current challenge is large scale deployment. To replace the 7.9 Mt of hydrogen consumed as feedstock in Europe in 2022 with only electrolytic hydrogen, Europe would need to install ~79 GW of water electrolysis capacity (depending on efficiencies and utilizations). That is almost 300 times of the currently installed water electrolysis capacity. Figure 1.2 shows the current project pipeline of water electrolytic projects in Europe aiming to be online by 2030 at 88 GWel with 63 GWel being in early development stages. Together with new clean hydrogen end-uses, European Commission 2040 Impact Assessment models 62 Mt of electrolytic hydrogen consumption in 2050 equating to ~620 GWel of electrolytic capacity by 2050, a massive deployment from current 300 MWel, even if a part of those will be covered by imports.

Technological challenges: Despite mature TRL levels, there are still significant regulatory and technological opportunities for improvement. These include large scale deployment and integration with the balance of plant equipment; applying R&D to improve and learning in large scale installations to maintain efficiency, reliability, degradation rates, operations at low and variable loads; developing standards and protocols to harmonize performance parameters reporting; finding replacements for catalysts like platinum and iridium and fluoropolymers in PEM membranes.

Figure 1.2: Cumulative operational and planned water electrolysis projects in Europe by the year 2024 - 2030 in GWel



Source: Hydrogen Europe; International Energy Agency

Water electrolysis is mature and can support energy system integration, decarbonise hard-to-electrify sectors, and benefit from excess renewables

Renewable energy availability

Electricity is more readily available in large volumes compared to some of the other feedstocks mentioned in this report such as biowaste or non-recyclable plastic waste, but its supply also has constraints. Renewable energy buildout in Europe has been slowed down by permitting, existing grid infrastructure constraints, and slow grid upgrades causing large connection queues in many European countries. Despite these challenges, electrolytic hydrogen, due to the availability of renewable electricity, has a large potential to satisfy the existing and new industrial scale hydrogen demand.

System benefits

- Electrolytic hydrogen can bring cheap and/or stranded renewable electricity from production centres in and outside of Europe to demand centres in Europe as a molecule thus limiting the necessary electricity grid reinforcements.
- Electrolytic hydrogen increases the security of energy supply and mitigates overall costs.
- Electrolytic hydrogen allows using renewable or low-carbon electricity in sectors/use cases that would be difficult to electrify directly including seasonal storage
- Electrolysers can also help provide grid flexibility services

Technology

- While continuing to improve in terms of efficiency, durability, and cost, low-temperature water electrolysis is a mature technology that has been deployed on a 100+ MWel scale in 20th century. Brine electrolysis, or the chlor-alkali process, similar technology to alkaline water electrolysers has been deployed in industrial settings on GWel scale
- High-temperature electrolysis, while less mature than low-temperature electrolysis, will be benefitting from increased energy efficiency and its ability to use current/voltage and temperature to compensate for stack degradation. Deployment wise, it will also benefit from low-temperature electrolysis's lessons learned as it continues its GW scale

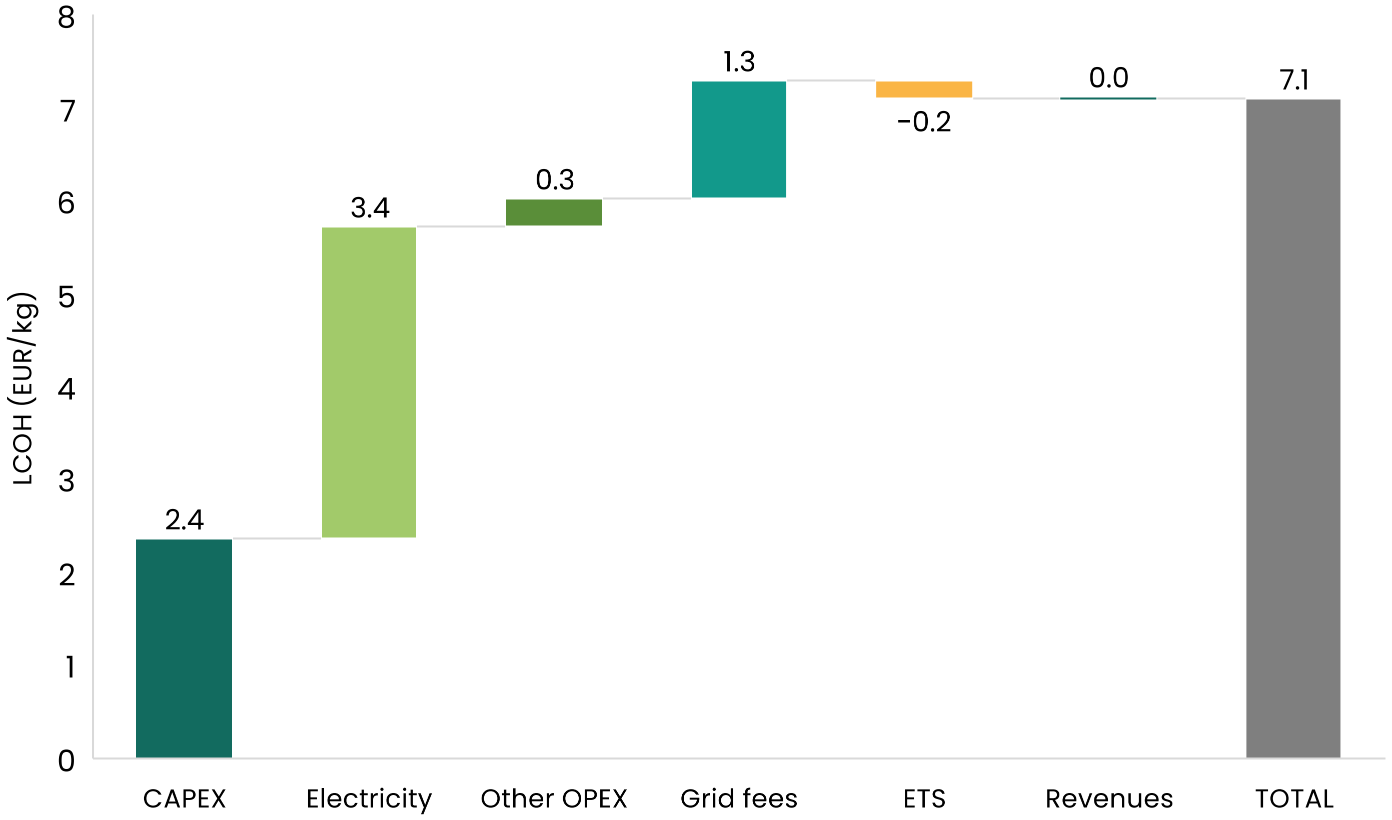
Electricity and grid fees are the most important cost driver for low-temperature electrolysis, representing 66% of the LCOH

Electricity and grid fees: For low-temperature electrolysis, electricity including grid fees constitute 66% of the total LCOH of 7.1 EUR/kg. This is with utilization of 5500 hours out of which 1100 hours are from a directly connected renewable resource, 3850 hours from a renewable PPA and 550 hours using grid electricity. The assumed utilization and electricity sources seek to achieve a balance between electricity costs and utilization while aiming to produce as much RFNBO hydrogen as possible. **Access to affordable renewable electricity is the most important factor determining financial viability of a project.**

CAPEX: The second largest cost segment is CAPEX at 34% of the total LCOH. CAPEX prices were expected to decrease in 2023. However, previous CAPEX estimates were based largely on smaller projects in existing industrial settings, without need for a grid connection. The larger scale projects on the other hand were in early stages of their feasibility studies and underestimated the CAPEX costs. As a result, the 7.1 EUR/kg reflects 2250 EUR/KW as a total CAPEX cost for an average low-temperature electrolysis project. In addition to stack and balance of plant, it also includes EPC management, owner's costs such as land and grid fee, insurance, permitting, financial arrangement, feasibility study, contingency (budget put aside to cover any unforeseen costs, risks and events).

Cost reductions from automation, economies of scale, and deployment experience are yet to materialize. There are more potential income streams from the sale of oxygen, flexibility services, or heat.

Figure 1.3: 2024 LCOH from low-temperature electrolysis of a theoretical 100 MWel project in Europe



Assumptions for prices: Alkaline technology; CAPEX: 2250 EUR/KW; LT electricity: LT grid electricity for 550 hours at 80 EUR/MWh for wholesale plus average network fees at 29.3 EUR/MWh, directly connected RE source for 1100 hours at 60 EUR/MWh, renewable PPA for 3850 hours at 60 EUR/MWh plus average network fees at 29.3 EUR/MWh; Other OPEX: 2% of CAPEX; Economic lifetime: 20 years; Energy consumption: 52 KWh/kg; Stack degradation: 0.12%/1000 hours; Operating hours: 5500 h/y; Project details: 100 MWel project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe

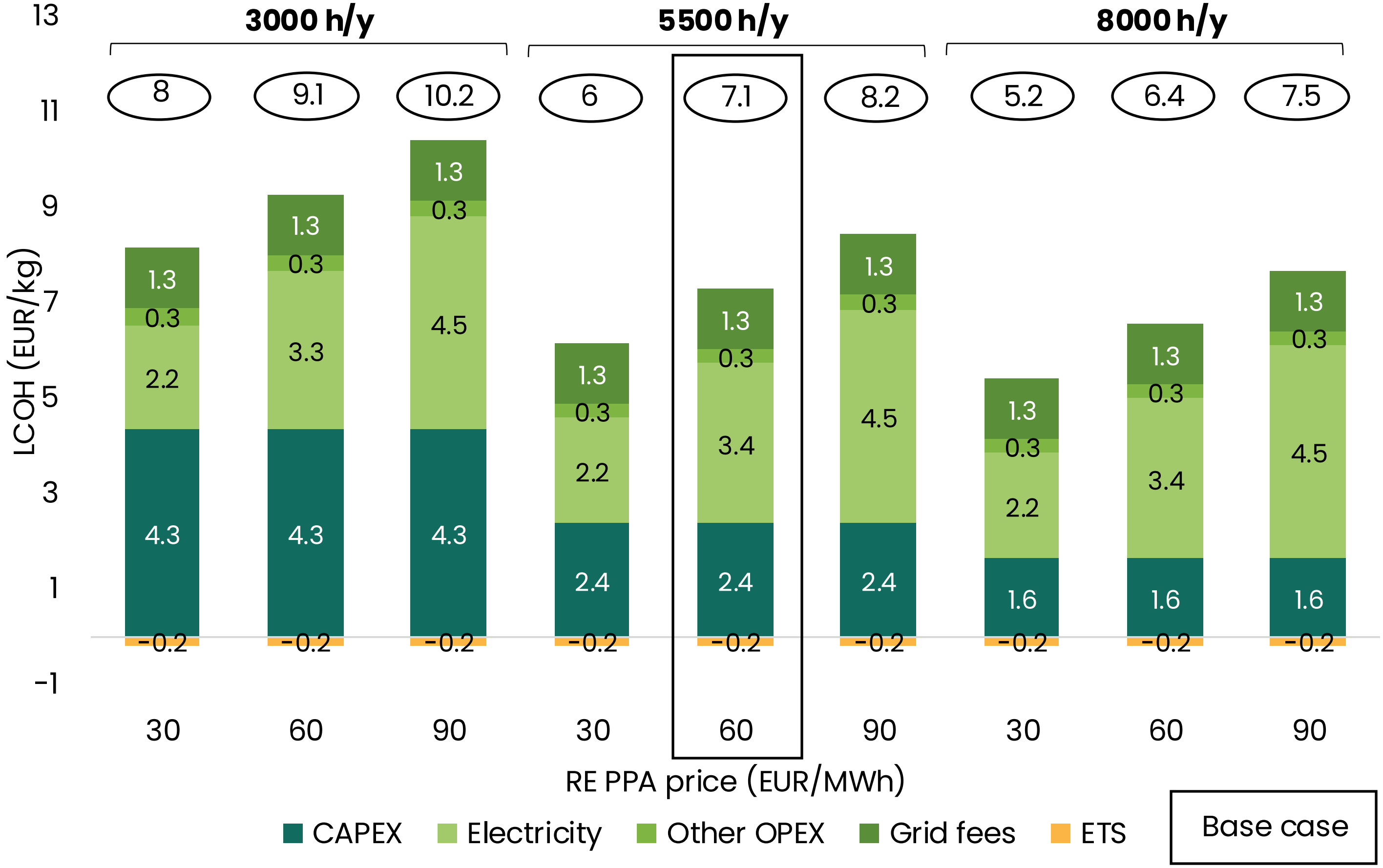
CAPEX costs can be significant if electrolyser utilisation is limited

Sensitivity: Figure 1.4 shows LCOH of low-temperature electrolysis with renewable energy PPA prices and utilization as variables. Electricity price has the largest impact on the total LCOH, ranging between 28% and 60%. With utilization at 5500 h/y which is the base case scenario, the LCOH is as little as 6 EUR/kg at 30 EUR/MWh RE PPA prices and as much as 8.2 EUR/kg at 90 EUR/MWh. At RE PPA prices of 60 EUR/MWh, LCOH ranges between 6.4 EUR/kg for 8000 h/y and 9.1 EUR/kg at 3000 h/y, demonstrating the importance of utilisation for keeping production costs manageable.

Model limitations: These are hypothetical scenarios**. There are projects in development with significantly better project economics due to abundant directly connected renewable resources, a grid with lower wholesale prices, or lower or zero grid fees allowing the electrolyser to run at higher utilizations.** There are also projects in development with other business models, such as only or mostly relying on directly connected renewable sources, saving money on a grid connection and thus reducing their CAPEX.

Revenues: While revenues from EUA allowances are included in the modelled prices, there are also **other project and location specific considerations that affect the modelled prices. These include potential revenues from selling produced oxygen, income from flexibility services, and income from providing heat for district heating.** While these are not applicable for all projects, they can make significant impacts on LCOH for some.

Figure 1.4: 2024 LCOH of low-temperature electrolysis depending on RE PPA price and utilisation



Assumptions for prices: Alkaline technology; CAPEX: 2250 EUR/KW; Electricity: grid electricity for 550 hours at 80 EUR/MWh for wholesale plus average network fees at 29.3 EUR/MWh, directly connected RE source for 1100 hours at 60 EUR/MWh, renewable PPA for 3850 hours at 60 EUR/MWh plus average network fees at 29.3 EUR/MWh; Other OPEX: 2% of CAPEX; Economic lifetime: 20 years; Energy consumption: 52 KWh/kg; Stack degradation: 0.12%/1000 hours; Operating hours: 5500 h/y; Project details: 100 MWel project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe

Western electrolysers are currently more expensive than Chinese ones but higher energy efficiency and durability can make up for the cost difference

Electrolyser costs: Multiple recent publications and reports point out that there exists a significant price difference (3 to 4 times) between electrolysers manufactured in the EU and those produced in China – reaching up to 600 EUR/kW for alkaline technology and even up to 1,000 EUR/kW for PEM electrolysers. When adjusting for local EPC cost differences (e.g. different materials, higher margins and extra costs for product certification in the EU), importing Chinese equipment can save 435 EUR/kW for a European alkaline electrolysis project. While ramping up the EU electrolyser manufacturing capacity promises – through economies of scale and increased automatization – to reduce the cost difference, as long as it persists, it poses a serious challenge for EU manufacturers. However, as shown on the previous page, electrolyser CAPEX has a much lower impact on the final LCOH than costs of electricity or even grid fees (in case of grid-connected electrolysis).

Performance characteristics' impact on LCOH: As the cost of electricity has such a determining factor on the levelized cost of hydrogen, a higher efficiency electrolysis systems can significantly offset higher CAPEX. With expected industry average electrolysis capacity factor of around 6,000 full load hours, an energy efficiency improvement of just 1 kWh/kgH2 (around 2% of total energy use) would have an equivalent impact on hydrogen production cost as an electrolyser cost lower by 124 EUR/kW (Figure 1.6). In other words, lower energy consumption by 4.8 kWh/kgH2 would be enough to completely offset the current electrolyser cost difference between EU and Chinese products. Besides energy efficiency, another electrolyser performance parameter, with a significant impact on the economics of hydrogen production is stack durability and degradation rates. Higher durability of electrolysers means higher average efficiency over the electrolyser lifetime, less frequent stack replacement and, as a result, lower replacement costs and less downtime. Consequently a 10% savings on electrolyser system purchase cost is not worth it, if the electrolyser is 10% less durable and has a higher degradation rate. A significant difference in stack current density could have a similar effect reducing, the installation's footprint and construction materials requirements.

Figure 1.5: CAPEX reduction equivalent to efficiency improvement by 1 kWh/kg H2

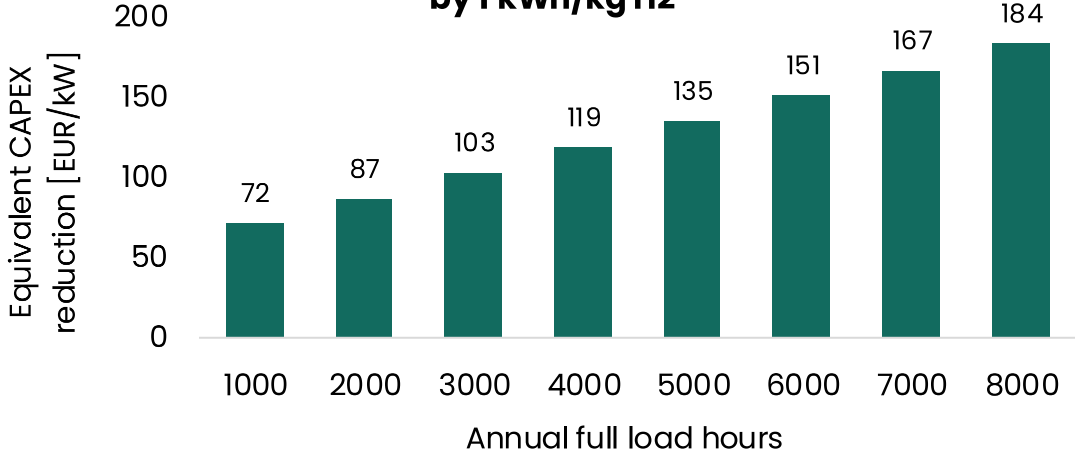
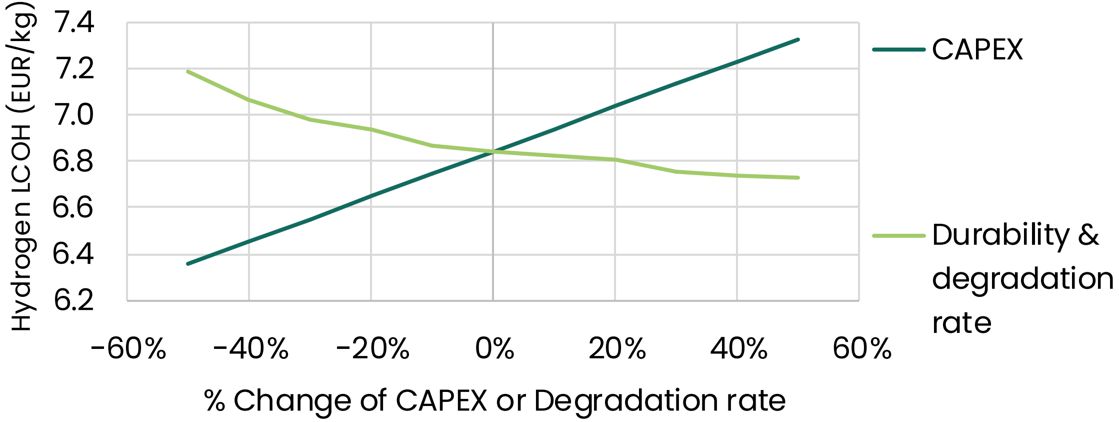


Figure 1.6: LCOH (EUR/kg) sensitivity to %change of electrolyser system CAPEX and stack durability & degradation rate



Notes: The % change show impact of a diversion from the base case, which is 2,250 EUR/kW for CAPEX, stack durability of 60,000 hours and degradation rate of 0.12% per 1,000 hours of operation
Source: Hydrogen Europe; BNEF

GHG emissions of electrolytic hydrogen depends on electricity input. Using grid electricity in Poland leads to a GHG intensity 3 times higher than SMR hydrogen

Figure 1.7 shows indirect emissions from producing hydrogen by low-temperature electrolysis using well-to-gate methodology. As such, it excludes emissions from equipment manufacturing and transport. **Using this methodology, GHG emission intensity of the electricity is the only factor affecting GHG emission intensity of the produced hydrogen.**

Grid GHG intensity impact: If 20% of the electricity comes from directly connected RES, 70% from RE PPA via the grid, and only 10% from the grid with EU-27 emissions, the total GHG emissions, all indirect, amount to 1.4 kgCO2eq/kgH2, well below the low-carbon threshold identified in RED II. However, **using average 2022 EU-27 grid GHG emission intensity of 69.7 gCO2/MJ, the value, at 13.7 kgCO2eq/kgH2, is higher than direct emissions from unabated SMR at 11 kgCO2eq/kgH2.** The values are even higher in locations like Poland with grid GHG emission intensity of 185 gCO2/MJ and resulting hydrogen at 36.3 kgCO2eq/kgH2.

Max grid mix share for RFNBOs: Figure 1.8 shows the maximum acceptable contribution of electricity with average grid mix GHG intensity in that country to be able to produce a Renewable Fuel of Non-Biological Origin (RFNBO). The numbers range from only being able to use 9% of total consumed electricity from grid for hydrogen production for it to be RFNBO in Poland to running an electrolyser only on grid electricity in France, Norway, Sweden, and Iceland. Selling oxygen would allow operators to allocate an economically proportional share of GHG emissions from the process to oxygen, reducing the GHG intensity of hydrogen.

Figure 1.7: GHG emission intensity of low-temperature electrolysis

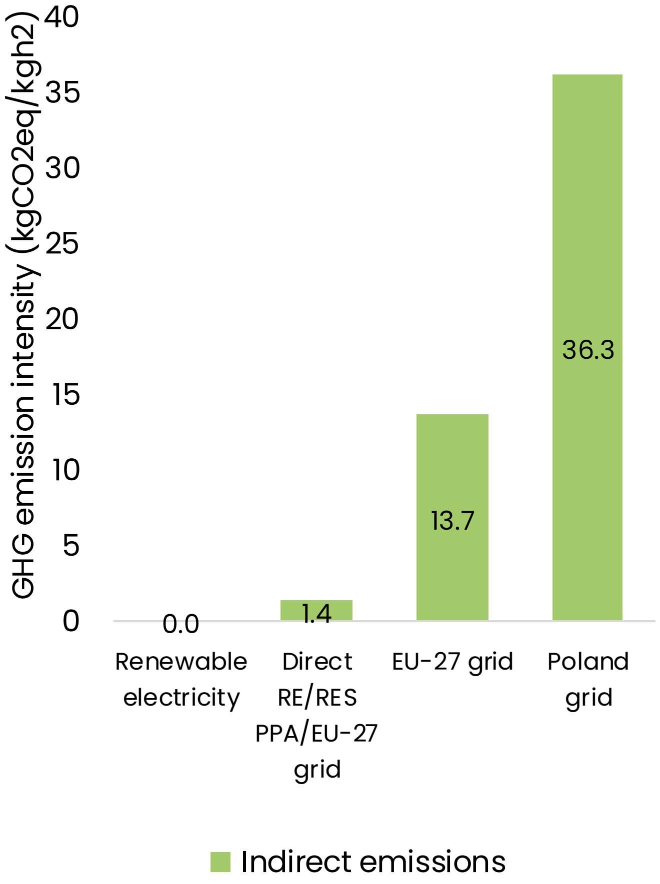
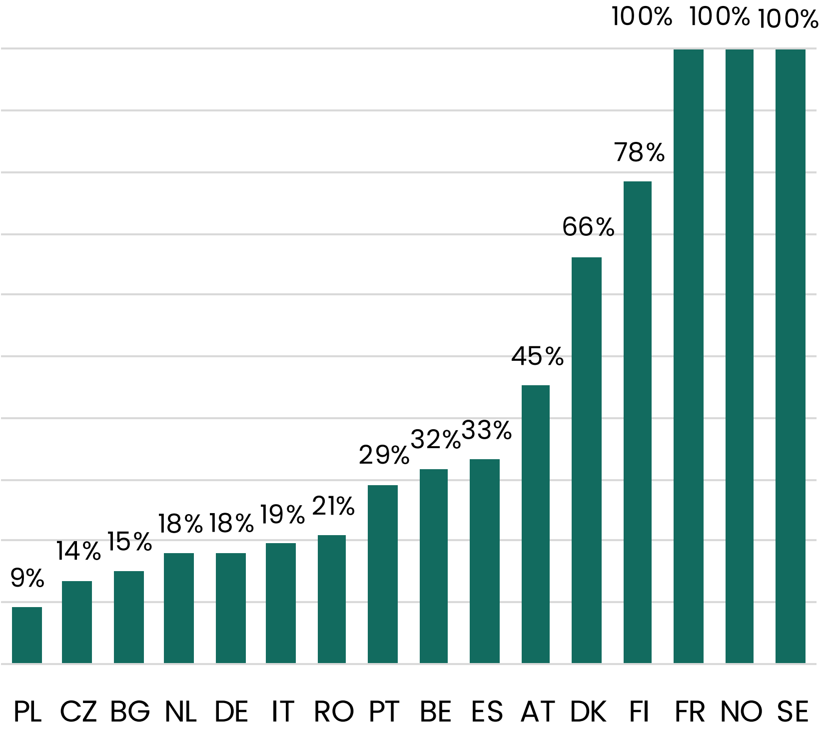


Figure 1.8: Maximum acceptable contribution of grid mix electricity for the production of RFNBO (%) in selected European countries



Assumptions: Direct RE at 20%, RES PPA at 50% and EU-27 grid at 10% of total running hours; EU-27 grid GHG emission intensity of 69.7 g CO2eq/MJ; Polish grid GHG emission intensity of 185 gCO2eq/MJ; France – means continental France, excluding overseas territories. Low-carbon threshold refers to 70% below fossil fuel comparator of 94 gCO2/MJ = 28.2 gCO2/MJ = 3.4 kg CO2/kgH2 from RED II;
Source: Hydrogen Europe; European Environmental Agency

HIGH TEMPERATURE ELECTROLYSIS

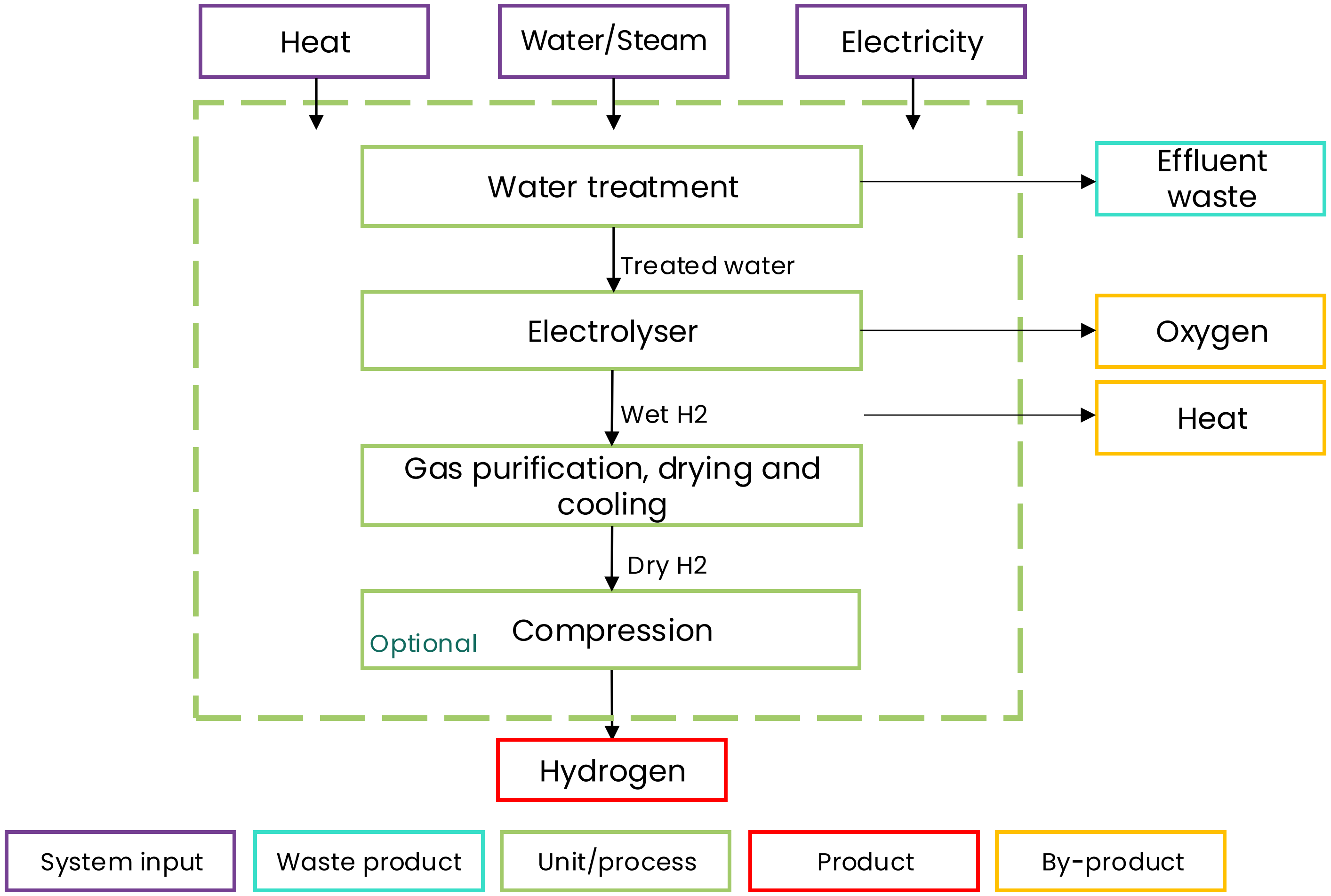
High-temperature water electrolysis reaches higher energy efficiency by using heat between 500°C and 900°C as an energy input, in addition to electricity

Similarly to low-temperature electrolysis the process begins with water treatment which depends on a water source. These include processes such as sand filtration, UF/UV filtration, desalination, softening, demineralization, degassing, and others.

Process: **High-temperature water electrolysis, particularly using solid oxide electrolysis cells (SOECs), is a method where water (in the form of steam) is split into hydrogen and oxygen at temperatures between 500°C and 900°C.** This process leverages the unique properties of solid oxide materials, which become highly ion-conductive at elevated temperatures, facilitating efficient electrolysis. At the anode, oxygen ions form and release electrons, while at the cathode, water molecules consume these electrons, forming hydrogen gas and oxygen ions. The oxygen ions then migrate through the solid oxide electrolyte to the anode, completing the circuit. This process is driven by the application of an electric current, and the high operating temperatures improve the reaction kinetics and ionic conductivity, leading to higher efficiencies. **One of the key advantages of high-temperature water electrolysis is its potential to integrate with external heat sources, thus reducing the electrical energy needed for the electrolysis from ~52 kwh/kg for current low-temperature stacks to ~40 kwh/kg.**

After the hydrogen is produced, it needs to be dried, purified, cooled, and potentially compressed. By-product oxygen and heat can be vented/released or valorised.

Figure 1.9: High-temperature electrolysis – process diagram



Heat

Water/Steam

Electricity

Water treatment

Effluent waste

Treated water

Electrolyser

Oxygen

Heat

Wet H2

Gas purification, drying and cooling

Dry H2

Optional

Compression

Hydrogen

System input

Waste product

Unit/process

Product

By-product

Source: Hydrogen Europe; ISO/TC 197/SC 1/WG

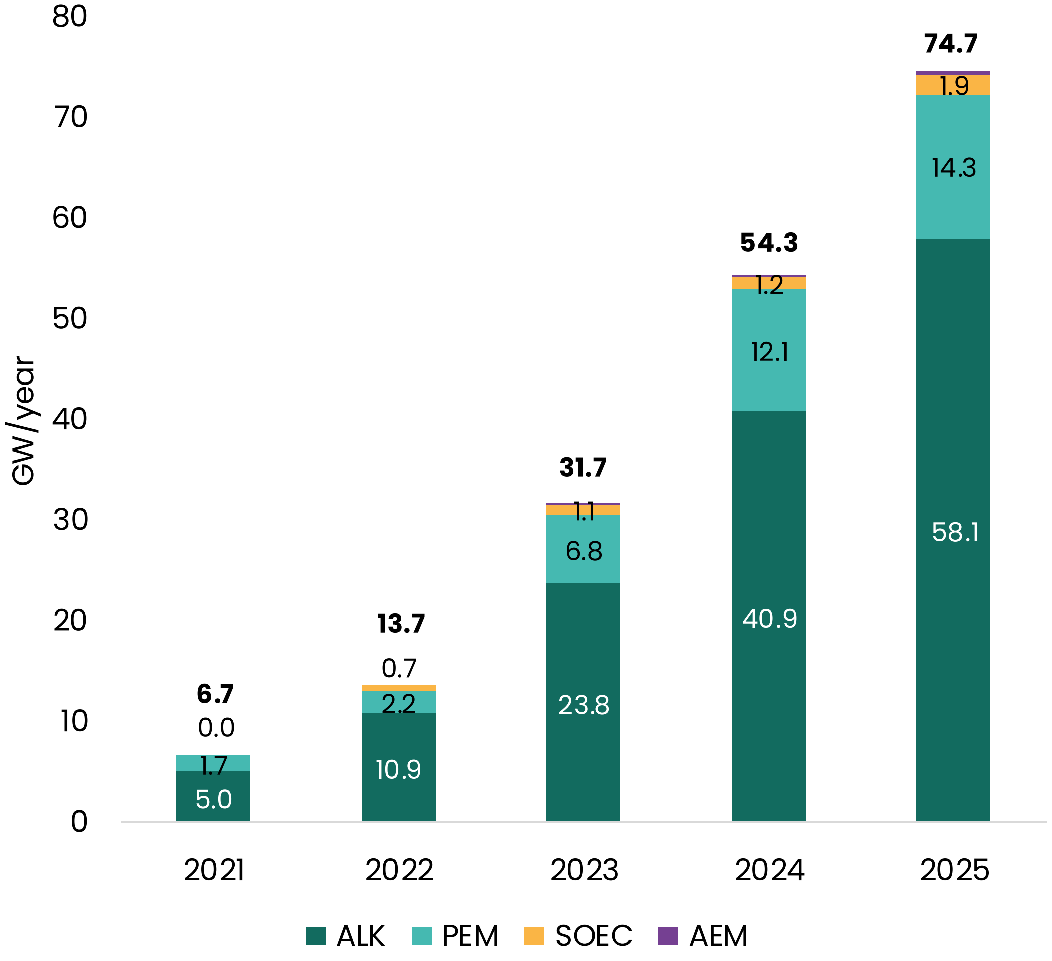
High-temperature electrolysis is rapidly advancing towards commercialization albeit a modest announced global manufacturing capacity

Technology readiness: Unlike low-temperature water electrolysis, high-temperature water electrolysis is not a widely deployed technology yet. Its maturity, as assessed through technology readiness levels (TRLs), is gradually increasing, supported by its application in a range of settings, from chemical production to steelmaking where waste heat can be valorised to increase the process efficiency. **IEA considers it to be at TRL 8 , first of a kind commercial deployment stage.**

Deployment: In 2021, Sunfire began tests of its 1-MW electrolyser in Leuna, Germany in 2021 for use in methanol synthesis. Another Sunfire demonstration project, MultiPLHY, under commissioning as of March 2024, plans to use high-temperature water electrolysis process at Neste's bioproducts refinery in Rotterdam for a commercial scale hydrogen production. **There are numerous other companies pursuing this technology in Europe and globally including Topsoe, Bloom Energy, Genvia, SolydEra, Elcogen, Ceres, and most recently Thyssenkrupp Nucera**.

Technological developments: The broader adoption and commercialization of SOEC technology faces technological challenges. **Similarly to low-temperature electrolysis, further research is going into improvements in degradation rates, efficiency, reliability, increasing stack size, integration with other industrial applications, and design, engineering, and deployment of multi-MW up to GW systems.** The high-temperature environment improves efficiency but also induces thermal stress, leading to accelerated component degradation. **Continuous research is ongoing to reduce the thermal stress, the degradation, and thus improving the resilience of the technology.** Engineers are further trying to increase the number of cells in a stack to increase the capacity per square meter, reducing footprint, and reducing balance of plant requirements. Figure 1.10 shows the progression of global electrolyser manufacturing capacity were based on announcements, SOEC will only constitute 3% of the total by the end of 2025. However, SOEC manufacturers are planning scale up significantly by 2030 to compete on costs even with low-temperature electrolysis.

Figure 1.10: Global electrolyser manufacturing capacity



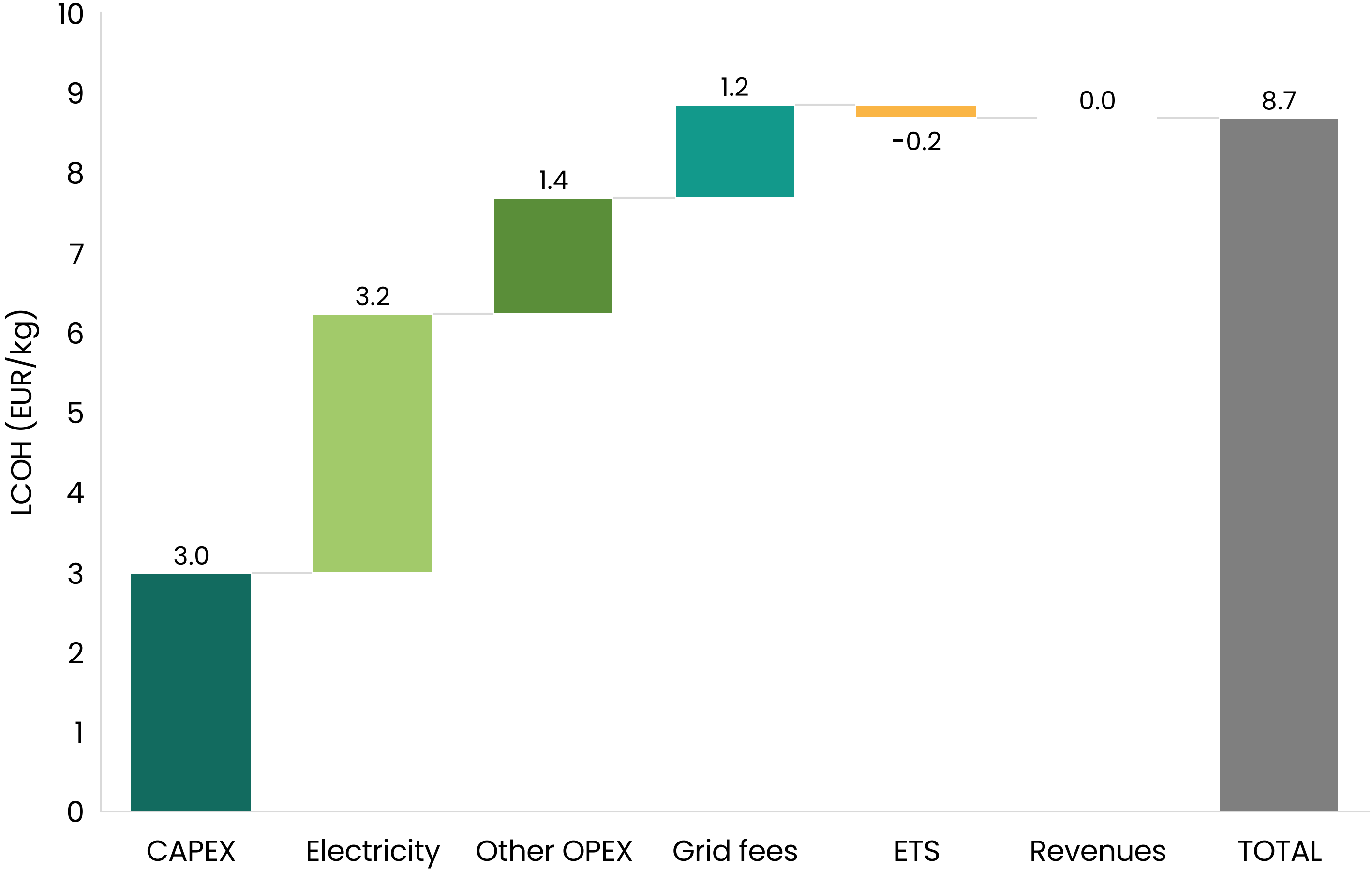
Source: Hydrogen Europe; International Energy Agency; Clean Air Task Force; Sunfire; BNEF

Electricity, grid fees and CAPEX are the largest cost drivers for high-temperature electrolysis, with future advancements reducing CAPEX and degradation

Impact of electricity costs and utilisation: Electricity costs and grid fees constitute 51% of the LCOH from high-temperature electrolysis. In this scenario, it is assumed that the electrolyser consumes electricity at 80 EUR/MWh plus grid fees and is running 8000 hours a year. The base case uses 80 EUR/MWh compared to 60 EUR/MWh for LT PPA to account for the need to run at higher utilisation. High utilisation is essential for HT electrolysis to amortise the high CAPEX costs, satisfy the need for consistent hydrogen production for off-takers reducing the need for storage, optimise performance and reduce the mechanical stresses on the electrolyser resulting from frequent cycling and temperature variations. Operating at high temperatures allows HT electrolysers to benefit from higher efficiency of ~85% $_{LHV}$ compared to ~64% $_{LHV}$ for LT electrolysis. **Lower electricity consumption's impact on the electricity segment of the LCOH is however mitigated by the previously mentioned higher assumed electricity cost**.

CAPEX represents 35% of the LCOH and is the second largest cost segment. It is significantly higher per KW than for low-temperature electrolysis due to current maturity and technological requirements of the technology. Figure 1.11 is based on 5400 EUR/KW. CAPEX figures here also include stack replacement costs assuming 0.8% degradation after 1000 hours which are also going to improve with additional R&D into the technology. Similarly, as with low-temperature electrolysis, there are additional potential revenues from the sale of oxygen, flexibility services, or heat.

Figure 1.11: 2024 LCOH from high-temperature electrolysis



Assumptions for prices: CAPEX: 5400 EUR/KW; Electricity: 80 EUR/MWh plus average network fees at 29.3 EUR/MWh ; Heat: 5.3 EUR/MWh as co-located with a heat source; Other OPEX: 3% of CAPEX; Economic lifetime: HT of 20 years; Energy consumption: 40 KWh/kg; Stack degradation: 0.8%/1000 hours; Operating hours: 8000 h/y: Project details: 10+ MWel project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe; Ramboll

As CAPEX decreases with technological maturity, electricity cost will become the main cost driver for high-temperature electrolysis, similar to low-temperature

HT CAPEX ranges: Figure 1.12 shows CAPEX ranges for high-temperature electrolysis based on different sources. European Commission's 2040 Impact Assessment and IEA both have very wide ranges as **CAPEX differs based on SOEC technologies operating at different temperatures and using different materials.** The CAPEX assumptions also differ between each other as CAPEX scope varies. **Assumed costs for these calculations at 5,400 EUR/kW are high but should be representative of using existing technology and theoretically beginning construction in 2024 for a large 10+MW project.**

Sensitivity analysis: Figure 1.13 shows a sensitivity analysis depending on grid electricity price and CAPEX with LCOH ranging from 5.7 to 9.5 EUR/kg. Should CAPEX drop to 2700 EUR/KW and the installation were able to secure electricity at 60 EUR/MWh plus 29.3 EUR/MWh grid fees, the LCOH would be at 5.7 EUR/kg. **Cost of heat plays only a minor role and as a result, the most likely high temperature electrolysis projects are going to be located based on availability of cheap electricity rather than waste heat.** Such example would be its location in an industrial cluster with low average electricity prices, low grid fees, and available waste heat. In this scenario, the LCOH could reach 5.7 EUR/kg and further continue decreasing as the technology improves.

Figure 1.12: High-temperature electrolysis CAPEX prices

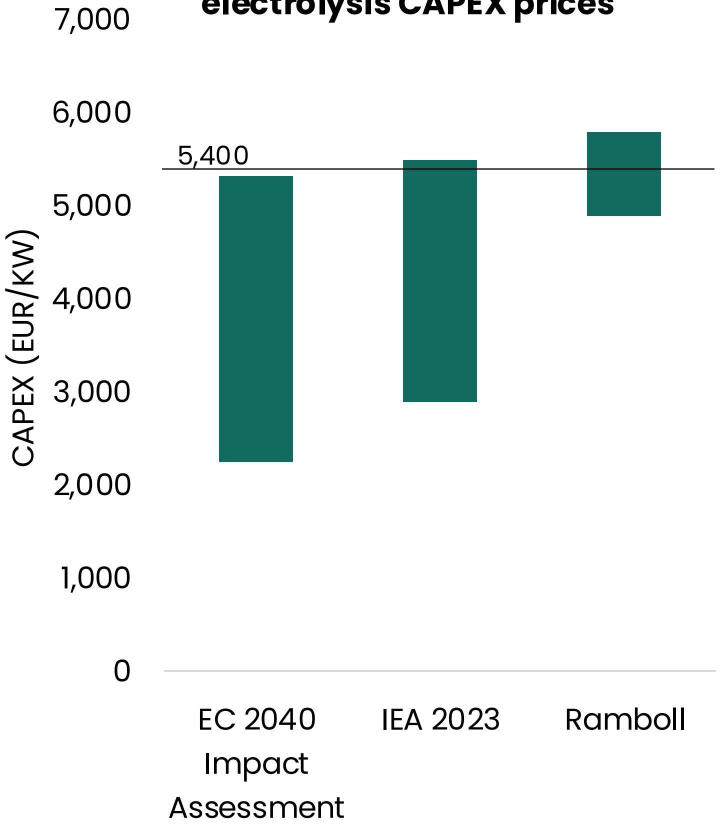
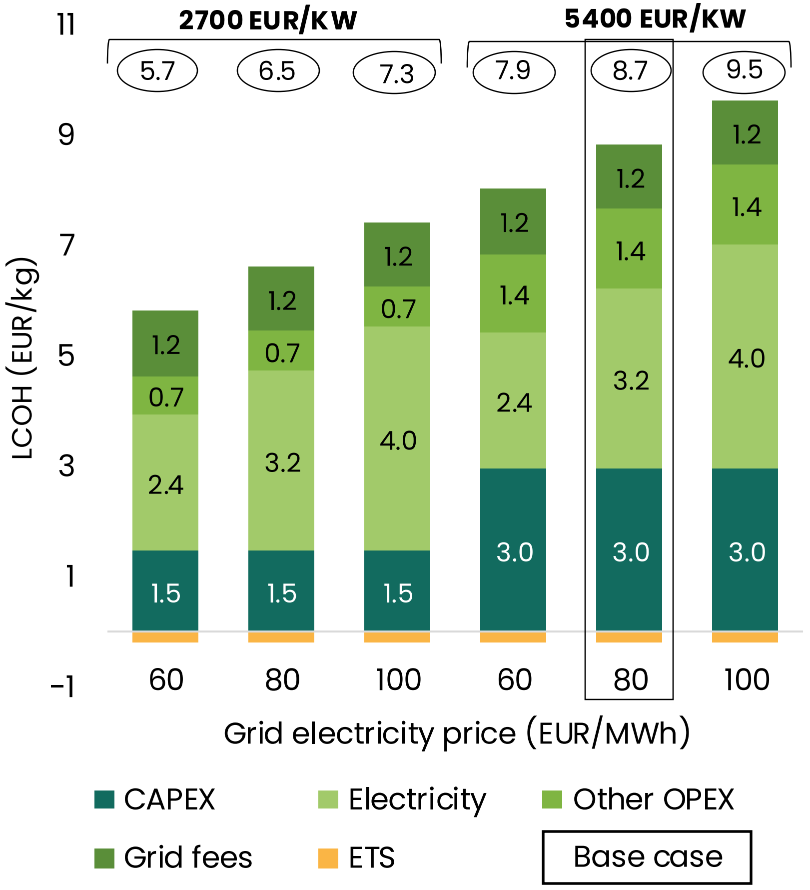


Figure 1.13: 2024 LCOH of high-temperature electrolysis depending on grid electricity price and CAPEX



Assumptions for prices: CAPEX: 2700/5400 EUR/KW; Electricity: 60/80/100 EUR/MWh plus average network fees at 29.3 EUR/MWh ; Heat: 5.3 EUR/MWh as co-located with a heat source; Other OPEX: 3% of CAPEX; Economic lifetime: HT of 20 years; Energy consumption: 40 KWh/kg; Stack degradation: 0.8%/1000 hours; Operating hours: 8000 h/y ; Project details: 10+ MWel project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe; International Energy Agency; Ramboll

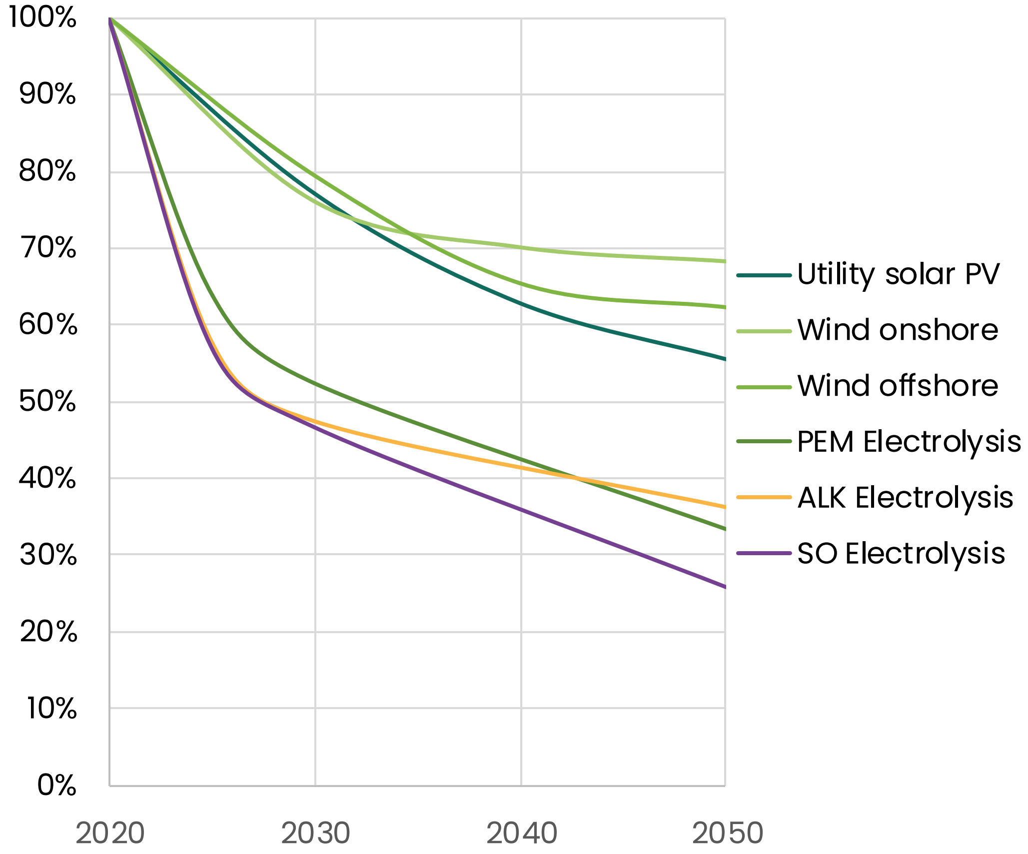
While costs of electrolytic hydrogen have actually increased, significant cost reductions are expected

Key cost reduction areas: As demonstrated, from the point of view of the levelized cost of RFNBO hydrogen, the cost components having by far the most impact on the total costs are costs of renewable electricity, followed by CAPEX. **Together costs of electricity and CAPEX are responsible for around 75% of production costs or even more than 90% of costs in case of electrolysis connected to a renewable source over a direct line without network costs.** It is therefore worth highlighting that **both the electrolyser costs, as well as the costs of renewable electricity, have a significant cost reduction potential** (see graph on the right).

Electrolyser CAPEX reduction: **Especially in the case of electrolysis, the ramp-up of manufacturing capacities should, through automatization and economies of scale, result in a reduction of CAPEX by up to 70% compared to current levels** – with the most cost reductions coming from reducing system electrical equipment costs. The fall in costs is expected to be greater in the case of SOEC. That is however a reflection of the fact that it is a relatively less mature technology, characterized by a higher current capital expenditures levels. **By 2050 the CAPEX for both major low temperature electrolysis technologies (alkaline and PEM) are expected to converge around 500 EUR/kW with the high temperature (SOE) CAPEX at around 600 EUR/kW**. Together with the expected further decrease of renewable electricity costs, this should result in a sharp decrease of RFNBO hydrogen production costs.

LCOH development: According to a recent forecast by BNEF, **renewable hydrogen production costs are expected to fall by close to 60% by 2030**, allowing renewable hydrogen to become competitive with existing grey H2 plants running at marginal costs in some markets with access to low-cost Renewables even as soon as by 2030 (Brazil, China, Sweden, Spain and India), in over 90% of markets by 2035 and in all markets by 2050. **The levelized cost of renewable hydrogen in 2050 ranges from $0.6-1.6/kg for both alkaline and PEM systems**. It should be stressed however that the displayed cost reductions will not happen by themselves. The timeline and the extent of the costs downward trajectory will depend on the actual deployment of technologies and especially in case of SOEC on further R&D efforts. Indeed, in the case of electrolysers, with the currently experienced delays in market deployment, we are rather observing that the CAPEX for the first-of-kind projects between 2020 and 2024 has increased.

Figure 1.15: CAPEX development for selected technologies used by EC in 2040 GHG targets modelling (2020 = 100%)



Source: Hydrogen Europe; International Energy Agency; Ramboll

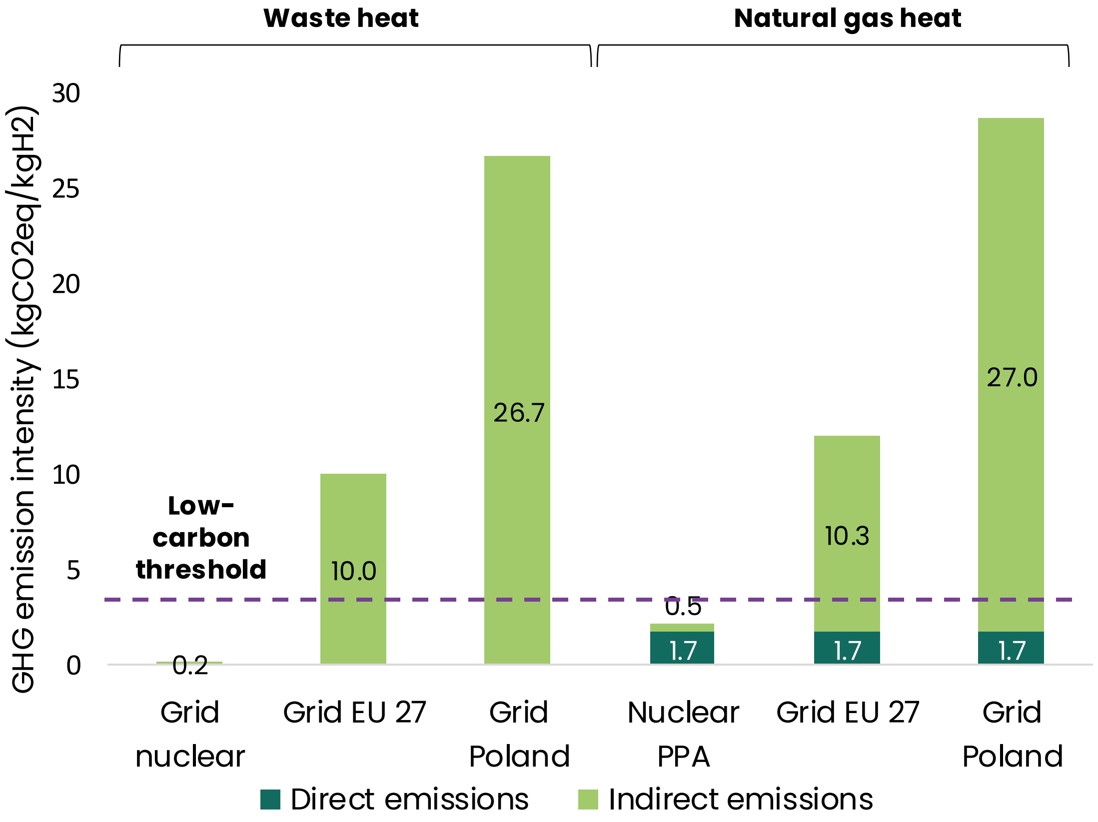
Electricity is the main driver of GHG emissions of hydrogen from HT electrolysis. Using average EU grid GHG intensity results in emissions comparable with SMR

Key drivers: GHG emission intensity of hydrogen produced by high-temperature electrolysis depends on GHG intensity of the two energy inputs – i.e. electricity and heat. Given the relative emission intensity factors and the relative amounts of heat and electricity consumption, **electricity is by far the main GHG emissions driver.**

Use of renewable electricity: If renewable electricity and waste heat would be used, the total well-to-gate emissions would be zero. However, in the case of high temperature electrolysis, there is usually a relatively low operational flexibility, requiring stable load and high annual capacity utilization. Such an operational profile might make it challenging to rely exclusively on renewable electricity as input – especially after hourly temporal correlation requirement comes into force. **If electricity used for hydrogen production would not be renewable, in order for hydrogen to still be classified as low-carbon (i.e. below 28.2 gCO2/MJ)** the GHG intensity of electricity would have to be lower than around and 85 gCO2/kWh – compared to ~65 gCO2/kWh for low temperature electrolysis (due to lower energy efficiency of LT electrolysis).

Importance of upcoming low-carbon fuels DA: However, using the average GHG emission intensity for EU electricity grids in 2022, hydrogen's emission intensity would reach 10 kgCO2eq/kgH2 with waste heat and 12 kgCO2eq/kgH2 with natural gas as a heat source – i.e. not only crossing the low-carbon threshold but comparable with SMR. Using electricity with Polish GHG emission intensity would result in producing over 34 kgCO2eq/kgH2, that is 3x more than SMR. For this reason, HT electrolysis would be well suited to operate on other sources of low-carbon electricity with a more stable production profile – e.g. nuclear energy. **When using electricity via nuclear PPA, the emission intensity is at 0.2 kgCO2eq/kgH2 when using waste heat and 2.2 kgCO2eq/kgH2** when using natural gas as a heat source – in both cases well below the low-carbon threshold of 3.4 kgCO2eq/kgH2. It should be noted, however that the only rules available in March 2024 that could be used for low-carbon hydrogen certification are in the RFNBO DAs and do not allow for a PPA to be signed with any other source than RES. It is expected that this possibility will be provided only in the upcoming low-carbon DA. Selling oxygen would also allow operators to allocate a proportional (to relative economic value of O2 vs H2) share of GHG emissions from the process to oxygen, reducing hydrogen's carbon intensity.

Figure 1.14: GHG emission intensity of high-temperature electrolysis with and without waste heat



Assumptions: Assumption for waste heat as zero emission; Direct RE at 20%, RES PPA at 50% and EU-27 grid at 10% of total running hours; Nuclear GHG emission intensity of 1.2 gCO2eq/MJ; EU-27 grid GHG emission intensity of 69.7 g CO2eq/MJ; Polish grid GHG emission intensity of 185 gCO2eq/MJ; Natural gas use GHG emission intensity of 56.2 gCO2/MJ; Low-carbon threshold refers to 70% below fossil fuel comparator of 94 gCO2/MJ = 28.2 gCO2/MJ = 3.4 t CO2/tH2 from RED II;

Source: Hydrogen Europe

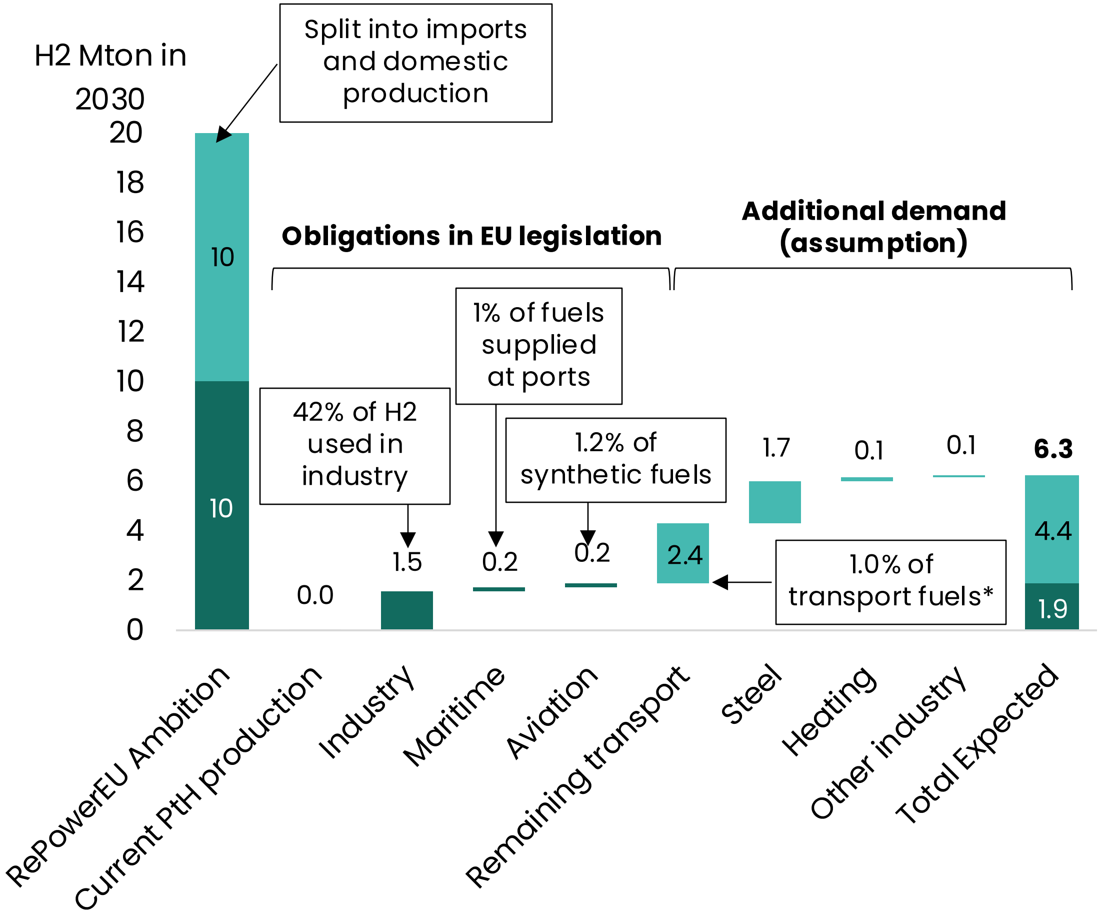
Hydrogen produced via electrolysis would be classified as RFNBO if produced with renewable electricity and with carbon intensity below 28.2 gCO2/MJ

Hydrogen classification: **Hydrogen produced via LT or HT electrolysis could be classified in several categories depending on the electricity source used**. RFNBO - If it would be produced with renewable electricity (not from biomass), biofuel, if electricity produced from biomass is used, or low-carbon fuel in case any other non-renewable electricity source is used.

Regulatory targets: Because of the role it can play in facilitating higher penetration of renewables in the energy system and sector coupling, **RFNBO hydrogen has been identified as one of priorities at EU level**. This has resulted in setting up of several regulatory targets with the aim of stimulating market demand for RFNBO hydrogen (and its derivatives). **By 2030 the total demand for RFNBOs stemming from policy targets (most notably embedded in the RED) would amount to 2.0 – 4.4 Mt,** and even up to 6.3 Mt including additional demand expected in sectors not using hydrogen today (e.g. the steel sector).

Regulatory barriers: **There are however significant regulatory challenges holding back the deployment of water electrolysis projects.** The greatest of those are the strict and inflexible rules for classifying electricity as fully renewable, including **additionality**, excluding the possibility for using subsidized renewable electricity, as well as **hourly temporal correlation** requirement (post 2030) - posing a challenge especially for industrial applications, where steady supply of hydrogen is a requirement. Securing a PPA with a dispatchable and stable low-carbon power source, e.g. a nuclear plant could provide a way out – especially in countries with high carbon-intensive grid electricity – but that possibility is only expected to be provided by the upcoming delegated act establishing GHG accounting rules for low-carbon fuels. Additionally, in case of high temperature electrolysis, waste heat would count as a rigid input since supply cannot be expanded to meet extra demand. As such, the emissions resulting from the diversion of those inputs from a previous or alternative use would have to be allocated to the production of the RFNBO. For new installations there are however no clear guidelines, as to how the next best economic alternative' counterfactual should be defined - creating unnecessary risk for investors. It is also uncertain whether waste heat or steam does not have to be demonstrated as renewable for any output to qualify as 100% RFNBO. Given the fact that the breakdown of the water molecule is driven by electricity, the origin of waste heat should not matter. The rules are however unclear.

Figure 1.16: RePowerEU 2030 ambitions compared with legislative obligations and target



*1% RFNBO in transport fuels with a x2 multiplier - i.e. effectively 0.5% RFNBO share. Total transport target = 5.5% for RFNBO and adv. biofuels

Source: Hydrogen Europe

Hydrogen infrastructure and renewable energy availability are the largest challenges for scaling water electrolysis from MW to GW

Feedstock and renewable energy availability

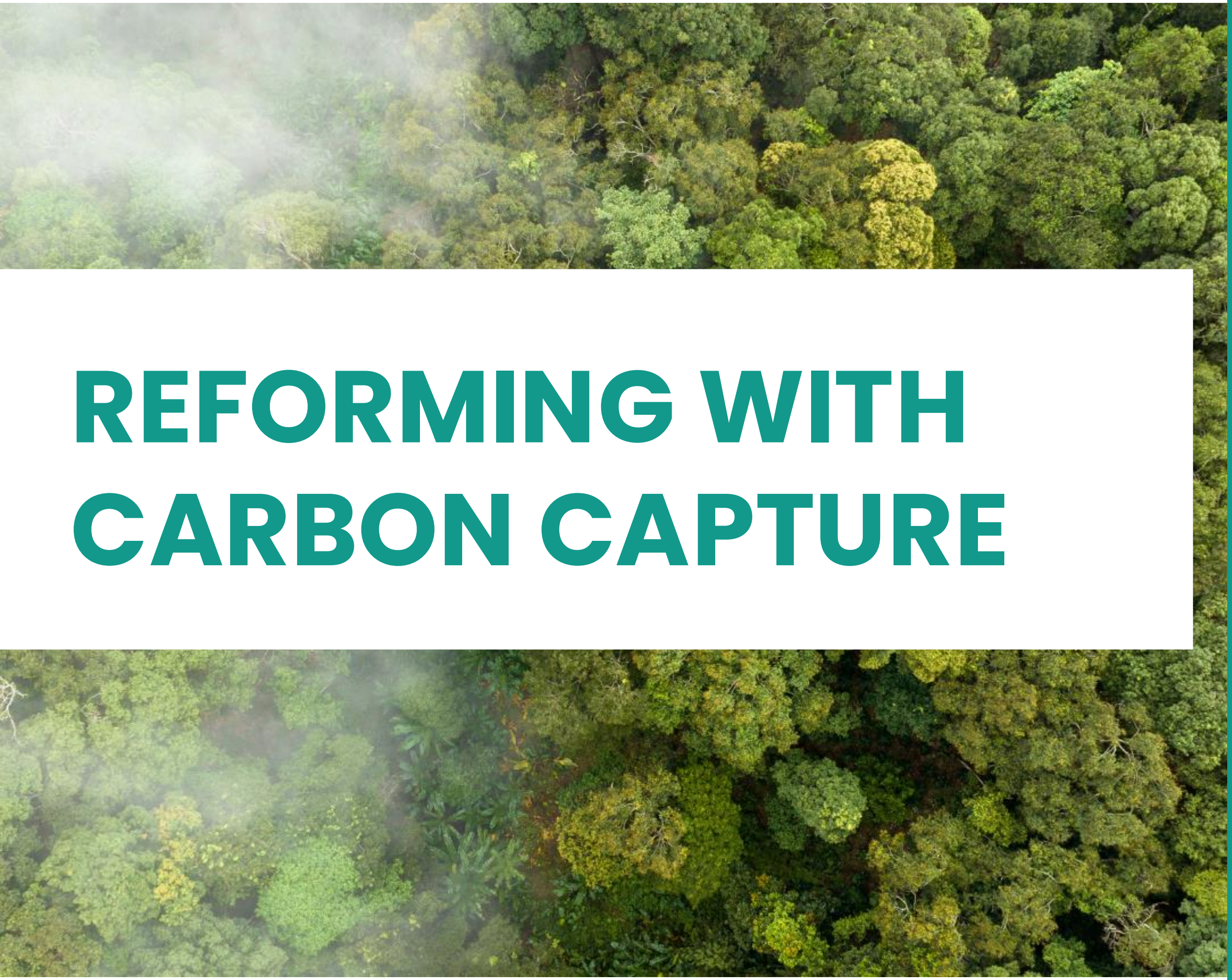
- To replace the 7.9 Mt of hydrogen consumed as feedstock in EU-27 in 2022 by electrolysis, the electrolysers would use up 40% of EU-27 2021 renewable electricity generation of 937 TWh.
- Renewable energy buildout in Europe has been slowed down by permitting, existing grid infrastructure constraints, and slow grid upgrades causing large interconnection queues in many European countries while in others too little renewable capacity is under development.
- The feedstock availability limits the electrolyser buildout both in terms of timing and scale. Due to competition for PPAs, some electrolysis projects are being delayed or downsized due to inability to secure a PPA from a renewable project that will go online within three years of the electrolyser.
- Scaling water electrolysis to GWel scale in water stressed regions could require dedicated water infrastructure such as desalination

Technology

- While low-temperature water electrolysis is a mature technology, companies continue to improve its efficiency, degradation, materials, stack size, ramp-up times, and reliability for both low and high-temperature electrolysis. These will not only improve performance but also decrease cost of the produced electrolytic hydrogen.
- High-temperature electrolysis is less mature and has only several deployed pilots, needs further R&D and demonstration projects
- Deployment improvements – Learning curve for equipment manufacturers, engineers, and integrators to design, build, and operate large scale production facilities. However, this also requires coherent and stable regulatory framework.

Infrastructure

Large water electrolytic projects are located close to renewable energy resources rather than close to existing hydrogen demand centers. The lack of hydrogen transport infrastructure to these demand centers poses a significant challenge for developers of these projects, limiting their options of offtakers, limiting their scale, and often hindering their feasibility. This challenge is very specific for electrolytic hydrogen projects that intend to produce large volumes, but are reliant on areas with available renewable energy, unlike other production methods.



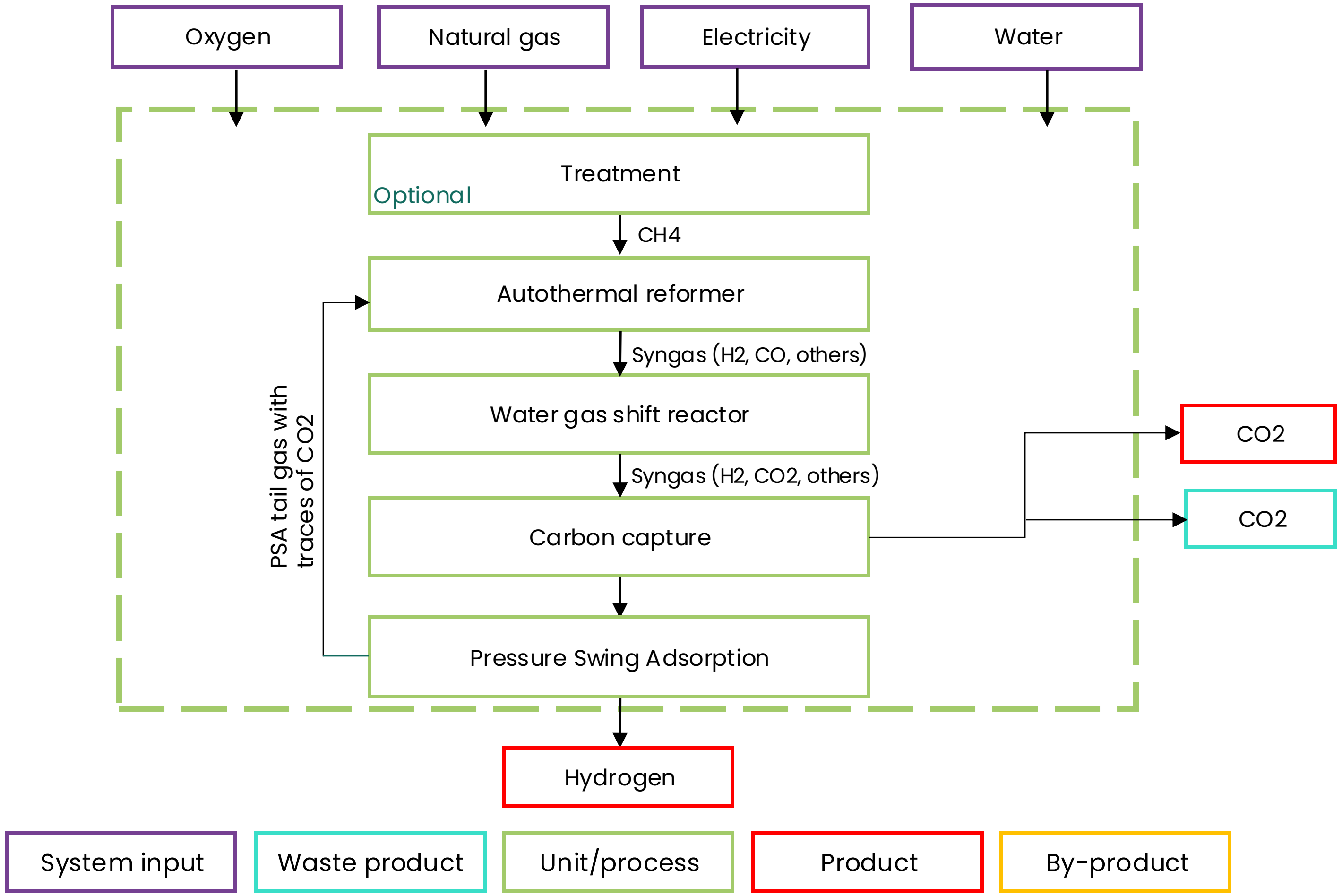
REFORMING WITH CARBON CAPTURE

- **Reforming with carbon capture** refers to using steam, heat, and air/oxygen, to “reform” methane, produce hydrogen, and capture most (at least 94%) of the CO2 produced in the process.
- **Unique technology benefits** – Reforming of natural gas with carbon capture utilizes existing gas infrastructure allowing sufficient feedstock supply to achieve the installation scale needed (100,000+ tonnes/y) to decarbonise the millions of tons of unabated hydrogen being consumed in industry today.
- **Technology** – While unabated steam methane reformers have been deployed globally for decades, most planned projects plan to use the autothermal reforming technology (ATR) and achieve high carbon capture rates of at least 94% (some capture technologies aim for even higher). ATR and carbon capture are mature technologies separately, but they have not been deployed at scale together for hydrogen production.
- **Costs** - LCOH is around 4 EUR/kg under basic modelled conditions. Key cost driver for reforming gas with high carbon capture is the cost of natural gas which can constitute up to 56% of the total cost per kg of hydrogen. It can compete with traditional SMR with emission allowances at 180 EUR/tonne.
- **Emissions** – Assuming high carbon capture rate, the source of natural gas and associated upstream emissions are the decisive factor determining the “low-carbon” character of hydrogen produced by natural gas reforming. Using LNG from the US would exceed the low-carbon threshold of 3.4 kgCO2/kgH2.
- **Scalability challenges** – The availability of CO2 transport and storage infrastructure is the largest challenge for scaling this technology as it is only going to be available in limited regions and will largely exclude landlocked countries. Additional societal challenges include locking the society into using fossil infrastructure and encouraging natural gas production.

Autothermal reforming with carbon capture combines steam methane reforming and partial oxidation in a single reactor

The process: **Autothermal reforming (ATR) with carbon capture combines steam methane reforming and partial oxidation in a single reactor, utilizing both steam and oxygen to convert natural gas into hydrogen and carbon monoxide.** The process feedstocks are steam, air, and natural gas. Oxygen is extracted through air separation unit and natural gas is often pre-treated to preserve the catalyst in the reactor. As part of feedstock treatment, in addition to desulphurisation, some processes include a pre-reforming step that enhances the efficiency and flexibility of the process by converting heavier hydrocarbons in the natural gas feed (ethane, propane, and butane) into simpler molecules before entering the main reactor. The mixture of oxygen, steam, and methane/methane rich gas stream is fed into the autothermal reformer reactor. In the reactor, **during the partial oxidation reaction, the oxygen reacts with a portion of the methane to produce carbon monoxide and hydrogen through an exothermic reaction (releases heat). The heat generated by the partial oxidation provides the energy required for the endothermic steam reforming reaction where methane reacts with steam to produce additional hydrogen and carbon monoxide.** The process generates the necessary heat internally, balancing between endothermic and exothermic reactions. Water gas shift reactor increases H2 yield in the produced syngas. A carbon capture is then applied aiming to capture at least 94% of the CO2 emissions. The gas stream is then generally purified via pressure swing adsorption and potentially compressed.

Figure 2.1: Autothermal reforming with carbon capture – process diagram



Oxygen

Natural gas

Electricity

Water

Treatment

Optional

CH4

Autothermal reformer

Syngas (H2, CO, others)

Water gas shift reactor

Syngas (H2, CO2, others)

Carbon capture

Pressure Swing Adsorption

PSA tail gas with traces of CO2

CO2

CO2

Hydrogen

System input

Waste product

Unit/process

Product

By-product

Notes: This is a generic process diagram that can vary significantly depending on the used technologies and plant setup
Source: Hydrogen Europe; ISO/TC 197/SC 1/WG

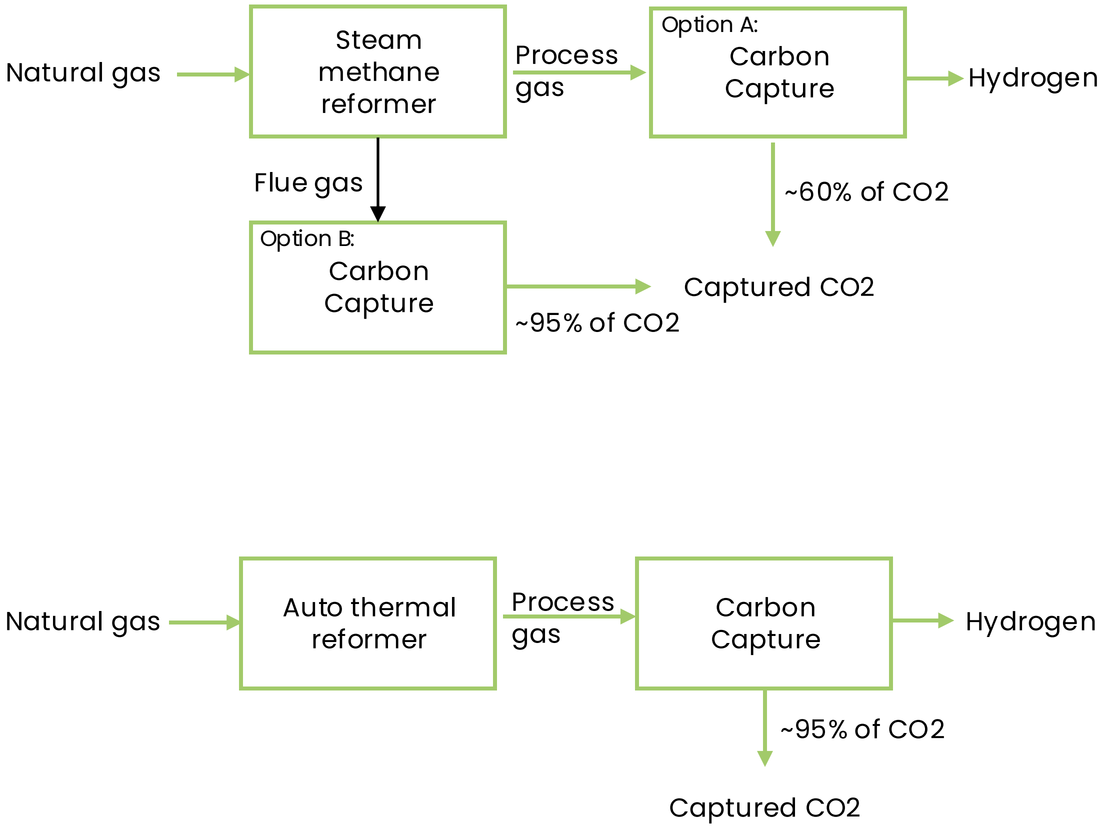
Most future reforming with carbon capture capacity will use autothermal reforming technology due to its simpler process flow and superior performance

There are multiple technologies used for reforming natural gas which is the most common production method for producing unabated hydrogen today. In this report, the focus is on autothermal reforming with carbon capture at 94% (reforming with carbon capture).

Steam methane reforming (SMR): The dominant industrial method for producing hydrogen today, favoured for its efficiency and established infrastructure. Developed in the early 20th century, it involves reacting methane with steam over a catalyst at high temperatures to produce hydrogen and carbon monoxide, which is further processed to increase hydrogen yield. Retrofitting carbon capture technology on existing SMR units is possible, but it reduces the efficiency of the process and increases costs of the hydrogen. **Carbon capture units must be installed to capture CO2 from the flue gas from the SMR process to achieve the highest CO2 capture rate at around 90% or higher. Existing SMRs retrofitted with carbon capture technology only in the process gas stream achieve a carbon capture rate of around 60%.**

Autothermal reforming technology (ATR) with carbon capture: Most developers considering investing in a new reforming unit to produce hydrogen while capturing CO2 emissions focus on autothermal reforming technology. That is also the default technology assumed in this chapter. Autothermal reforming (ATR) of natural gas combines steam methane reforming and partial oxidation. ATR is recognised for its compact design and lower capital costs, but challenges include catalyst longevity and the need for precise oxygen control to optimise hydrogen yield. When using carbon capture, unlike with steam methane reforming, carbon capture equipment does not have to be installed twice (on process and flue gases), thus simplifying the process, making it more efficient, and lowering its costs. **Projects planning to use auto thermal reforming with carbon capture aim to achieve at least 94% carbon capture rates.** While being a choice for large majority of future low-carbon hydrogen projects, ATR with carbon capture does not yet have a significant commercial operational experience. **While IEA rates SMR and carbon capture at TRL 9, ATR with high capture rates is rated at TRL 5-6 (large prototype/full prototype) due to a lack of this commercial experience.** However, the reactors and carbon capture technologies used for ATR are mature and receiving orders, thus TRL is not a limiting factor.

Figure 2.2: Simplified comparison of steam methane reforming and autothermal reforming with carbon capture



Notes: Figure 2.2 is simplified and omits treatment of natural gas feedstock, pre-reforming, water gas shift reaction, and purification of the produced H2.
Source: Hydrogen Europe

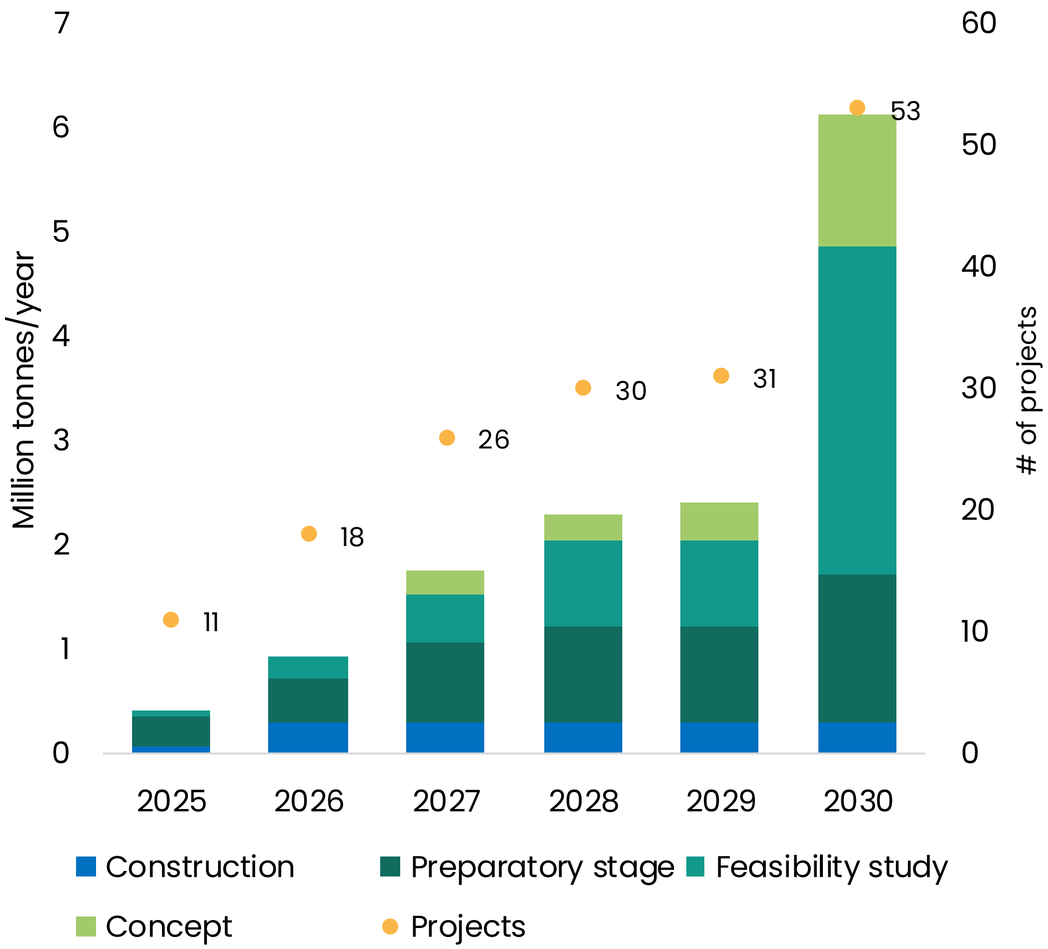
Only one operational SMR project with carbon capture focuses on permanent CO2 storage while most future projects aim to use ATR with carbon capture

Operational projects: The integration of carbon capture with methane reforming for hydrogen production is a relatively recent development. IEA's global hydrogen production projects database lists eight operational projects utilizing SMR coupled with carbon capture. However, only a single project is focused on capturing and storing the captured CO2 while the rest utilize the captured CO2 for various end-uses including enhanced oil recovery, merchant sale, and others. **The only operational project** (to the best of our knowledge) **capturing and storing CO2 is operated by Shell and began in 2015 near Edmonton, Canada.** CO2 is captured from three SMR units with about half of produced CO2 captured and subsequently transported via pipeline to be stored in a deep saline geological formation called Basal Cambrian Sands.

The other projects capturing CO2 from hydrogen production are using it for enhanced oil recovery (EoR) or other industrial purposes. Since the CO2 is not stored, it is not a sustainable means of hydrogen production. However, it shows technical experience with installing and operating carbon capture equipment on SMRs. The first such plant was put into operation in 1982 at Enid Fertiliser facility in Oklahoma, USA. In 2013, Air Products retrofitted two existing SMR's at its refinery in Port Arthur, Texas, USA with carbon capture on its process streams. The captured CO2 from these two projects is used for EoR. In 2015, Air Liquide began operating its carbon capture technology on an SMR in Port Jerome, France and selling the captured CO2 for industrial applications. In 2020, Nutrien, a fertiliser producer in Alberta, Canada retrofitted one of its existing SMR units with carbon capture technology to transport it by pipeline and use it for enhanced oil recovery in the province.

Project pipeline: While these operational projects utilize SMR together with carbon capture technology, future projects are planning to use ATR with carbon capture rates above 90%. **Figure 2.3 shows a project pipeline of almost 50 projects that have been announced in Europe to produce hydrogen from gas and capturing the associated emissions. Most of the new projects are planning to use ATR technology.** If they came online, they could produce up to 6 million tonnes of low-carbon hydrogen a year. However, many of them are dependent on building CO2 infrastructure and only a few have reached a financial close.

Figure 2.3: Announced production capacity (cumulative) in Europe for natural gas reforming with carbon capture



Source: Hydrogen Europe; International Energy Agency; Global CCS Institute

Reforming with carbon capture is a mature technology that can support immediate large-scale decarbonisation of hydrogen demand in a competitive way

Feedstock and infrastructure availability

- Feedstock availability – Natural gas constituted 15% (340 Mtoe) of Total Available Energy in the EU in 2021 (1462 Mtoe). In energy terms it is approximately 118 million tonnes of hydrogen. As such the feedstock for reforming hydrogen with carbon capture is widely available, partially from European production, but mostly from imports.
- Infrastructure – In addition to the large-scale availability of the feedstock, the existing infrastructure for gas with its over 200,000 km of transmission pipelines in Europe allows for this technology to be used almost anywhere. Especially near current industrial installations thus avoiding the need for hydrogen transport infrastructure. The availability of CO2 transport and storage is a constraint further discussed in the scalability challenges.

Scale and technology

- Large scale – Current hydrogen consumers such as ammonia plants or refineries consume on average around 100,000 tonnes of hydrogen a year per plant. This hydrogen is provided mostly from unabated SMR installations on-site. Abating the hydrogen production emissions from a single installation like this would require ~1 GWel of water electrolysis capacity which is almost four times more than is installed in Europe in March 2024. Reforming with carbon capture and at high carbon capture rates can provide the necessary scale to supply low-emission hydrogen to large installations and industry clusters earlier.
- Technology maturity – The steam methane reforming technology is deployed all over the world. The various carbon capture technologies used for capturing CO2 from process or flue gases are also mature technologies that could be retrofitted to existing installations. The autothermal reforming technology, planned for most new reforming with carbon capture projects including those reaching FID, while not deployed at commercial scale is expected to be deployed quickly and with limited delays.

Cost

The technology enjoys a competitive advantage over water electrolysis production in most of Europe in the near term with production costs around 4 EUR/kg assuming gas prices at 40 EUR/MWh and EUAs at 80 EUR/t. While the price gap with electrolysis will narrow in the future, reforming with carbon capture could for several years provide low-emission hydrogen at a smaller premium than water electrolysis.

Natural gas costs represent almost 56% of the LCOH from reforming with carbon capture while the cost of transporting and storing CO2 is highly uncertain

Cost structure: **Natural gas cost dominates the cost structure of producing hydrogen from gas with high carbon capture rate, constituting 56% of the LCOH** in the base case scenario with natural gas wholesale price at 40 EUR/MWh.

The second largest cost component are CO2 storage and transportation costs at 10% of the price of hydrogen. Cost of 100 EUR/tonne was assumed, but these will significantly vary across projects. CAPEX represents the investment needed to build a new asset reforming natural gas with carbon capture rate of at least 94%. While representing only 8% of the total cost per kg, this value represents installation of an ATR and carbon capture unit. In the case of retrofitting existing SMR units, albeit with lower capture rates, the CAPEX would be even lower.

Competitiveness: Comparing different gas prices, **with gas at 40 EUR/MWh, the costs are at 3.9 EUR/kg which is very competitive with 2024 offers for large scale supply of electrolytic hydrogen in 2024. With gas prices at long-term average of 20 EUR/MWh, this low-carbon hydrogen could be produced for 2.9 EUR/kg and would have a 1 EUR/kg premium over unabated hydrogen from amortised SMR.** With EUAs rising in the following years, it could be affordable enough for industrial installations to decarbonise even though it is not an RFNBO.

Figure 2.4: LCOH from reforming with carbon capture

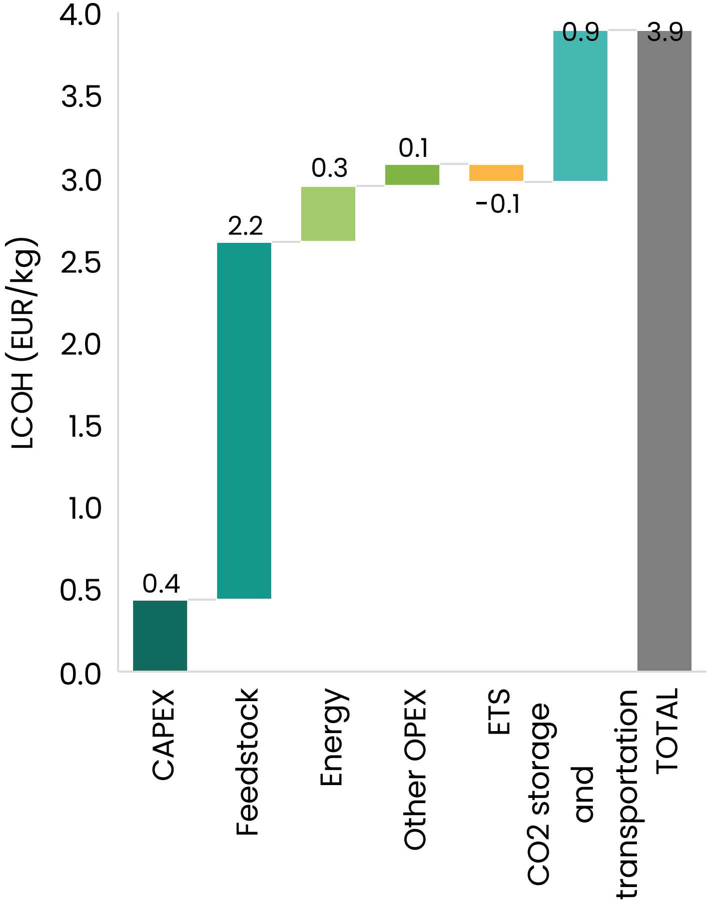
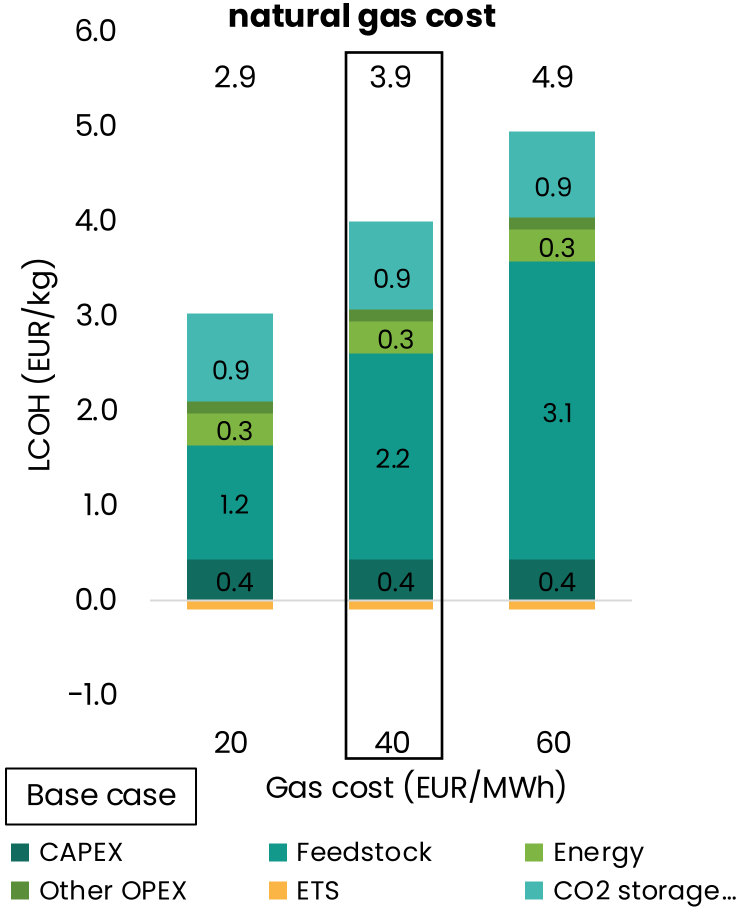


Figure 2.5: LCOH from reforming with carbon capture depending on natural gas cost



Assumptions for these values: ATR with carbon capture technology used; CAPEX, 900 EUR/KW; Energy: Natural gas at 20/40/60 EUR/MWh and average network fees at 5 EUR/MWh and electricity costs at 80 EUR/MWh plus average network fees at 29.3 EUR/MWh; Other OPEX: 3.5% of CAPEX; CO2 capture rate at 94%; CO2 storage and transportation 100 EUR/t; Economic lifetime of 20 years; Operating hours of 8000 a year; Project details: Large scale ~10 t/h project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe

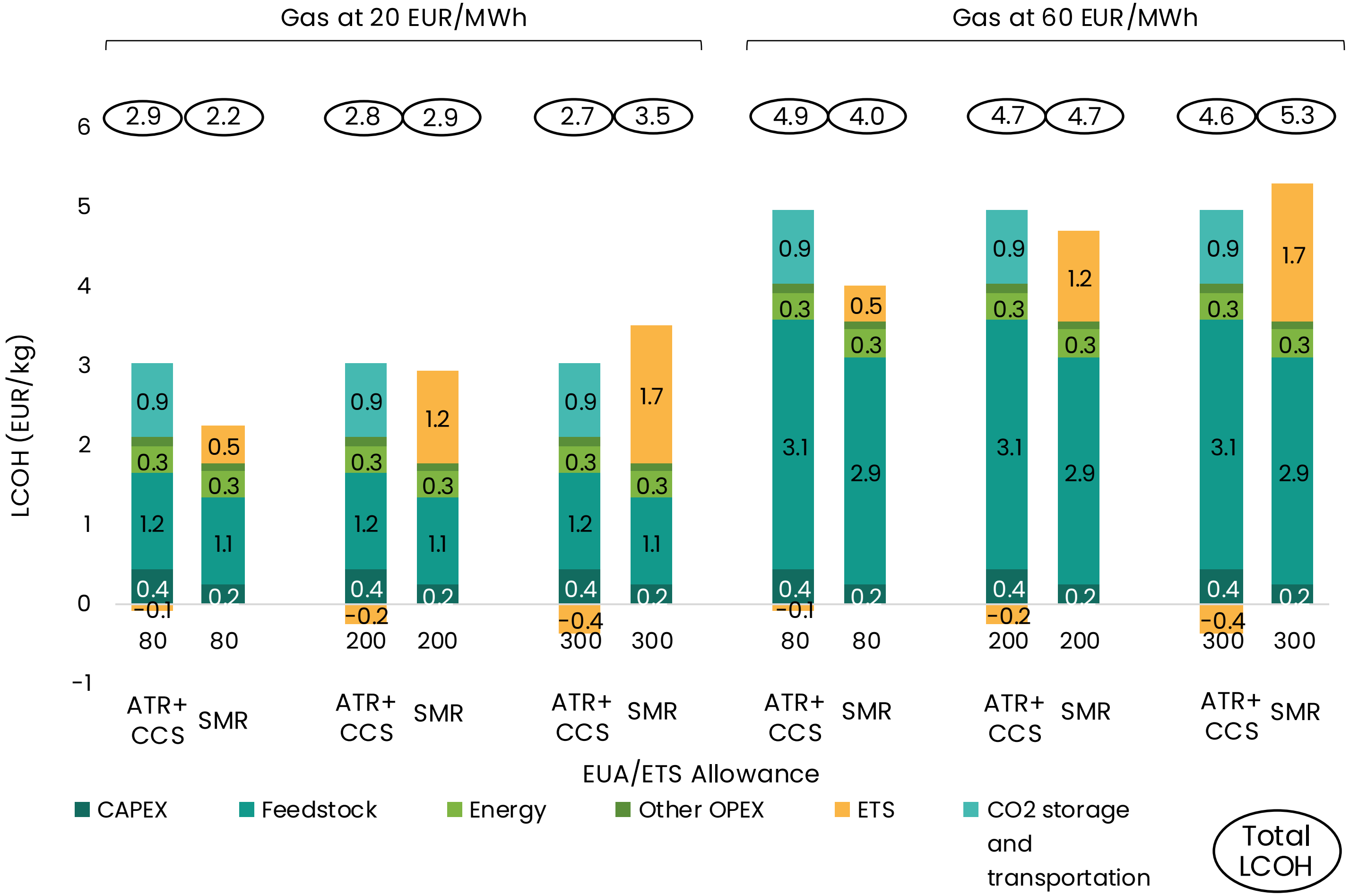
Reforming with carbon capture can price compete with traditional SMR with EUA at 180 EUR/tonne

Figure 2.6 compares LCOH of new SMR without carbon capture (SMR on the graph) and building a new reformer with high carbon capture rate (ATR+CCS on the graph) with gas price and EUA price as variables. **With the EUA price at around 80 EUR/t, hydrogen from a new unabated SMR enjoys an approximate 30% cost advantage compared to building a new ATR with carbon capture.** Compared to a fully depreciated SMR, the cost gap is around 45% per kg of hydrogen.

Impact of emission allowances: That premium for new installations disappears when EUAs reach around 180 EUR/tonne at which point a newly installed ATR with high carbon capture can compete on price with a newly installed SMR without carbon capture. **For the carbon capture installations to compete with existing SMRs, the EUAs would have to reach around 210 EUR/tonne.** With EUAs at 300/t, it would enjoy a 15% cost advantage. **These price levels around 3 EUR/kg for low-carbon hydrogen are relatively competitive with current offers for large scale supply of RFNBO hydrogen in 2024 which commands a further premium due to regulatory targets.**

Besides the gas and EUA prices, another key uncertainty factor is the cost of CO2 storage and transportation. Based on industry feedback, the analysis is based on assumed cost level of 100 EUR/t, translating into 0.9 EUR/kgH2. As more CO2 storage projects are being deployed there is potential for these costs to fall markedly.

Figure 2.6: LCOH from reforming with CO2 capture and SMR with no capture



Assumptions for these prices: ATR with carbon capture technology used; CAPEX: 900 EUR/KW and SMR CAPEX: 550 EUR/KW; Energy: Natural gas at 20 and 60 EUR/MWh plus average network fees at 5 EUR/MWh and electricity costs at 80 EUR/MWh plus average network fees and taxes at 29.3 EUR/MWh; Other OPEX: 3.5% of CAPEX for reforming with carbon capture and 4% of CAPEX for SMR; CO2 capture rate at 94%; CO2 storage and transportation 100 EUR/t; Economic lifetime of 20 years; Operating hours of 8000 a year; Project details: Large scale ~10 t/h project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe

The source of natural is gas one of the decisive factors determining the low-carbon character of hydrogen produced by natural gas reforming

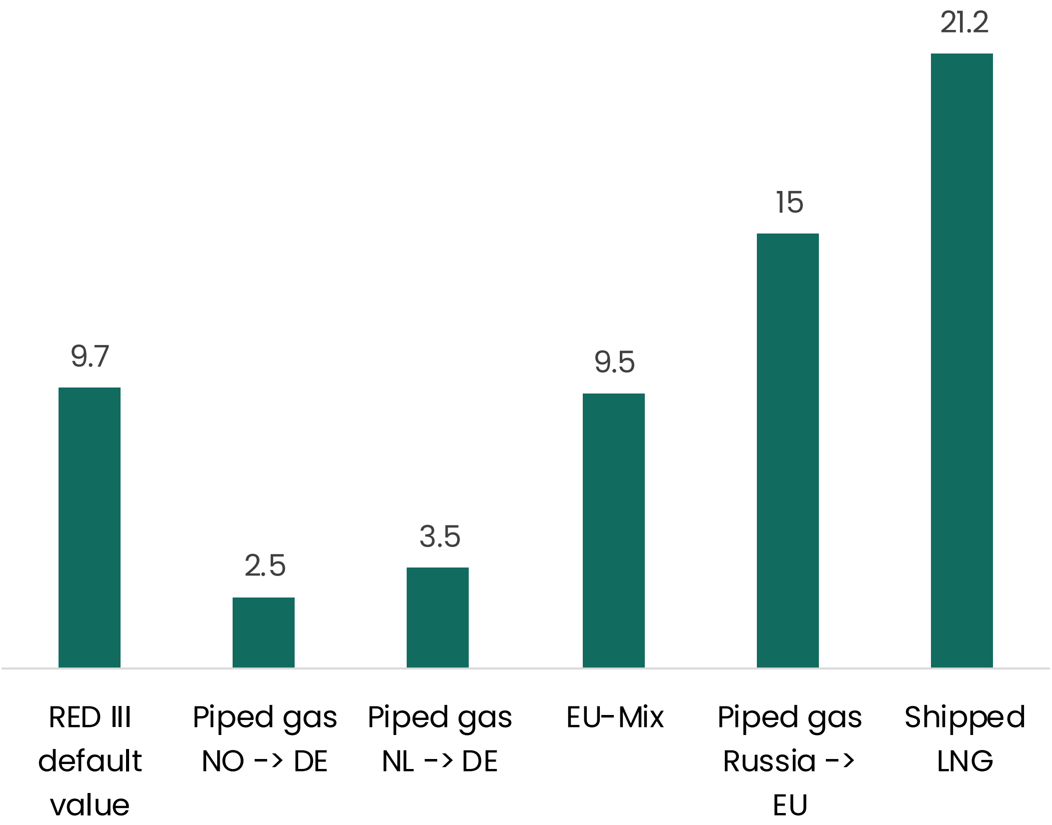
GHG emission intensity of hydrogen produced from reforming of natural gas are highly dependent on the source of the used gas. Figure 2.7 shows GHG emission intensity of different gas sources.

Upstream emission factors: The main differences steam from distances of transportation and methane leakages during extraction and transportation of the gas. In general, Norwegian gas has a comparatively lower GHG intensity due to efforts to eliminate gas flaring and leakage during transportation due to use of fully welded pipelines (instead of flanged ones). On the other hand, **relatively low (or non-existent) environmental standards in Russia, combined with longer transport distance, result in the upstream emissions for Russian gas delivered to Germany being 6 times higher than gas from Norway.** Gas supplied as LNG has the highest GHG emission intensity due to the added GHG footprint of the gas liquefaction and long-distance shipping. **With upstream emission intensity above 20 gCO2eq/MJ, use of LNG for low-carbon hydrogen production would be impossible.**

Using different upstream emission intensities: The delegated act defining rules for RFNBO hydrogen established a single EU-wide emission factor of 9.7 gCO2eq/MJ. Replicating such an approach for low-carbon hydrogen under the upcoming delegated act for low-carbon fuels could be problematic. **Having one single EU-wide emission factor fails to deliver any incentives for project developers to use less carbon-intensive sources of natural gas on one hand and it allows for the greenwashing of projects relying purely on LNG**.

One way of ensuring a more accurate and robust GHG accounting would be to develop regionally differentiated gas emission factors (e.g. separately for each TSO network). This would better reflect regional gas supply differences and would at least incentivise locating investments in regions having access to low-GHG intensive gas. **The most accurate approach would be to require use of project specific estimates**.

Figure 2.7: Upstream emissions for natural gas energy input depending on the source of supply (in gCO2eq/MJ)



Source: Hydrogen Europe; European Commission; Equinor; DBI Gas- und Umwelttechnik; US Department of Energy

Reforming of natural gas with CCS can only result in low-carbon hydrogen if a very high carbon capture rate is ensured

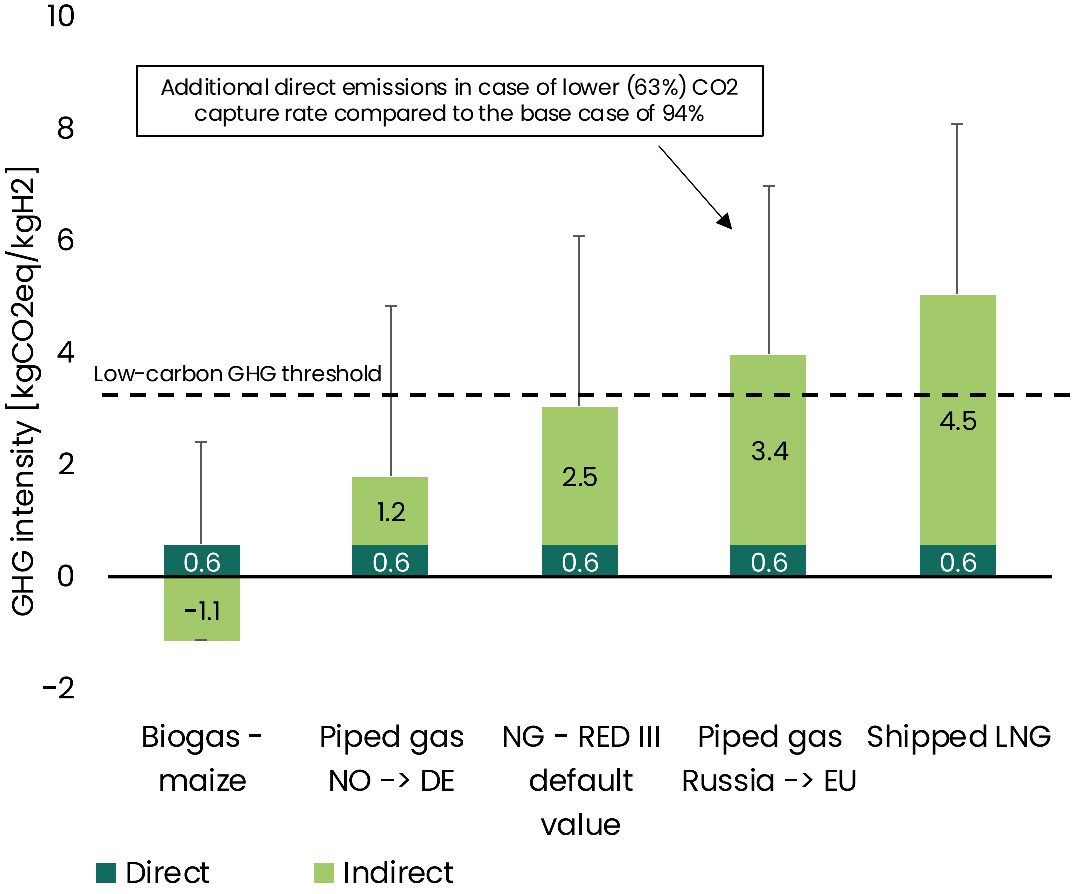
Carbon capture rate: Other than upstream emissions of natural gas supply, the other key factor determining the final GHG intensity is the achieved CO2 capture rate. As has been explained, depending on the approach the capture rate can be around 60% (limiting carbon capture only to SMR process gas) or even up to 97% (ATR with carbon capture). The importance of achieving a high capture rate is demonstrated on Figure 2.8.

If the capture rate were to fall in the range of 55-65% the GHG intensity of hydrogen would be well above the required limit for that hydrogen to qualify as a low-carbon fuel – even with strict methane leakages prevention. The only possibility to produce hydrogen at an emission level below 28.2 gCO2eq/MJ with a low CO2 capture rate would be to use biogas (or biogas/natural gas mixture) as feedstock instead of natural gas. With biogas from maize the total emissions would be around 20 gCO2/MJ (2.4 kgCO2eq/kgH2) and **If advanced biogas sources would be used such as biogas from wet manure, even a net-negative emission level could be achieved**.

On the other hand – **when using gas with high carbon footprint, like LNG or Russian gas, even 100% carbon capture rate would not be enough to produce hydrogen qualifying as low-carbon**.

Excluded from the analysis: It should be noted however that the above estimations do **not include emissions related to CO2 compression/liquefaction, transportation and storage**, which in extreme circumstances (CO2 liquefaction using GHG intensive grid electricity and shipment of CO2 to offshore storage site), could add as much as 0.5-0.7 kgCO2/kgH2 of additional GHG emissions. Another important factor to **consider are additional methane leakages** from the production process itself. As methane is a potent GHG (with a GWP around 30 x higher than CO2) in order to ensure a low-carbon character of produced hydrogen, methane leaks should be closely monitored and, if possible, avoided.

Figure 2.8: GHG emissions for hydrogen produced via gas reforming depending on gas source and carbon capture rate



Notes: Low-carbon threshold refers to 70% below fossil fuel comparator of 94 gCO2/MJ = 28.2 gCO2/MJ = 3.4 kgCO2eq/kgH2 as established in the decarbonised gas and hydrogen package. The error bars on the graphs indicate emissions level with the minimum (63%) and maximum (94%) CO2 capture rate. Assumptions for the calculated GHG emission intensity values: Indirect electricity GHG emission intensity of 66.1 gCO2/MJ; Indirect emissions from gas from various locations; Direct gas combustion emissions 56.2 gCO2/MJ, CO2 capture rate between 63 and 94%;

Source: Hydrogen Europe; European Commission; Equinor; DBI Gas- und Umwelttechnik; US Department of Energy

CO2 transport and storage infrastructure availability are limiting reforming with carbon capture's geographical potential

Infrastructure

- CO2 transport and storage infrastructure – While there are projects planning to build this infrastructure in Norway, Netherlands, UK, and elsewhere, mostly focused on industrial clusters, the infrastructure largely does not yet exist. A lack of CO2 infrastructure availability is even more prominent for landlocked countries with no existing CO2 pipeline to a maritime port from which the CO2 could be shipped out.
- CO2 storage potential – It isn't evenly distributed among EU member states, leading to some installations transporting CO2 over large distances, making the required emission threshold even more difficult to attain.
- Gas infrastructure dependence - Dependence on existing gas infrastructure that might slowly decrease its utilization, endangering supply for this technology while potentially locking in the use of natural gas infrastructure in the future.
- Slowing hydrogen infrastructure buildout - As majority of hydrogen infrastructure will be repurposed, increasing the use of this technology and gas infrastructure could be detrimental to repurposing gas infrastructure to hydrogen infrastructure.
- Planning - Lack of integrated infrastructure planning aimed at reconverting existing infrastructure towards H2 and CO2 transport for industrial clusters and regional integration

Technology

Carbon capture rates - While various plants applied carbon capture technology on hydrogen production around the world, e.g. Air Liquide at Port Jerome, Air Products at Port Arthur, their carbon capture rates are significantly lower than the 94% assumed in the modelling in this report. There are 116 projects in various stages of development (from concept to construction) around the world planning to develop new reforming facilities and most of those with high carbon capture rates (above 90%).

Sustainability

Upstream emissions - Europe will continue to be an importer of natural gas. Under current geopolitical conditions, large percentage of this natural gas will be imported as LNG from US, Middle East, and elsewhere. The upstream emissions associated with this feedstock present a significant challenge for producing hydrogen below the 3.4 kgCO2eq/kgH2 threshold.

METHANE SPLITTING (PYROLYSIS)

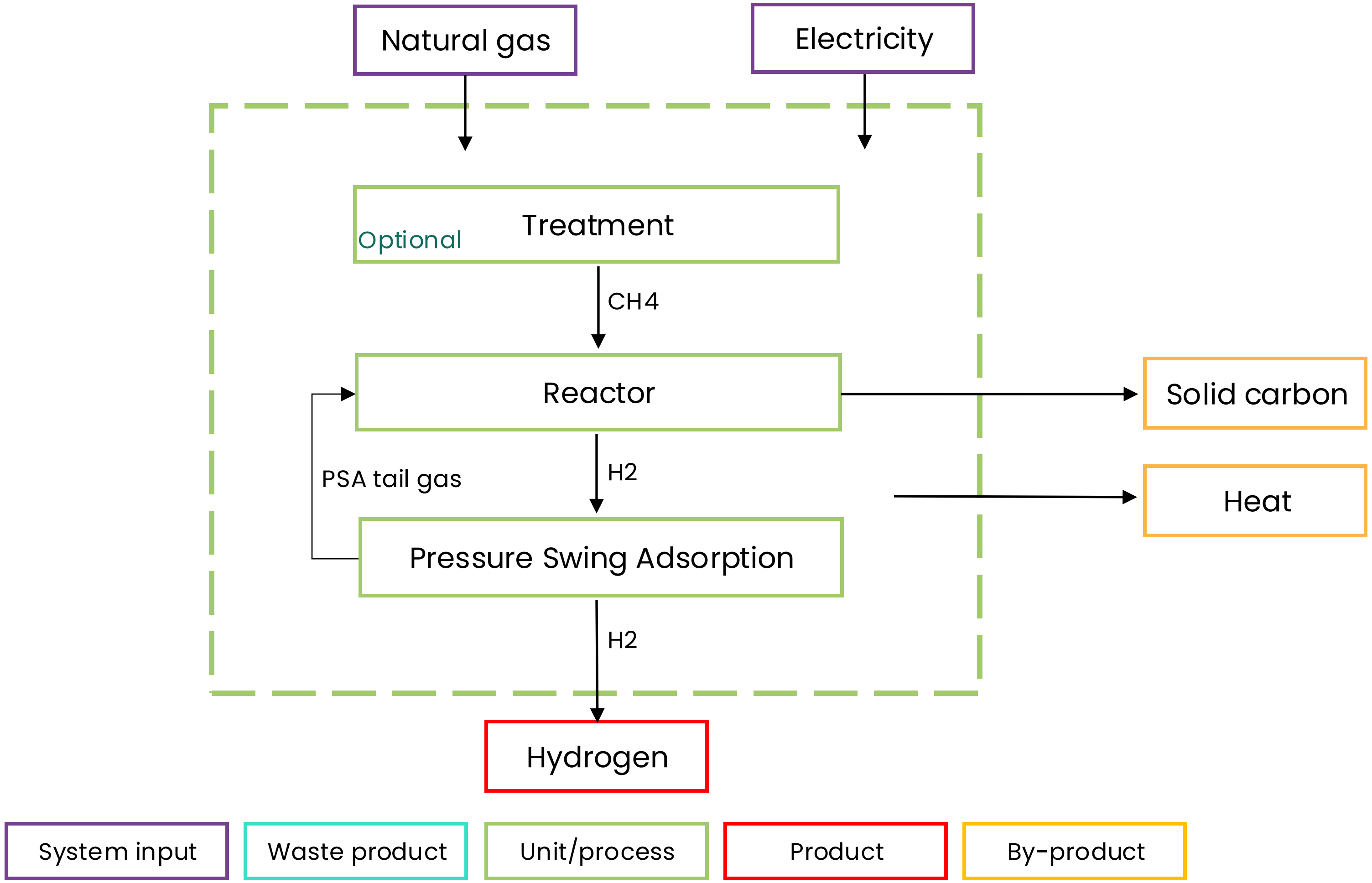
- **Methane splitting** refers to hydrogen production through dry decomposition of methane (CH4) and is commonly referred as methane pyrolysis.
- **Unique technology benefits** – Availability of natural gas and the related infrastructure allows this technology to scale to volumes needed for industrial applications. The generation of solid carbon by-products with their own markets further improves the technology's competitiveness.
- **Technology** – Different methane splitting technologies are at various technology readiness levels, but pilot, demonstration, and commercial plants are all being built. Technology R&D is focusing on improving hydrogen purity, the form and quality of the solid carbon by-product, energy consumption, durability/degradation of the reactor, price and availability of used catalysts, and transitioning from batch production to continuous production.
- **Costs** – Feedstock accounts for 45% of the costs of producing hydrogen by methane splitting and by-product revenues can reduce that cost by 34% in the base case scenario. At February 2024 gas prices, hydrogen from methane splitting could be priced for 2.3 EUR/kg or lower depending on the solid carbon prices.
- **Emissions** – Upstream emissions and electricity GHG emission intensity are the decisive factors determining the "low-carbon" character of hydrogen produced by methane splitting. Using LNG imported from the US would only fall below the low-carbon threshold of 3.4 kgCO2eq/kgH2 if using very clean grid electricity such as in Sweden.
- **Scalability challenges** – Reliance on natural gas and its associated infrastructure is a long-term scalability concern. In addition, the technology carries relatively high CAPEX costs and is heavily reliant on revenues from solid carbon by-product which are very uncertain.

Methane splitting has fewer steps than other pathways, but the reactor design varies significantly depending on the process and desired by-products

The process: The technical term pyrolysis refers to **the thermal decomposition of materials at elevated temperatures in the absence of oxygen.** The report uses the term methane splitting instead of pyrolysis to include technologies that work on a similar principle but do not refer to themselves as pyrolysis. Methane splitting decomposes methane into its elemental components: hydrogen and solid carbon. The reaction is endothermic and the energy necessary for the reaction can come from various sources. Depending on the process, the natural gas used as a feedstock must be treated to filter other gaseous hydrocarbons and other compounds present in that natural gas stream. Once hydrogen exits the reaction, depending on the final end-use, it can (but doesn't have to be) treated/purified to achieve a specific purity level. While this chapter focuses on methane splitting, other gaseous hydrocarbons can be used in the process such as propane.

Solid carbon by-products: The reactor design, used catalyst, and process temperatures dictate the type and characteristics of the produced allotropes of carbon. Carbon black is made at higher temperature reactions (+1300C), graphite depends on carbon-based catalysts, and metal-based catalysts can yield carbon nanotubes or nanofibers. **With three tonnes of solid carbon per tonne of hydrogen, its management and valorisation are often essential for a project's economic feasibility.** Companies strive to improve their technologies to achieve optimised solid carbon production with specific allotrope output.

Figure 3.1: Methane splitting – process diagram



Notes: This is a generic process diagram that can vary significantly depending on the used technologies and plant setup; While reforming of methane could also be perceived as splitting, the Reforming production pathway is explained in chapter 2.
Source: Hydrogen Europe; ISO/TC 197/SC 1/WG; Canadian Institute for Clean Energy

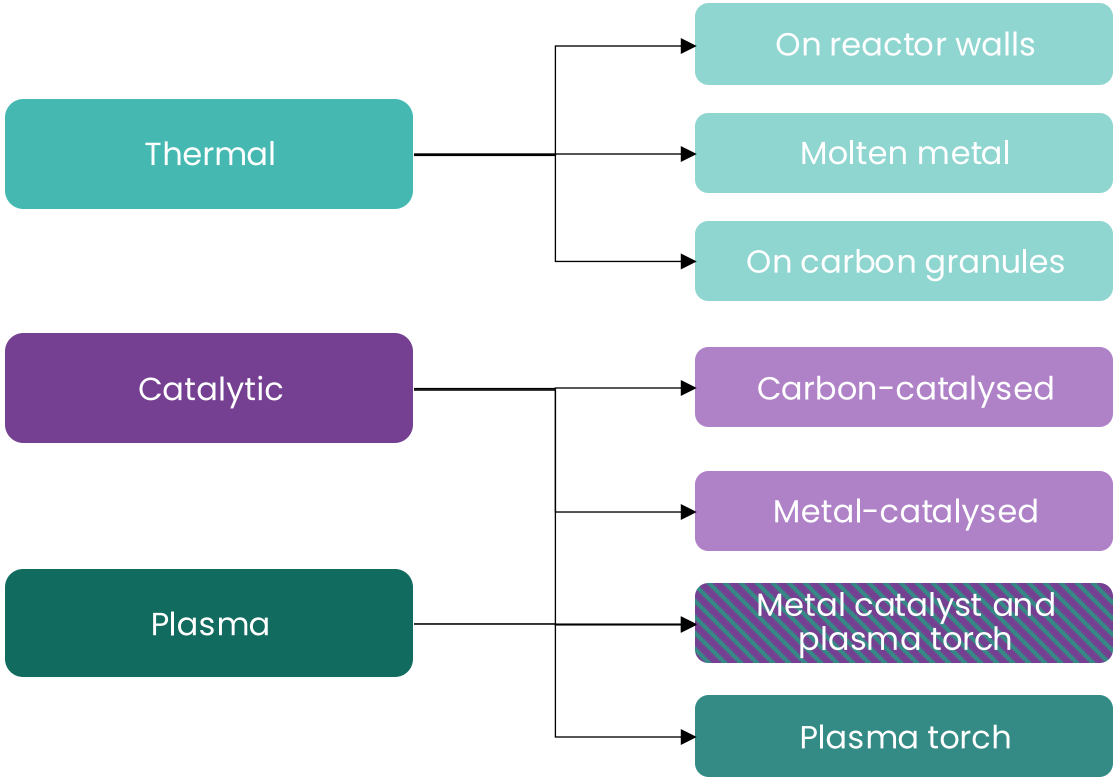
Different technologies are being developed to optimise for hydrogen yield, solid carbon yield, and lower temperatures

Technology development: Traditional pyrolysis reactors focused on the thermal decomposition of methane at extremely high temperatures (1000°C) to produce hydrogen. However, higher temperatures require more robust and thus costly materials as well as higher energy inputs. **As a result, numerous companies are developing innovative reactors to improve the hydrogen yield, decrease needed temperatures and increase reactor durability, and control and improve the solid carbon by-product.** The measures to do so include quickly increasing reactor temperature, utilizing a catalyst to decrease the reaction temperature, increasing the catalyst surface area, using microwave or electric beams, or others. The technology readiness of these innovations ranges between advanced R&D activities at low TRL levels to commercially deployed processes at TRL8 and approaching TRL9.

Technology categories: **The technologies can largely be split into thermal, catalytic, and plasma categories** but, as Figure 3.2 shows, the technologies and processes are also often combined. Thermal methane splitting involves the direct heating of methane to high temperatures, causing the molecular bonds to break down, resulting in hydrogen and solid carbon. The thermal black process is a traditional pyrolysis method where methane is decomposed at temperatures usually exceeding 1000°C with the objective of carbon black production. Catalytic methane splitting makes use of a catalyst such as nickel, iron, or carbon to lower the temperature required for the methane decomposition reaction, thus improving energy efficiency and process control. Plasma pyrolysis leverages plasma - a highly ionized or electrically charged gas - to provide the energy needed for methane decomposition. This category contains thermal splitting where the plasma's thermal energy drives the reaction and electrochemical plasma where plasma with an electrochemical gradient is used to enhance the pyrolysis process.

Technology aspects: The different technologies are reflective of ongoing research aimed at optimising the process for industrial-scale hydrogen production**. Each pathway has its advantages and challenges, such as hydrogen purity, the form and quality of the solid carbon, the energy consumption, durability of the reactor, price and availability of used catalysts, transitioning from batch production to continuous, and others.** The process used in the following calculations for LCOH and GHG emission intensity is based on thermo-catalytic splitting of methane.

Figure 3.2: Methane splitting categories and a selection of technologies



Source: Hydrogen Europe; Canadian Institute for Clean Energy; Schneider, S., Bajohr, S., Graf, F., & Kolb; Shah, M., Mondal, P., Nayak, A. K., & Bordoloi, A.

Methane splitting is a known technology with a huge potential for innovation being deployed globally

Historical perspective: The methane splitting technology has evolved significantly in the last several decades, but mostly **driven by the processes optimising for carbon black production rather than hydrogen production.** An example of that is the Kvaerner process developed by the Norwegian company Kværner (now Aker Solutions). It deployed commercial-scale methane splitting facility utilising hot plasma technology in 1999 in Karbomont, Canada with capacity of 20,000 tonnes of carbon black and 6,000 tonnes of hydrogen per year, but it was decommissioned in 2003 after facing carbon black quality issues.

Current projects: **Monolith Materials continued improving on that plasma technology** and has deployed methane splitting commercial size plant in 2020 in Nebraska, USA. **The primary objective continues to be carbon black production** at 14,000 tonnes/year and hydrogen production at ~4,600 tonnes/year. It has received a $1 billion conditional loan from US Department of Energy's Loan Programs Office for an expansion to produce 194,000 tonnes/year of carbon black and ~64,000 tonnes/year of hydrogen. It is considered to currently have the highest TRL technology.

Besides Monolith, Figure 3.3 summarises plant developments and technology of a selection of companies with TRL between 6 and 8 focusing on methane splitting originally prepared by British Columbia Centre for Innovation and Clean Energy.

Australian Hazer Group uses iron ore catalyst and began its industrial scale demonstration plant in January 2024 with a current production capacity of ~100 tonnes of hydrogen/year and 380 tonnes of graphite/year. Finnish company Hycamite developed a thermo-catalytic decomposition technology based on catalyst that lowers the temperature needed for methane splitting while increasing the quality of obtained solid carbon. It began constructing its first industrial scale demonstration plant in 2024 in Kokkola, Finland with the aim to have it operational by the end of 2024. It will have an annual capacity of 2,000 tons of clean hydrogen and 6,000 tons of solid carbon. Berlin based Graforce has already built a demonstration plants in Austria using high frequency plasma for splitting methane or other gaseous hydrocarbons.

Figure 3.3: Selection of companies with TRL 6-8 and projects pursuing various methane splitting technologies

	Company	Status	Technology
🇺🇸	Monolith	Commercial plant (13 t/d) in Nebraska in 2020, expansion to 165 t/d in 2026.	High temperature electric heating - plasma
🇦🇺	Hazer Group	Demo plant (275 kg/d) in Perth in 2024, commercial plant (7 t/d) in Canada 2025.	Low temp fluid bed iron ore catalytic pyrolysis
🇺🇸	C-Zero	Pilot plant (400 kg/d) planned for 2024, commercial plant (6 t/d) 2025.	Bubble column molten metal / salt pyrolysis
🇺🇸	Huntsman Nanocomp	Bench scale (1 kg/d), pilot plant (25 kg/d) in Texas in 2023, commercial demo plant (1 t/d) in 2026.	Thermocatalytic pyrolysis
🇺🇸	H-Quest	Pilot plant (250 kg/d) in 2023, with commercial target of 1 t/d.	Microwave plasma pyrolysis
🇫🇮	Hycamite	Bench scale, pilot plant (5.5 t/d) planned for 2024 (Finland).	Thermocatalytic pyrolysis
🇬🇧	Hiiroc Hydrogen	2 demo plants in operation (UK), pilot plant (400 kg/d) planned for 2024.	Vortex plasma torch and molten metal pyrolysis
🇺🇸	Modern Hydrogen	2 micro demo plants (5 kg/d) 2023, pilot plant (500 kg/d) in 2024.	High temp pyrolysis
🇨🇦	Ekona Power	Bench scale reactor (200 kg/d), pilot plant (1 t/d) in Alberta planned for 2025.	Thermal pulsed methane pyrolysis
🇬🇧	Levidian	Demo plants (27 kg/d) in Scotland and demo plant (55 kg/d) planned for 2025 in UAE.	LOOP - microwave plasma methane cracking
🇫🇷	Plenesys	Demo plant (150 kg/d) in Australia planned for 2024 with commercial target of 275 kg/d and 2.7 t/d units.	Hyplasma (AC plasma arc)
🇩🇪	Graforce	Demo plant in Austria in 2024.	Plasmalysis
🇫🇷	Sakowin	Small demo launched in 2022 in Switzerland (4 kg/d). Industrial demo planned for 2024 (72 kg/d).	Plasmalysis

Source: Hydrogen Europe; Canadian Institute for Clean Energy; CSIRO; GasRoundtable; Graforce; Hycamite; Halford, B; Energy News; Mondal, P., & Dalai, A. K. ; Australian manufacturing; Hu, X; Ekona Power Inc. ; Tullo, A. H. ; Ansys; Schneider, S., Bajohr, S., Graf, F., & Kolb; Shah, M., Mondal, P., Nayak, A. K., & Bordoloi, A.;

Methane splitting doesn't rely on developing new infrastructure, doesn't encounter feedstock issues, and can be produced at a competitive price

Feedstock availability and infrastructure

- Feedstock availability – Natural gas constituted 15% (340 Mtoe) of Total Available Energy in the EU in 2021 (1462 Mtoe). In energy terms it is approximately 118 million tonnes of hydrogen. As such the feedstock for methane splitting is widely available, partially from European production, but mostly from imports. The availability of distributed biowaste in Europe means that smaller scale distributed hydrogen production from biomethane is also an option.
- Infrastructure - In addition to the large-scale availability of the feedstock, the existing infrastructure for gas with its over 200,000 km of transmission pipelines in Europe allows for this technology to be used almost anywhere. Especially near current industrial installations thus avoiding the need for hydrogen transport infrastructure.

Scale and costs

- Large scale – Current large hydrogen consumers need on average around 100,000 tonnes of hydrogen a year. While methane splitting technologies are not operational on that scale, given the feedstock availability, it is possible to produce these large volumes of hydrogen from methane splitting to supply low-emission hydrogen to large installations and industry clusters.
- Cost – Using base assumptions, hydrogen from methane splitting could reach 3.3 EUR/kg with gas prices at 40 EUR/MWh and solid carbon at 500 EUR/t. This is cheaper than available low-temperature electrolytic hydrogen and could, like reforming with carbon capture, for several years provide low-emission hydrogen at a smaller premium to existing SMRs than water electrolysis.

Other

- Scale - Due to feedstock availability and availability of natural gas infrastructure, hydrogen from methane splitting can help provide large volumes of clean hydrogen in a decarbonised world
- By-product - Solid carbon by-product can be a valuable domestic source of products and materials needed for the energy transition - including graphite (batteries), carbon fibre (hydrogen tanks), carbon nano-tubes (potentially replacing copper for electric wiring), and others.

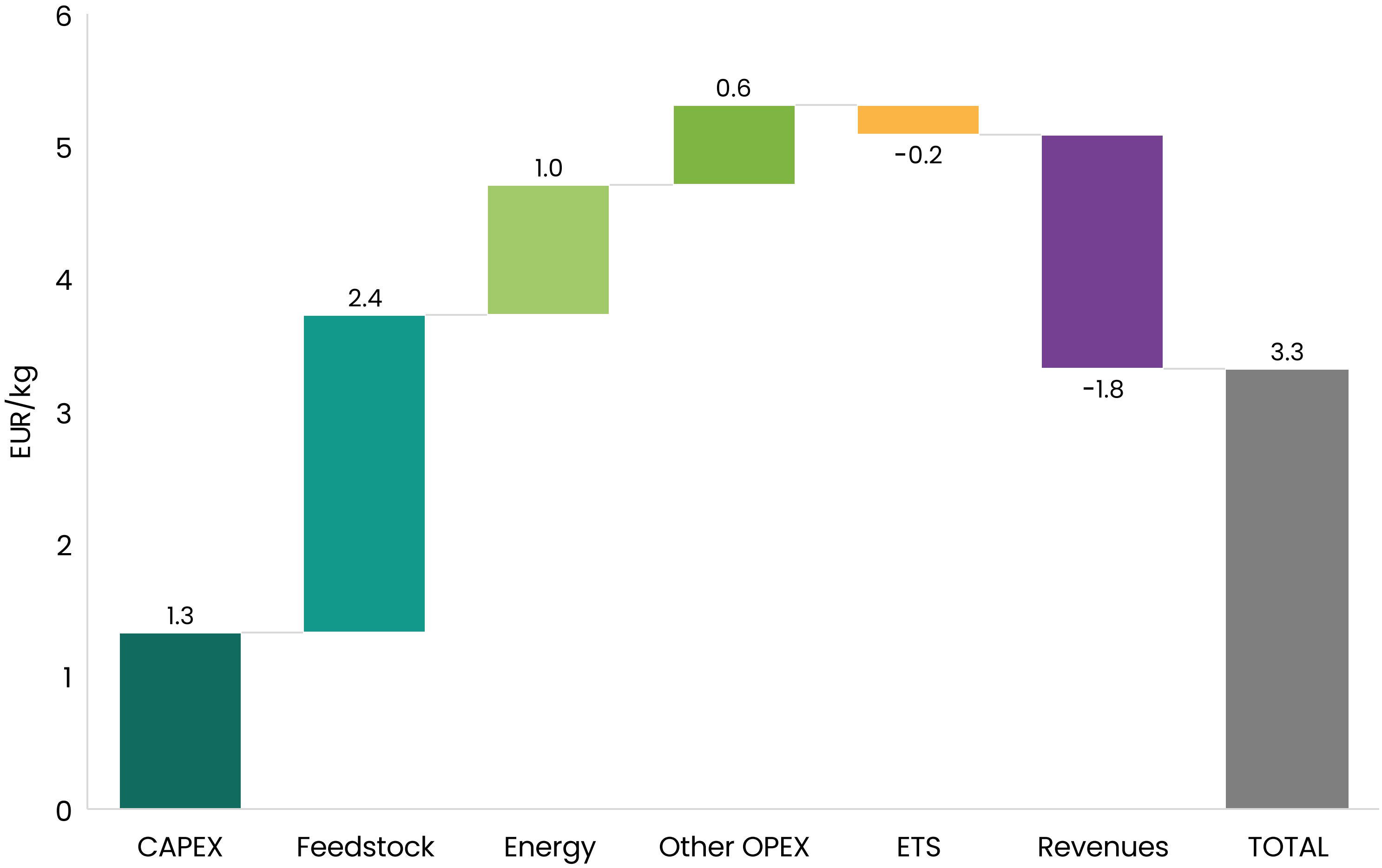
Hydrogen cost could be as low as 3.3 EUR/kg, with feedstock making 45% of the cost and solid carbon revenues reducing LCOH by 34%

Feedstock: Fuel costs amount to 45% of the costs of hydrogen in the base case scenario with natural gas prices at 40 EUR/MWh. On the other hand, in contrast to reforming natural gas, in methane splitting technologies electricity consumption can play a much more important role (1 EUR/kg vs 0.3 EUR/kg). These values depend on the used technology.

CAPEX: Since methane splitting is a less mature technology than natural gas reforming, the upfront capital expenditures are also much higher - but also with more room for improvements in the future. While in reforming, CAPEX costs are approximately 9% of the costs per kg, in methane splitting, they represent ~25%.

Solid carbon revenues: The single largest impact on the LCOH of hydrogen from methane splitting are revenues from the sale of solid carbon that, at 500 EUR/t, reduce LCOH by 34% from 5.3 EUR/kg to 3.3 EUR/kg. While 500 EUR/t is a base case assumption for average solid carbon by-product, that price can vary significantly. Carbon black can reach 1000 to 1800 EUR/t and is mostly used for tire manufacturing, other non-tire automotive applications, inks, coatings, and pigments, plastics, and increasingly electrodes. Another potential by-product, graphite, is used in batteries, refractory applications, steel production, and elsewhere. It can be also refined into graphene with its own uses and sectors. **The different grades of solid carbon by-product have separate market dynamics and prices that are beyond the scope of this report but are essential in understanding the long-term economics of methane splitting projects.**

Figure 3.4: LCOH of methane splitting



Assumptions for these prices: Thermo-catalytic pyrolysis technology used; CAPEX: 3000 EUR/KW; Electricity costs at 80 EUR/MWh plus average network fees at 29.3 EUR/MWh; Natural gas at 40 EUR/MWh plus average network fees at 5 EUR/MWh; Other OPEX: 4.8% of CAPEX; Economic lifetime of 20 years; Solid carbon at 500 EUR/tonne; Operating hours of 8000 a year ; Project details: 1 t/h project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

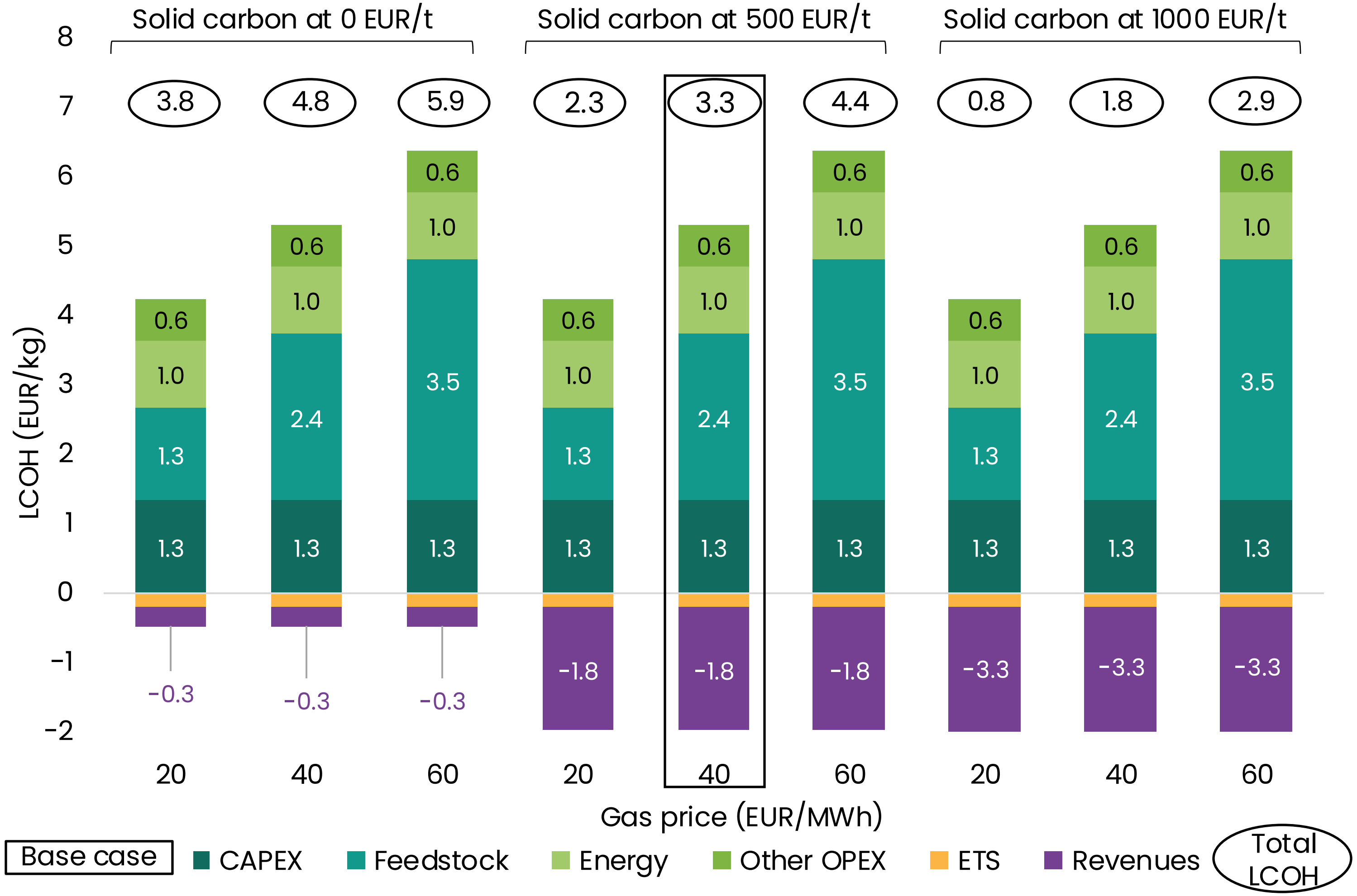
Source: Hydrogen Europe; Canadian Institute for Clean Energy; U.S. Geological Survey

Besides gas prices, solid carbon revenues are the key factor determining the economic feasibility of methane splitting projects that range from 0.8 to 5.9 EUR/kg

Figure 3.5 compares LCOH of methane splitting with gas price and solid carbon price as variables. **With gas hovering around 20 EUR/MWh in February 2024 and assumed solid carbon around 1000 EUR/tonne, the theoretical project could reach LCOH of 0.8 EUR/kg.** That is well below the 2 EUR/kg for an existing SMR unit at same gas price levels.

Solid carbon markets and revenues: The solid carbon revenues provide a major upside for the hydrogen production economics and this theoretical project could theoretically earn more from selling solid carbon than it would cost it to produce hydrogen. In sensitivity analysis, we assumed price levels of 0, 500, 1000 EUR per tonne of solid carbon, but the solid carbon prices could be even higher. On the other hand, significant deployment of methane splitting could cause the solid carbon prices to plummet as various carbon markets have relatively constrained existing market sizes. The current carbon black market of ~16 million tonnes could be saturated with ~5 Mt/year capacity of methane splitting hydrogen production capacity with pure carbon black by-product production. Such market saturation would decrease the average price and impact economics of methane splitting projects. That is why the bottom end of the sensitivity is 0 EUR/t if carbon was only used as a carbon sink. While large supply of solid carbon could also create new demand in batteries, electrodes, plastics, and elsewhere, it is important to recognise that the **by-product revenues can significantly vary depending on the technology and the produced by-product, geography, and future development of various solid carbon markets.**

Figure 3.5: LCOH for methane splitting depending on price of gas and solid carbon



Assumptions for these prices: Thermo-catalytic pyrolysis technology used; CAPEX:3000 EUR/KW; Energy: Electricity costs at 80 EUR/MWh plus average network fees at 29.3 EUR/MWh; Fuel: Natural gas at 20/40/60 EUR/MWh plus average network fees at 5 EUR/MWh; Other OPEX: 4.8% of CAPEX; Economic lifetime of 20 years; Solid carbon at 0/500/1000 EUR/tonne; Operating hours of 8000 a year ; Project details: 1 t/h project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe; Intratec

Hydrogen from imported LNG and using average EU grid electricity would not meet the required low-carbon emission threshold

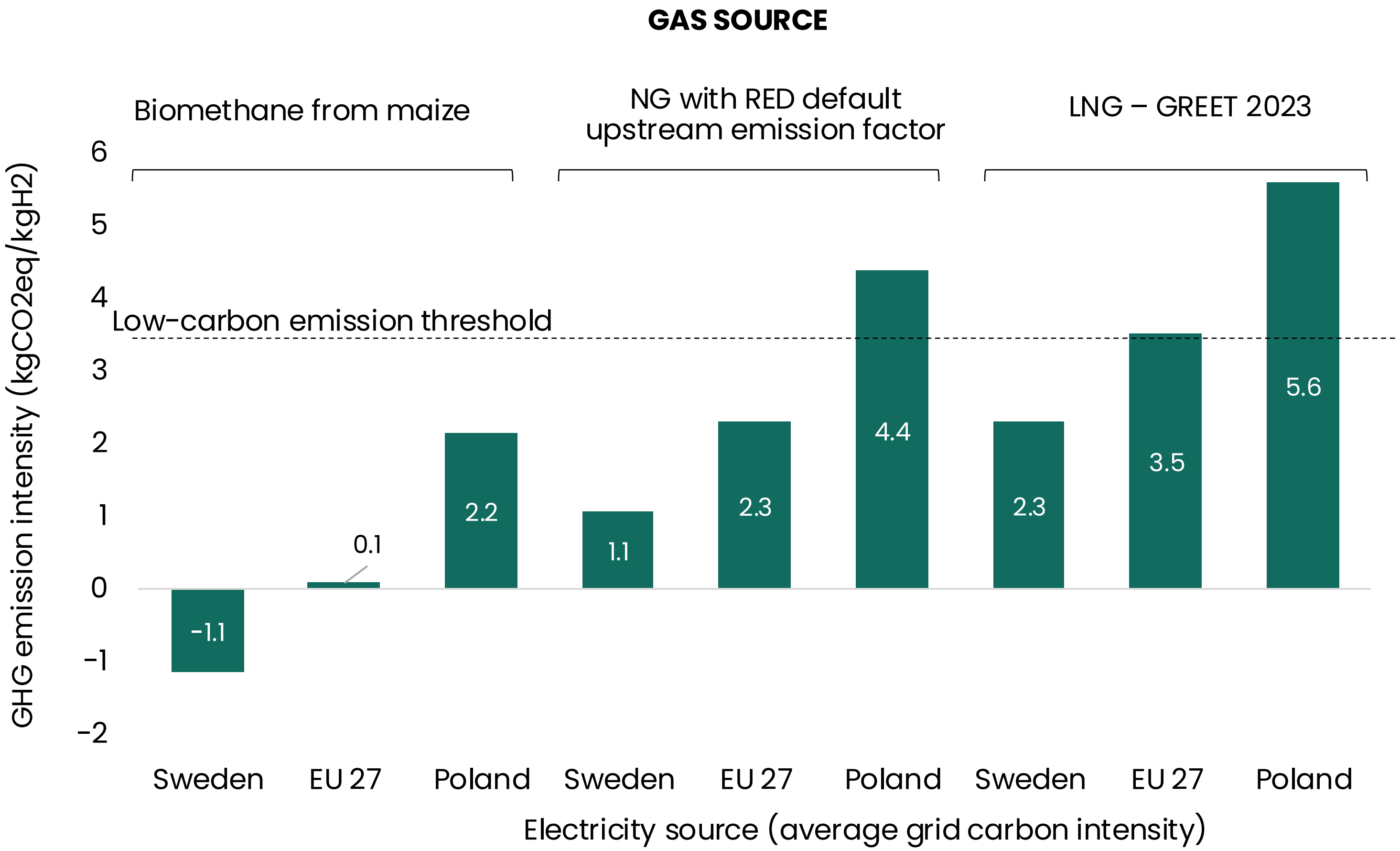
In terms of GHG emissions, the main advantage of methane splitting is the fact the process allows for almost complete avoidance of direct CO2 emissions – yielding solid carbon as a valuable by-product instead. Furthermore, transporting and storing carbon is cheaper and less energy intensive than CO2 transportation and storage.

Emission variables: **GHG emission intensity** of hydrogen produced from methane splitting varies depending on the **source of gas used.** However, in the case of methane splitting, **higher electricity consumption means that the carbon intensity of electricity is equally important.**

In a low-carbon electricity grid like Sweden's, using biogas from maize has negative GHG emissions as the CO2 embedded in the biomass feedstock are 'captured' as solid carbon during the process.

With natural gas as feedstock the GHG footprint of hydrogen can still fall below the low-carbon threshold – but only if carbon intensity of electricity is low enough. In the extreme case when **imported LNG would be used as feedstock, the electricity carbon intensity would have to be lower than 210 gCO2/kWh** (i.e. lower than current EU average) **to satisfy the low-carbon emission threshold.**

Figure 3.6: Carbon intensity of methane splitting depending on gas source and electricity carbon intensity



Assumptions: : Thermo-catalytic pyrolysis technology used; Swedish GHG emission intensity 2 gCO2eq/MJ ; EU-27 GHG emission intensity (70 gCO2eq/MJ); Polish GHG emission intensity (102 gCO2eq/MJ); CO2 allocation to solid carbon based on its relative energy content;

Source: Hydrogen Europe

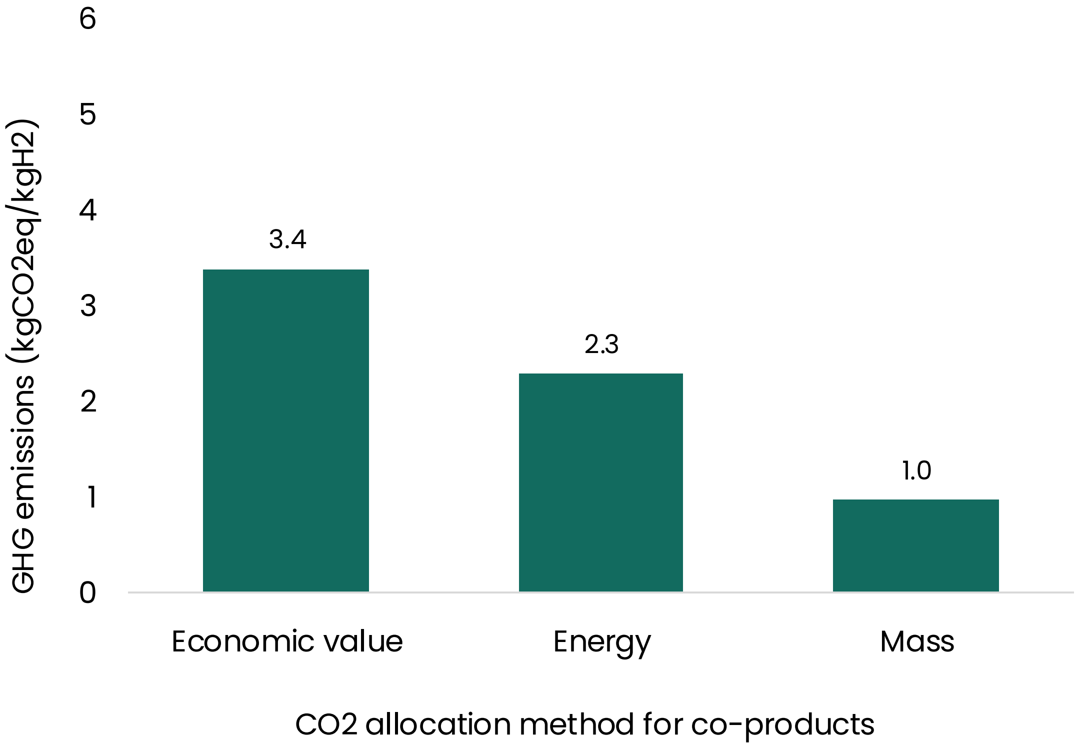
The commercial viability of methane splitting is largely dependent on several EU regulations not yet in place and a broader definition of carbon capture

CO2 allocation method: The method for allocating CO2 between hydrogen and solid carbon co-product is key. **For methane splitting, the rules are yet to be defined in the upcoming delegated act on low-carbon fuels.** The existing rules applicable for RFNBO and RCF hydrogen stipulate that whenever hydrogen is co-produced with other fuels, the emission allocation should be done based on the relative energy value of those fuels (effectively leading to a unified emission intensity value per MJ of each fuel produced). In case hydrogen is co-produced with other products which are not fuels, the appropriate basis for GHG emission allocation is the relative economic value of products. While in case of solid carbon products, they in most cases won't (and shouldn't) be used as fuels, they still have a significant calorific value, which suggest that **for methane splitting the emission allocation based on energy as the appropriate one** (following the clarification by the European Commission, that all products with a calorific value should be treated as fuels).

Recognition of solid carbon as a carbon storage solution: Both the Net Zero Industrial Act and the Industrial Carbon Management Strategy set ambitious targets for carbon capture and storage. However, they both focus solely on captured CO2 emissions, neglecting the potential of precombustion carbon capture and storage methods like solid carbon from methane splitting. It's essential to **broaden the EU's carbon capture targets and definitions to include solid carbon from methane splitting as a viable CCUS technology.** It will not only diversify our option to capture CO2 but would also foster investments and innovation in this field.

Carbon black under ETS: the current definition of carbon black producing activity under the EU ETS covers the production of carbon black involving the carbonisation of organic substances such as oils, tars, cracker and distillation residues, where combustion units with a total rated thermal input exceeding 20 MW are operated. Such a definition would exclude solid carbon co-produced with hydrogen via methane splitting, where no combustion takes place. **Expanding the scope of the definition could have positive impact on the business case for methane splitting.**

Figure 3.7: Carbon intensity of methane pyrolysis depending on CO2 allocation method



Assumptions: The economic value allocation assuming 500 EUR/t solid carbon price and 6 EUR/kg hydrogen market price.
Source: Hydrogen Europe

High gas and electricity consumption differences between various methane splitting technologies can lead to significant cost and emissions variability

The presented results in this chapter were based on thermo-catalytic pyrolysis technology. However, as has been described methane splitting (or methane pyrolysis) is a relatively broad term which encompasses multiple technological approaches, with of those having their own advantages and challenges.

Technological differences: Thermal and plasma decomposition has a relatively low gas consumption (53-56 kWh per kg of hydrogen) but relatively high electricity consumption (12-18 kWh per kgH2), compared to catalytic pyrolysis (72 kWh/kgH2 and 2 kWh/kgH2 respectively). Furthermore, **some companies developing the technology design the process to maximise solid carbon yield to the point where hydrogen becomes almost a by-product, while others target hydrogen as a primary product.** Therefore, in order to provide a more complete view of the methane splitting technology potential, we have estimated costs and emissions based on 10 different data sources (both public sources and based on data received directly from companies developing the technology).

Figures 3.8 and 3.9 show that these **variations can have significant impact on both costs and emissions with the delta between technologies of around 2.8 EUR/kg 3.3 kgCO2/kg (for the base scenario).**

Figure 3.8: LCOH comparison of different methane splitting technologies

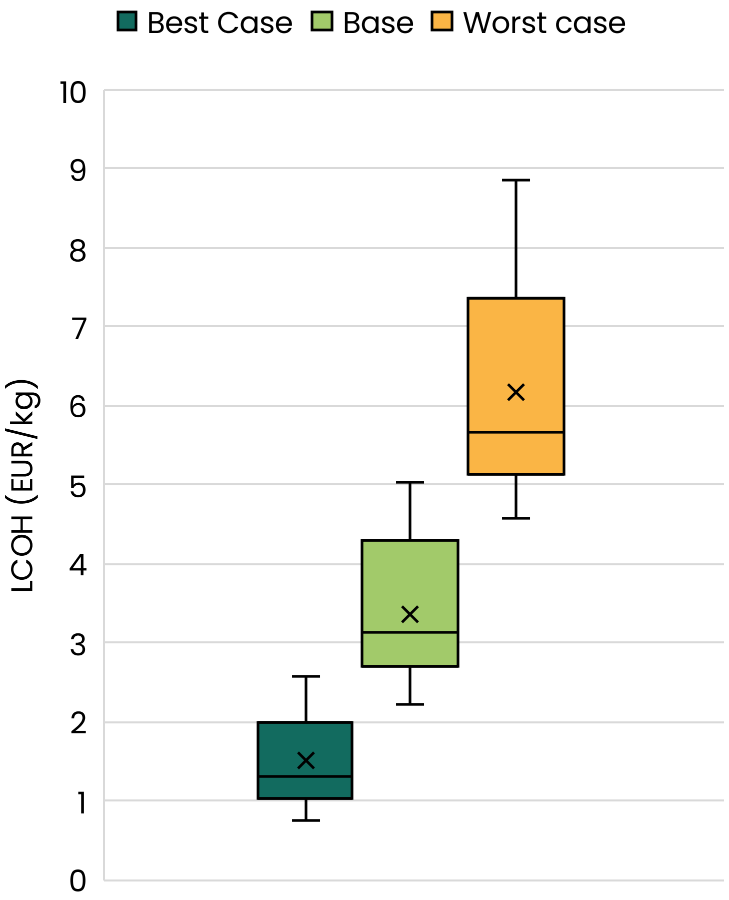
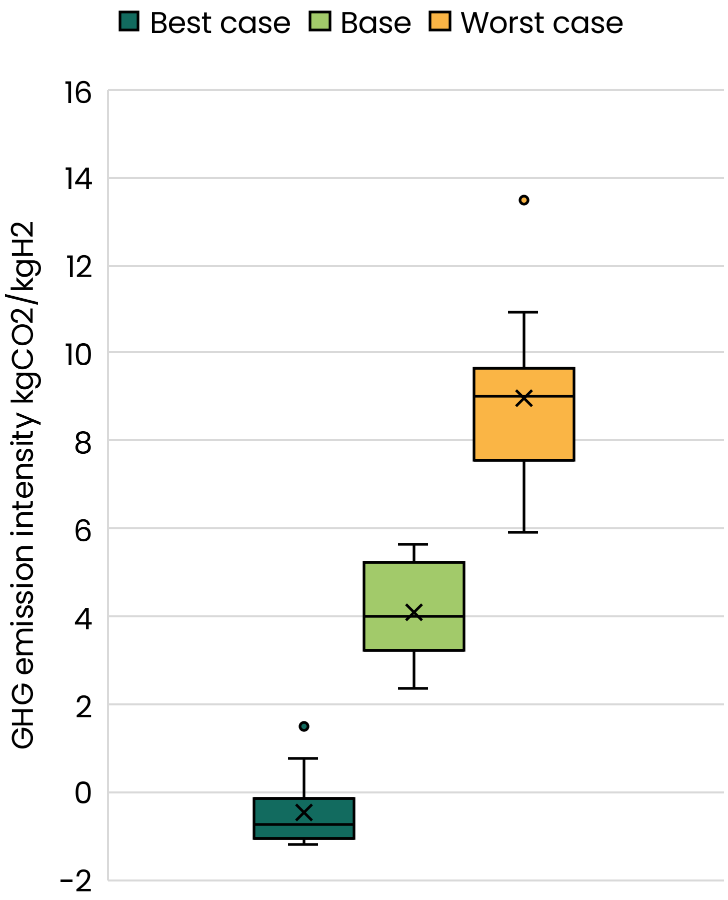


Figure 3.9: GHG intensity comparison of different methane splitting technologies



Notes: For LCOH comparison: best/base/worst case: natural gas costs at 20/40/60 EUR/MWh and solid carbon sales price at 1,000/500/0 EUR/t.; For GHG intensity comparison: best/base/worst case: gas source: biomethane from maize/EU average gas supply/shipped LNG and electricity source: nuclear/EU grid average/PL grid average.
Source: Hydrogen Europe

In the long term, its reliability on gas infrastructure and solid carbon revenues are the largest scalability challenges for methane splitting

Feedstock availability and gas infrastructure

- Ability to produce hydrogen by methane splitting only where there is available gas infrastructure
- Lack of conducive framework for the repurposing of gas infrastructure could potentially delay the deployment of hydrogen infrastructure
- Potential lock-in of fossil infrastructure that could be otherwise decommissioned or repurposed for hydrogen
- Potential gas availability issues in the long term

Technological challenges

21st century methane splitting technologies focused on hydrogen production are only just now entering demonstration and early commercial phases. This results into relatively high CAPEX and technological deployment risks. Technology owners are working to improve the purity of the hydrogen produced, the form and quality of the solid carbon by-product, the energy consumption, durability/degradation of the reactor, price and availability of used catalysts, transitioning from batch production to continuous, and other aspects.

Cost and by-product prices

The LCOH from methane splitting heavily depends on the revenues from sale of the solid carbon by-product. Different methane technologies produce different forms of solid carbon as a by-product. As a result, it is difficult to assess the market conditions for all of these products. At 500 EUR/t, the revenues can offset almost 2 EUR/kg. With solid carbon prices at 1000-1500 EUR/t, revenues can offset 4-6 EUR/kg of hydrogen LCOH. With increasing hydrogen production from methane splitting and saturating the existing solid carbon demand, future demand for solid carbon allotropes as well as their price levels are crucial for methane splitting project economics and scaling this technology.

BIOWASTE-TO-HYDROGEN

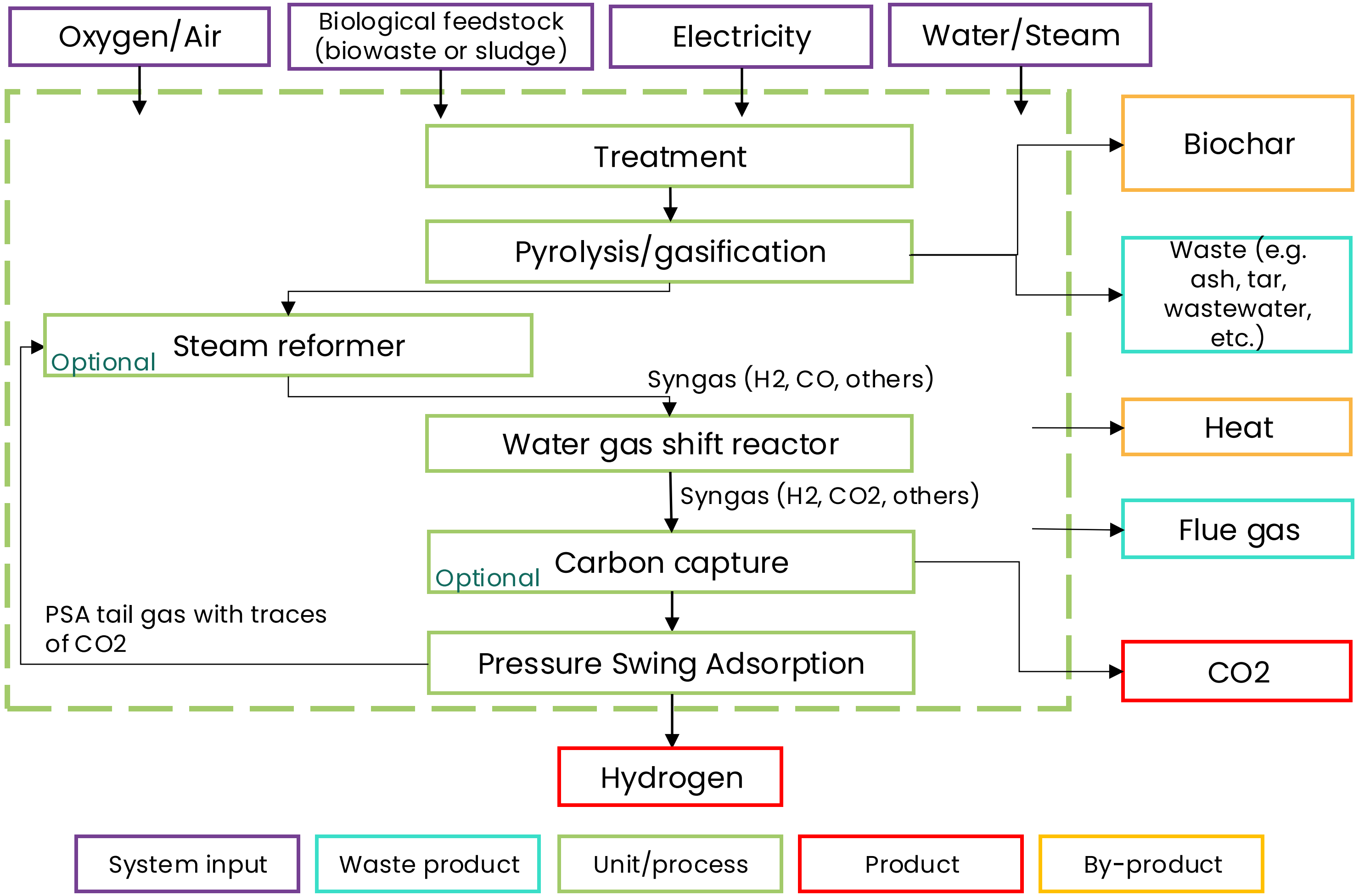
- **Biowaste-to-hydrogen** refers to technologies transforming solid or liquid biomass waste feedstock for hydrogen production.
- **Unique technology benefits** – Biomass wastes are largely local and readily available across Europe from their existing production in agriculture, forestry industry, wastewater treatment plants, and elsewhere. The technology can promote local decarbonization and also help tackle the unabated agriculture emissions from biowaste decomposing out in nature.
- **Technology** – There are numerous biological, thermochemical, and bioelectrochemical technologies. Some pyrolysis and gasification technologies for biohydrogen production are reaching TRL 8 and early commercialization while others continue to develop and improve.
- **Costs** - Hydrogen from biowaste can be produced at around 4.8 EUR/kg under basic modelled conditions. Revenues from the biochar by-product improve the competitiveness of this technological solution.
- **Emissions** – Biowaste-to-hydrogen emissions are highly dependent on the feedstock used, but as long as the feedstock is waste based, it can deliver in all cases emissions below the Renewable Energy Directive threshold. The biochar accounting methodology can help to further improve the emissions footprint.
- **Scalability challenges** – Competition with other biowaste users with potentially higher willingness to pay such as biomass based SAFs or biomass based maritime fuels. Since this hydrogen from biomass is classified as biogas/biofuel, only regulatory demand for biogas/biofuel production is relevant. Modularity allows these technologies to scale as needed, but it is restricted by potential feedstock availability and economics of transporting biomass waste to supply industrial sized installations.

Gasification and pyrolysis reactions are the basis, but the reactor design varies significantly depending on the feedstocks and desired by-products

The biowaste-to-hydrogen pathway is based on gasification and/or pyrolysis of biomass waste. The term gasification refers to chemical transformation of solid or liquid into a gas. Pyrolysis refers to thermal decomposition of materials at elevated temperatures in the absence of oxygen. These two processes can be combined as part of the same technology. The process can significantly differ depending on technology and feedstock.

The process: First, the biowaste feedstock has to undergo pretreatment mostly focused on moisture control and the particle size using dryers and shredders. Subsequently, the gasification or a combination of pyrolysis and gasification reactions occur in the reactor producing hydrogen containing gas mixture (syngas) and by-products. The by-products depend on the feedstock and technology and can include ash, biochar, and tar. Waste heat from various processes, flue gas from steam reformer and PSA, and potentially CO2 are additional by-products. Syngas is cleaned of various solid, liquid, or gaseous compounds for further processing. Depending on the reactor, the cleaned syngas can be reformed with steam, before maximizing the hydrogen yield with water gas shift reaction, separating hydrogen in a pressure swing adsorber or via other method, and capturing CO2 from the stream (optional). The process can significantly vary depending on technology and feedstock. **This chapter focuses on woody biowaste as a feedstock, but other common feedstocks include agricultural biowastes, industrial biowaste, and also sewage sludge.**

Figure 4.1: Categories and technologies for hydrogen production from biomass



Oxygen/Air
Biological feedstock (biowaste or sludge)
Electricity
Water/Steam
Treatment
Pyrolysis/gasification
Biochar
Waste (e.g. ash, tar, wastewater, etc.)
Optional Steam reformer
Syngas (H2, CO, others)
Water gas shift reactor
Heat
Syngas (H2, CO2, others)
Flue gas
Optional Carbon capture
PSA tail gas with traces of CO2
Pressure Swing Adsorption
CO2
Hydrogen

System input
Waste product
Unit/process
Product
By-product

Notes: This is a generic process diagram that can vary significantly depending on the used technologies and plant setup
Source: Hydrogen Europe; ISO/TC 197/SC 1/WG

Pyrolysis and gasification processes for biowaste-to-hydrogen production are flexible and can be combined and optimised for hydrogen and/or by-product yield

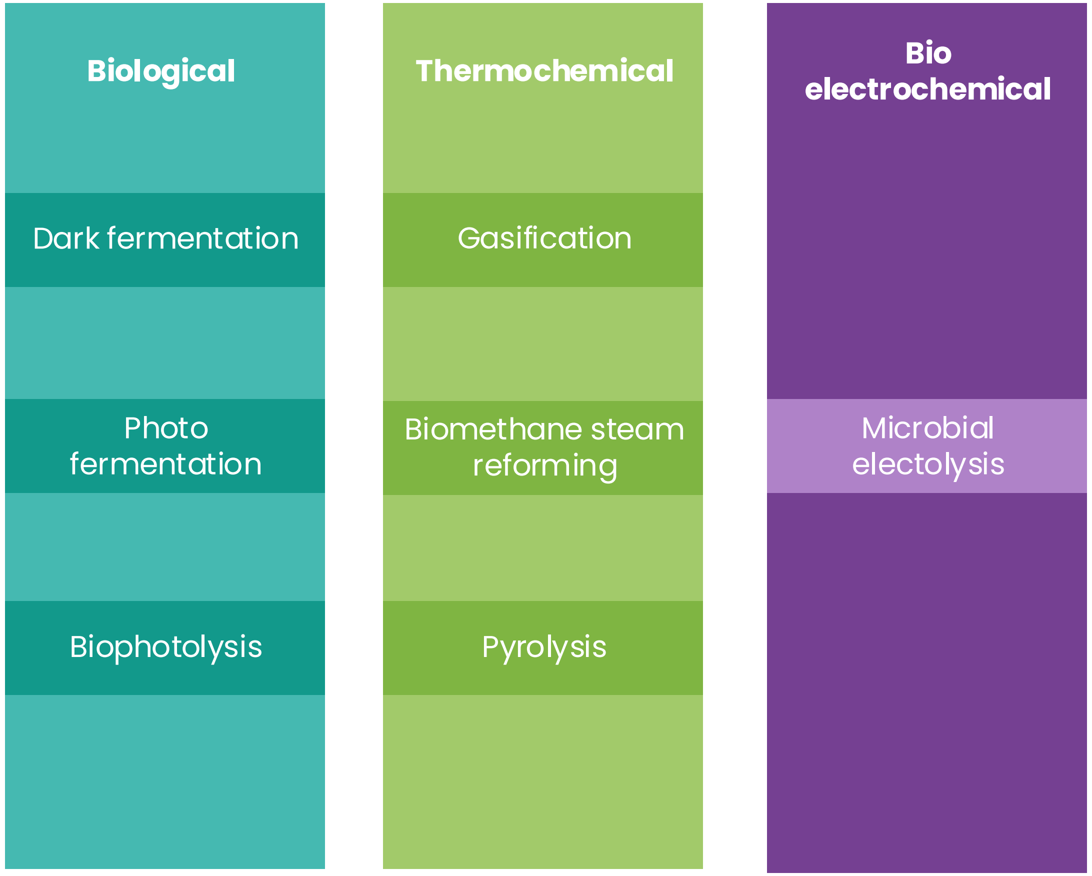
There are biological, thermochemical, and bioelectrochemical processes to produce hydrogen from biowaste. This chapter focuses on the thermochemical processes such as gasification and pyrolysis and excludes others such as dark fermentation, photo-fermentation, biophotolysis, and steam reforming of biomethane.

Pyrolysis of biomass: It is a thermochemical process that involves heating organic materials in the absence of oxygen. This process leads to the decomposition of biomass into a solid residue known as biochar, a liquid known as bio-oil, and a mixture of gases including hydrogen, methane, carbon monoxide, and others. Pyrolysis operates at temperatures typically between 400°C and 600°C when optimizing bio-oil yield. Temperatures depend on the specific technology and those optimizing for hydrogen yield aim for higher temperatures around 1000 °C. **The process is versatile and depending on the temperature and heating rate can be tailored to maximize the production of either biochar for soil amendment, bio-oil for energy use, or syngas for subsequent hydrogen or other products.** Most operational biomass pyrolysis have been focusing on production of bio-oil and technology companies recently started changing their processes to optimize for high hydrogen yields instead.

Gasification of biomass: It is also a thermochemical process and uses a controlled amount of oxygen or air to achieve an incomplete combustion generally between 700-1,200°C. It transforms biomass into a combustible gas mixture, consisting of carbon monoxide, hydrogen, traces of methane, and others. Similarly, as with pyrolysis, the gasification process can be optimized to aim for high yields of syngas and hydrogen production while minimizing the production of unwanted gases and solids.

The two processes can be combined as part of the same technology to achieve the desired efficiencies, hydrogen yield, and by-products.

Figure 4.2: Categories and technologies for hydrogen production from biomass



Biological	Thermochemical	Bio electrochemical
Dark fermentation	Gasification	Microbial electolysis
Photo fermentation	Biomethane steam reforming	
Biophotolysis	Pyrolysis	

Source: Hydrogen Europe; European Biogas Association

The most advanced pyrolysis and gasification technologies for biohydrogen production are reaching TRL 8 but many others are in pilot scale

Technology development: **The current TRL of biomass gasification for hydrogen production is at TRL 5-6 according to the IEA. However, there are also technologies at TRL level 8.** The technology providers can be split into three main categories: i) those generating syngas for heat and power, ii) those generating various renewable products, and iii) those producing biohydrogen. While the third category is the focus of this chapter, the first two categories are significantly more deployed around the world. As an example of an installation generating heat and power from biowaste, Fortum deployed a pyrolysis plant in 2013 in Finland aimed at producing bio-oil from biomass used in boilers. For renewable products production, BTG Bioliquids started their commercial fast pyrolysis plant for production of liquid bio-oil in 2015 in the Netherlands and deployed additional installations in 2021.

Technology aspects: Since the technologies can be optimised to produce syngas for heat and power, renewable products, or biohydrogen, companies tend to offer technological solutions covering all these categories. Figure 4.3 includes a selection of companies and projects using gasification and pyrolysis technologies with biowaste feedstock. Some of them focus purely on biohydrogen but most have a wider product offering. Their technologies can also be quite flexible in terms of feedstock. German BtX Energy built a pilot plant in 2020 to produce biohydrogen from pelletised biogenic residues. The Looper gasification pilot developed by Indeloop from Croatia processes sewage sludge to generate syngas. Haffner Energy deployed its Hynoca thermolysis process in Strasbourg in 2021 assessed at the time at TRL 7-8 by DNV.

In terms of technology, companies focusing on hydrogen production from biowaste focus primarily on gasification, although pyrolysis can as well be be a part of the reactor design.

Further research is ongoing to **improve tar and char processing, used catalysts, heat recovery, feeding system reliability, biowaste flexibility,** and other challenges.

Figure 4.3: Selection of companies and projects using gasification and pyrolysis technologies with biowaste feedstock

Company	Status	Technology and feedstock
Eqtec	Pilot plants from 2011 in Spain and Italy in 2023 focused on electricity generation. Other plants in development focusing also on hydrogen production besides electricity.	Gasification of biowaste (olive paste, agricultural, and forestry waste)
Enerkem	First plan in Alberta being decommissioned. Varrenes Carbon Recycling planned for 2025 (wood waste and non-recyclable waste) in Canada. Ecoplanta in Spain in development.	Gasification of biowaste and non-recyclable solid waste
BtX Energy	Pilot plants in 2020 and 2022 in Germany.	Gasification of pelletised biogenic residues and animal manure
Haffner Energy	Hynoca Industrial demonstration in 2021. Working on additional client deployments.	Thermolysis - a two-step thermochemical process
Indeloop	Pilot plant operational. Large scale plant in Zagreb received Innovation Fund funding in 2023.	Combination of gasification and pyrolysis of sewage sludge
KEW	Commercial scale demonstration plant in UK in 2021. Additional plants under development in UK.	Gasification of woody or agricultural biowaste, sewage sludge, or municipal solid waste.
WaysH2	Pilot plant in 2021 in Tokyo.	Gasification of dried wastewater sludge
Green Hydrogen Technology	Pilot plant in Austria in 2023.	Gasification of biomass waste, sewage sludge, or other feedstocks
Xylergy	Previous deployments focused on CHP. Demonstration plant in Japan planned for 2024.	Gasification of biowaste
Catagen	Received UK grant in 2023 for a demonstration of their reactor.	Gasification of biowaste
Compact Syngas Solutions (CSS)	Received UK grant in 2023 for a pilot plant.	Gasification of biowaste

Source: Hydrogen Europe; Columbia University; Chemical Engineering; BioDME; Biomethaverse; BTX Energy; Fortum; Bioliq; BTG Bioliquids; European Biogas Association; Balkan Green Energy News; Enerkem; UK Government; Catagen; Compact Syngas Solutions; EQTEC; Northumbria University;

Biowaste-to-hydrogen can utilise local biomass waste, promote local decarbonization and help to tackle unabated agriculture emissions

Feedstock

Biowastes are largely supplied from local source, limiting the transport emissions. They are readily available across Europe from their existing production in agriculture, forestry industry, wastewater treatment plants, and elsewhere. Since the technology is adaptable, the biomass wastes are largely fungible. This reduces risk of insufficient feedstock availability and also allows for hydrogen to be produced at a constant rate throughout the year (i.e. not limited by intermittent renewable electricity).

Costs

Using base assumptions, hydrogen from woody biowaste for 60 EUR/t can reach 4.8 EUR/kg with biochar prices around 300 EUR/t. This is cheaper than available low-temperature electrolytic hydrogen and could, similar as reforming with carbon capture, and methane splitting provide low-emission hydrogen at a smaller premium or even compete, depending on local conditions, with unabated SMRs. Additional revenues could be generated by the sale of carbon removal certificates – with current market price at around 150 EUR/t.

Other

- **Abating otherwise unabated emissions**: Unabated emissions from agriculture are modelled to represent 60% of the total emissions in 2050. Biowaste-to-hydrogen technologies can help reuse and sequester CO2 from these various biowaste feedstocks.
- **Production of useful by-products**: Biowaste-to-hydrogen process produces biochar used in agriculture, industry, and other uses. It also produces biogenic carbon needed for food sector, industry, and potentially highly valuable and easily transportable feedstock for e-fuels production.
- **Locally focused decarbonisation**: The focus on locally sourced biomass and locally produced and consumed hydrogen encourages local deployment of decarbonization solutions. These can range from partial decarbonization of waste treatment plants, decarbonization of local mobility, off-road mobility used in agriculture, and other use cases. These can create unique business cases and promote decarbonisation, development, and industrialisation also in rural areas.

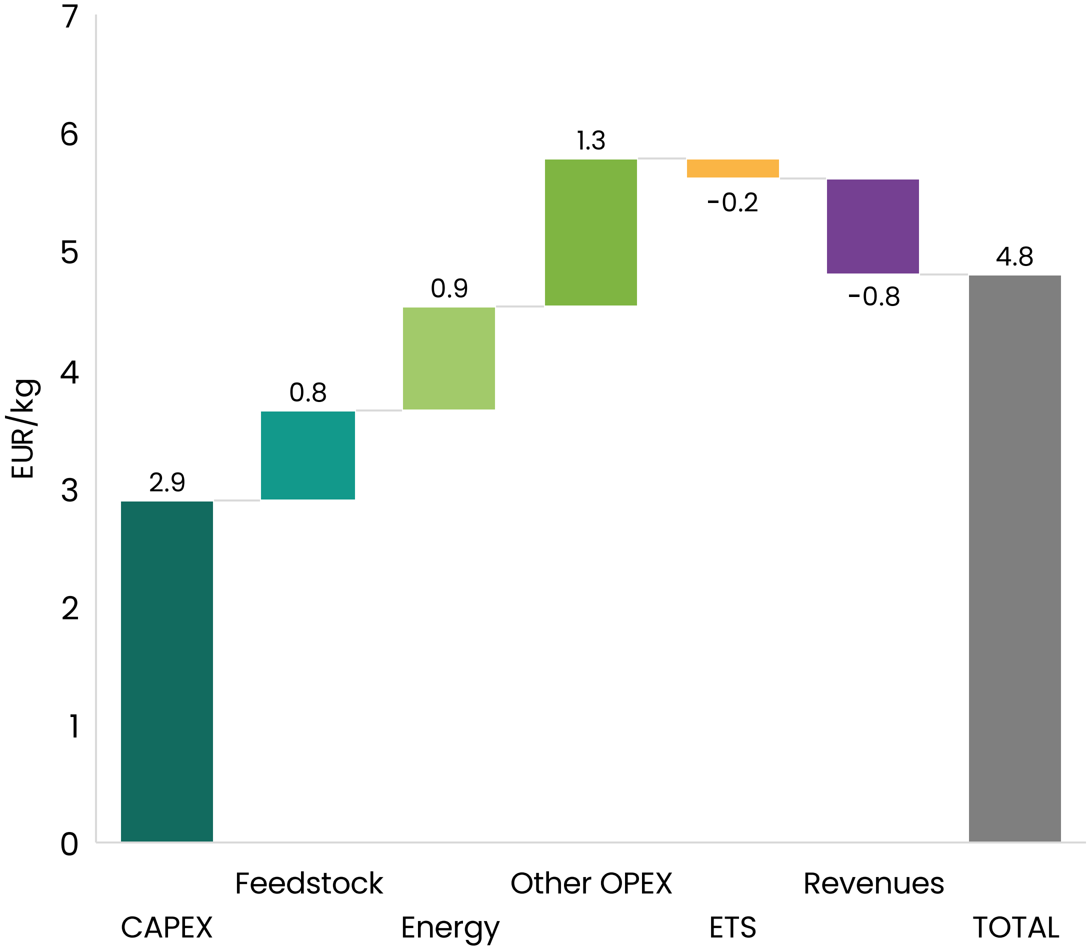
Biowaste-to-hydrogen processes can deliver local biohydrogen at 4.8 EUR/kg

Cost structure: CAPEX dominates the cost structure of producing hydrogen from woody biowaste, constituting 60% of the LCOH. CAPEX is comparatively high as these technologies are only now entering large scale commercialization. Energy costs - mostly electricity - and feedstock costs are also significant. **While a stable cost of woody biowaste was assumed for the purpose of this calculation, biowaste markets are influenced by a variety of factors, primarily the availability and type of biomass wastes in local regions, collection costs, transportation costs, treatment costs, and other considerations.** Areas with a prominent forestry sector may have supply of wood chips, sawdust, tree trimmings, and bark from forestry operations. Regions with extensive agricultural operations might have an abundant supply of crop residues such as straw, husk, shell, and other by-products from crops like corn, rice, and wheat. Elsewhere, the organic portion of municipal solid waste, biogenic waste from industrial processes, animal manure, or sewage sludge might be available. All of these can be readily used for hydrogen production, but their costs can significantly vary.

Feedstock management: Each type of biomass may require specific treatments to optimize its conversion into hydrogen, considering the variability in composition and physical properties. Effective pretreatment not only maximizes hydrogen yield but also prolongs the lifespan of the processing equipment. The most common are drying to reduce the moisture content; shredding to reduce the physical size of the waste feedstock; and torrefaction which produces a more energy-dense, hydrophobic material that is easier to gasify. All of these can increase the feedstock cost. The cost of transporting biomass, not included in the analysis, can also be significant, as biomass is often bulky and not energy-dense, making long-distance transportation economically unfeasible unless densification processes like pelletization are employed.

Revenues: While the revenues from sold EUAs are relatively marginal, sales of by-product biochar can be significant. Biochar is used mostly in agriculture for soil amendment but has various other end-uses. At an assumed biochar sale price of 300 EUR/t, by-product revenues decrease the total LCOH of hydrogen by 14%. Additional revenues could be generated by the sale of carbon removal certificates (not included in the analysis) – with current market price at around 150 EUR/t.

Figure 4.4: 2024 LCOH of woody biowaste-to-hydrogen



Assumptions for these prices: Pyro /gasification technology without carbon capture; CAPEX: 6306 EUR/KW; Energy: Electricity costs at 80 EUR/MWh plus average network fees at 29.3 EUR/MWh; Fuel: Woody biomass at 60 EUR/t; Other OPEX: Fixed OPEX at 2.9% of CAPEX and variable OPEX at 0.5 EUR/kg; Economic lifetime of 20 years; Biochar at 300 EUR/tonne; Operating hours of 8000 a year ; Project details: 1 t/h project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe

Biowaste-to-hydrogen costs are dominated by CAPEX, with feedstock costs and revenues from biochar impacting its business cases

Figure 4.5 compares LCOH from woody biowaste with feedstock and biochar price as variables creating an LCOH range between 4.3 and 5.8 EUR/kg.

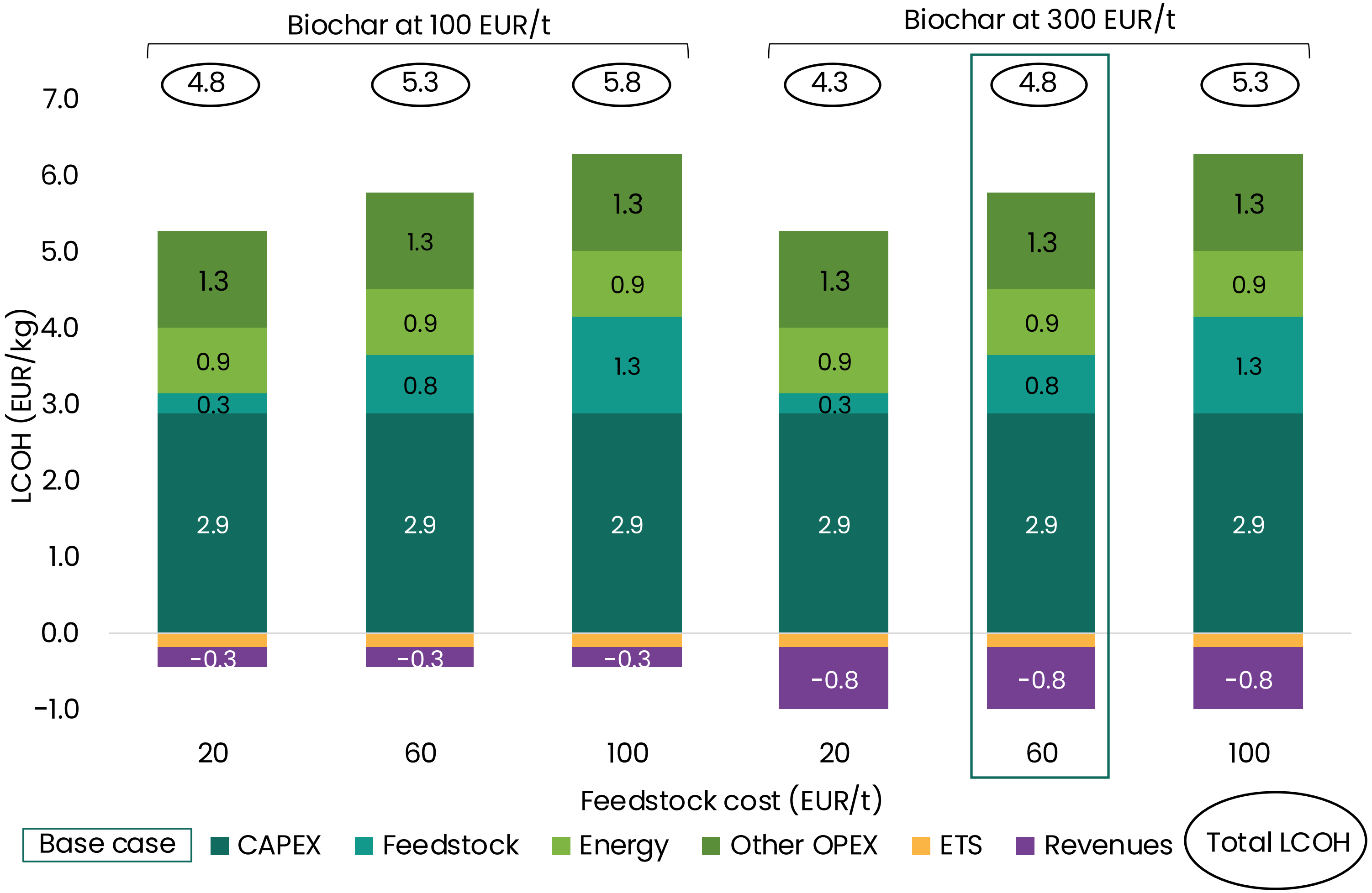
Biochar prices: They depend on quality, scale, and geography and can range between 100-800 EUR/t. We believe the **assumed sensitivity of 100 and 300 EUR/t reflects the likely scenarios as these revenues are highly vulnerable to demand/supply and price fluctuations in local biochar markets.**

Feedstock cost: While we assume woody biowaste, the previous page explains the different potential sources of biowaste for biohydrogen production in different geographies. **While 20-100 EUR/t range is relevant for woody biowaste, other biowaste feedstocks might be more expensive or even generate revenue from their owners for disposing of them.**

Regulatory: Depending on bio feedstock, **this biohydrogen is biogas from a regulatory perspective and counts for advanced biofuels targets.** As a result, it doesn't enjoy the same price premium afforded to RFNBOs. It is forced to compete primarily on price where it can be competitive to satisfy the needs of local industry or mobility.

However, it is important to note that **limited market deployment to date is creating uncertainty with regards to techno-economic assumptions underlaying this cost analysis.**

Figure 4.5: 2024 LCOH from woody biowaste depending on feedstock and biochar prices



Assumptions for these prices: Pyro/gasification technology without carbon capture; CAPEX: 6306 EUR/KW; Energy: Electricity costs at 80 EUR/MWh plus average network fees at 29.3 EUR/MWh; Fuel: Woody biowaste at 20, 60, 100 EUR/t; Other OPEX: Fixed OPEX at 2.9% of CAPEX and variable OPEX at 0.5 EUR/kg; Economic lifetime of 20 years; Biochar at 100 or 300 EUR/tonne; Operating hours of 8000 a year; Project details: 1 t/h project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe

Biowaste-to-hydrogen technologies can deliver hydrogen with very low emissions, highly dependent on the feedstock

Biowaste feedstocks: **The emission intensity of hydrogen produced from biomass is highly variable and depends on the selected feedstock**. In case of biowaste feedstock, reaching the required emission level should not be a problem – and in case of sewage sludge or wet manure where CH4 emission avoidance credit would be applicable, the carbon intensity of hydrogen could be negative.

On the other hand, **if crop-based biomass would be used, the emission intensity could be too high for the hydrogen to qualify as sustainable – unless the production facility would include carbon capture and storage**.

Allocation of biochar emissions: However, the carbon intensity of hydrogen could be significantly lower if the emission calculation methodology would recognise the carbon bound as biochar on a level footing as CCS – i.e. allow to deduct the avoided CO2 emissions from the total GHG intensity in a similar way as emission savings from carbon capture and geological storage. A recognition of this fact, combined with **the biogenic character of the avoided CO2 emissions would result in the biowaste-to-hydrogen technology leading to net carbon removal – even with first generation biomass feedstock**.

Benefits of biochar for soil: If the biochar would be used for soil amendment, due to its porous nature, it could improve the soil's water retention capacity, increasing yield and decreasing the need for fertilisation leading to additional GHG benefits not included in this analysis.

Figure 4.6: Emission intensity calculation for biowaste-to-hydrogen (woody biowaste feedstock)

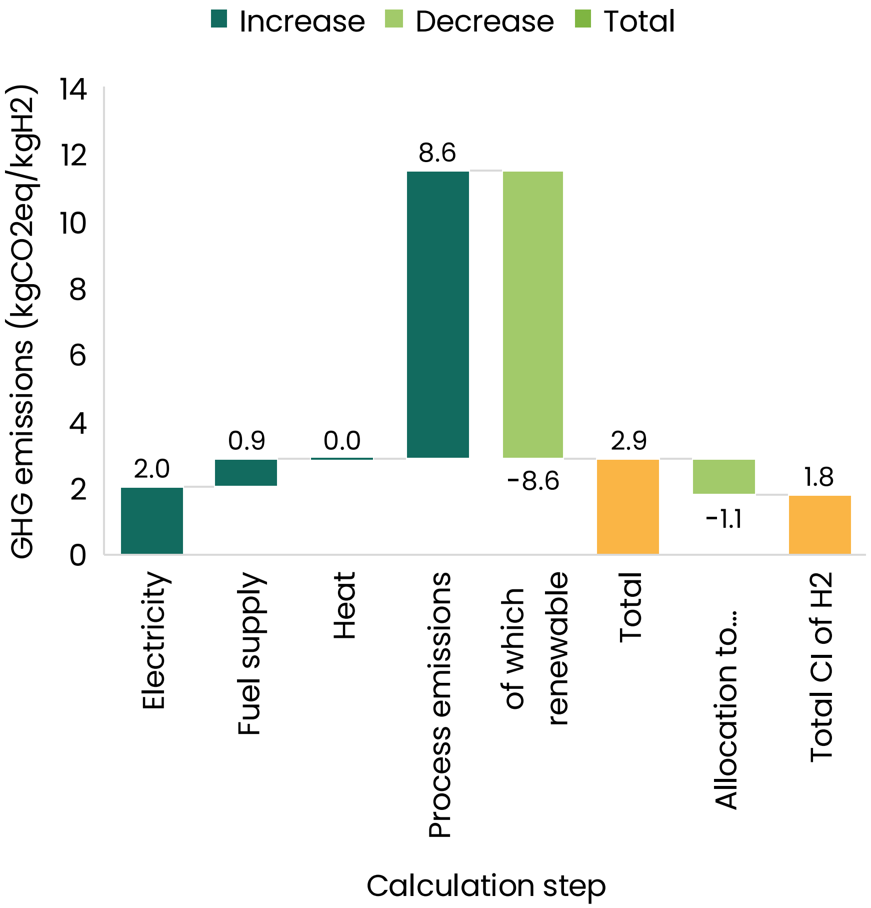
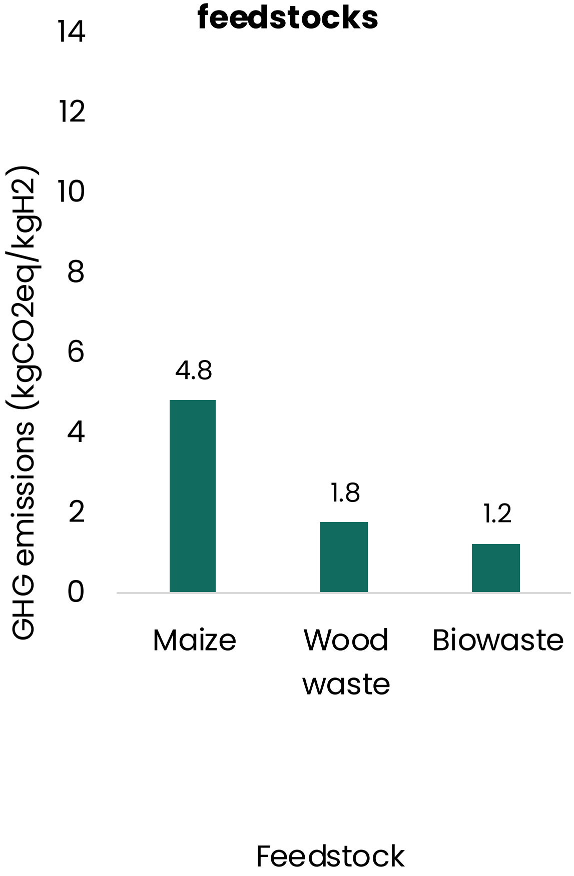


Figure 4.7: Emission intensity of biowaste-to-hydrogen for selected feedstocks



Assumptions: Pyro /gasification technology without carbon capture; indirect emissions from supply include emissions for collection, seasoning and chipping of woody biomass as well as its transportation; Notes: GHG emissions threshold for biohydrogen will vary depending on the application. For biogas used in the transport sector the maximum emission level is at least 65% below the fossil fuel comparator of 94 gCO2/MJ and at least 70% below the fossil fuel comparator of 183 gCO2/MJ for electricity, heating and cooling production from biomass fuels.

Source: Hydrogen Europe; Prussi, M., Yugo, M., De Prada, L., Padella, M., & Edwards, R

Hydrogen produced from biowaste would be classified as advanced biofuel and as such would be eligible for various EU fit-for-55 targets

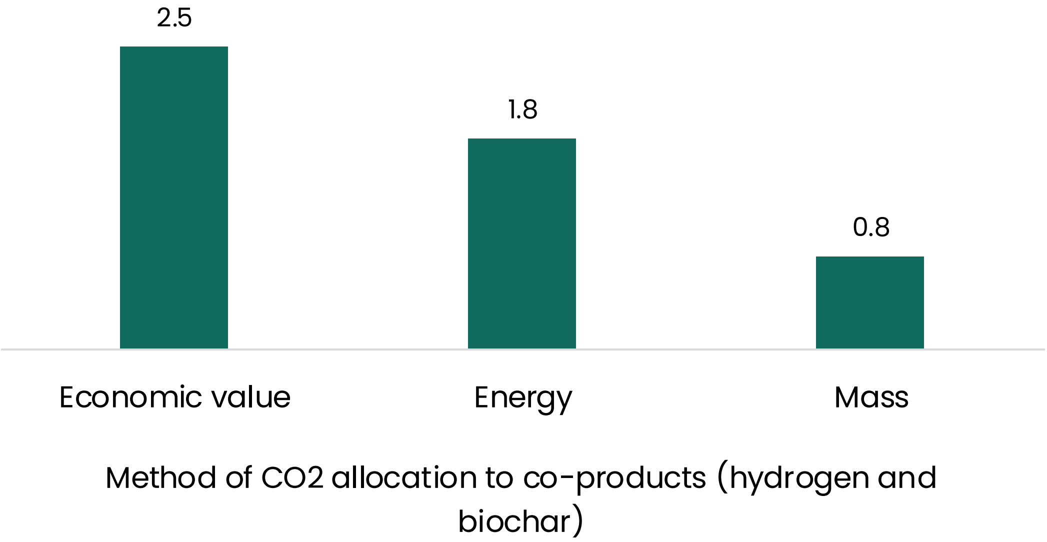
Treatment under RED: Depending on the feedstock used, bio-hydrogen produced from biodegradable waste could be classified as an advanced biofuel. As such, this **biohydrogen could be used towards compliance with a number of Renewable Energy targets, including a 5.5% combined advanced biofuels and RFNBO sub target in the transportation sector**. At the same time, there are several regulatory barriers preventing a faster deployment of the technology on the market. First, the consumption targets for biofuels exist only in the transportation sector and therefore this biohydrogen **cannot be considered for the 42% consumption target in industry**, placing biohydrogen at a significant disadvantage.

Allocation of GHG emissions: The technology also faces similar challenges as already described for methane splitting. First there is an uncertainty about how to allocate the emissions to hydrogen and the biochar by-product. The rules in force for RCF and RFNBO fuels state that in case of fuels the allocation should be done based on the relative energy content of the products and in case of co-production of hydrogen with non-fuel products - based on the relative economic value. **As biochar can be used both as a fuel and as a material product, the appropriate allocation method is not clear, creating an unnecessary risk for investors.**

Biochar as a CCS option: Furthermore, while the **Net Zero Industrial Act and the Industrial Carbon Management Strategy** set ambitious targets for CO2 carbon capture and storage, these **targets overlook biochar as a carbon removal technology. The current focus is solely on captured CO2 emissions**, neglecting the potential of precombustion carbon capture and storage methods like solid carbon from waste-to-hydrogen technologies.

Biochar not recognised by the ETS: Finally, while identical on a molecular level with carbon black, **biochar would not fit into the current definition of carbon black producing activity under the EU ETS.** As such waste-to-hydrogen plants would be eligible only for free allowances for hydrogen and not for the carbon output, putting them at a disadvantage versus industrial plants using fossil fuels for the production of carbon black.

Figure 4.8: Emission intensity of hydrogen from biowaste-to-hydrogen depending on the method of CO2 allocation to co-products (waste wood feedstock) [kgCO2eq/kgH2]



Source: Hydrogen Europe

Potential competition for feedstock with other biowaste users in the future and size restricted by local feedstock availability are the main scalability challenges

Feedstock

- Competition with other biomass waste users with potentially higher willingness to pay. These include biomass based SAFs or biomass based maritime fuels.
- These installations can accommodate different feedstocks, but feedstock standardization improves yields and reduces catalyst degradation. E.g. once setup for woody biowaste, feeding other feedstocks is possible but can have impact on yields and longevity of the installation.

Regulatory

- Classification – Hydrogen from biowaste as described in this chapter is classified as "advanced biofuel and biogas" within the RED III target for transport sector. As such, hydrogen produced via biowaste-to-hydrogen technologies could contribute towards the RED target of 5.5% of energy in transport sector to be supplied by advanced biofuels and RFNBOs by 2030, as well as towards the general 29% renewable energy share in the transport sector target.
- However, there are no hydrogen specific targets for hydrogen from biowaste and it could not be used to comply with the RED target for the use of RFNBO in industry. As a result, hydrogen from biowaste is not on equal terms with RFNBO which limits the demand for it.
- The regulatory framework for GHG emissions accounting does not allow for a proper recognition of the net carbon removal potential of the technology on an equal footing to CCS.
- The production of solid carbon (biochar) via the waste-to-hydrogen approach would not be eligible for ETS free allowances.

Scale

- Modularity allows these technologies to scale as needed, but it is restricted by potential feedstock availability and economics of transporting biomass waste to reach industrial sized installations. As such, biowaste-to-hydrogen technologies are unlikely to supply all of the hydrogen for a refinery, ammonia plant, methanol plant, or a steel mill.
- While some biowaste-to-hydrogen technologies are being deployed commercially, others are in relatively low TRL levels (5-6)

NON-BIOLOGICAL WASTE-TO-HYDROGEN

- **Non-biological waste-to-hydrogen** refers to technologies transforming solid non-biological and non-recyclable waste feedstock to produce hydrogen and capture the associated CO2 emissions. Under European legislation (Renewable Energy Directive), this route is considered to produce Recycled Carbon Fuel.
- **Unique technology benefits** – While waste recovery and recycling need to be further expanded, production of hydrogen from non-biological and non-recyclable waste can help tackle the excessive landfilling in Europe as well as shipping that waste around the world. The focus on locally sourced non-recycleable plastic waste and locally produced and consumed hydrogen encourages local deployment of decarbonization solution independent of hydrogen infrastructure.
- **Technology** – Deployment of gasification and pyrolysis for non-biological and non-recyclable feedstocks and optimization for different products (hydrogen, liquid products, etc.) is what challenges and differentiates the different technology providers. Some technologies are reaching TRL 8 while others continue to develop and improve.
- **Costs** – CAPEX is the largest cost driver at 36% of the LCOH per kg. With wholesale electricity costs at 80 EUR/MWh, the LCOH of hydrogen from ASR/plastic would reach 5 EUR/kg. However, decreasing CAPEX costs and cheap electricity could bring the LCOH closer to 3.5 EUR/kg.
- **Emissions** – Gasifying ASR/Plastic waste would result in direct emissions of only 1.0 kgCO2eq/kgH2, below the 3.4 kgCO2eq/kgH2 threshold under the Renewable Energy Directive. These are caused mostly by the CO2 that wouldn't be captured during the process as well as indirect emissions from electricity consumption. In the counterfactual scenario when ASR/Plastic waste feedstock would be incinerated with energy recovery every kgH2 produced removes 5.5 kgCO2eq.
- **Scalability challenges** – Competition with plastic waste users with potentially higher willingness to pay such as chemical industry. High CAPEX at this early commercialization stage. The scale of the installations is limited to the feedstock availability in the region. Reliance on available CO2 transport and storage infrastructure.

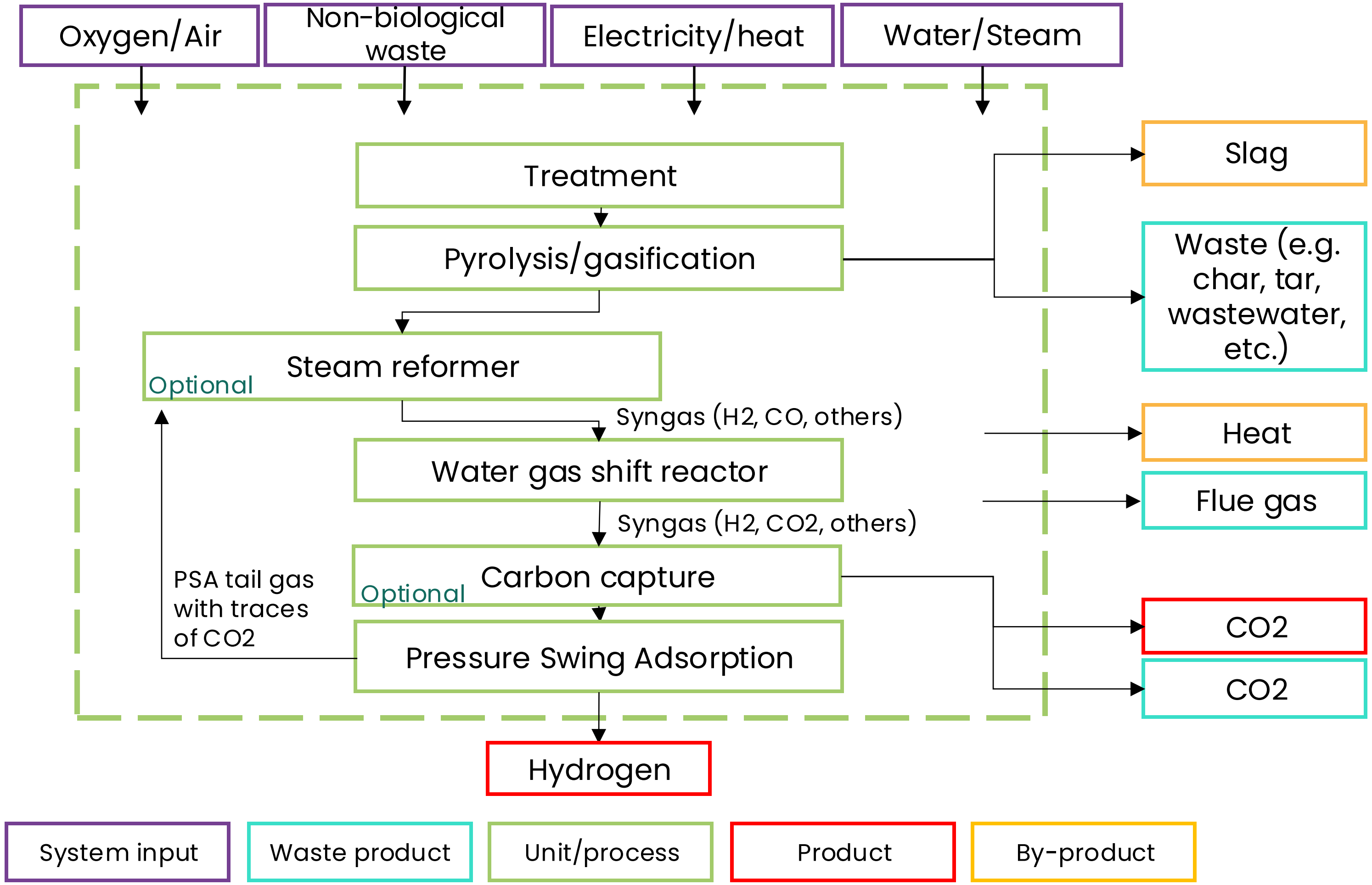
Gasification and pyrolysis reactions are the basis, but the reactor design varies significantly depending on the feedstocks and desired by-products

The non-biological waste-to-hydrogen pathway is based on gasification and/or pyrolysis of non-biological waste. Gasification refers to thermochemical transformation of solid or liquid into a gas. Pyrolysis refers to thermal decomposition at elevated temperatures in the absence of oxygen. These two processes can be combined as part of the same technology. The process can significantly differ depending on technology and feedstock.

The process: In this example for non-recyclable plastic waste, the feedstock has to undergo **pretreatment focused on shredding it to smaller pieces, reducing the moisture level in a dryer, and removing or treating contaminants in the feedstock such as glass, metal, and chlorinated plastics.** Many of these processes can be done by the feedstock supplier before feedstock delivery to the installation.

Subsequently, the gasification and/or pyrolysis reactions occur in the reactor producing hydrogen containing gas mixture (syngas) and by-products. The waste and by-products depend on the technology and feedstock. Syngas is cleaned of various compounds for further processing. Depending on the reactor, the cleaned syngas can be reformed with steam, before maximizing the H2 yield with the water gas shift reaction, separating hydrogen in a pressure swing adsorber or via other method, and capturing CO2 from the stream (optional). **This chapter focuses on non-recyclable plastic waste/ASR mixture as a feedstock, but other common feedstocks include textiles, rubber and tires, or non-recyclable municipal solid waste.**

Figure 5.1: Non-biological waste-to-hydrogen – process diagram



Notes: This is a generic process diagram that can vary significantly depending on the used technologies and plant setup
Source: Hydrogen Europe; ISO/TC 197/SC 1/WG

Gasification and pyrolysis of non-biological waste streams like plastics can be tailored depending on waste streams and desired products

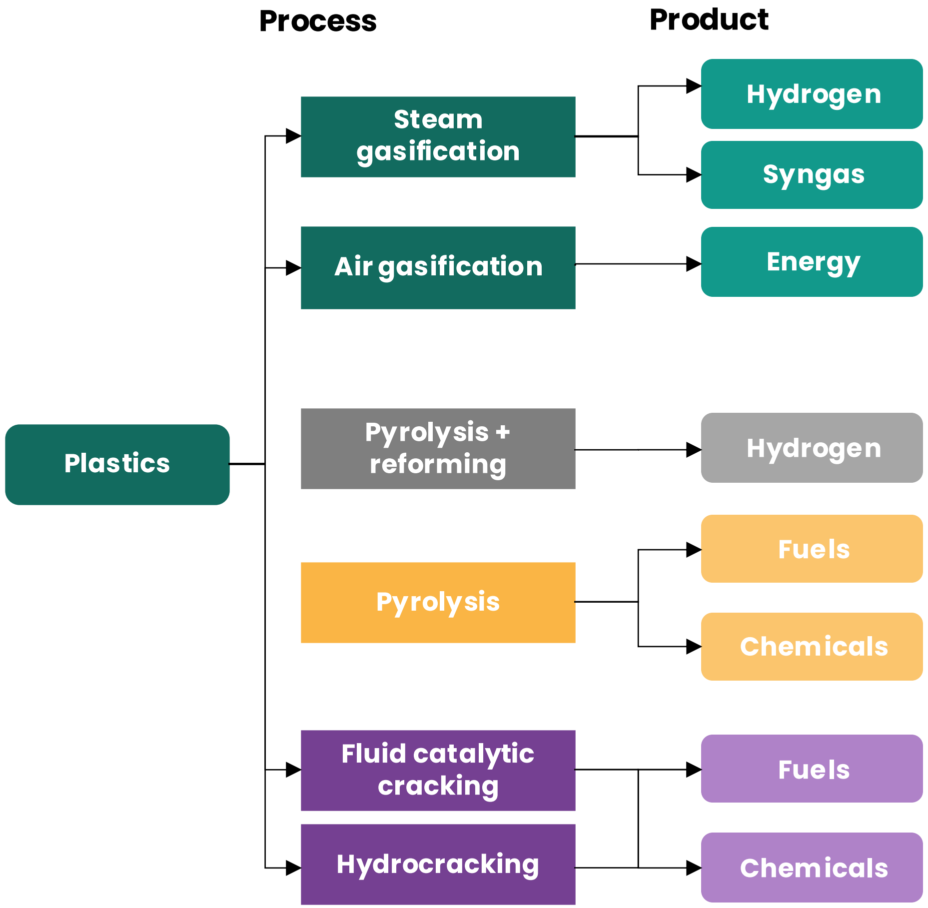
Numerous companies have been exploring the potential of using different plastic types and other non-biological and non-recyclable waste types for H2 rich gas and liquids production via gasification and pyrolysis. The setup of a specific technology has a major impact on quality and yield of the different products. **The primary variables of that setup can include pressure, residence time, reactor type, temperature, and catalysts.**

Gasification of non-biological waste: It is a thermochemical conversion of carbon-based materials that seeks the highest possible yield of gaseous output. In some cases, pyrolysis occurs before gasification as part of the process to further break down some of the complex hydrocarbons. Temperatures mostly range between 800 °C and 1,500°C. Gasifying non-biological waste streams like plastics produces solids such as ash, liquids such as oil and tar, and hydrogen-rich gas called syngas. The ratios and yields of solids, liquids, and gases depends on the technology's setup and feedstock. Some of the main gasification technologies are fixed bed, fluidized bed, entrained flow, and plasma gasifiers. Using steam in the gasification process is the most common when aiming to produce syngas or hydrogen as end-product.

Figure 5.2 on the right visualizes the different processes best suited for thermochemically processing plastics depending on the desired product.

Pyrolysis of non-biological waste: It is a thermal decomposition process that breaks down polymers into smaller molecules, in the absence of oxygen, and at temperatures typically between 300°C and 900°C. The process converts plastic waste into valuable products like oil, syngas, and char. Different plastics and reactors yield varying amounts of oil, gas, and char so the choice of process is dependent on the desired end products. For hydrogen production, pyrolysis coupled with in-line catalytic reforming is gaining traction in academia and industry as it enhances conversion efficiency and reduces the amount of tar and other undesirable by-products.

Figure 5.2: Overview of products that can be made via different processes from plastics



Source: Hydrogen Europe; Zhou, Y., Zhang, L., Wang, J., & Wang, Y

Pyrolysis for plastic waste recycling is at commercial scale, gasification or pyrolysis of non-biological waste streams for hydrogen production is slightly less mature

There are numerous existing and planned facilities using pyrolysis to break down plastic waste into feedstock for further chemical/plastics production such as recycling polystyrene into styrene monomer or mixed plastics into naphtha and mid distillates. These are used by chemical companies to increase the circularity of their products. Examples include *Plastic Energy* with commercial plants in Spain and one under construction in Netherlands and *Quantafuel* with commercial scale demonstration plant in Denmark.

Technology readiness level: While commercial adoption of non-biological waste gasification/pyrolysis for hydrogen production is limited for now, some projects focusing on non-recyclable plastic waste, auto shredder residue, wind turbine blades, and other waste feedstocks are reaching the commercial stage. **Unlike for the other production technologies covered in the report, the International Energy Agency does not include TRL levels for gasification/pyrolysis of non-biological feedstocks for hydrogen production. As with other technologies, there is a wide range of companies with the most advanced ones at TRLs 8 and reaching 9.**

Deployment: Figure 5.3 provides a selection of technologies and companies pursuing processing non-biological waste feedstocks for hydrogen production or other products. Enerkem operated its facility in Edmonton, Canada since 2016 until decommissioning in 2024. It focused on gasifying municipal solid waste and production of biofuels. *Plagazi* uses plasma gasification technology to treat non-recyclable plastic waste, auto shredder residue, wind turbine blades, and other waste feedstocks. It had operated a proof-of-concept plant in USA since 2011 and is developing a commercial project in Sweden. *Boson Energy uses* plasma assisted gasification to transform non-recyclable waste and biomass into clean hydrogen and industrial-quality CO2. The company operated a pilot plant in Israel and is now in the process of developing commercial scale installations. *Green Hydrogen Technology* began tests of its pilot entrained flow reactor gasification technology in 2023 in Austria. While still in early stages, it plans to use non-recyclable plastic waste or biowaste for syngas production and subsequently hydrogen. Similar to the biohydrogen chapter, companies tend to offer technological solutions covering different waste feedstocks and final products.

Figure 5.3: Selection of companies and projects using gasification and pyrolysis technologies of various mostly non-biological waste feedstocks for hydrogen or other products

	Company	Status	Technology and feedstock
🇸🇪	Plagazi	Pilot in US since 2011. Developing several projects including a commercial plant in Sweden (12,000 tH2/y) by 2025.	Plasma gasification of various non-recyclable waste
🇨🇦	Enerkem	Operational plant in Canada 2016-2024.	MSW gasification for biofuels production
🇺🇸	Plasma Development	Deployed around the world and developing large scale commercial plants in US.	Gasification of MSW, biowaste, and others with plasma conversion to generate clean syngas
🇬🇧	Powerhouse	Developing a commercial plant at Peel Plastic Park in UK.	Gasification of non-recyclable plastic for hydrogen
🇺🇸	SGH2	Pilot in USA and developing commercial plant (3,800 tH2/y) in USA.	Plasma enhanced gasification of various landfill waste
🇺🇸	Raven	Developing a commercial plant (2,400 tH2/y) in USA.	Processing various waste products for hydrogen production for heavy duty
🇱🇺	Boson Energy	Operated a pilot plant in Israel	Plasma assisted gasification of non-recyclable waste and biowaste for clean hydrogen
🇩🇪	Green Hydrogen Technology	Pilot plant in Austria in 2023.	Gasification of non-recyclable plastic waste and biowaste for hydrogen
🇺🇸	FusionOne	Technical demonstration project in progress in USA.	Plastic waste decomposition

Source: Hydrogen Europe; Lepage, T., Kammoun, M., Schmetz, Q., & Richel; Aziz, M., Darmawan, A., & Juangsa, F; Wijayasekera, S. C., Hewage, K., Siddiqui, O., Hettiaratchi, P., & Sadiq, R; Plastic Energy; Quantafuel; GHG Technology; Plasma Development; SGH2 Energy;

Non-biological waste-to-hydrogen can assist with waste management issues while supporting decarbonisation with locally produced hydrogen at competitive prices

Feedstock

Waste management - Despite increasing rates of mechanical recycling across Europe, waste continues being landfilled. Out of 2 billion tons of waste generated in EU in 2020, 0.8 billion tonnes were recycled and 0.8 billion tonnes had been landfilled or otherwise disposed in 2020 with incineration only accounting for 0.01 billion tonnes. Efforts need to be expanded based on the waste hierarchy to significantly increase waste recovery and recycling. However, there will remain, in various volumes, non-recyclable waste that would end up in landfills or would be incinerated. These can include mixed municipal solid waste, non-recyclable plastic waste, and others. The costs and emissions in this report focus on non-recyclable plastic waste combined with auto shredder residue.

Costs

Cost - Using base assumptions, hydrogen from non-recyclable plastic waste, could be around 5 EUR/kg. This is cheaper than available low-temperature electrolytic hydrogen and could, similar to reforming with carbon capture and methane splitting, provide low-emission hydrogen at a smaller premium or even compete, depending on local conditions such as gate fees and electricity prices, with existing unabated SMRs or other low-carbon hydrogen production technologies.

Other

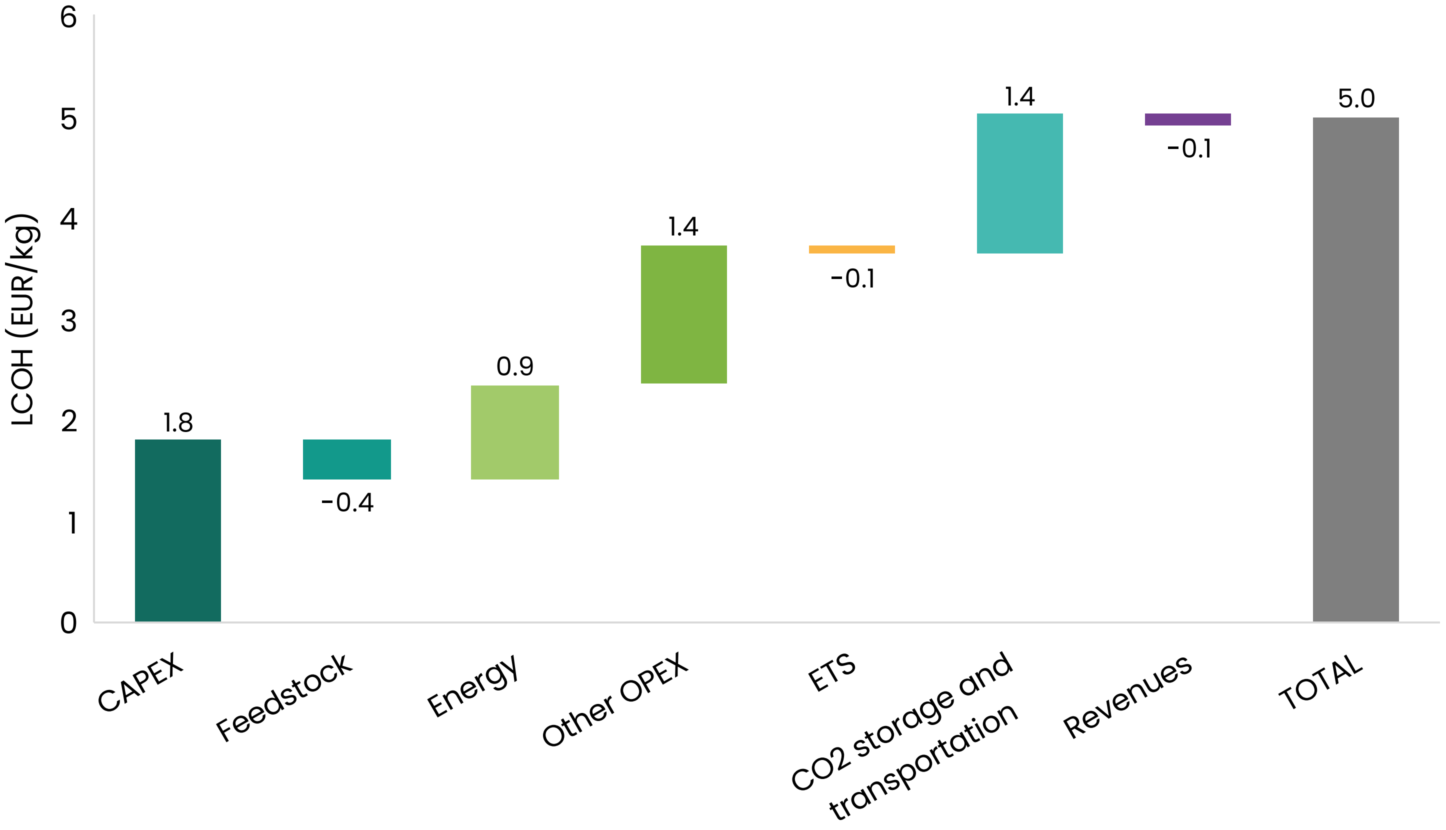
- Locally focused decarbonisation - The focus on locally sourced non-recyclable plastic waste and locally produced and consumed hydrogen encourages local deployment of decarbonization solutions while assisting with the society’s waste and landfill issues.
- Not reliant on hydrogen transport infrastructure buildout as it can be produced close to potential end-use.
- Ability to locate the manufacturing facility close to urban areas, combined with significant heat recovery potential offers potential synergies with local district heating applications.

At early commercialisation, CAPEX dominates the cost structure for hydrogen from plastic waste/ASR at 5 EUR/kg

Cost structure: CAPEX dominates the cost structure of producing hydrogen from non-recyclable plastic waste combined with auto shredder residue (ASR), constituting 36% of the LCOH. CAPEX is comparatively high as these technologies are only now entering early commercialisation. The second largest part is the transportation and storage of the captured CO2. OPEX costs are also significant at 1.4 EUR/kg partially due to a more labour-intensive process and expected maintenance, compared to other technologies. As it is an energy intensive process, the electricity cost is also significant. The air separation unit consumes large volumes of electricity to produce oxygen for the CCS.

Revenues: ETS refers to revenues and costs related to receiving free allowances and eventually having to buy free allowances for the non-captured CO2. **Income from gate fees under feedstock category contributes to lowering the total LCOH of hydrogen produced from non-recyclable plastic/ASR waste. Gate fees represent price that waste producers will pay to offload their waste, but they will differ significantly between countries depending on waste type and quality.** The revenues column represents sale of waste heat. While this is not a given for every business case for this technology, the advanced pyro/gasification projects do include the sale of heat in their business models. Nitrogen from air separation units could also be marketed and valorised as a by-product. The captured CO2 could be also sold to provide additional revenues, but significantly impacting the emissions as the CO2 would be used and emitted elsewhere.

Figure 5.4: 2024 LCOH of plastic waste/ASR to hydrogen



Assumptions for these prices: Gasification with carbon capture technology used; CAPEX: 4000 EUR/KW; Plastic waste/ASR feedstock gate fees: 60 EUR/t; Electricity: 80 EUR/MWh plus average network fees at 29.3 EUR/MWh; Other OPEX: 1.24% of CAPEX; CO2 costs: 100 EUR/t ; Project details: 1 t/h project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe

With increasing deployment and declining CAPEX, hydrogen from ASR/plastic could reach 4 EUR/kg

Sensitivity: Figures 5.5 and 5.6 compare LCOH of non-recyclable waste-to-hydrogen with electricity prices and CAPEX as variables. In the base case scenario, CAPEX represents 36% of the LCOH. If CAPEX decreased from the current levels to 2000 EUR/KW, the LCOH would decrease to 3.8 EUR/kg. **Given that this technology is at the beginning of commercialisation, it is likely that CAPEX will continue decreasing with increasing deployment.** OPEX is also relatively high at 31% of the total LCOH and is currently a function of CAPEX. As a result, it is also to decrease with further commercialisation and deployment.

For projects located in areas with average long-term wholesale electricity prices at 40 EUR/MWh, the total hydrogen price would be 4.7 EUR/kg. That is competitive with hydrogen from reforming with high carbon capture at 60 EUR/MWh gas prices.

Revenues: **Fuel prices, or gate fees, are the other main flexible variable impacting the final hydrogen price. They represent revenue of 0.4 EUR/kg, but they significantly differ across Europe.** Besides revenues from ETS and sale of heat, the model is assuming that there are no additional revenues from by-products of the process such as vitrified slag or others.

Figure 5.5: 2024 LCOH from plastic waste/ASR depending on different CAPEX

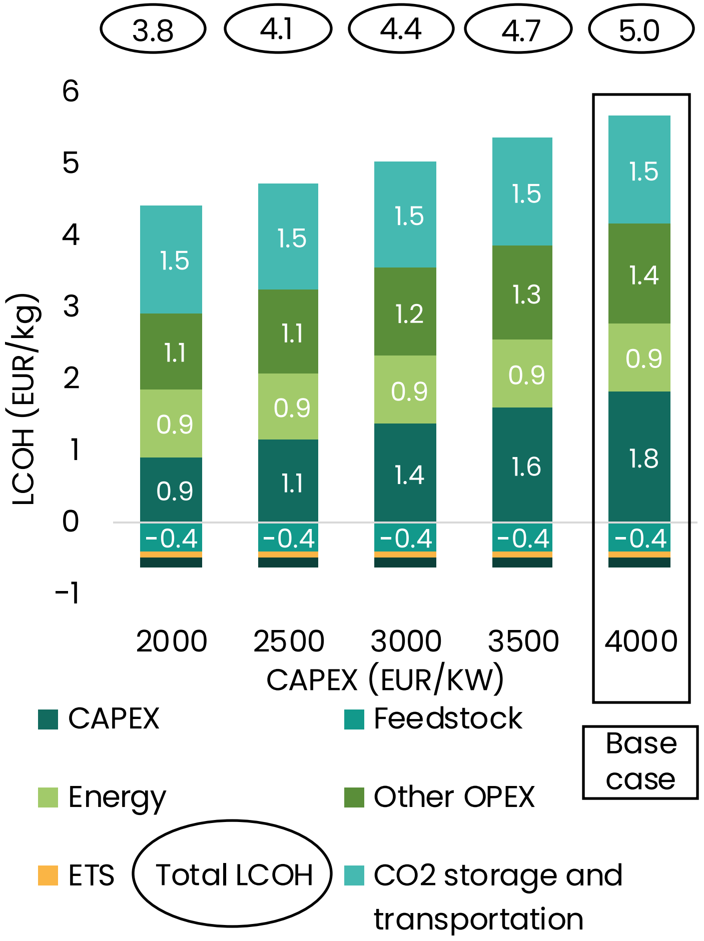
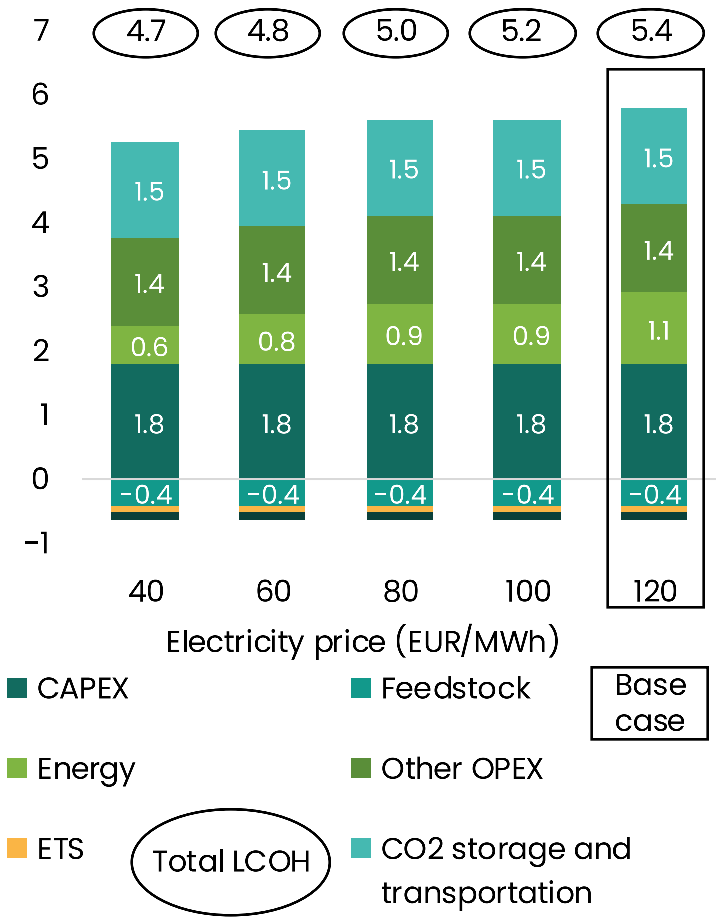


Figure 5.6: 2024 LCOH from plastic waste/ASR depending on electricity price



Assumptions for these prices: Gasification with carbon capture technology used; CAPEX: 4000 EUR/KW; Plastic waste/ASR feedstock: 60 EUR/t; Energy: 80 EUR/MWh plus average network fees at 29.3 EUR/MWh; Other OPEX: 1.24% of CAPEX; CO2 costs: 100 EUR/t; Project details: 1 t/h project starting construction in 2024 in Europe; Rest of the assumptions in the associated Excel

Source: Hydrogen Europe

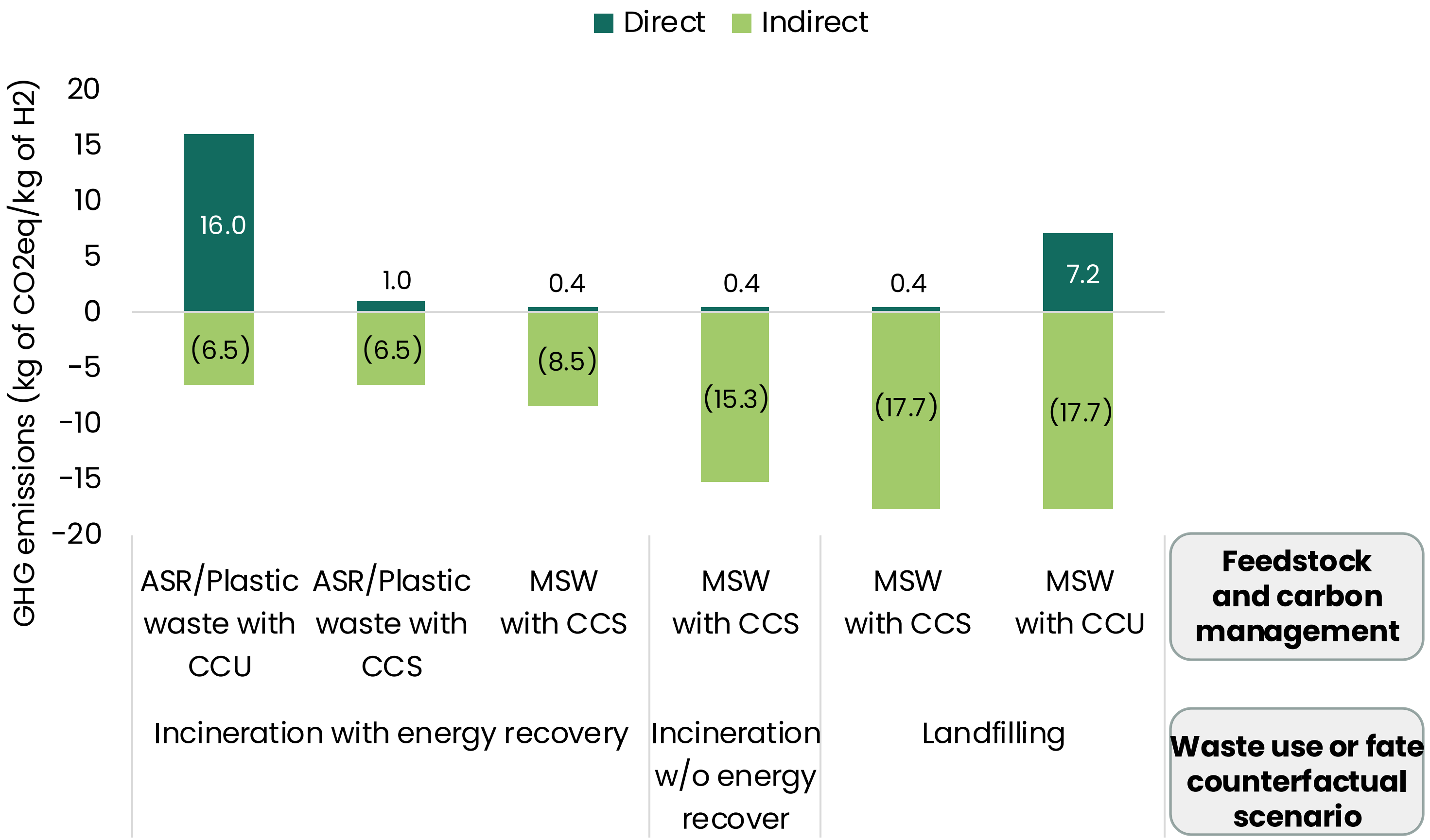
Depending on the type of waste and the end-of-life of waste used, hydrogen from MSW could have net negative GHG footprint of up to -17.2 kgCO2eq/kgH2

GHG emission intensity of hydrogen produced from non-recyclable waste by gasification depends mostly on the carbon capture rate and waste feedstock existing end-of-life fate (Figure 5.7).

Waste incineration counterfactual: If waste would be redirected from waste incineration with energy recovery the GHG emissions balance would include both avoided emissions from waste incineration, but also additional emissions related with the heat and power generation to replace the previously recovered energy. In such case **CCS would be required to avoid the overall GHG intensity of hydrogen to stay below the required emission threshold of 3.4 kgCO2eq/ kg of H2.**

Landfilling counterfactual: If waste would be redirected from landfilling, the overall emission footprint of hydrogen would be negative - and in the case of using MSW as feedstock (with 50-60% share of biogenic fraction) – the negative GHG footprint would be achieved even without carbon capture. This would allow the WtH plants to sell the biogenic CO2 for the purpose of e-fuels production without impacting the low-carbon character of produced hydrogen.

Figure 5.7: GHG emissions of hydrogen from ASR/Plastic compared with MSW gasification under different counterfactual scenarios



Assumptions for this emission intensity: Gasification with or without carbon capture technology used; For carbon capture 94% capture rate is assumed; The assumed share of biogenic content is 0% in ASR/plastic waste and 60% in MSW. Assumed efficiency of waste incineration with energy recovery is 14% for electricity and 41% for heat; Additional electricity that would have to be generated after redirecting waste for hydrogen production replaced with electricity with average EU GHG intensity, and in case of heat – GHG emissions representing natural gas combustion with 95% efficiency; Avoided GHG emissions from landfilling estimated following the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, 2000.

Source: Hydrogen Europe

Main scalability challenges include reliance on CO2 transport and storage infrastructure and feedstock issues to reach 100,000 t/y installation sizes

Feedstock and infrastructure

- Mostly local availability of feedstock which can hinder the availability in sufficient volumes for large scale production (~100,000 tH2/year)
- For some feedstocks, operators might compete with chemical industry for their chemical and feedstock recycling company targets
- CO2 transport and storage infrastructure – The infrastructure largely does not yet exist, and its unavailability is even more prominent for landlocked countries with no existing CO2 pipelines to a maritime port from which the CO2 could be shipped out.

Technology

- While some technologies are reaching TRL8-9, its application for hydrogen production is at early commercialisation stage has not been deployed at large scale. However, except the reactor which is a proprietary technology, the reformer, pressure swing adsorber, CO2 capture technology are widely commercially deployed.
- Due to the early commercialisation stage, CAPEX is high for now, but will continue to decrease not only with technology developments, but also experience from EPC contractors in deploying the technology

Regulatory demand, scale and cost

- Classification - Hydrogen from non-recyclable plastic waste as described in this chapter is classified as “recycled carbon fuel” (RCF). While having to comply with the same emission threshold as RFNBOs, the regulatory framework lacks any targets specific to RCFs and it is not possible to use it in order to comply with the 42% RFNBO target for industry under the renewable energy directive. As a result, RCF won’t be able to command the same price premium as RFNBOs.
- Scale - Similarly to biowaste hydrogen, this technology is modular and scalable. While it is more common to transport non-biological non-recyclable waste on longer distances than biowaste, it is likely that these production installations will also not reach the scale needed for ammonia or steel plants. However, they will facilitate development of other end-uses such as mobility and smaller scale industry, while reducing landfilling.

OTHER HYDROGEN PRODUCTION PATHWAYS

- **Solar thermochemical hydrogen production** – there is a whole array of emerging production technologies with lower technological maturity but with high potential for low-cost and sustainable hydrogen production. These could include new highly efficient and cheap electrolyser technologies but also completely novel approaches – with solar thermochemical cycles one of those - with potential hydrogen production costs at 2-3 EUR/kg.

- **LPG pyrolysis** - Outside of natural gas, propane can also be used as the raw material for obtaining CO2-free hydrogen via catalytic pyrolysis, offering a very attractive solid carbon yield

- **Natural hydrogen** – natural hydrogen deposits could prove to be a significant disruption on the emerging hydrogen market in the coming years with a potential renewable deposits estimated by some in 10's of millions of tonnes per year. With both very competitive extraction costs (0.5-2.5 EUR/kg) as well as very low environmental footprint (0.4-1.5 tCO2/tH2). However, the full potential still needs to be evaluated.

- **By-product hydrogen** – hydrogen produced as a by-product of other industrial processes is an important source of hydrogen in the current economy, supplying around a third of all hydrogen used by the European industry. While by-product hydrogen from some sources can be considered low-carbon, any environmental benefits from its use would be lost if it would be replaced by natural gas in its existing applications. Furthermore, as by-product hydrogen is exempted from the RED industry targets, special effort should be made to avoid it being utilized as an option to circumvent those targets.

Solar thermochemical cycles could deliver abundant and low-cost renewable hydrogen

The basics: The solar direct normal irradiation (DNI) is the main renewable resource needed to power thermochemical cycles (TCCs) for solar-driven hydrogen production, as they usually require high temperatures (>400 °C) to operate. **Annual DNIs above 2000 kWh/m² are commonly considered as the threshold for the feasibility of concentrated solar technologies**. Under this constraint, some locations stand out, such as the Middle East and North Africa (MENA), northern Chile and Argentina, southwestern USA, northwestern Mexico, southern Africa, and Australia (see Figure 6.1).

Global supply potential and costs: Several assessments of country-specific potentials of solar hydrogen production are found in literature. However, the consideration of different TCCs and technical assumptions makes direct comparisons not straightforward. Despite this, the study by Falter and Sizmann is a notable example of this kind of assessment. It focuses on the USA and considers a solar-driven two-stage thermochemical redox cycle, including several sustainability criteria to identify suitable areas where the process could be developed. In such locations, about 12 times the current global and 80 times the current national hydrogen production could be produced via solar-driven TCCs, with a **projected levelized cost of hydrogen and specific emissions between 2.1–3.2 EUR/kgH2 and 1.4 kgCO2eq/kgH2**, respectively.

Furthermore, a study by Fraunhofer concluded that nearly half of Europe's hydrogen demand in 2050 – estimated at 25.9 Mt – could be sourced from MENA. Positive factors influencing this include competitive production costs, geographical proximity, and the possibility of using or repurposing existing infrastructure to transport and store the produced hydrogen.

Figure 6.1: World annual DNI distribution, highlighting locations with values over 2000 kWh/m²

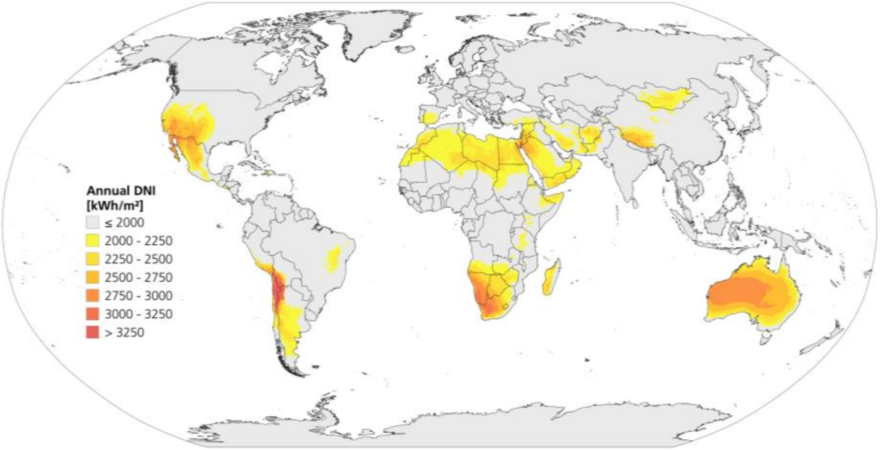
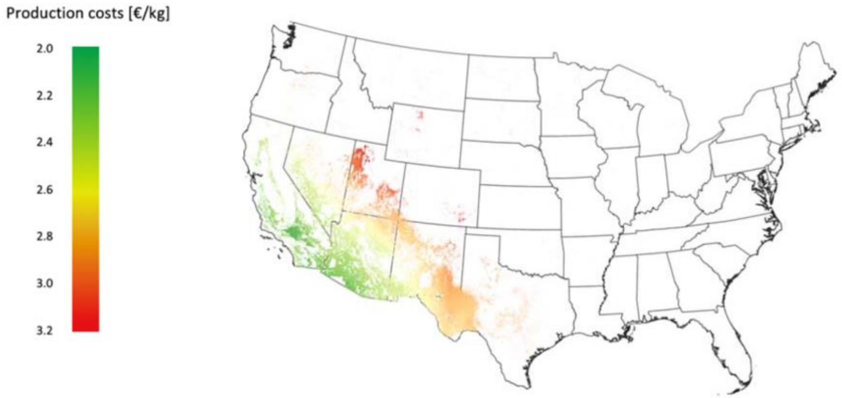


Figure 6.2: Cost of producing solar thermochemical hydrogen in the USA at suitable sites



Source: Hydrogen Europe; International Renewable Energy Agency; World Bank Group; Natural Earth; Falter C. & Sizmann A.; Braun, J., Frischmuth, F., Gerhardt, N., Pfennig, M., Schmitz, R., Wietschel, M., Carlier, B., Réveillère, A., Warluzel, G., & Wesoly, D.

By allowing to use the full spectrum of solar radiation, solar thermochemical cycles offer potential for high-efficiency and low-cost hydrogen production

The process: Solar thermochemical cycles (TCC) for hydrogen production use high temperature heat provided by a receiver and solar concentrator to run endothermic reactions. **Using the full spectrum of the solar radiation and by avoiding intermediate electricity production, the cycles have theoretically a high efficiency potential and resultingly low hydrogen production costs.** In research, two paths to water splitting have emerged that are particularly promising in terms of their efficiency: metal oxide redox cycles and sulphur cycles.

In metal oxide redox processes for water splitting, a redox material is cyclically reduced and oxidized (Figure 6.3). The endothermic reduction takes place at high temperatures (above 1200°C) and low partial pressures of oxygen. During a second step at somewhat lower temperatures (below 1000°C), steam is fed through the reactor producing hydrogen while the redox material is re-oxidized. These cyclic processes are referred to as circular processes because the redox material reaches different reduction states but is not itself consumed. The state-of-the-art technology uses ceria as redox material applied as a packed bed in a cavity receiver-reactor operated in batch with a reduction temperature of about 1500°C.

In addition to two-step processes, there are a number of other processes that consist of a higher number of process steps, whereby the required maximum temperatures can be lowered. However, as additional process and conversion steps are associated with energy losses, the highest efficiency potential is attributed to two-step cycle processes. The wide range of possible redox materials and process concepts and the already promising state-of-the-art performance suggests that economically attractive solutions can be developed in the future.

Figure 6.3: Metal oxide redox cycle for solar thermochemical water splitting

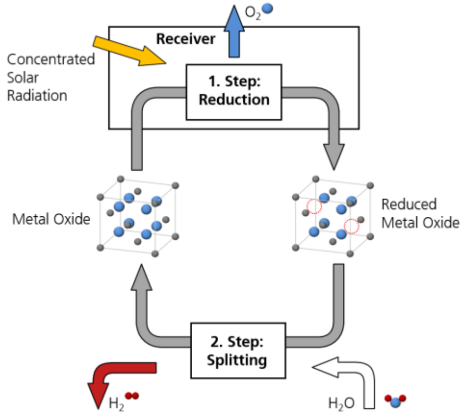
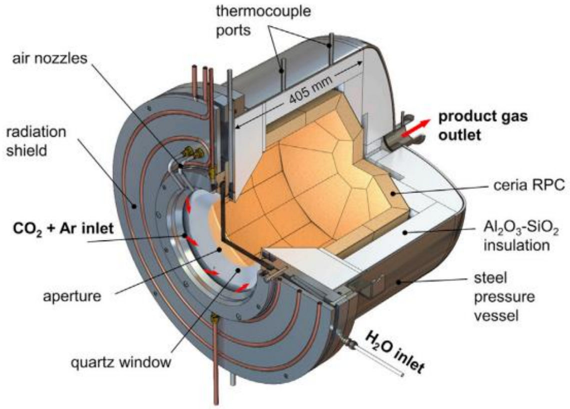


Figure 6.4: Receiver-reactor technology for water and CO2 splitting via the ceria-based thermochemical redox cycle



Source: Deutsches Zentrum für Luft- und Raumfahrt ; Zoller S et al.

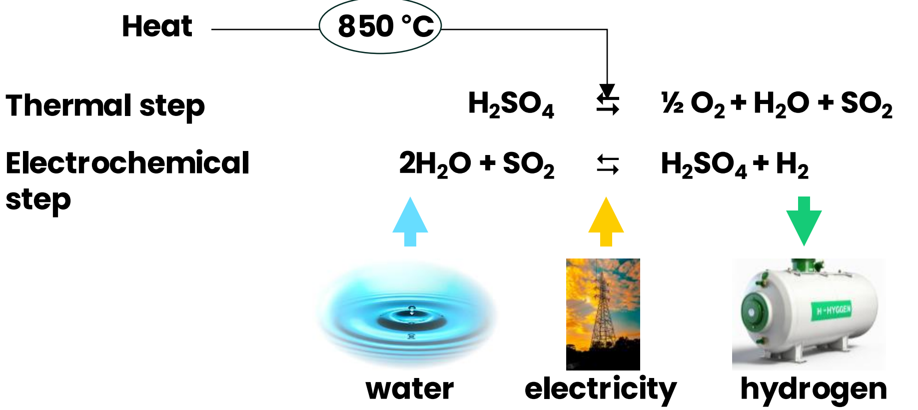
Sulphur Cycles have the potential to significantly reduce the amount of electrical power required compared to water electrolysis

Sulphur Cycles: **Sulphur-based cycles are considered the prime processes for potential commercial Hydrogen production** as stated by screening analysis carried out under the U.S. Department of Energy (DOE) Hydrogen Program, that identified the performance of more than 200 thermochemical cycles. In these cycles, Sulphur as the central element is recycled in different compounds.

All Sulphur cycles share a common thermal dissociation step of Sulphuric Acid first to water and Sulphur trioxide (SO_3) and a subsequent catalytic splitting of SO_3 to Sulphur dioxide (SO_2) and oxygen. Among the Sulphur cycles, the Hybrid Sulphur (HyS) one is especially as most of the electrical energy is replaced by heat introduced in the thermal step where the maximum temperature required is < 900ºC, which can be generated directly and entirely by 100% Renewable Energy sources like Concentrating Solar Technologies. The process is called hybrid because of the combination of the thermal decomposition of sulphuric acid with the electrochemical oxidation of SO_2 with water (electrolysis) to yield hydrogen and re-generate sulphuric acid which is completely recycled in the process. **This electrochemical step requires electrical power at a theoretical cell potential of only 0.17V and therefore only about 14% compared to conventional water electrolysis** exhibiting a theoretical voltage of 1.23V[4]. Hence, this **Sulphur dioxide-depolarized electrolyser (SDE) has the potential to significantly reduce the amount of electrical power required.**

Production costs Current efforts on the HyS focus on the experimental demonstration of the complete cycle with attractive solar-to-hydrogen efficiencies of over 10% and targeted long-term hydrogen production costs of < 5€/kg in multi-MW plants.

Figure 6.5: Basic reaction scheme of the HyS cycle



Heat 850 °C

Thermal step $H_2SO_4 \rightleftarrows \frac{1}{2} O_2 + H_2O + SO_2$

Electrochemical step $2H_2O + SO_2 \rightleftarrows H_2SO_4 + H_2$

water **electricity** **hydrogen**

Figure 6.6. Process flow diagram for an experimental demonstration of the HyS cycle

solar thermal & thermochemical processes

chemical & electrochemical processes

Source: Perret, R.; Brown et al.; Corgnale, C., Gorensek, M. B., & Summers, W. A.; Sattler, C., Roeb, M., Agrafiotis, C., & Thomey, D; HySelect

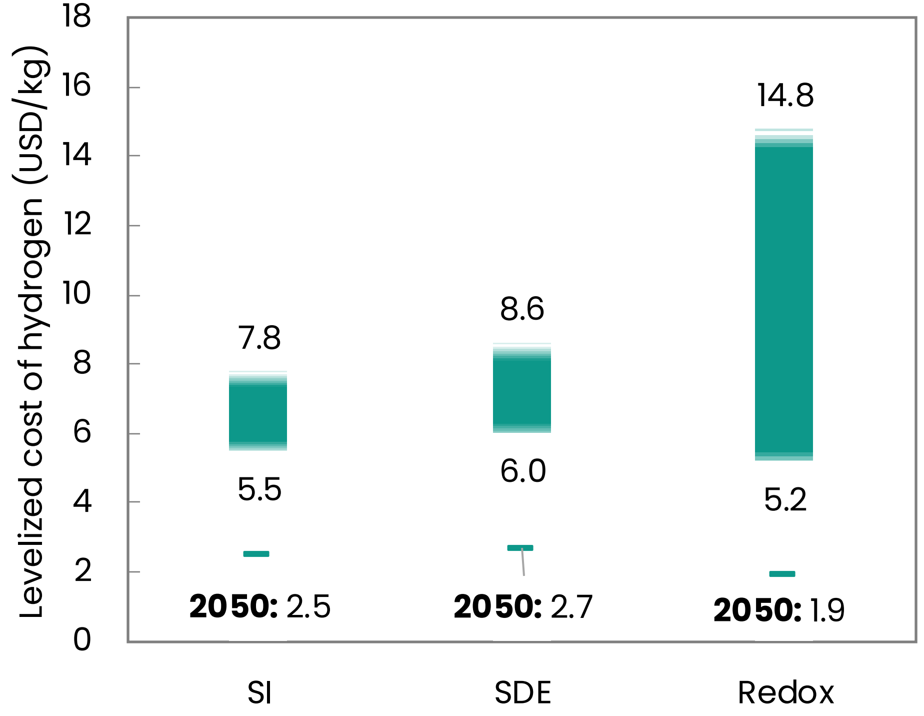
Cost reduction of solar technologies and efficiency improvements is expected to reduce the LCOH to 2-3 USD/kg

Production costs: The main cost driver for solar thermochemical cycles is the capital expenditure (CAPEX) required to build the infrastructure. Since solar thermochemical cycles require high temperatures, solar tower systems are commonly used to achieve them. While the electricity produced by this type of technology results in a price similar to other renewable energies such as PV, the still relatively low thermal efficiency of the thermochemical cycles forces the plants to be oversized, and therefore **the cost of solar thermal energy becomes one of the main contributors to the CAPEX**. In addition, the CAPEX of the chemical equipment is also an important factor: for the sulfur-iodine (SI) and sulfur dioxide depolarized electrolysis (SDE) cycles, the equipment must be resistant to highly corrosive chemicals. In contrast, the equipment for the redox cycles deals with much milder chemicals, but some components must withstand higher temperatures.

It is important to note that while the SI and redox cycles rely uniquely on solar heat, SDE requires an input of green electricity. The source of this electricity can be diverse, but its price, carbon intensity and availability will have a significant impact on the emissions footprint and on the operational expenditure (OPEX).

It is also important to highlight that while there are a significant number of techno-economic assessments in the literature for the redox cycles, these studies are less numerous for SDE and SI, limiting the accuracy of the reported levelized cost of hydrogen (LCOH). **The expected future LCOH is based on the expected cost reduction of the solar equipment and the efficiency improvement of the technologies as their technology readiness level (TRL) increases**.

Figure 6.7: Estimation of the current and future levelized cost of hydrogen (LCOH) produced by the sulfur iodine (SI), sulfur dioxide depolarized electrolysis (SDE), and redox thermochemical cycles.



Source: Moser, M., Pecchi, M., & Fend, T; Corgnale, C., Gorensek, M. B., & Summers, W. A; Kim, J., Park, J., & Yoon, Y.-S.; Guerra Niehoff, A; Chen, C., Jiao, F., Lu, B., Liu, T., Liu, Q., & Jin, H.; Finke, C. E., Leandri, H. F., Karumb, E. T., Zheng, D., Hoffmann, M. R., & Fromer, N. A. ; Song, H., Luo, S., Huang, H., Deng, B., & Ye, J.

If full life-cycle emissions were considered concentrated solar thermal systems have comparatively low GHG emissions compared to other non-fossil technologies

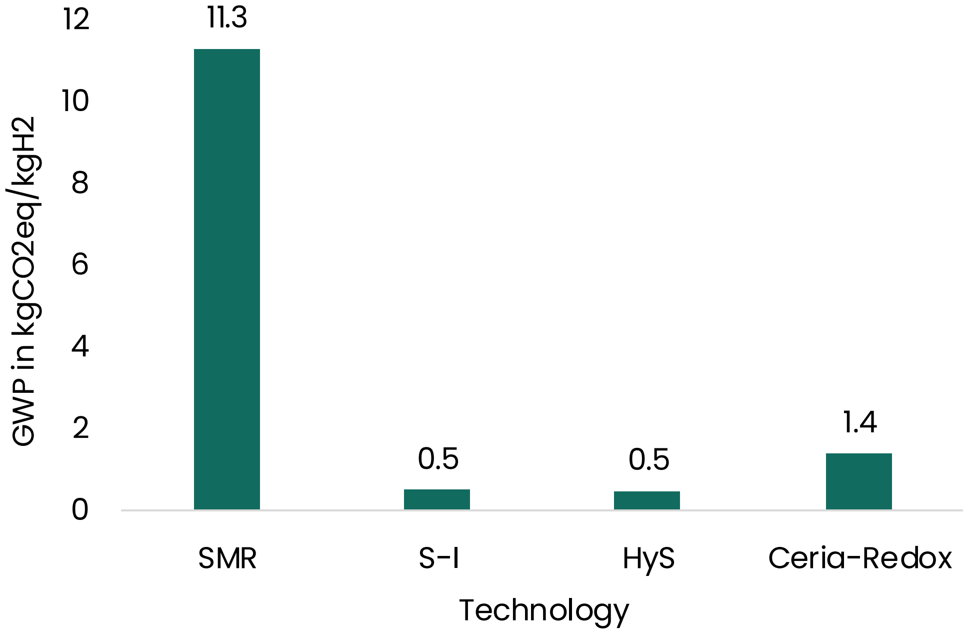
GHG intensity: Several studies show that **concentrated solar thermal (CST) systems have comparatively low greenhouse gas emissions over their entire life cycle compared to other non-fossil energy provision technologies**.

CST systems are particularly efficient at providing thermal energy at high temperatures. Therefore, driving thermochemical cycles for hydrogen production with solar thermal energy is a promising approach for sustainable hydrogen production that can potentially outperform electrochemical hydrogen production in terms of environmental impact.

A recent study compared the life cycle impacts of three alternative thermochemical hydrogen production processes. It was found that the **solar-based thermochemical hybrid sulfur (HyS) cycle has the lowest global warming potential, abiotic depletion, acidification potential, ozone layer depletion, and human toxicity potential**.

Most of the resource requirements and therefore the environmental impact of a solar thermal system arise during the construction of the reflective surface. **The specific GHG emission intensity of the technology depends heavily on the available solar resource** and also on the selected boundary conditions. The results of the various LCA studies shown in Figure 6.8 therefore only show the tendency that all analyzed solar thermochemical cycles can reduce CO_2 emissions by more than 80% compared to hydrogen produced from natural gas by steam methane reforming (SMR).

Figure 6.8: GHG intensity of different hydrogen production technologies



Source: Intergovernmental Panel on Climate Change.; Gasa, G., et al. ; Safari, F., & Dincer ; Batgi, S. U., & Dincer; Falter, C., & Sizmann, A.

Pyrolysis of propane (LPG) is a viable hydrogen production pathway that offers a very attractive solid carbon yield

Production process: Outside of natural gas, propane can also be used as the raw material for obtaining hydrogen free of CO2 via catalytic pyrolysis. The attraction of the development of hydrogen production based on propane is associated with the fact that, in contrast with methane, propane can be stored at a normal temperature in a liquefied state at lower pressures. **This makes LPG a better feedstock in areas without access to natural gas network.** An even more important advantage of propane lies in the possibility of selective decomposition of propane into hydrogen and carbon with the formation of gas mixtures with increased hydrogen : methane ratio. Furthermore, as propane is a heavier molecule than methane, **the yield of valuable solid-carbon by-product is also significantly higher, with a C:H ratio of 4.5 compared to 3.0 for methane splitting**. This would not only increase revenues of the process but also decrease the carbon footprint of hydrogen as a higher share of GHG emissions would be allocated to carbon.

Feedstock: **Even using fossil LPG (obtained from natural gas extraction process) the estimated emission intensity of hydrogen would be below the required low-carbon emission threshold. This could be further reduced if a more sustainable feedstock would be used, e.g. bio-LPG or e-LPG.** Currently bio-LPG is being produced as a by-product of other sustainable fuels such as renewable diesel and SAF (via HVO/HEFA route). The production of renewable diesel via Hydrotreated Vegetable Oil (HVO) would produce around ~5% yield for bio-LPG. Many routes for on-purpose production with significantly higher yields for bio-LPG are in development.

Production costs: The estimated costs are slightly higher than for methane splitting – but this is mostly a consequence of smaller scale (inflating the impact of fixed costs). Long-term the costs of the two technologies is expected to be roughly on par with the competitive advantage decided by the relative cost of feedstock.

Figure 6.9: LCOH of LPG pyrolysis

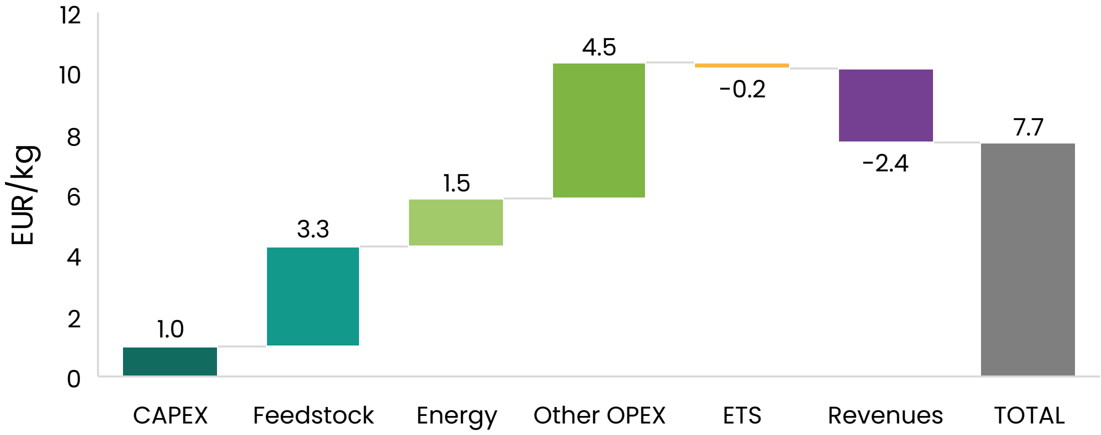
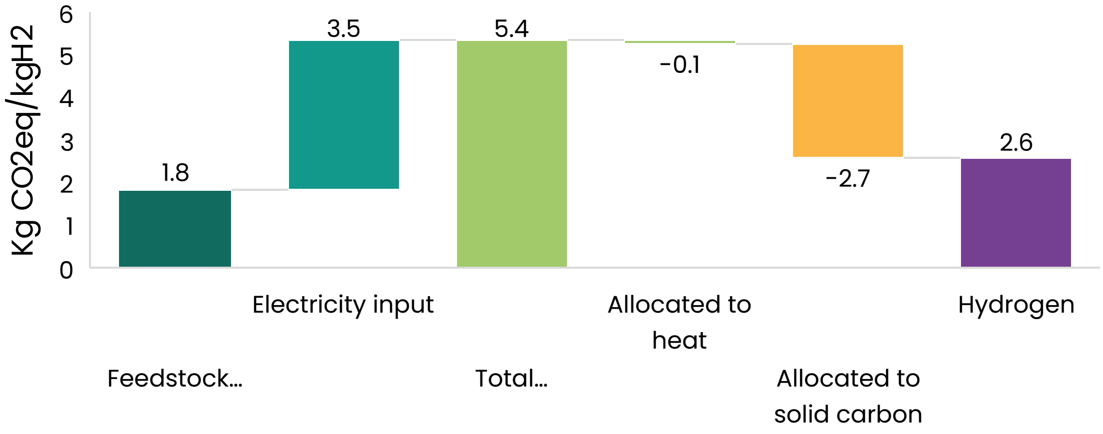


Figure 6.10: GHG intensity of LPG pyrolysis



Assumptions for these prices: Thermo-catalytic pyrolysis technology used; CAPEX: 2400 EUR/KW; Electricity costs at 80 EUR/MWh plus average network fees at 29.3 EUR/MWh; LPG costs of 600 EUR/t; Other OPEX: 45% of CAPEX; Economic lifetime of 20 years; Solid carbon at 500 EUR/tonne; Operating hours of 8000 a year ; Project details: project starting construction in 2024 in Europe for a pilot scale, non-commercial project.
Source: Hydrogen Europe, industry sources, Solov'ev, E. A., Kuvshinov, D. G., Chukanov, I. S., Ermakov, D. Yu., & Kuvshinov, G. G

Hydrogen formed by natural processes could be a breakthrough renewable resource, but more research is needed to evaluate its potential

Fundamentals: Natural hydrogen, also known as geological or white hydrogen, is becoming more and more popular. It has recently come under the spotlight in the mainstream and business media and are generating more and more interest among policy makers and industry players. **Following a discovery made in Mali and very recent efforts on R&D and exploration activities, it has been identified as a potential alternative source of low-carbon hydrogen to accelerate the shift to a net-zero economy in the next decades**.

Production process: **Natural hydrogen is hydrogen formed by natural processes**. As far as we currently know, the key element of this process is the water which percolates in the rocks and is split either through an oxydo-reduction reaction with iron-rich minerals (#1 in Figure 6.11), or through radiolysis by radioactive components of granitic rock (#2). These are the two main explanations for its generation among scientific community. Hydrogen is thus released and migrates through the overlying rocks. As it moves upward, in favorable geological context, it can be trapped by a sealing layer, such as salt for example, overlying a reservoir rock. Once a natural hydrogen accumulation is discovered, it can be produced through a well (#7) using conventional methods. **Unlike fossil energies, natural H2 is a sustainable source of energy, with a constant replenishment of the water percolating and reacting with rock.**

Supply potential: **A recent study from United States Geological Survey[1] estimates that the natural hydrogen generated worldwide is 10's of millions of tonnes**. Some stakeholders are critical regarding this resource while becoming attentive to this topic. Even though R&D is carried out worldwide and some exploration activities just started, the full natural hydrogen potential is still unveiled. Recent efforts are focused on understanding how and where it can be accumulated in the subsurface and how we can better detect prospective areas. **The full potential needs to be further evaluated**.

Figure 6.11: Processes forming natural hydrogen

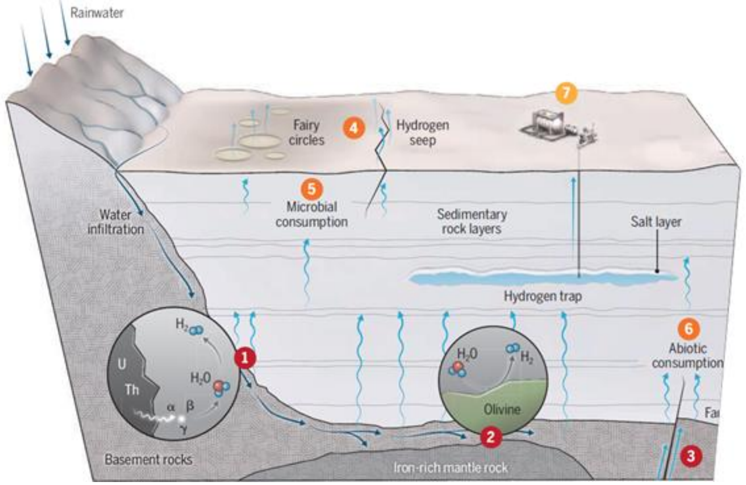


Figure 6.12: The occurrence of natural hydrogen

Source: Ohnsman, A; Zgonnik, V.; Davies, K., Esteban, L., Keshavarz, A., & Iglauer, S

Natural Hydrogen can become a market disruptor offering both extremely low production costs and low GHG intensity

GHG Intensity: In term of environmental impact, natural hydrogen has many advantages:

- It generates very limited greenhouse gas emissions: a recent study made by the Stanford university on the Life Cycle Analysis of its production, provides weighted mean baseline production intensity of **0.37 kg CO2eq per kg of H2 produced** over the life of the well. This could increase to **1.5 kg CO2eq/kg H2** in case of a gas mix with a composition 75% H2 and 22.5% CH4.
- It has limited impact on water resources and limited demand for critical materials.
- It has limited footprint on land, which corresponds to well head perimeter (around 1,000 sqm).

Production costs: The LCOH of natural hydrogen once an accumulation is discovered, can be rather well assessed as all the means for the production are coming from the mature exploration and Production (E&P) sector with known cost for well drilling and equipment. It will mainly depend on depth of the discovered reservoir, volume accumulated, well deliverability and gas composition. The current cases investigated give range **between 0.5 and 2.5 EUR per kg of H2 produced**.

Deployment barriers: While Europe was pioneering, the rest of the world is quickly catching-up, with the United States putting in place incentives and seeing several R&D projects developing and exploration wells being drilled very recently. To develop the natural hydrogen potential, the **regulatory frameworks** in Europe needs to be adapted, as only few countries have existing procedures for licensing, permitting, producing, etc. More importantly, for natural hydrogen be to exploited, it has to be discovered first which is hindered by gas exploration is bans in force in some EU countries as natural hydrogen is classified under gas exploration regulations. These frameworks are usually defined at national level, However some common components can be shared at EU level, which would help facilitating countries adopting natural hydrogen regulation.

Figure 6.13: Process flow diagram for the baseline case

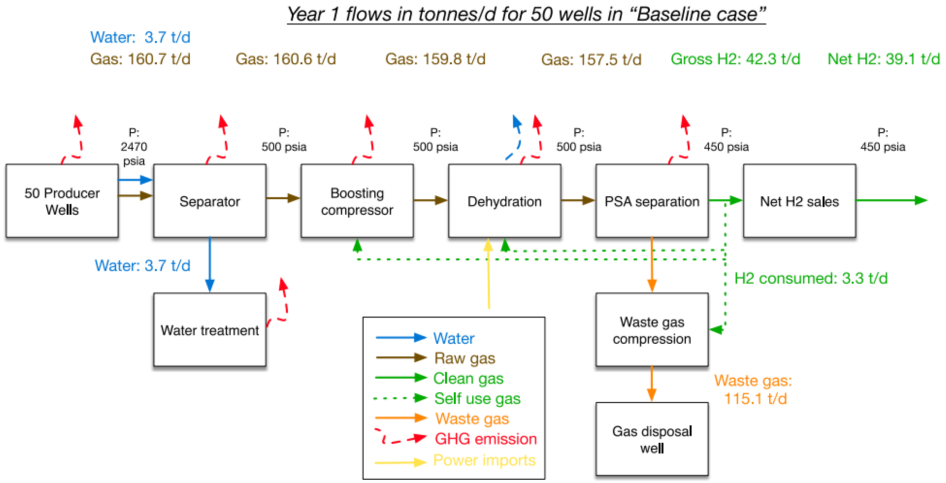
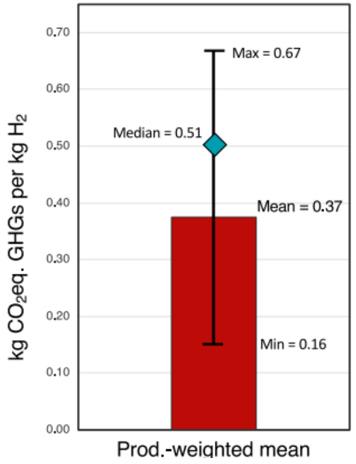


Figure 6.14: Production-weighted mean GHG intensity



Source: Davies, K., Esteban, L., Keshavarz, A., & Iglauer, S; Brandt, A. R.

By-product hydrogen from chlorine production would not be considered low-carbon unless renewable electricity would be, at least partially, used as input

Supply capacity: The chlor-alkali industry is, as part of **the chlorine production process, capable of producing around 0.4 Mt of by-product hydrogen per year**. In most cases that hydrogen is used on-site as a fuel for heat and or power generation. In some cases (around 15%) hydrogen is just being vented to the atmosphere.

GHG intensity: Most of the GHG emissions are energy related – with around of 10 GJ of energy inputs required for every tonne of chlorine, with 82% of that being electricity. As a result, **the total emissions are highly dependent on the carbon intensity of electricity**. And their value is closely linked to the method of CO2 allocation between hydrogen and the main products of the chlorine production process, which are chlorine and caustic soda (sodium hydroxide).

Given hydrogen's low weight, the most favourable CO2 allocation method would be mass based, resulting in only around 1.3% of the process, allocated to hydrogen (i.e. around 6 gCO2/MJ), allowing it to meet the low-carbon emission threshold. All **other emission allocation methods would result in hydrogen carbon intensity being above the low-carbon threshold – unless additional measures would be taken (e.g. contracting part of electricity via renewable PPAs)** – with the extreme being enthalpy-based allocation, resulting in hydrogen CI of 203 gCO2/MJ (24.4 kgCO2/kgH2**)**. Using the same approach as in the RFNBO DA, for cases when hydrogen is produced with other products which are not fuels (i.e. products which do not have calorific value) the most appropriate CO2 allocation method would be allocation based on relative economic value of products**,** resulting in around 16% of emission being allocated to hydrogen and **a GHG Intensity of close to 60 gCO2/MJ (7.1 kgCO2/kgH2)**. For existing installations however, when hydrogen would be redirected from an existing use, the most appropriate method would be the substitution approach, resulting in emissions of **65.8 gCO2/MJ (7.9 kgCO2/kgH2)** - assuming hydrogen would be replaced with natural gas.

Figure 6.15: Production process of by-product hydrogen from the chlor-alkali industry

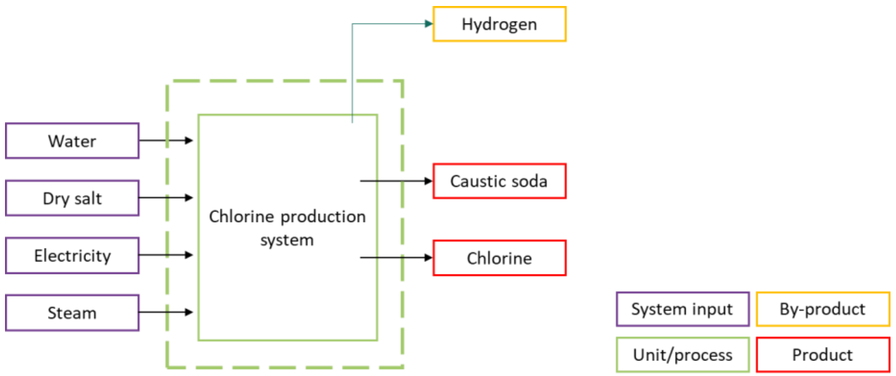
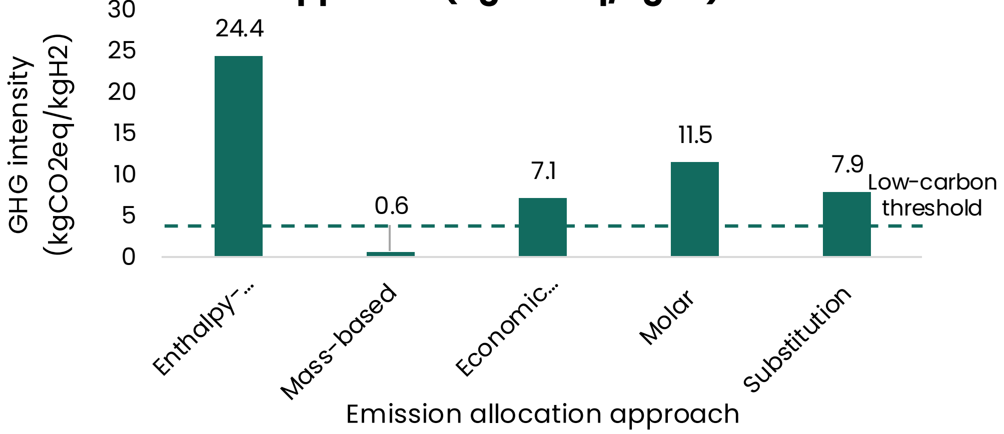


Figure 6.16: GHG intensity of by-product hydrogen from chlorine production depending on emission allocation approach (kgCO2eq/kgH2)



Source: Hydrogen Europe; ISO/TC 197/SC 1/WG

By-product hydrogen from steam cracking, redirected from existing use would not meet sustainability criteria, unless it would be replaced by low-carbon solution

Supply potential: Another important source of by-product hydrogen in industry is steam cracking of naphtha, used to generate olefins, i.e. ethylene and propylene, as well as various other high value chemicals and compounds as co-products. Olefins are mostly used further for the production of plastics and other chemical products. The dominant feedstock in the EU is naphtha, but other feedstocks can be used as well, with ethane being especially prominent in countries with high shale-gas extraction volumes, like the United States. **Total by-product hydrogen production capacity in Europe from steam cracking is estimated at around 0.55 Mtpa.**

GHG Intensity: Hydrogen is only around 1% of the total output from naphtha steam cracking by mass, meaning that if mass would be used for allocating GHG emissions, hydrogen could be considered low-carbon at around 1.3 kgCO2/kgH2. On the other hand, since the share of hydrogen in total outputs measured by their relative energy content is around 2.6-3.3% (depending on source), **energy-based GHG allocation would result in emission intensity at around 2.6-3.3 kgCO2/kgH2, i.e. close to the low-carbon emission threshold** of 3.4 kgCO2/kgH2. However, given the fact that, except for gasoline and small amounts of fuel oils, most of the co-products would not be used as fuels, **the economic value based allocation seems the most appropriate and would result in hydrogen GHG-intensity value of around 2.3 kgCO2/kgH2**.

In case of using by-product hydrogen from existing steam-cracking facilities however of more importance is that in most cases the by-product hydrogen is used on-site as part of the fuel gas either for the furnace or to fire a boiler to generate steam (or both). As replacing by-product hydrogen from such use would most likely result in an increased consumption of natural gas, **the emissions intensity would be around 7.9 kgCO2/kgH2**. As a result, the by-product hydrogen would not count as low-carbon unless replaced with low-carbon solution (e.g. renewable gas, CCS).

Figure 6.17: By-product hydrogen from steam cracking

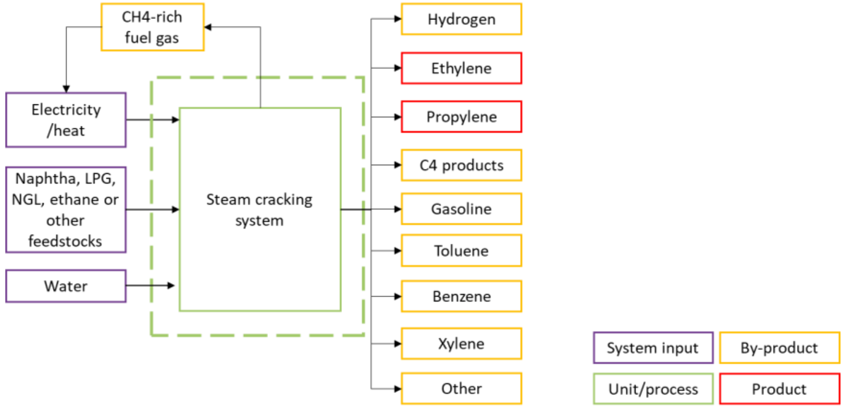
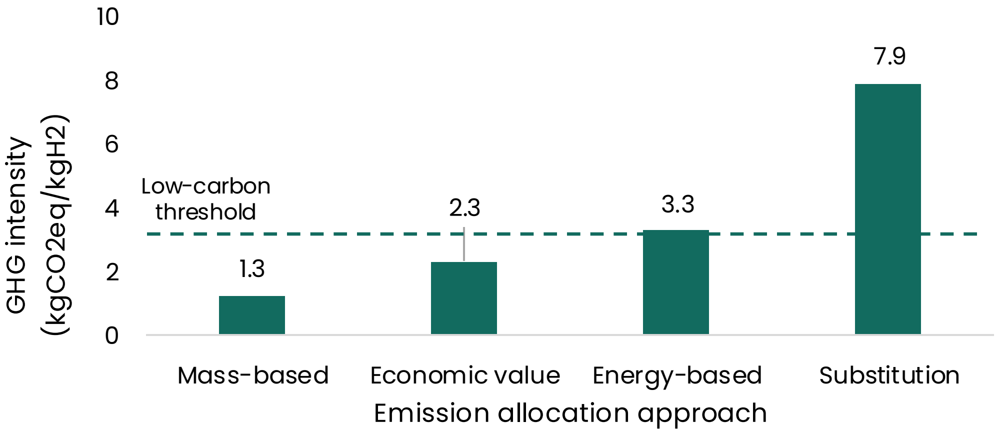


Figure 6.18: GHG intensity of by-product hydrogen from steam cracking of naphtha depending on emission allocation approach (kgCO2eq/kgH2)



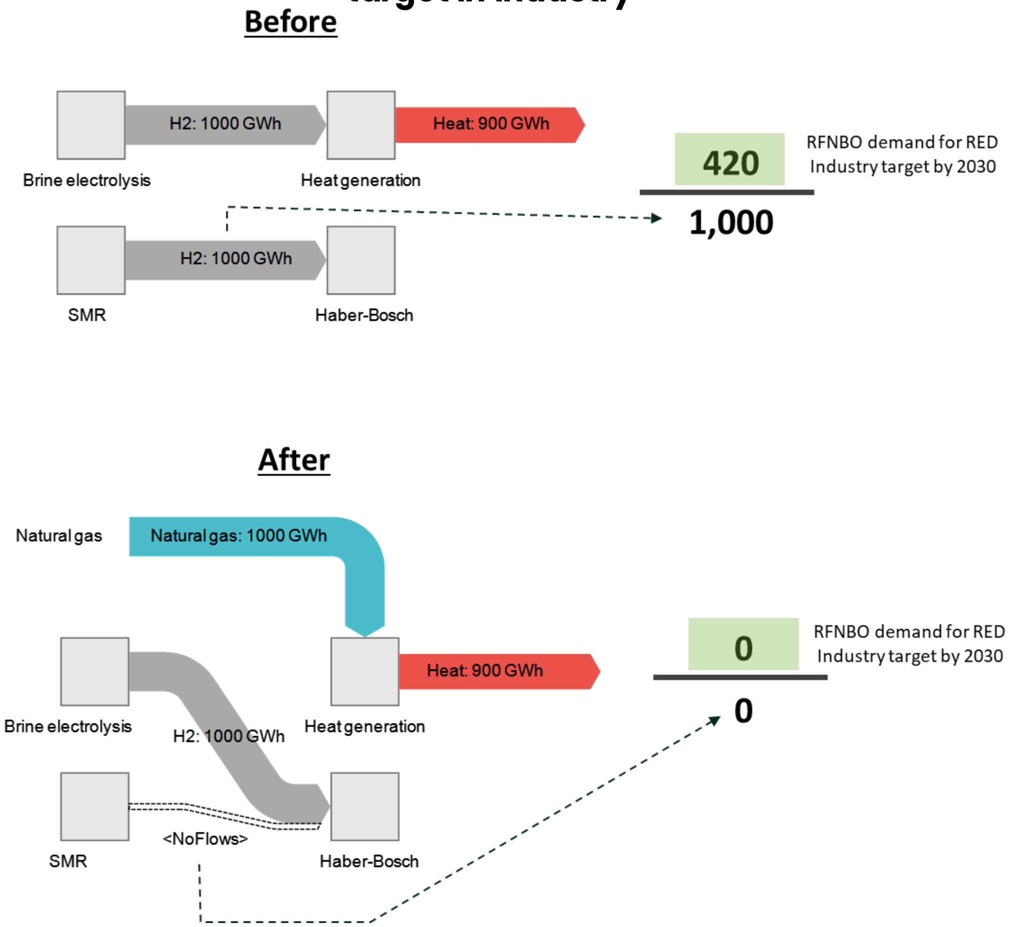
Source: Hydrogen Europe; ISO/TC 197/SC 1/WG

By-product hydrogen is excluded from RED targets and could significantly reduce the demand for RFNBO in industry

Supply potential: By-product hydrogen production is currently an important source of industrial hydrogen supply. **In 2022 the by-product hydrogen production capacity accounted for around 9% of total hydrogen production capacity in Europe.** The two main sources of industrial by-product hydrogen are the chlor-alkali industry, where hydrogen is a by-product of the brine electrolysis producing chlorine and sodium hydroxide and the petrochemical industry, where hydrogen is produced as a by-product of steam cracking of naphtha (or other hydrocarbons), producing high value chemicals like ethylene and propylene. Total hydrogen by-product production capacity from these two processes is close to 1 Mtpa. This number is however significantly underestimated, as it misses by-product hydrogen produced via catalytic reforming, which - in a simple hydro-skimming refinery - is often the only source of hydrogen with no dedicated SMR necessary. **With around 3.9 kg of hydrogen produced as a by-product of catalytic reforming per 1 tonne of refined crude oil, the total European refining industry can produce around 2.7 Mt of additional by-product hydrogen, bringing the total by-product supply to 3.7 Mt (around 35% of total hydrogen production capacity in Europe).**

Regulatory uncertainty: While by-product hydrogen is unlikely to play a significant role in the developing hydrogen economy, it can still be an important source of hydrogen in a transitional period. In this context it is especially worth noticing that the use **by-product hydrogen is exempted from having to be replaced with a minimum share of RFNBOs** (42% by 2030 and 60% by 2035) in the RED. As by-product hydrogen is currently predominantly used either as a heating fuel, where it could be replaced by natural gas, or as feedstock in refining, considered to be part of the transport sector under RED, **If by-product hydrogen would be redirected to sectors covered by the RED industrial targets, it could significantly water it down.** In the extreme case, **if all of the 3.7 Mt of by-product hydrogen would be redirected to be used as feedstock in fertiliser and chemical industries, the demand for RFNBOs, driven by the RED industry target, would fall to zero.**

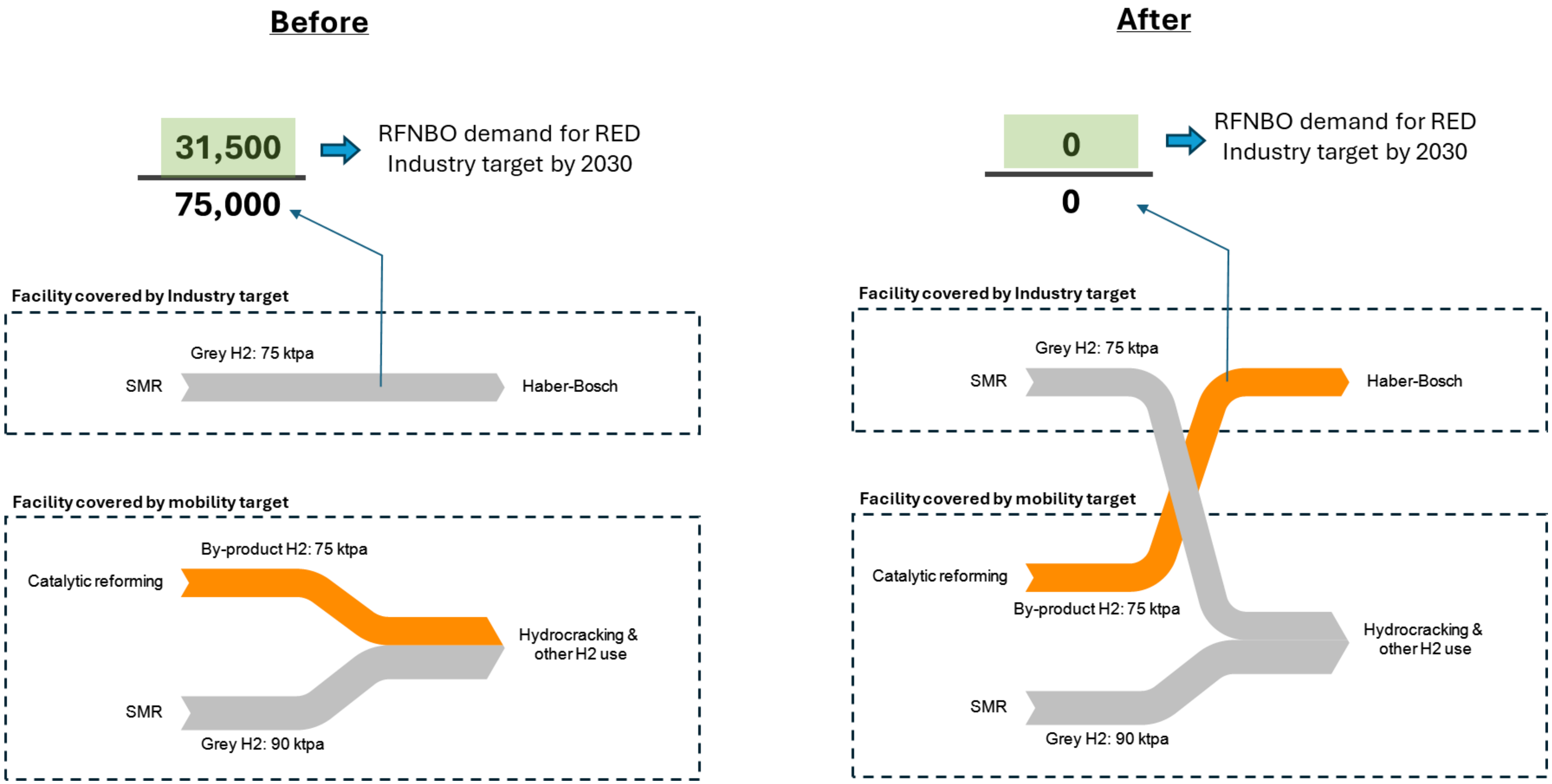
Figure 6.19: Example impact of redirecting by-product hydrogen from current use to sectors covered by the RED target in industry



Source: Hydrogen Europe

By-product hydrogen is excluded from RED targets and could significantly reduce the demand for RFNBO in industry

Figure 6.20: Potential impact of sing by-product hydrogen in sectors covered by RED industry target



Source: Hydrogen Europe

POLICY RECOMMENDATIONS

Implications for the

Low-Carbon Delegated Act

- **Low-carbon hydrogen (LCH)** is an essential piece of the emerging hydrogen economy that will, in our opinion, play a significant role in the energy transition. Especially in the market ramp-up phase, it will be required for several decarbonisation purposes, where renewable hydrogen is not yet available in sufficient quantities or at sufficiently affordable prices.

- **Low-carbon fuels delegated act -** the upcoming Delegated Act with a methodology enabling the assessment of GHG emission intensity of low-carbon fuels will complement the so called RFNBO DAs from June 2023, and hence should be presented by the European Commission as soon as possible to ensure an effective stakeholder engagement and a rapid adoption of the rules.

- **Relevance:** Because of the importance of the low-carbon hydrogen pathways, the new rules contained in the upcoming Delegated Act are crucial for the entire hydrogen sector. They will guarantee regulatory certainty required for investments to happen at the pace expected by all stakeholders.

- **Recommendations:** The following chapter presents Hydrogen Europe's recommendations aimed at ensuring the rules are robust to prevent greenwashing but flexible enough to facilitate FID both in low-carbon hydrogen and RFNBOs. And extensive set of detailed recommendations can be found in a separate position paper.

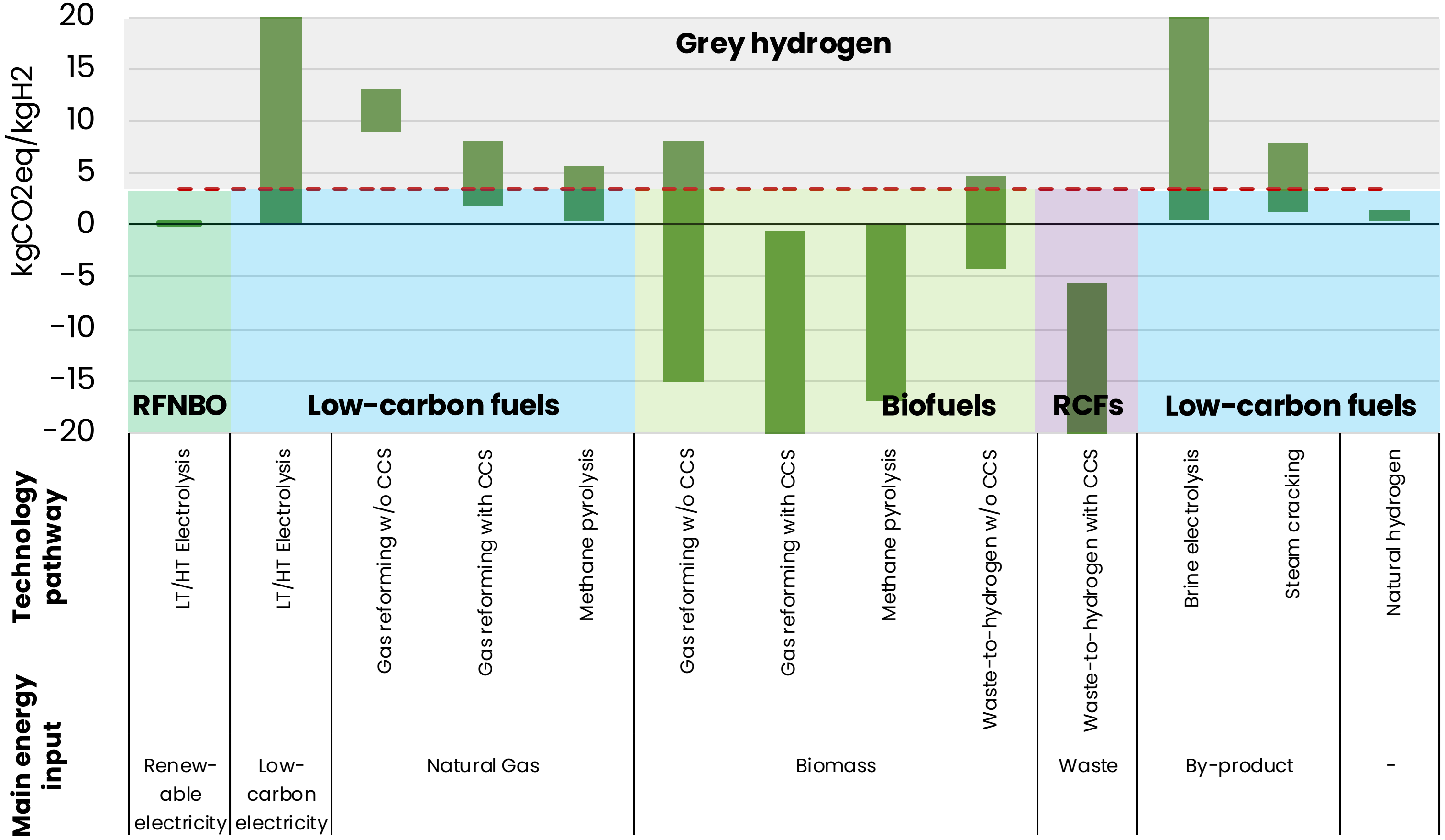
All analysed technologies can have a substantial positive contribution towards climate change mitigation

GHG intensity: **All of the hydrogen production pathways can produce clean hydrogen** – i.e. hydrogen at a carbon intensity level that is low enough to classify them as substantially contributing to climate change mitigation in line with the technical screening criteria for hydrogen manufacturing proposed by the EU taxonomy for sustainable finance. **In some cases, the carbon footprint can be even negative resulting in net carbon removal from the atmosphere**.

Regulatory framework: On the other hand, if the carbon capture rate is low or if the feedstock or energy inputs are not sustainable, the resulting emissions could be high – sometimes many times higher than the fossil fuel-based steam methane reforming technology dominating the market today. This demonstrates the importance of designing a strong regulatory framework, which would promote sustainable solutions, while at the same time, not creating unnecessary investment barriers – as has happened with renewable hydrogen.

Unfortunately, for low-carbon hydrogen, which is an essential part of the emerging hydrogen economy, the GHG accounting framework is still missing.

Figure 7.1: Emission intensity range for analysed technologies (kgCO2eq/kgH2)



Source: Hydrogen Europe

Low-carbon hydrogen requires speedy adoption of robust GHG accounting methodology contained in the upcoming Delegated Act

Low-carbon hydrogen (LCH) is an essential piece of the emerging hydrogen economy that will play a significant role in the energy transition. Especially in the market ramp-up phase, it will be required for several decarbonisation purposes, where renewable hydrogen is not yet available in sufficient quantities or at sufficiently affordable prices. **Because of the importance of the low-carbon hydrogen pathways, the new rules contained in the upcoming Delegated Act (DA) are crucial for the entire hydrogen sector.**

Speedy adoption and simplicity of the rules are of essence: It is essential that time is not lost in too lengthy creation and implementation of such Delegated Act, as it was the case with the RFNBO-DAs, so that investments aren't held back, and projects aren't delayed. The same goes for making sure that new rules are as simple and hence as easily applicable as possible to reduce red tape and administrative burden as well as accelerate the certification process of LCH.

Ensuring consistence with DAs 2023/1184 and 2023/1185: We endorse the need to ensure consistency with the methodology for assessing GHG savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels as developed under DA 2023/1185. Having a coherent legislative framework for various production pathways is paramount for the viability of emerging projects. Any option for sourcing low-carbon electricity, other than renewable, that is put forward in the upcoming LCH DA, must also be added to the RFNBO DAs.

Rules should reflect some fundamental differences between renewable and low-carbon production pathways. A coordinated and coherent framework is needed for low-carbon and renewable hydrogen to optimise their production potential. Nerveless, the rules for low-carbon fuels should be adapted to the various low-carbon production pathways, with different set of factors to be considered.

Figure 7.2: Recommendations for low-carbon fuels Delegated Act

- Use of waste heat in high temperature electrolysis should not affect the renewable character of the fuel
- The allocation of emissions to by-product hydrogen should be based on a project specific counterfactual.
- The allocation of emissions for low-carbon hydrogen co-produced with other products should be based on relative energy content or (if not possible) on relative economic value
- Recognition of permanent and long-lasting CO2 binding technologies
- Science-based approach to regulating maximum hydrogen leakage rates
- Flexible allocation of 'low-carbon credits', whereby incremental 'low-carbon' inputs can be freely allocated to a selected product within the product slate (e.g. aviation fuel)

Source: Low carbon hydrogen: key principles for a coherent methodology in the upcoming Delegated Act, June 2024, Hydrogen Europe

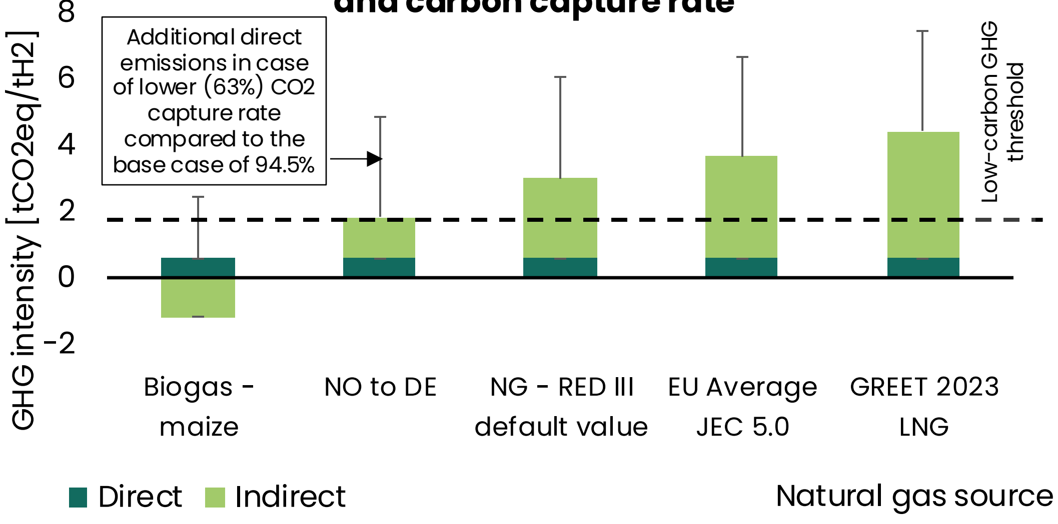
Instead of the single EU-wide default emission factor, a more project specific and accurate accounting of natural gas upstream emissions should be adopted

Upstream emission factor for natural gas: The Delegated Regulation (EU) 2023/1185 sets an **upstream emission factor default value for natural gas of 9.7 gCO2/MJ**. For RFNBO fuels, the use of natural gas as input is limited, and the emission factor is mostly used when calculating the carbon footprint of the electricity grid, along with other emission factors from other electricity sources (coal, oil, nuclear, etc.). As such, the effects of this value are also rather limited and thus, it is understandable that a default/harmonised value would be applied. However, in the case of some low-carbon hydrogen production pathways – like autothermal or steam methane reforming with CCS or methane pyrolysis, the natural gas emission factor has a much higher impact on the overall GHG emission, hence a more granular and targeted approach is needed to differentiate among the associated feedstock emissions.

Using the same standard value for low-carbon fuels would have significant drawbacks. First it would disincentivise the project promoters from seeking to use gas sources with the lowest possible carbon intensity (e.g. local gas sources or natural gas from countries with strict environmental regulations limiting methane leakage – like Norway). **A single homogeneous emission factor would also prevent accurate GHG accounting in case of shipped LNG, effectively allowing for greenwashing.**

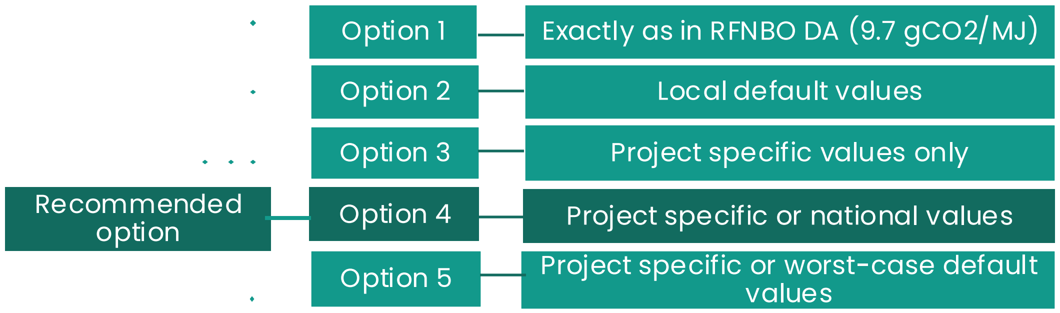
Recommendation: Therefore, Hydrogen Europe recommends a more flexible and accurate approach which allows for project promoters to calculate the project specific GHG emissions intensity of used natural gas based on the origin of gas inputs used. The LCH DA would have to specify the methodology the project promoters can follow to calculate the project specific gas emission intensity. Furthermore, we call on the European Commission, in collaboration with national energy regulators, to work on **establishing a set of national default values for gas emission intensity**, as it has been done for the average emissions of electricity intensity in the 2023/1185 DA (table A, part C). These values should be periodically reviewed.

Figure 7.3: GHG emissions for hydrogen produced via natural gas reforming depending on natural gas source and carbon capture rate



Additional direct emissions in case of lower (63%) CO2 capture rate compared to the base case of 94.5%

Figure 7.4: Options regarding gas upstream emissions


Option 1 – Exactly as in RFNBO DA (9.7 gCO2/MJ)
Option 2 – Local default values
Option 3 – Project specific values only
Recommended option – Option 4 – Project specific or national values
Option 5 – Project specific or worst-case default values

Source: Low carbon hydrogen: key principles for a coherent methodology in the upcoming Delegated Act, June 2024, Hydrogen Europe

The possibility to sign PPAs for the supply of electricity for hydrogen production should be extended to other sources besides renewables

GHG intensity of electricity: The current framework governing the GHG allocation rules for RFNBOs and RCFs prescribes that if electricity is used as input for fuel production, its **carbon intensity should be based on the average electricity mix in the bidding zone where the hydrogen production takes place – with the only exception being granted for fully renewable electricity** either connected directly or via a direct PPA. Such an option is so far not available to any other sources of low-carbon electricity.

Recommendation: Hydrogen Europe advocates for an approach that would **allow producers to sign PPAs also with low-carbon electricity sources and have the actual carbon intensity of used electricity impact reflected in the hydrogen carbon footprint**. This includes, for instance, electricity produced from nuclear sources as well as from waste incineration plants. At the same time, the framework for doing so, should recognise that **low-carbon electricity sources supply is more elastic than that of renewable electricity. Consequently, applying the exact same additionality criteria, which were applied to fully renewable electricity would be neither sensible nor logical** - especially in the case of underutilized dispatchable low-carbon power sources.

Any option for sourcing low-carbon electricity, other than renewable, that is put forward in the upcoming LCH DA, must also be added to the RFNBO DAs.

Justification: The proposed approach would ensure the utilization of low-carbon sources is maximized, while recognizing that dispatchable low-carbon electricity supply is much more elastic that renewable one. Also, our proposal for a recognition of nuclear share of the electricity in bidding zones is fully consistent with what already exists for recognition of renewable energy share in the grid mix under the RFNBO framework and presents the benefit of enabling the LCH derived from nuclear electricity to be eligible for ReFuelEU Aviation.

Figure 7.4: Mixing different sources of electricity for hydrogen production

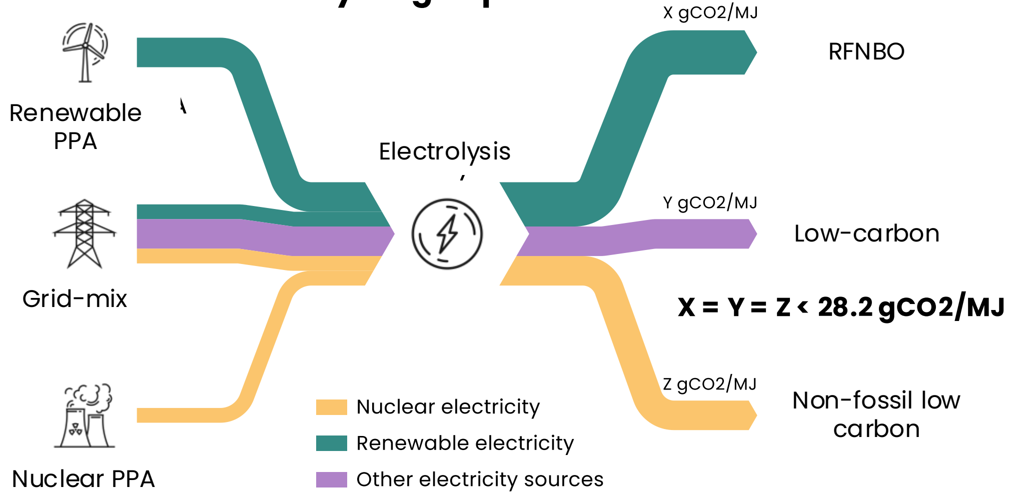


Figure 7.5: Options regarding sourcing of electricity

	Option 1	Exactly as in RFNBO DA (only RES and grid)
Recommended option	Option 2	Using share of low-carbon electricity in the grid without PPA
	Option 3	PPAs possible but with the same conditions as RES PPAs
Recommended option	Option 4	PPA needed with existing or new low-carbon energy sources. No additionality requirement.

Source: Low carbon hydrogen: key principles for a coherent methodology in the upcoming Delegated Act, June 2024, Hydrogen Europe

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