CENTER FOR APPLIED ENVIRONMENTAL LAW AND POLICY

Hydrogen Production GHG Control Technology Review

Report

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29 February 2024

Level 4, 155 Fenchurch Street
London, EC3M 6AL, United Kingdom

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Executive summary

Hydrogen is a versatile element that can form compounds with a wide range of other elements, opening a large possibility of interesting opportunities in the pursuit of climate neutrality. Advisian has been tasked by CAELP to conduct a study analysing hydrogen production technologies and the Greenhouse Gas (GHG) emissions reduction potential of each, the objectives of which were to:

- **Legislation Overview** – Summarize and evaluate applicable U.S. legislation and identify the consequences with consideration of key strategic objectives, opportunities (e.g., tax credits) and applicable limitations
- **Technology Overview and Economic Analysis** – Summarize existing and emerging hydrogen production pathways with consideration of the potential scale, technology readiness level (TRL), commercial readiness index (CRI), Carbon intensity (CI) and associated costs
- **GHG Emissions Reduction Pathways and Economic Analysis** – Identify paths to transform new and existing pathways into producers of low GHG hydrogen, evaluate resultant emissions reductions and costs for implementation of enabling technology
- **Sensitivity Analysis** – Create a discussion basis to inform the legislative and financial environment required to enable these paths (required policy incentives)

At a high level, the methodology followed for the study is shown in Figure 0-1.

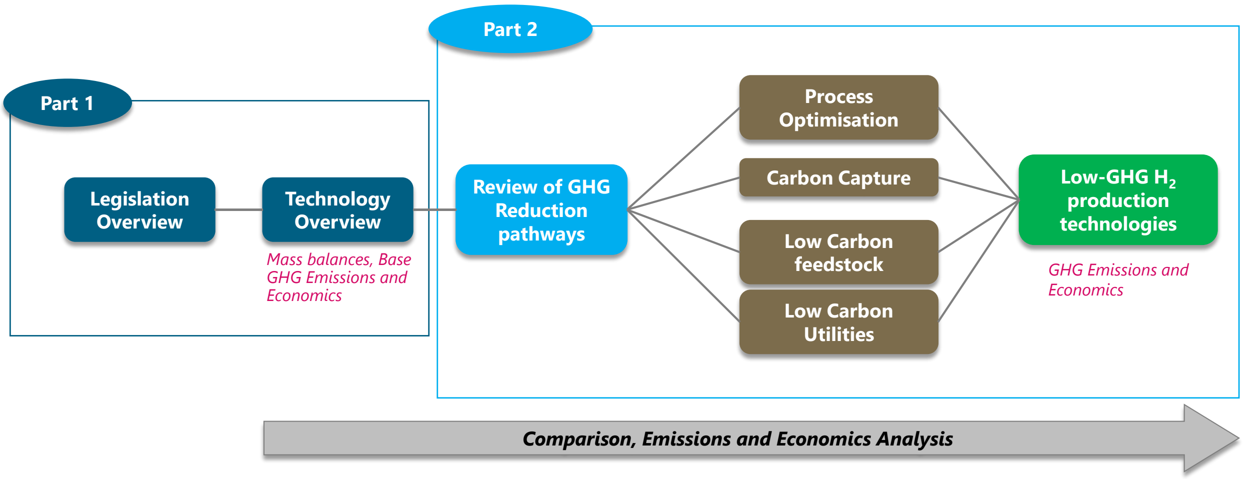
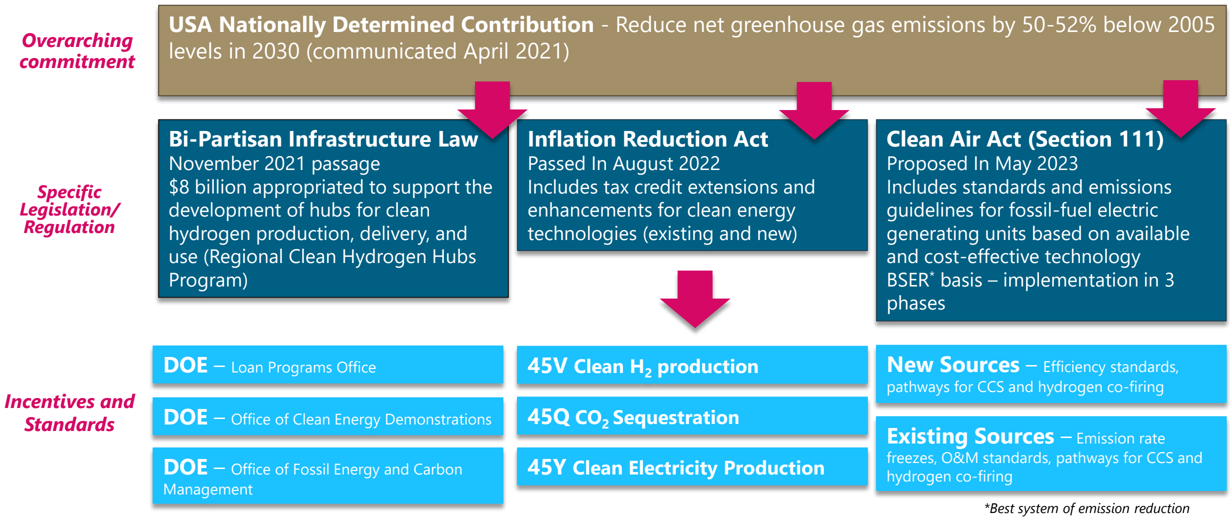


Figure 0-1 High level study methodology

Legislation and Regulation Overview

A review of the relevant legislation and regulation was conducted and is summarised in Figure 0-2 as it relates to the production of hydrogen. In the U.S., various incentives and standards for low-GHG hydrogen have been established as outcomes of relevant legislation and regulation.



Overarching commitment

USA Nationally Determined Contribution - Reduce net greenhouse gas emissions by 50-52% below 2005 levels in 2030 (communicated April 2021)

Specific Legislation/ Regulation

Bi-Partisan Infrastructure Law
November 2021 passage
$8 billion appropriated to support the development of hubs for clean hydrogen production, delivery, and use (Regional Clean Hydrogen Hubs Program)

Inflation Reduction Act
Passed In August 2022
Includes tax credit extensions and enhancements for clean energy technologies (existing and new)

Clean Air Act (Section 111)
Proposed In May 2023
Includes standards and emissions guidelines for fossil-fuel electric generating units based on available and cost-effective technology BSER* basis – implementation in 3 phases

Incentives and Standards

DOE – Loan Programs Office

DOE – Office of Clean Energy Demonstrations

DOE – Office of Fossil Energy and Carbon Management

45V Clean H_2 production

45Q CO_2 Sequestration

45Y Clean Electricity Production

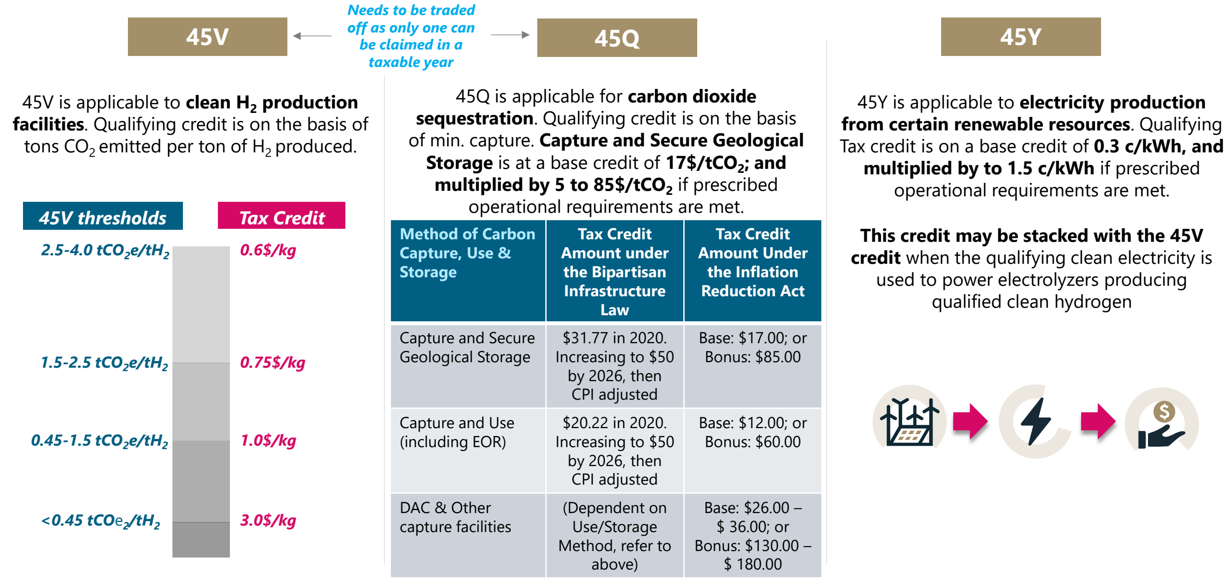
New Sources – Efficiency standards, pathways for CCS and hydrogen co-firing

Existing Sources – Emission rate freezes, O&M standards, pathways for CCS and hydrogen co-firing

**Best system of emission reduction*

Figure 0-2 Legislation Overview Summary

The consequences of legislation on individual hydrogen production technologies are discussed in the report with specific focus on 45V, Q and Y, which are tax credit incentives associated with clean H_2 production, CO_2 sequestration and clean electricity production respectively. Figure 0-3 provides an overview of the tax credits, applicability, and the qualifying criteria of each.



45V

Needs to be traded off as only one can be claimed in a taxable year

45Q

45Y

45V is applicable to **clean H_2 production facilities**. Qualifying credit is on the basis of tons CO_2 emitted per ton of H_2 produced.

45V thresholds	Tax Credit
2.5-4.0 tCO_2e/tH_2	0.6$/kg
1.5-2.5 tCO_2e/tH_2	0.75$/kg
0.45-1.5 tCO_2e/tH_2	1.0$/kg
<0.45 $tCOe_2/tH_2$	3.0$/kg

45Q is applicable for **carbon dioxide sequestration**. Qualifying credit is on the basis of min. capture. **Capture and Secure Geological Storage** is at a base credit of **17$/$tCO_2$; and multiplied by 5 to 85$/$tCO_2$** if prescribed operational requirements are met.

Method of Carbon Capture, Use & Storage	Tax Credit Amount under the Bipartisan Infrastructure Law	Tax Credit Amount Under the Inflation Reduction Act
Capture and Secure Geological Storage	$31.77 in 2020. Increasing to $50 by 2026, then CPI adjusted	Base: $17.00; or Bonus: $85.00
Capture and Use (including EOR)	$20.22 in 2020. Increasing to $50 by 2026, then CPI adjusted	Base: $12.00; or Bonus: $60.00
DAC & Other capture facilities	(Dependent on Use/Storage Method, refer to above)	Base: $26.00 – $ 36.00; or Bonus: $130.00 – $ 180.00

45Y is applicable to **electricity production from certain renewable resources**. Qualifying Tax credit is on a base credit of **0.3 c/kWh, and multiplied by to 1.5 c/kWh** if prescribed operational requirements are met.

This credit may be stacked with the 45V credit when the qualifying clean electricity is used to power electrolyzers producing qualified clean hydrogen

Figure 0-3 Overview of 45V/Q/Y Tax credits

Technology Overview

The hydrogen production technologies analyzed in this study range from traditional to emerging. These have been classified into 4 distinct groups based on technology maturity and commercial readiness using the indicative metrics of technology readiness level (TRL) and commercial readiness index (CRI) as shown in Figure 0-4.

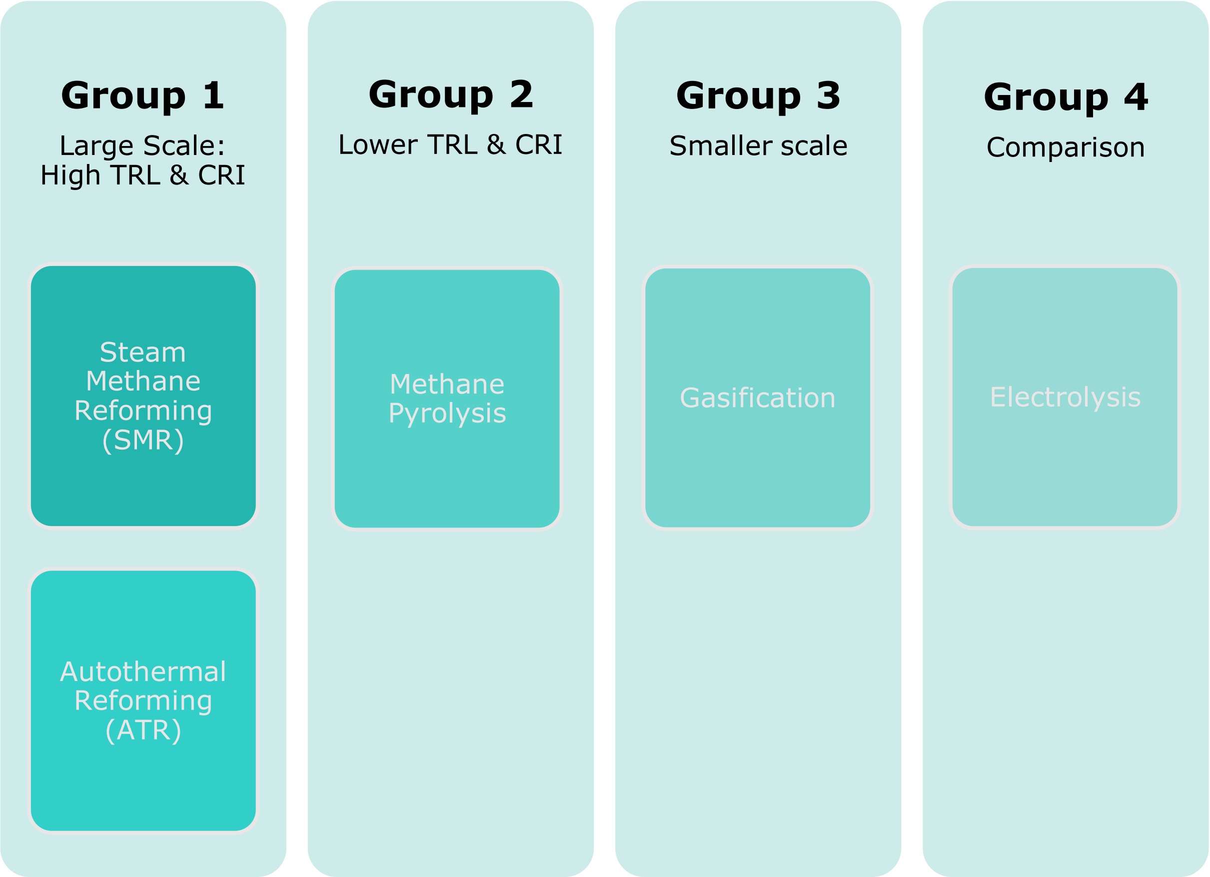


Figure 0-4 Hydrogen Production Technology Categories

Group 1 technologies are technically mature and rank high on the CRI as they have been proven at large scales and are either already widely available or in advanced stages of commercial application. Hydrogen produced from these technologies are commonly used in industrial processes such as refining, chemicals, including ammonia and steel (as direct reduced iron).

Group 2 technologies are not as technically mature or commercially viable but have the potential to be scaled up.

Group 3 technologies are technically and commercially viable and implemented at large scale for syngas production, while at relatively smaller scale for on-purpose hydrogen production. Gasification from different feedstocks (including coal, petcoke, biomass, and residue) are evaluated in this analysis. However, for the case study comparison, biomass gasification is evaluated in more detail.

Note that the technologies included in **Groups 1-3** are categorized to produce unabated hydrogen (commonly referred to as grey, black/brown, or turquoise hydrogen).

Electrolysis, classed in **Group 4**, is evaluated as a clean emerging technology for comparison purposes; it is considered to have the lowest overall carbon intensity when powered with low-carbon renewable electricity and is used to benchmark other technologies.

The above does not represent a comprehensive outline of all possible hydrogen production technologies but rather an assessment of those that are most advanced in terms of TRL and CRI. There are other emerging technologies with lower TRL's and CRI's which have not been evaluated in detail.

Hydrogen production technologies differ greatly, thus, archetype facilities were selected to enable baseline emissions and reductions calculations in evaluating GHG emissions reduction options for each. The archetype facilities are conceptualized based on capacity, configuration, current technological readiness, and commercial viability.

The archetype facilities are representative of typical facilities in the U.S. and globally; aspects of which can apply to multiple real-life operating facilities.

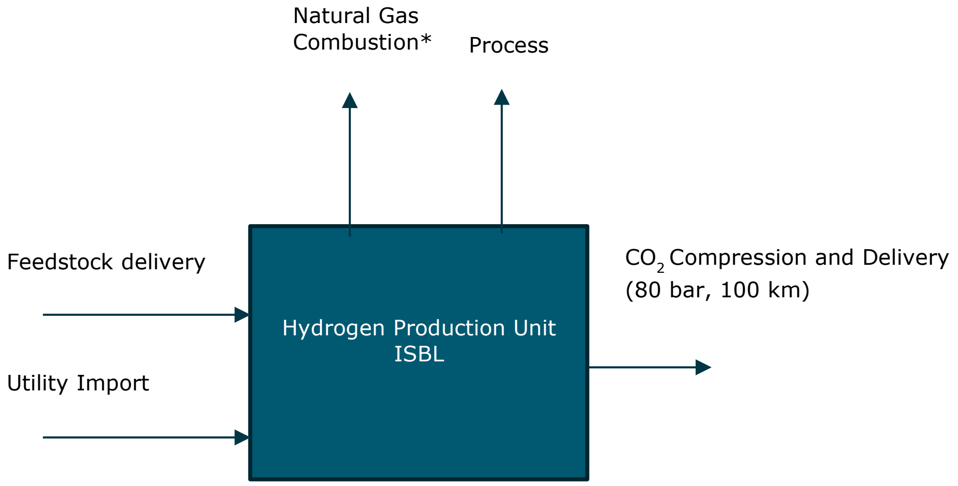
GHG emissions reduction options applied to these archetype facilities provide a wide range of solutions, which can be customized for individual application. The selected technology configurations and capacities for each hydrogen production technology archetype are provided in Table 0-1.

Table 0-1 Selected Technology Configuration and Capacity

	ATR	SMR	Methane Pyrolysis	Gasification	Electrolysis
H_2 capacity (tpd)	358	358	110	164	43
Key configuration specifications	Natural Gas/ O_2 fed integrated heat reformer design	Fuel fired reformer furnace	Plasma arc pyrolysis	Biomass (woodchips) Feed	100 MW Electrolyser

Emissions and Abatement

A well-to-gate approach is used to define the boundary limits for the emissions calculations as represented in Figure 0-5. For the purposes of this study, boundary limit properties do not include additional compression or purification of hydrogen beyond standard levels for a given production technology. This is true for when the hydrogen is to be used for applications such as combustion but may not be true for applications such as chemical or industrial processes.

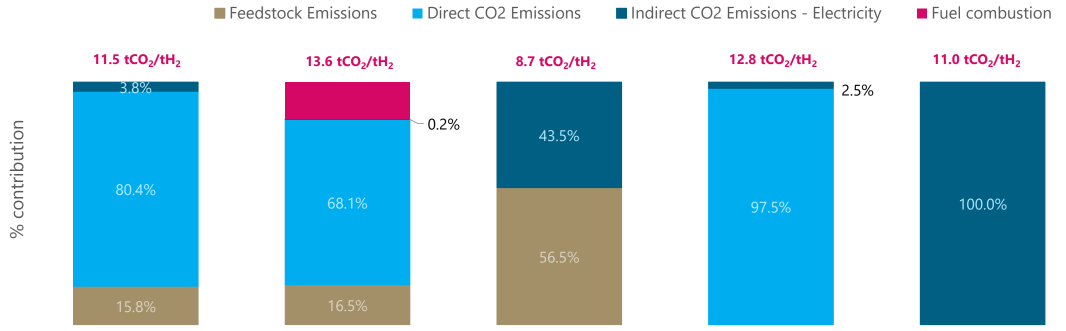


**Only applicable to steam methane reforming, where natural gas is used as a feedstock and fuel*

Figure 0-5 Points of Emission

It is important for putting the context of the results in perspective to understand and to be clear on the assumptions for any study of this kind. Sensitivity analyses have been conducted to highlight those variables with the greatest uncertainty and impact on the outcomes. When comparing different studies, it is critical to understand the assumption set used in any modelling of carbon intensity or levelized cost of hydrogen (LCOH) production.

Emissions related to the feedstock and electricity supply (driven by upstream processes) are included in the emissions calculation, although they are assumed to be outside the scope of influence for these facilities (i.e., the carbon intensity of the electricity or natural gas imported may not be fully dictated by the hydrogen producers). The emissions contributors, and therefore opportunities for possible GHG emissions reduction in the production process, for each technology are presented in Figure 0-6.

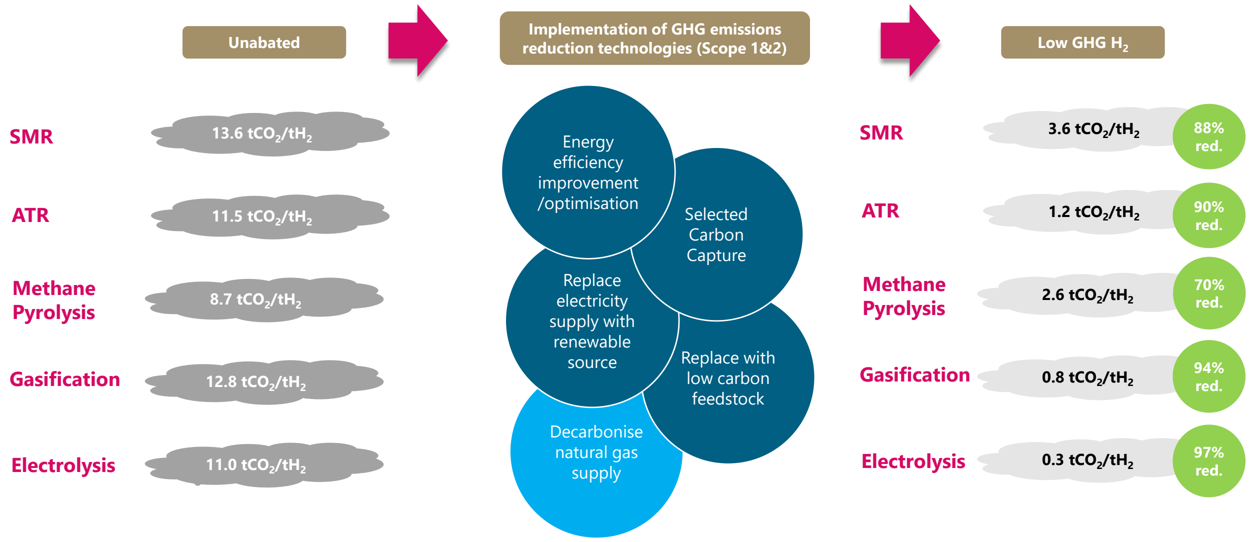


Lever	**ATR**	**SMR**	**Methane Pyrolysis**	**Biomass Gasification***	**Alkaline Electrolysis**
Process Optimization	-	●	-	-	-
Low Carbon feedstock	-	-	-	●	-
Low Carbon utility supply	●	●	●	●	●
Carbon Capture	●	●	-	●	-

Note: Figure is based on grid supplied electricity and not renewables; for gasification, base case feed is assumed to be non-biogenic

Figure 0-6 Unabated emissions contributors and GHG reduction levers

Implementation of GHG emissions reduction levers on the base cases of each technology results in low GHG hydrogen production as represented by Figure 0-7.

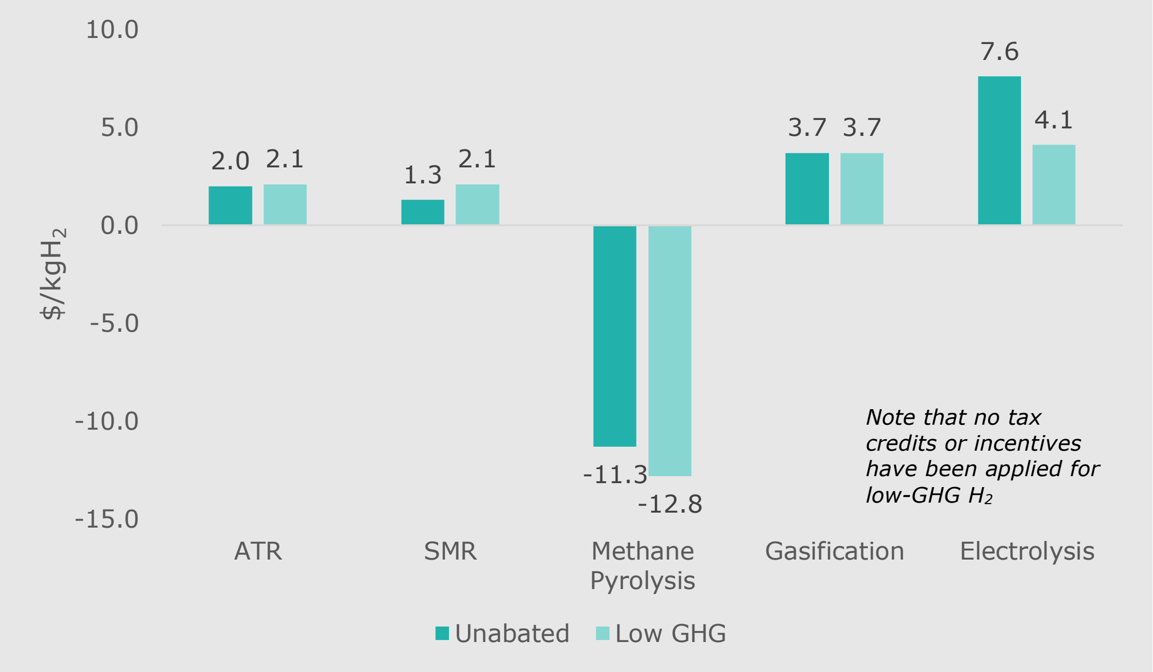


Note: Decarbonization of emissions associated with natural gas exploration/production/distribution imported may not be fully dictated by the hydrogen producers (denoted in light blue). These emissions are assumed to reduce by 50% by 2050. Renewable electricity supply assumed in all low GHG H_2 cases

Figure 0-7 Hydrogen production technologies abatement summary

Under the specified set of GHG reduction assumptions for this study, all the low carbon hydrogen production technologies considered in this study qualify for varying degrees of 45V tax credits and the three technologies that specifically use carbon capture to abate emissions are eligible for 45Q tax credits.

Economics and Sensitivity Analysis



Note that no tax credits or incentives have been applied for low-GHG H_2

Figure 0-8 Levelized Cost of Hydrogen – Unabated and Low GHG H_2

In terms of LCOH for the base case unabated modelling, methane pyrolysis is the lowest (and negative) since the H_2 produced is a by-product and the primary product is carbon black which has a high value. This is followed by SMR and then ATR. Electrolysis has the highest LCOH, followed by gasification.

The LCOH is impacted by the assumptions around electricity costs and the value of additional products. In particular, the prices of natural gas, carbon black, biomass and renewable electricity are variables that have varying and at times significant impacts across the technologies.

For the LCOH of low GHG hydrogen, ATR and SMR are at comparable levels and likewise for gasification and electrolysis. Low GHG electrolysis is significantly lower than that of unabated due to a lower assumed renewable electricity price compared to the grid price. Unabated and low GHG gasification have the same LCOH as the value from lower renewable electricity prices is offset by additional carbon capture costs.

The key sensitivities to LCOH for unabated emissions for each technology are summarised in Figure 0-9.

	Technology	Sensitivity	Range
1	SMR	Natural gas price (2025)[1]	4.2–6.8 $/MMBTU
2	ATR	Natural gas price (2025)[1]	4.2–6.8 $/MMBTU
3	Methane pyrolysis	Natural gas price (2025) [1]	4.2–6.8 $/MMBTU
4		Carbon Black price	0–1880$/t
5	Gasification	Biomass feed price	35–75$/t
6	Electrolysis	Oxygen Product Price	0–580$/t

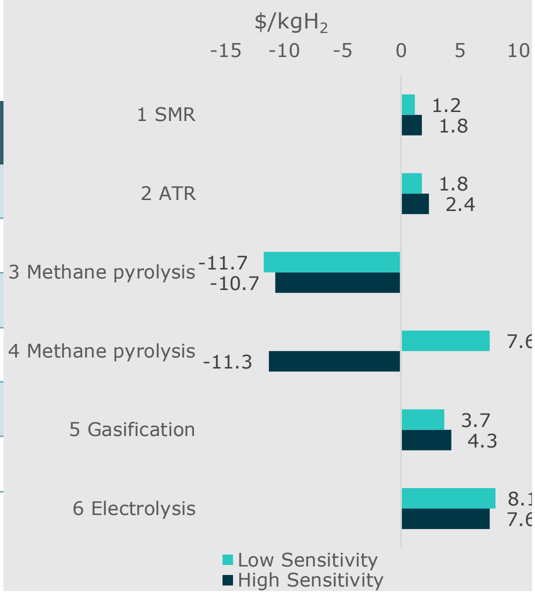


Figure 0-9 Key sensitivities for unabated emissions

The key sensitivities to LCOH for low GHG emissions for each technology are summarised in Figure 0-10.

	Technology	Sensitivity	Range
1	SMR	CO_2 Transport and Storage Cost	10–40$/t
2	ATR	CO_2 Transport and Storage Cost	10–40$/t
3	Methane pyrolysis	RE price	17–35$/MWh
4	Gasification	CO_2 Transport and Storage Cost	10–40$/t
5	Electrolysis	RE price	17–35$/MWh

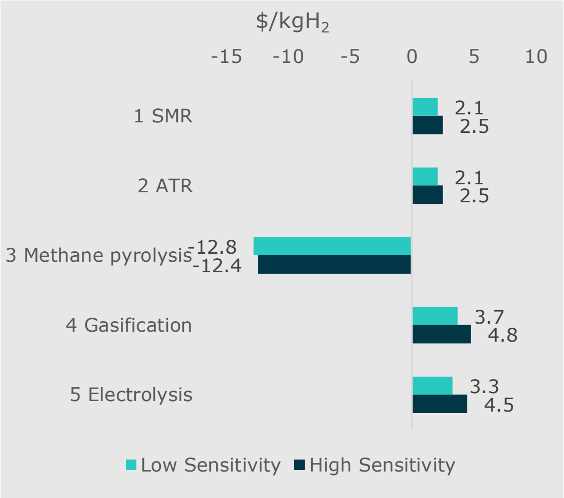


Figure 0-10 Key sensitivities for low GHG emissions

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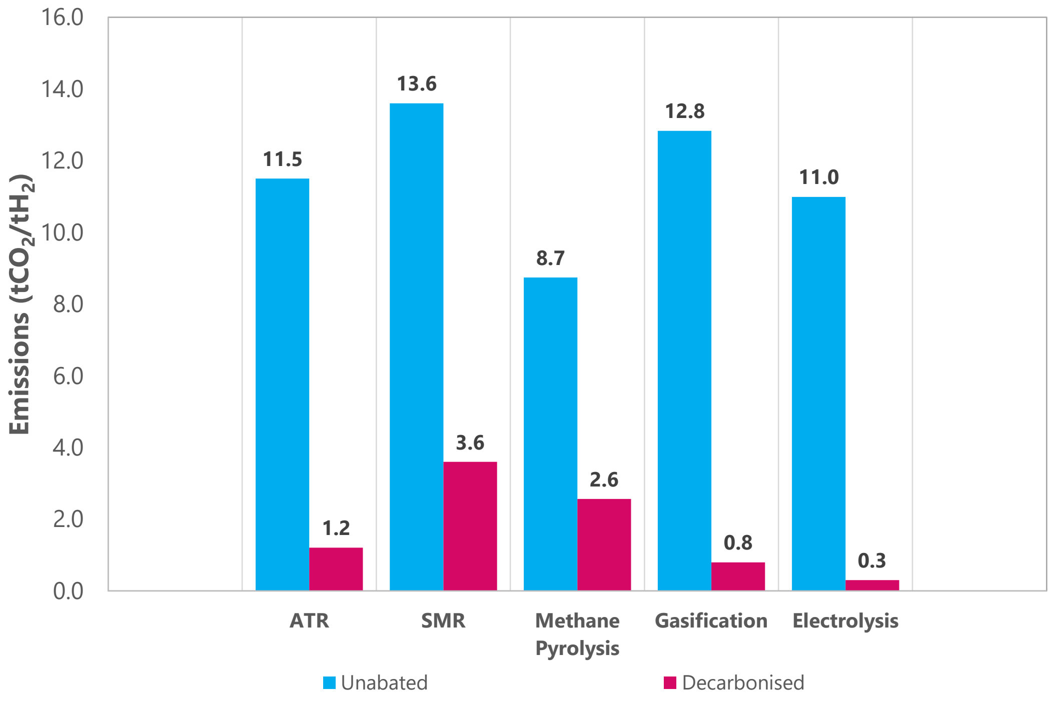
[1] U.S. Energy Information Administration, Annual Energy Outlook 2023, March 2023. Range represents the price range between the High Oil and Gas Resource Case (i.e., low gas price) and Low Oil and Gas Resource Case (i.e., high gas price)

Conclusions and Comparative Analysis

A comparative analysis of the carbon emissions intensity is shown in Figure 0-11.



Note: Renewable Grid CI 0.005 tCO_2/MWh aligned with Evolved Energy ADP 2022; 50% feed emissions decarbonisation (ex. Gate)

Figure 0-11 Technology comparison of unabated and decarbonized emissions

The relative carbon intensity of each technology is largely consistent with evaluated literature sources[2] in terms of highest and lowest intensities.

Methane pyrolysis has the lowest carbon intensity while SMR and gasification have the highest in the unabated base case modelling. For electrolysis, the carbon intensity is completely dependent on the carbon intensity of the grid or other electricity source. For the unabated model it is assumed that grid sourced electricity is used.

Application of GHG reduction technologies to the unabated cases could achieve the following order from lowest to highest carbon intensity: electrolysis, gasification, ATR, methane pyrolysis and finally SMR. Methane pyrolysis has the lowest potential for GHG reduction while gasification has the highest.

Under the specified set of GHG reduction assumptions in this study, all the low carbon hydrogen production technologies, once abated, qualify for varying degrees of tax credits under the 45V thresholds as summarized in Figure 0-12.

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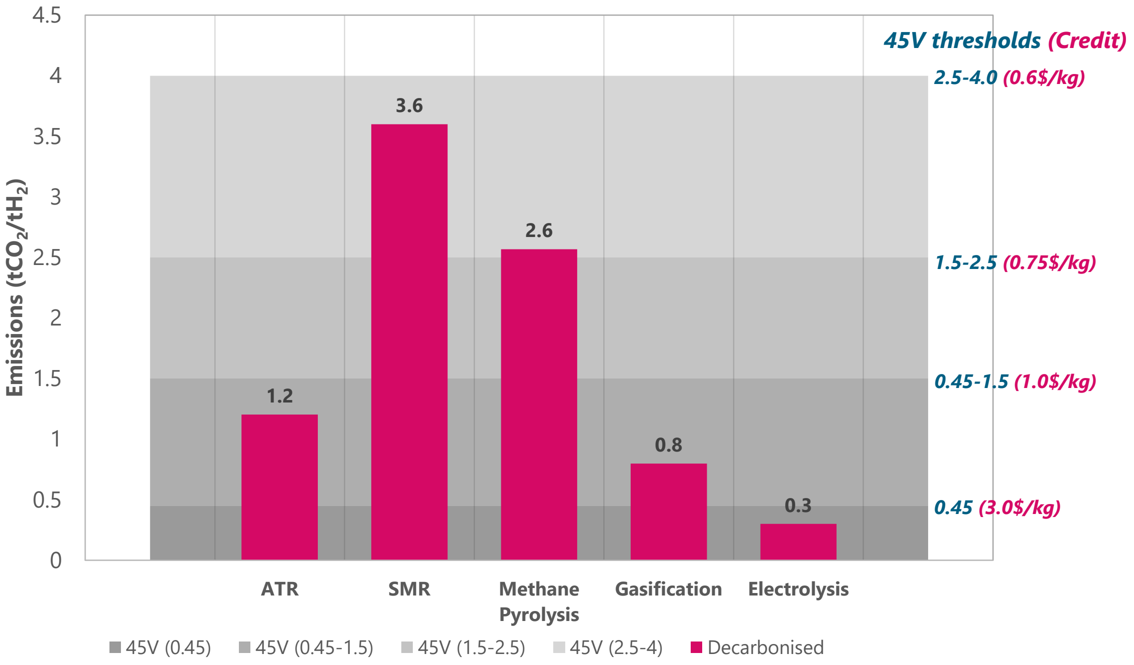
[2] https://www2.gov.bc.ca/assets/gov/business/natural-resource-industries/reports/carbon_intensity_of_hydrogen_production_methods.pdf



Note: Renewable Grid CI 0.005 tCO_2/MWh aligned with Evolved Energy ADP 2022; 50% feed emissions decarbonisation (ex. Gate)

Figure 0-12 Technology comparison for low GHG H_2 production with 45V

Additionally, under the specified set of GHG reduction assumptions in this study, all three technologies that use carbon capture to decarbonize are eligible for 45Q credits at a base credit of 17$/$tCO_2$ and bonus credit up to 85$/$tCO_2$. However, the Internal Revenue Code (IRC) specifically disallows the combination of the new 45V hydrogen production tax credit with the carbon dioxide sequestration tax credit provided under section 45Q for the taxable year or any prior taxable year. The practical application of 45V and Q can be described as follows:

- For tax liable companies, either incentive can be claimed as a direct payment for first 5 years, and thereafter to off-set tax for the next 5-7 years.
- The period for which the incentives can be claimed is for 10 years under 45V and 12 years under 45Q

An analysis to determine which of 45V or Q has a higher impact on the LCOH for the applicable technologies was conducted and is summarized in Figure 0-13.

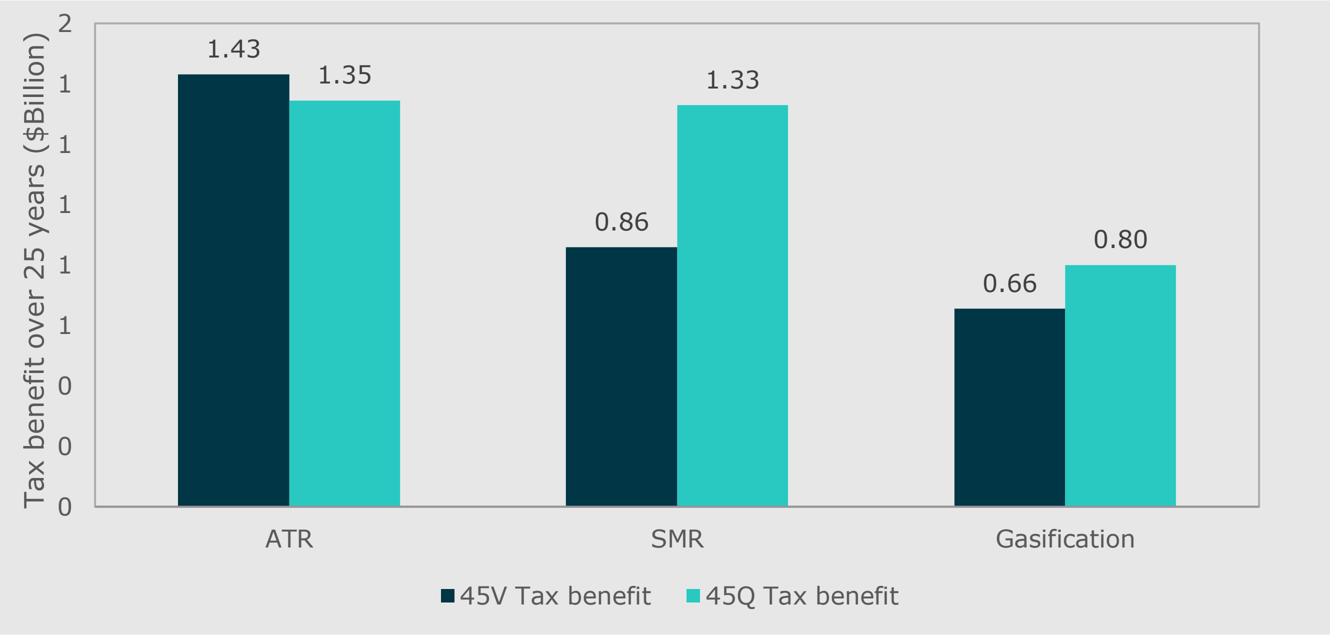


Figure 0-13 Tax benefits 45V versus 45Q

In comparing the application of 45V and Q for the eligible technologies, 45Q represents better savings over 45V for the SMR and gasification, while for ATR, the reverse is true driven by SMR qualifying for a lower 45V tax credit than ATR (0.6 $/kg vs 1.0 $/kg respectively) and a higher hydrogen to CO_2 ratio for reforming technologies in comparison to gasification technology.

The highest impact of the 45V tax benefit is for electrolysis as the associated carbon intensity of H_2 produced through this pathway qualifies for the maximum 45V credit if low carbon renewable electricity is used. The analysis suggests that the reforming technologies (SMR and ATR) remain competitive against electrolysis even though they qualify for a lower tier value credit in comparison.

It is important to note that this analysis is based on several assumptions, the sensitivities for which are shown above in Figure 0-9 and Figure 0-10. For electrolysis, the renewable electricity price is particularly sensitive and this needs to be considered when comparing against other hydrogen production technologies.

The tax impacts (from year 6 onwards) need to be understood to further evaluate the impact of total credit savings on the LCOH. Since the levelised cost does not consider the cash flow of a project, tax credit breaks cannot be directly deducted from the LCOH.

Acronyms and abbreviations

Acronym/ Abbreviation	Definition	Acronym/ Abbreviation	Definition
AC	Alternating current	**LCOH**	Levelized Cost of Hydrogen
ADP	Annual Decarbonization Perspective	**LHV**	Lower Heating Value
ASU	Air Separation Unit	**LOGR**	Low Oil and Gas Resource (forecast)
ATR	Autothermal Reformer	**MW**	Megawatt
AWE	Alkaline Water Electrolysis	**NAAQS**	National Ambient Air Quality Standards
BIL	Bipartisan Infrastructure Law	**NDC**	Nationally Determined Contribution
BSER	Best system of emission reduction	**NGL**	Natural Gas liquid
CAPEX	Capital Expenditure	**NRDC**	Natural Resources Defence Council
CCS	Carbon Capture and Storage	**OPEX**	Operating Expenditure
CCUS	Carbon Capture, Utilization and Storage	**OSBL**	Outside Battery Limits
CI	Carbon Intensity	**PEM**	Proton Exchange Membrane
CRI	Commercial Readiness Index	**PM**	Particulate Matter
DOE	Department of Energy	**PSA**	Pressure Swing Adsorption
EoL	End of Life	**SMR**	Steam Methane Reformer
EPA	Environmental Protection Agency	**SOEC**	Solid Oxide Electrolyzer Cell
GHG	Greenhouse Gas	**TPD**	Tons per day
GW	Gigawatt	**TRL**	Technology Readiness Level
HOGR	High Oil and Gas Resource (forecast)	**WGS**	Water Gas Shift
IEA	International Energy Agency	**WHR**	Waste Heat Recovery
IRA	Inflation Reduction Act		
IRC	Internal Revenue Code		
ISBL	Inside Battery Limits		
KW	Kilowatt		
LCH	Low carbon hydrogen		

1. Project Scope and Background

The scope of this project is to analyse the state of technologies for reducing or eliminating greenhouse gas (GHG) emissions at new and existing hydrogen production facilities.

The analysis focuses on hydrogen production methodologies that create on-site GHG emissions. The lifecycle emission intensity of electrolytic hydrogen is also discussed to place the emissions of other production types in context.

Hydrogen production is expected to increase dramatically and is incentivised under the Inflation Reduction Act (IRA). The U.S. Environmental Protection Agency (EPA) has proposed GHG performance standards that may be met in part through co-firing hydrogen in new and existing combustion turbines. The EPA is proposing to define low-GHG hydrogen as hydrogen produced with an overall emissions intensity of less than **0.45 $kgCO_2e/kgH_2$** with the boundary conditions of well-to-gate, consistent with the Congressional definitions provided in Section 13204 of the IRA which establishes Internal Revenue Code (IRC) Section 45V tax credit program. In comparison, typical emissions for unabated Steam Methane Reforming (SMR), which is currently the most common and cost-effective method for hydrogen production, is approximately 8-16 $kgCO_2/kgH_2$.

The Center for Applied Environmental Law and Policy (CAELP) commissioned a detailed survey of the state of GHG abatement technologies to assess the potential for reducing the emissions associated with producing hydrogen. The key objectives are:

- Define and explain the most common hydrogen production pathways
- Review the options available for reducing GHG emissions and other potential air pollutants (NO_x, SO_x, CO, particulates, etc.), including consideration of the potential scale, technology readiness level (TRL) and commercial readiness index (CRI) of both the hydrogen production pathway and the GHG reduction technology
- Calculate the cost implications for each unabated and low GHG pathway – in the form of CAPEX and OPEX
- Provide the resulting carbon intensity of the hydrogen produced and the impact the GHG reduction has on the cost of production.

2. Legislation and Regulation Overview

2.1 U.S. Energy Transition Targets

In accordance with Article 4, paragraph 2 of the Paris Agreement, each party to the United Nations Framework Convention on Climate Change must prepare, communicate, and maintain Nationally Determined Contributions that embody the effort to be made by the nation to reduce emissions and adapt to the impacts of climate change. In the most recent update by the United States submitted in April of 2021, the nation set an economy-wide target of reducing its net greenhouse gas emissions by 50-52 percent below 2005 levels in 2030.

To achieve its ambitious targets, the government has laid out a cross-sectoral plan with emissions reductions pathways in the energy sector related to electricity, transportation, buildings, and industry. For example, a goal has been set to reach 100 percent carbon-free electricity by 2035, implement policies that reduce tailpipe emissions and vehicle efficiency standards, provide for electric heating and cooking in buildings, promote fuel switching to low-carbon hydrogen and incentivize the adoption of carbon abatement at point sources.

Following industry nomenclature, green hydrogen is produced via water electrolysis using renewable electricity or biomass gasification, blue hydrogen is produced by implementing carbon capture on the reformer, turquoise hydrogen is produced via methane pyrolysis, and unabated hydrogen is denoted as grey hydrogen.

2.2 Infrastructure Investment and Jobs Act

In November 2021, Congress passed the Infrastructure Investment and Jobs Act, more commonly referred to as the Bipartisan Infrastructure Law (BIL). This $1.2 trillion investment will not only work to rebuild roads, bridges, rails and expand access to clean drinking water and high-speed internet, but approximately $68 billion has been allocated for programs that will help tackle the climate crisis.

Most notably for the development of clean hydrogen projects in the U.S., the BIL appropriates $8 billion for a Regional Clean Hydrogen Hubs Program to support the development of hubs for clean hydrogen production, delivery, and use. Of this funding, $7 billion was allocated for funding to establish 6 to 10 projects across the nation. The 7 projects listed below were selected for funding in October of 2023.

- Appalachian Regional Clean Hydrogen Hub (West Virginia, Ohio, Pennsylvania)
- Alliance for Renewable Clean Hydrogen Energy Systems (California)
- HyVelocity H_2Hub (Texas Gulf Coast)
- Heartland Hub (Minnesota, North Dakota, South Dakota)
- Mid-Atlantic Clean Hydrogen Hub (Pennsylvania, Delaware, New Jersey)
- Midwest Alliance for Clean Hydrogen (Illinois, Indiana, Michigan)
- Pacific Northwest Hydrogen Hub (Washington, Oregon, Montana)

In addition to the Regional Clean Hydrogen Hubs Program, the BIL appropriated $1 billion toward the Clean Hydrogen Electrolysis Program, $500 million for Clean Hydrogen Manufacturing and Recycling Activities, and financing for clean hydrogen projects through the Department of Energy’s Loan Programs Office.

2.3 Inflation Reduction Act

In August of 2022, the United States Government passed the Inflation Reduction Act (IRA) and immediately changed the climate technology investment landscape. Embedded within this landmark legislation is a portfolio of technology-neutral climate action programs fueled by fiscal appropriations estimated at nearly $400 billion. In addition to funds earmarked for grant and loan programs for the Department of Energy to administer, the IRA wrote into the Internal Revenue Code (IRC) enhancements and extensions for multiple existing clean energy tax credits and introduced new tax credits for technologies that weren't previously incentivized. Details of the tax credits applicable to clean hydrogen production are provided in Section 2.3.1 of this report.

According to the White House, on the one-year anniversary of the enactment of the law, over $110 billion has been announced in clean energy manufacturing investment, greater than 110,000 clean energy manufacturing jobs have been created, and it is estimated that the IRA could create more than 1.5 million additional jobs.

In many sections of the IRA that establish or enhance tax credit programs, there is a paragraph that requires the Secretary of Revenue to issue regulatory guidance and clarifications within a specified timeframe – often 180 days to one year. For the Section 45V tax credit program, a guidance was released in December 2023, which further elaborates on the life cycle assessment and clean energy matching requirements. Further details on the guidance are provided in Section 2.3.145V, 45Q, and 45Y

Section 45V Credit for the production of clean hydrogen

Section 13204 of the IRA introduces a tax credit for the production of clean hydrogen by establishing Section 45V of the IRC. Credits are issued to taxpayers who produce qualified clean hydrogen during such taxable year at a qualified clean hydrogen production facility. The credits can be claimed for a 10-year period beginning on the date such facility was originally placed in service.

Qualified clean hydrogen is defined in the IRC as hydrogen that is produced through a process that results in a lifecycle greenhouse gas emissions rate of not greater than 4 kilograms of CO_2e per kilogram of hydrogen. Additional criteria include that the hydrogen must be produced in the United States in the ordinary course of trade or business and verified for sale or use by an unrelated party. A qualified clean hydrogen production facility is defined as one that is owned by the taxpayer, produces qualified clean hydrogen, and begins construction before 01 January 2033.

The amount of the tax credit is dependent on the carbon intensity of the production method for hydrogen, rather than the method of production itself. Therefore, green hydrogen is treated no different than production methods involving fossil fuels (i.e., blue, brown) if emissions of CO_2e per kg of hydrogen produced are the same. Credit amounts are calculated as an applicable percentage of $0.60 per kg of hydrogen and rounded to the nearest cent per kg of hydrogen. Table 2-1 below provides the applicable percentage used in the calculation for production at various carbon intensities.

Qualified clean hydrogen facilities are also eligible for increased credit amounts if prevailing wage and apprenticeship requirements are established. This provision for enhanced (or "bonus") credit amounts is also found in the sections applicable to other tax credit programs such as that for Carbon Oxide Sequestration (Section 45Q). The increased credit amounts are simply described as the base credit amounts multiplied by 5.

The \$0.60 base credit amount, and resultingly the increased credit amount, will be adjusted by multiplying such amount by the inflation adjustment factor for the calendar year in which the qualified clean hydrogen is produced.

Table 2-1 Bonus Tax Credits Summary

Lifecycle Greenhouse Gas Emissions Rate for Hydrogen Production	Base Tax Credit Amount per kg of Hydrogen	Bonus Tax Credit Amount per kg of Hydrogen
Less than or Equal to 4 kg CO_2e / kg H_2; and **Greater than or Equal to 2.5 kg CO_2e / kg H_2**	20% * \$0.60 = \$0.12	20% * \$3.00 = \$0.60
Less than 2.5 kg CO_2e / kg H_2; and Greater than or equal to 1.5 kg CO_2e / kg H_2	25% * \$0.60 = \$0.15	25% * \$3.00 = \$0.75
Less than 1.5 kg CO_2e / kg H_2; and Greater than or equal to 0.45 kg CO_2e / kg H_2	33.4% * \$0.60 = \$0.20	33.4% * \$3.00 = \$1.00
Less than 0.45 kg CO_2e / kg H_2	100% * \$0.60 = \$0.60	100% * \$3.00 = \$3.00

The IRC specifically disallows the combination of the new 45V hydrogen production tax credit with the carbon oxide sequestration tax credit provided under section 45Q for the taxable year or any prior taxable year. However, in certain instances, the section 45V tax credit can be combined with the credit for electricity produced from renewable resources if that electricity is used to produce clean hydrogen. That electricity must be used by a qualified clean hydrogen production facility to produce qualified clean hydrogen, and such use must be verified by an unrelated third party.

On 22 December 2023, the US Treasury Department released the Notice of Proposed Rulemaking for regulations that will implement the Clean Hydrogen Production Tax Credit under Section 45V of the US Internal Revenue Code. The proposed regulations would require the determination of lifecycle greenhouse gas emissions rates for hydrogen production to be calculated in accordance with the most recent GREET model from the US Department of Energy's (DOE) Argonne National Laboratory. Specifically, a variation of the model – 45VH2-GREET – will be used for the purposes of the hydrogen production tax credit. The 45VH2-GREET model only includes emissions associated with feedstock growth, gathering, extraction, processing, and delivery to a hydrogen production facility. The model would also include any other emissions associated with the hydrogen production process, including electricity and any capture and sequestration of carbon dioxide used or generated by the hydrogen production facility.

The current 45VH2-GREET model incorporates eight hydrogen production pathways:

- Steam methane reforming (SMR) of natural gas with potential CCS
- Autothermal reforming (ATR) of natural gas with potential CCS
- SMR of landfill gas with potential CCS
- ATR of landfill gas with potential CCS
- Coal gasification with potential CCS
- Biomass gasification with corn stover and logging residue with no significant market value with potential CCS
- Low-temperature water electrolysis using electricity
- High-temperature water electrolysis using electricity and potential heat from nuclear power plants

For hydrogen production technology or feedstock not accounted for in the GREET model (such as biomass feedstock or geologic hydrogen production), an alternative avenue is provided to allow the taxpayer to petition for a provisional emission rate (PER) determination.

The proposed regulations put significant limitations on the feedstock renewable or low-carbon electricity source in the hydrogen production process. This would be enforced through Energy Attribute Certificates (EACs). An EAC would be defined to mean a tradeable contractual instrument issued through a qualified registry and represents the energy attributes of a specific unit of energy produced. Renewable energy certificates are also considered forms of EACs. A qualifying EAC must meet the "three pillars" criteria test of incrementality, temporal matching and deliverability, and be verified by a qualified verifier.

Section 45Q Credit for carbon dioxide sequestration[3]

Section 13104 of The Act provides for an extension and modification of the credit for Carbon Oxide Sequestration. Internal Revenue Code (IRC) Section 45Q incentivizes decarbonization of industry by providing for a performance-based tax credit for facilities that capture and store CO_2 that would otherwise be emitted into the atmosphere. The IRA amends the existing Section 45Q tax credit to improve investment certainty and encourage CCUS development using multiple strategies. The deadline to initiate construction on a project is pushed out to 01 January 2033, which represents a seven-year postponement of the existing 01 January 2026 deadline.

Another notable enhancement is that the minimum annual capture requirements to be eligible for the tax credit are reduced significantly, as exhibited in Table 2-2 below.

Table 2-2 Minimum annual capture requirements

Source Type	Existing Minimum Annual Capture Requirement for Section 45Q Tax Credit Eligibility	Minimum Annual Capture Requirement for Section 45Q Tax Credit Eligibility Under the Inflation Reduction Act of 2022
Power Plants	500,000 Metric Tons	18,750 Metric Tons[4]
Other Carbon (CO_2) Emitting Facilities	25,000 Metric Tons	12,500 Metric Tons
Direct Air Capture and other Capture Facilities	100,000 Metric Tons	1,000 Metric Tons

The enhancement of the proposed Section 45Q tax credit for Carbon Oxide Sequestration is one of three energy tax credits included in The IRA's framework that can be claimed by any taxpayer as a direct payment, which was a key wish-list provision for many CCUS proponents and other tax credit program participants. In lieu of other means of monetizing the tax credit, taxpaying entities claiming the credit will be treated as making payment against the taxes imposed on them in the amount of such credit, which will benefit taxpayers with little to no tax liability.

Upon its introduction into the Internal Revenue Code in 2008, the Section 45Q tax credit expired once credits were claimed for 75 million metric tons. The Bipartisan Budget Act of 2018 removed this cap, and qualifying taxpayers are now eligible to collect credits for 12 consecutive years

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[3] Note that the statutory language for the 45Q credit describes it as the "Credit for Carbon oxide sequestration"

[4] Carbon capture equipment for power plants must have a capture design capacity of not less than 75 percent of the baseline carbon oxide production of such unit

beginning with the year the capture facility was placed in service. The IRA did not change the 12-year credit period.

Perhaps the most advantageous proposed amendment to Section 45Q is the Modified Applicable Dollar Amounts for the tax credits. The language in the bill structures the credit amounts in a manner that is different from the way they are currently provided in Section 45Q(b)(1)(A) and Section 45Q(d)(2)(A). Similar to the current code, there are base credits. These have been reduced from the amounts established by the Bipartisan Budget Act of 2018, as exhibited in the table below. However, a new subsection has been added – entitled "(h) Increased Credit Amount for qualified facilities and carbon capture equipment." This subsection multiplies the credit amount by 5 for any facility that meets certain prevailing wage and apprenticeship requirements. This multiplied credit has been referred to as the enhanced bonus credit.

Table 2-3 45Q Tax Credit Summary

Method of Carbon Capture, Use & Storage	Section 45Q Tax Credit Amount under the Bipartisan Budget Act of 2018 (Placed in service 15 Nov 2021 or after)	Section 45Q Tax Credit Amount Under the Inflation Reduction Act of 2022
Capture and Secure Geological Storage	$31.77 in 2020. Increasing to $50 by 2026, then inflation-adjusted.	Base Credit: $17.00; or Bonus Credit: $85.00
Capture and Use *(including EOR)*	$20.22 in 2020. Increasing to $35 by 2026, then inflation-adjusted.	Base Credit: $12.00; or Bonus Credit: $60.00
Direct Air Capture and other Capture Facilities	(Dependent on Use/Storage Method, refer to above)	Base Credit *(Storage):* $36.00; or Bonus Credit *(Storage):* $180.00 Base Credit *(Use/EOR):* $26.00; or Bonus Credit *(Use/EOR):* $130.00

Section 45Y Clean Electricity Production Credit

An existing tax credit for the production of electricity from certain renewable resources was extended to allow for eligibility until the end of 2024, but a new tax credit was enacted to incentivize clean electricity production in the U.S. beyond the expiration of this credit.

Section 13701 of the IRA established the clean electricity production credit under section 45Y of the IRC. Along with replacing the existing credit for clean electricity, the new program is structured like the credits under sections 45Q and 45V in that a base amount is offered, and the credit is multiplied by 5 when prevailing wage and apprenticeship requirements are followed. The base amount of the credit is 0.3 cents per kWh, and the bonus amount would therefore be 1.5 cents per kWh. The credit is available for a period of 10 consecutive years from the date the facility was originally placed in service. In addition to the bonus credit criteria, credits are increased by 10% when requirements for locating in an energy community and/or utilizing domestic content are followed. Details surrounding these requirements are provided in the statute.

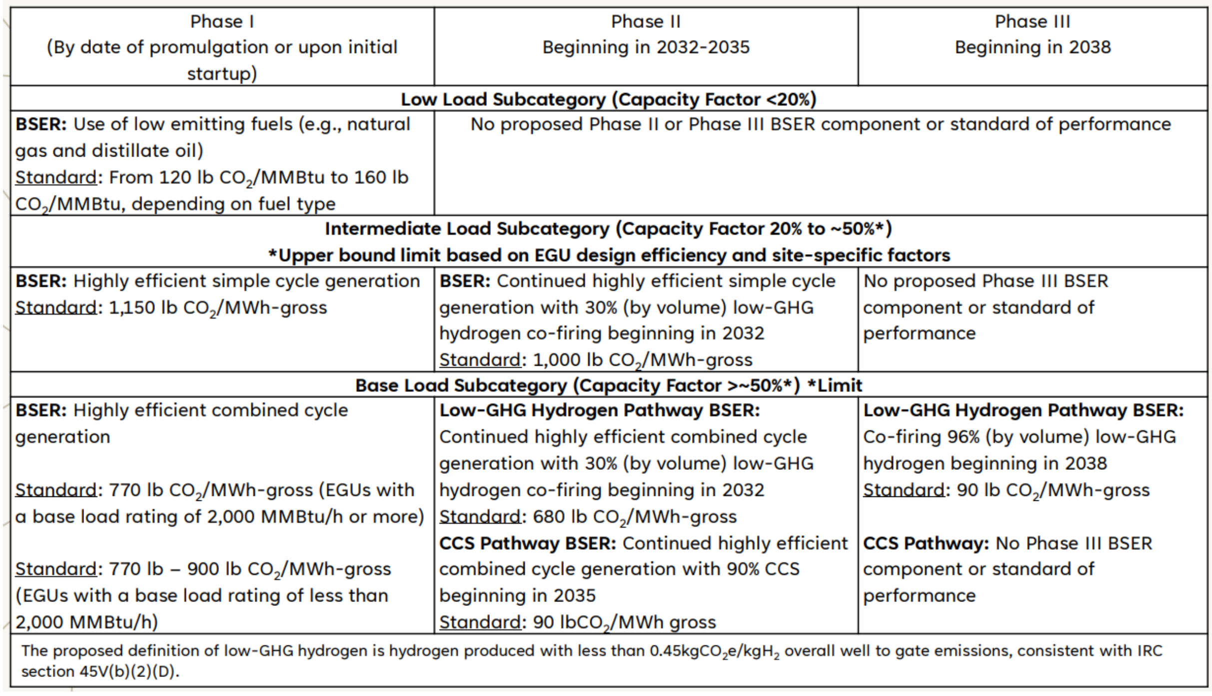
As mentioned in the discussion on the Section 45V tax credit for clean hydrogen production, this credit may be stacked with the 45V credit when the qualifying clean electricity is used to power electrolyzers producing qualified clean hydrogen. If power purchase agreements are to be used to source clean electricity from the grid, forthcoming regulatory guidance will need to be consulted to ensure compliance with requirements related to additionality and time-matching.

2.4 Regulations Pursuant to the Clean Air Act (Section 111)

The EPA issued a proposed rulemaking in May of 2023 to regulate greenhouse gas emissions from fossil fuel-fired electric generating units under Section 111 of the Clean Air Act. The proposed rulemaking includes proposed regulations for three affected sources: new stationary combustion turbines, existing stationary combustion turbines, and boilers fuelled by coal, natural gas, or oil. Each of these sources are further broken down into subcategory based on, among other things, capacity factor and operating horizon. For each subcategory, EPA is proposing a distinct "best system of emission reduction" (BSER) and standard of performance or emission guideline based on its evaluation of the feasibility, emissions reductions, and cost reasonableness of available controls.

If finalized as proposed, implementation of the standards will occur in three phases: Phase one beginning with promulgation of the rule, Phase two beginning between 2032 to 2035, and Phase three beginning in 2038. The table below defines the proposed BSER prescribed under the authority of Section 111(b) of the Clean Air Act for new stationary combustion turbine sources for each phase and capacity factor.

Table 2-4 Proposed BSER for new stationary combustion turbine sources



Phase I (By date of promulgation or upon initial startup)	Phase II Beginning in 2032-2035	Phase III Beginning in 2038
Low Load Subcategory (Capacity Factor <20%)		
BSER: Use of low emitting fuels (e.g., natural gas and distillate oil) Standard: From 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on fuel type	No proposed Phase II or Phase III BSER component or standard of performance	
Intermediate Load Subcategory (Capacity Factor 20% to ~50%*) ***Upper bound limit based on EGU design efficiency and site-specific factors**		
BSER: Highly efficient simple cycle generation Standard: 1,150 lb CO_2/MWh-gross	**BSER:** Continued highly efficient simple cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032 Standard: 1,000 lb CO_2/MWh-gross	No proposed Phase III BSER component or standard of performance
Base Load Subcategory (Capacity Factor >~50%*) *Limit		
BSER: Highly efficient combined cycle generation Standard: 770 lb CO_2/MWh-gross (EGUs with a base load rating of 2,000 MMBtu/h or more) Standard: 770 lb – 900 lb CO_2/MWh-gross (EGUs with a base load rating of less than 2,000 MMBtu/h)	**Low-GHG Hydrogen Pathway BSER:** Continued highly efficient combined cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032 Standard: 680 lb CO_2/MWh-gross	**Low-GHG Hydrogen Pathway BSER:** Co-firing 96% (by volume) low-GHG hydrogen beginning in 2038 Standard: 90 lb CO_2/MWh-gross
	CCS Pathway BSER: Continued highly efficient combined cycle generation with 90% CCS beginning in 2035 Standard: 90 lbCO_2/MWh gross	**CCS Pathway:** No Phase III BSER component or standard of performance
The proposed definition of low-GHG hydrogen is hydrogen produced with less than 0.45kgCO_2e/kgH_2 overall well to gate emissions, consistent with IRC section 45V(b)(2)(D).		

Source: U.S. Environmental Protection Agency

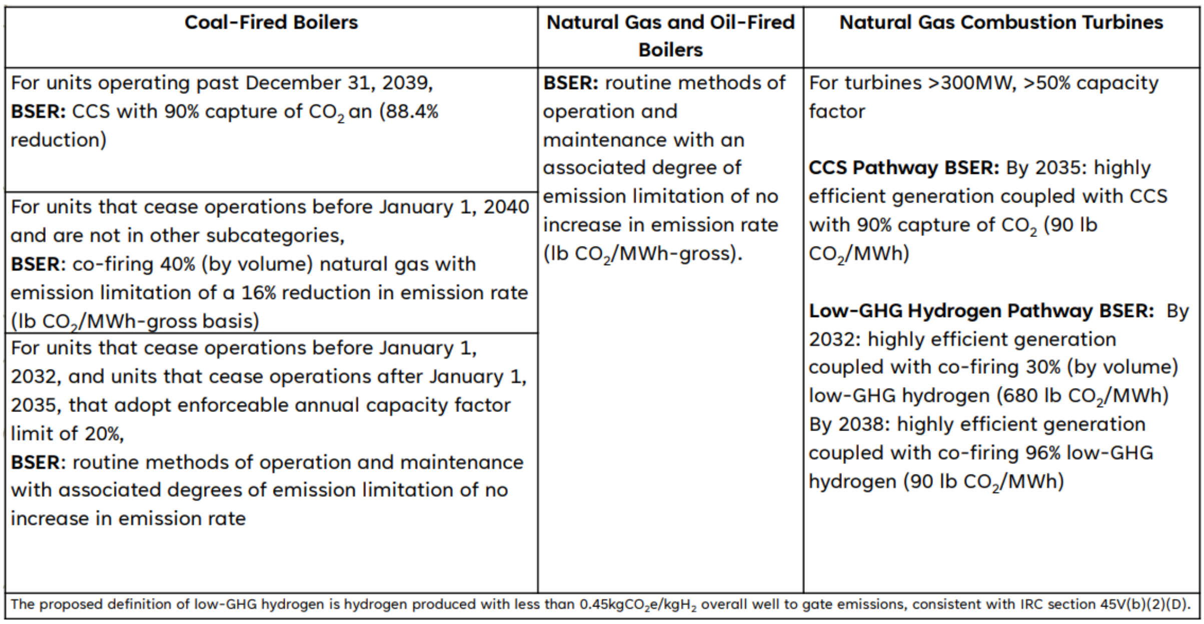
As mentioned in the summary of this report, the EPA has included in this regulatory proposal a definition for low-GHG hydrogen that is consistent with that established by U.S. Congress in the IRA.

"Low-GHG hydrogen is defined in this proposal as hydrogen produced with less than 0.45 kilograms of CO_2 equivalent overall emissions per kilogram of hydrogen (kgCO_2-e/kgH_2) from "well to gate" (meaning from input feedstock extraction to the exit gate of the hydrogen production facility)."

Existing and new gas-fired turbines could choose to comply with the relevant standard or emissions guideline by co-firing hydrogen. Accordingly, it is possible that these standards, if finalized, could significantly increase the demand for hydrogen in the electric sector.

Table 2-5 below demonstrates the proposed BSER that will be prescribed under the authority of Section 111(d) of the Clean Air Act for existing coal, oil, and natural gas-fired boilers and large natural gas-fired combustion turbines.

Table 2-5 BSER for existing fossil fuel fired plants



Coal-Fired Boilers	Natural Gas and Oil-Fired Boilers	Natural Gas Combustion Turbines
For units operating past December 31, 2039, **BSER:** CCS with 90% capture of CO_2 an (88.4% reduction)	**BSER:** routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross).	For turbines >300MW, >50% capacity factor **CCS Pathway BSER:** By 2035: highly efficient generation coupled with CCS with 90% capture of CO_2 (90 lb CO_2/MWh) **Low-GHG Hydrogen Pathway BSER:** By 2032: highly efficient generation coupled with co-firing 30% (by volume) low-GHG hydrogen (680 lb CO_2/MWh) By 2038: highly efficient generation coupled with co-firing 96% low-GHG hydrogen (90 lb CO_2/MWh)
For units that cease operations before January 1, 2040 and are not in other subcategories, **BSER:** co-firing 40% (by volume) natural gas with emission limitation of a 16% reduction in emission rate (lb CO_2/MWh-gross basis)		
For units that cease operations before January 1, 2032, and units that cease operations after January 1, 2035, that adopt enforceable annual capacity factor limit of 20%, **BSER:** routine methods of operation and maintenance with associated degrees of emission limitation of no increase in emission rate		
The proposed definition of low-GHG hydrogen is hydrogen produced with less than 0.45kgCO_2e/kgH_2 overall well to gate emissions, consistent with IRC section 45V(b)(2)(D).		

Source: U.S. Environmental Protection Agency

3. Technology Overview

Hydrogen is a versatile element that can form compounds with a wide range of other elements. Hydrogen is therefore used in the chemical industry to produce ammonia and in petroleum refineries. Other sectors and applications for hydrogen are also increasingly coming into focus, as hydrogen opens interesting opportunities in the areas of mobility, heat, and electricity in the pursuit of climate neutrality. [5]

Figure 3-1 below highlights a range of hydrogen applications. Whilst hydrogen in industrial processes such as refining, chemicals, including ammonia and methanol, are traditional and well-known operations, newer applications such as in transport, industrial heating and steel production (as direct reduced iron), are gaining traction to meet net-zero targets.

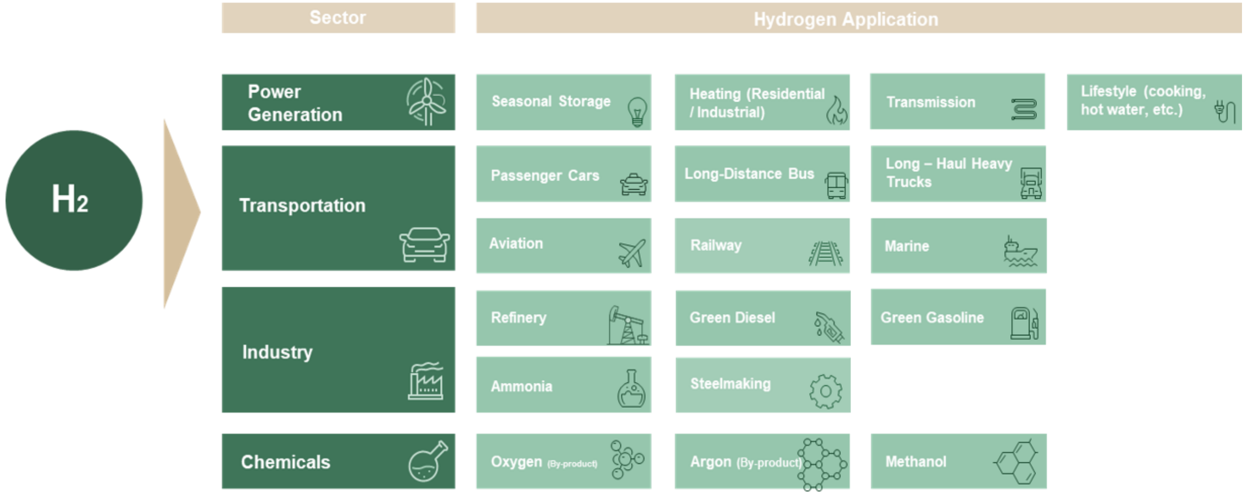


Figure 3-1 Current and Future Hydrogen Applications

This section defines the different hydrogen production technologies evaluated in this study; these have been classified into 4 distinct groups based on technology maturity and functionality as shown by Figure 3-2. Currently, approximately 84% of all hydrogen produced globally uses the Steam Methane Reforming (SMR) process, with the remainder using coal gasification. However, Autothermal Reforming (ATR) is gaining popularity due to its high CO_2 capture potential and superior energy efficiency.[6] Technologies such as methane pyrolysis and biomass gasification for on-purpose hydrogen production are yet to be proven at a commercial scale.

Different purities of hydrogen are required for different applications; when used as a fuel or in certain chemical industries, lower purities of hydrogen may be used, however when using as a transport fuel, 99.99% purity is required. Similarly, hydrogen production technologies vary in outlet pressures, thus, varying degrees of compression is required to meet transportation and application needs. For the purpose of this study, boundary limit properties do not include additional compression or further purification of hydrogen beyond what is produced by the archetypical production facility for each type.

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[5] https://www.ewe.com/en/shaping-the-future/hydrogen/hydrogen-applications

[6] https://www.rystadenergy.com/insights/production-of-blue-hydrogen-using-ccs

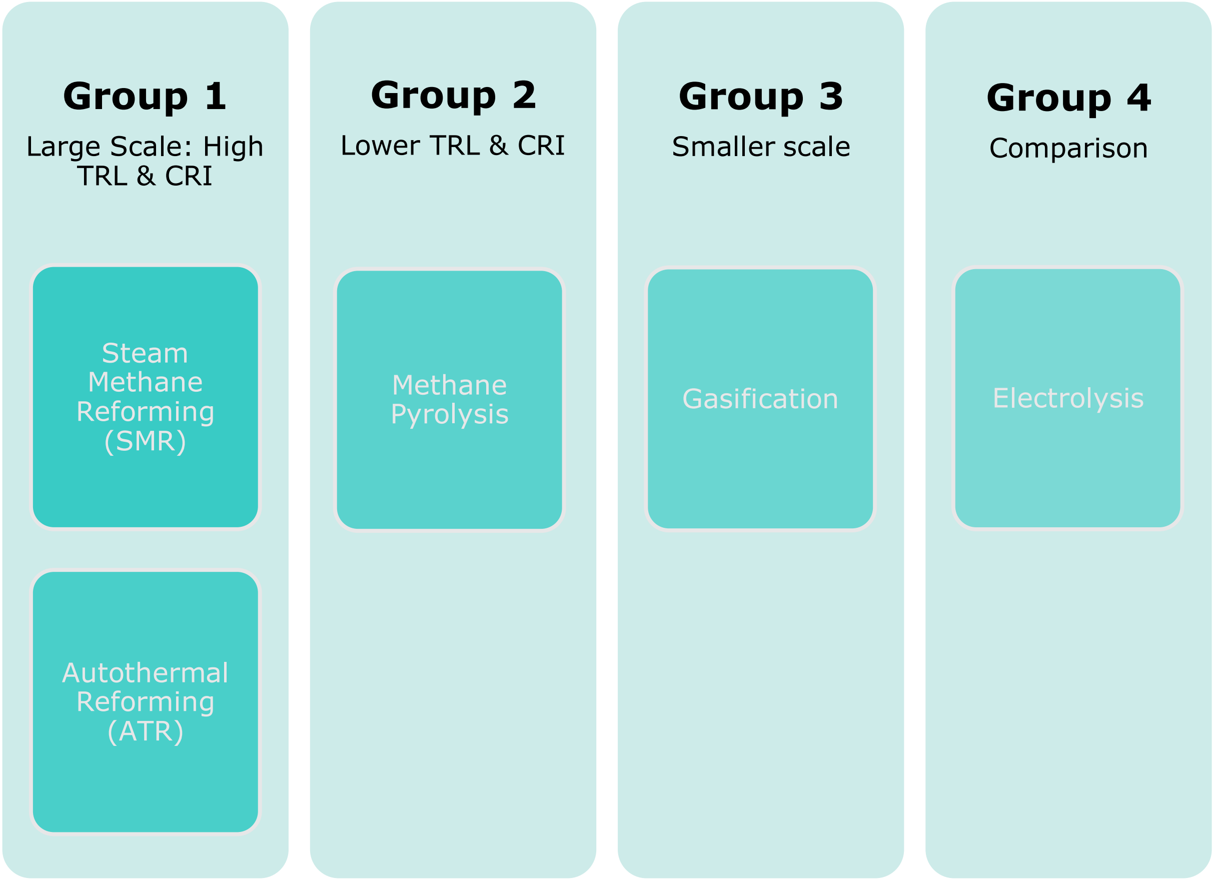


Figure 3-2 Hydrogen Production Technology Categories

Group 1 technologies are technically mature and rank high on the CRI. These technologies have been proven at large scales and are either already widely available or in advanced stages of commercial application.

Group 2 technologies, on the contrary, are not as technically mature or commercially viable, yet have the potential to be scaled up.

Gasification, as a Group 3 technology, is technically and commercially viable and implemented at large scale for syngas production. However, it is implemented at a relatively smaller scale when targeting on-purpose hydrogen production. In addition, feedstock availability is a key limitation for the scale up of this technology.

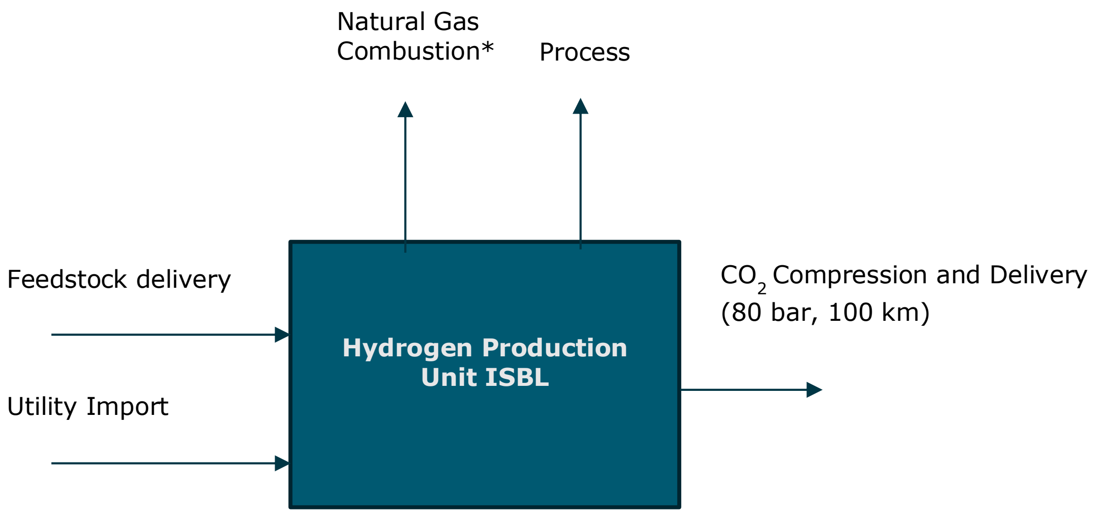
A key characteristic of SMRs, ATRs, and gasification is the intermediate production of syngas, a mixture of CO, CO_2 and H_2, which is shifted and purified for hydrogen production. The ratio of H_2:CO in the syngas produced via a SMR is relatively more suited for hydrogen production than that from the ATR or gasification, which are in turn more suited for methanol production. Hence, SMR is currently the most widely available hydrogen production technology. ATRs and gasifiers are currently more prevalent in the methanol industry; however, the future demand for low carbon hydrogen has led to technological advancements towards better hydrogen production performance.

Electrolysis, classed in Group 4, does not have onsite GHG emissions but is evaluated for comparison purposes; it is considered to have the lowest potential overall GHG emissions when powered with clean electricity and is used to benchmark other technologies. Note that these technologies are categorized to produce unabated hydrogen; it is not indicative of the decarbonisation options.

In terms of hydrogen purity, SMR, ATR, gasification and electrolysis all result in high purity hydrogen production of 99.99% primarily due to the need for further treatment of the product gas. In the case of methane pyrolysis, the typical hydrogen purity achieved is approximately 95% but can be increased with further treatment.

Figure 3-2 does not outline the complete suite of hydrogen production technologies; refer to Section 6.1.1 for an overview of additional emerging technologies.

3.1 Emissions Factors



**Only applicable to steam methane reforming, where natural gas is used as a feedstock and fuel*

Figure 3-3 Hydrogen Production Emission Points

In this study, various emissions factors have been utilised to calculate the overall greenhouse gas emissions for hydrogen production from the selected technologies.

Figure 3-3 illustrates the emission points considered for the calculations; this includes the upstream natural gas emissions, electricity import, natural gas combustion in the SMR, and CO_2 delivery for low GHG hydrogen production.

Table 3-1 outlines the carbon intensities of natural gas and the electricity grid. The upstream natural gas intensity factor accounts for the emissions during extraction and delivery; this includes emissions from power for compression and extraction, intermediate flaring, and potential methane slip. The natural gas combustion emissions are further broken down into its elements in Table 3-2.

Table 3-1 GHG Emissions Factors

	Unit	Value	Source
Natural Gas (upstream)	gCO_{2e}/MJ	15	Advisian Standard
Natural Gas (combustion)	gCO_{2e}/MJ	55	Advisian Standard

Power (US Grid Average, 2020)	gCO_{2e}/kWh	373	Carbon Footprint & US Energy Information Administration
Power (2030)	gCO_{2e}/kWh	184	IPM modelling conducted by Natural Resources Defence Council (NRDC)
Renewable Power	tCO_{2e}/MWh	0.005	Evolved Energy Annual Decarbonization Perspective (ADP) 2022

Table 3-2 Combusted Natural Gas Composition (IPCC, 2006)

	Unit	Value
CO_2	gCO_2/MMBTU Natural Gas	59200
CH_4	gCH_4/MMBTU Natural Gas	1.05
N_2O	gN_2O/MMBTU Natural Gas	0.105

The global warming potential (GWP) was developed to allow comparisons of the impacts of different gases. Specifically, it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of CO_2. The larger the GWP, the more that a given gas warms the Earth compared to CO_2 over that time period. The period usually used for GWPs is 100 years. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory), and allows policymakers to compare emissions reduction opportunities across sectors and gases.[7] Table 3-3 outlines the 100-year GWP used by the EPA. As shown N_2O emissions have the highest emissions potential.

Table 3-3 GHG Global Warming Potential

	Unit	Value
CO_2	tCO_{2e}/tCO_2	1
CH_4	tCO_{2e}/tCH_4	27
N_2O	tCO_{2e}/tN_2O	273

3.2 Group 1 Technologies: High TRL and CRI

3.2.1 Steam Methane Reforming (SMR)

Steam Methane Reforming (SMR) is currently the most common and cost-effective method for hydrogen production, contributing to approximately 95% of the hydrogen production in the U.S. and about 50% of the production worldwide. The technology has been in existence since the early 1900s and is a well-understood technology for syngas production from natural gas. Steam methane reforming (SMR) has a high thermodynamic hydrogen yield efficiency (~65-75% on LHV basis) and uses a catalyst, typically nickel, to facilitate the thermochemical reaction of natural gas and water at temperatures of around 850°C.

Facilities needing a continuous supply of hydrogen often use steam methane reforming to produce it. For these units, energy consumption and temperature variability affect costs, output quality,

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[7] https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

and safety. This variability stems from combustion inefficiency, process variability, and equipment degradation.

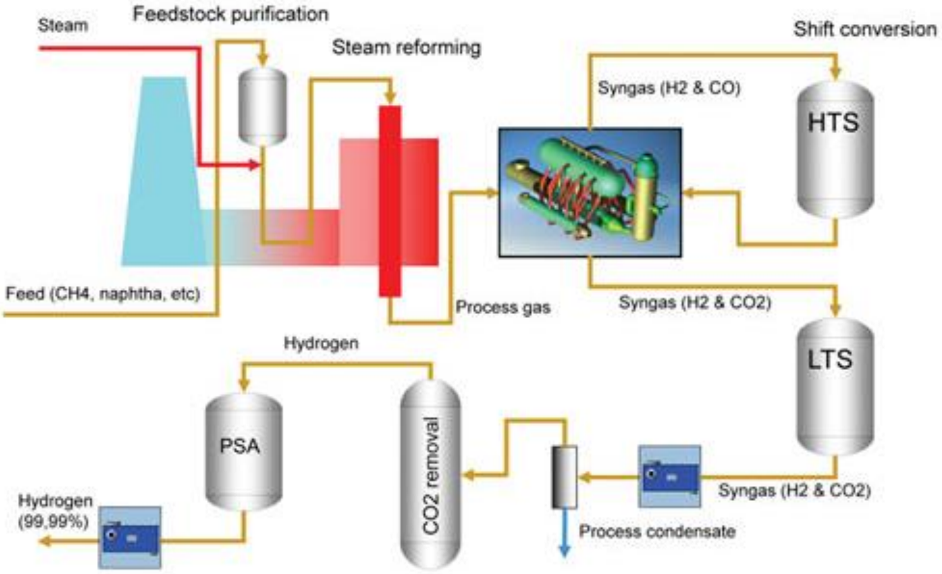

Figure 3-4 Steam Methane Reformer Schematic

(Source: Alfa Laval)

Some key players involved in the steam methane reforming hydrogen generate market include Air Products and Chemicals, Johnson Matthey, Linde, Air Liquide, Topsoe, and Plug Power.

3.2.1.1 Process Description

Overall, the process of hydrogen production via an SMR involved two governing reactions as shown by the equations below:

$$CH_4 + H_2O \Leftrightarrow CO + 3H_2$$

Equation 1 $Steam\ Methane\ Reforming$

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

Equation 2 $Water\ Gas\ Shift\ Reaction$

Steam, generated internally from waste heat of the flue gas stream, is added to the feedstock which is passed to the steam reforming step. The primary reaction across a nickel-based catalyst in the SMR is the highly endothermic reforming equilibrium reaction where methane and water react to produce carbon monoxide and hydrogen. Simultaneously, the water gas shift equilibrium reaction converts CO and water to CO_2 and more hydrogen. The SMR is operated at high temperatures, in the order of 815 to 871°C as, under those conditions, the equilibrium favours methane conversion. To achieve high temperatures and deliver the reaction duties required, the SMR is designed as a fired heater with catalyst-filled tubes in the radiant section. The significant amount of waste heat that remains in the flue gas is recovered in the convection section to preheat the feed, generate steam and/or preheat combustion air. Licensors have considered secondary steam reforming reactors that use some of the waste heat, but these have been less commonly used in industry. Many units consider a pre-reformer to improve process efficiency or to mitigate fouling risks associated with heavier feedstocks in the main reactor. In the pre-reformer, heavier hydrocarbons are broken down to methane, carbon monoxide and hydrogen. The SMR furnace is typically fired with tail gas recovered from the downstream pressure swing absorption (PSA) unit along with supplemental fuel gas (usually natural gas).

The SMR synthesis gas (syngas) effluent contains a significant amount of CO. This syngas from the SMR reactor is then directed to a water gas shift (WGS) reactor. In the WGS, the carbon monoxide and steam equilibrate across an iron-based and/or copper-based catalyst to produce additional hydrogen and carbon dioxide. The exothermic WGS reaction is favoured at lower temperature and WGS configurations with high-temperature shift, medium temperature shift and low temperature shift are optimized around project economics.

The hydrogen rich syngas is then cooled and purified. In addition to the convection section, heat recovery is maximised through BFW pre-heating and steam generation. The cooled syngas is then typically routed to a PSA unit to produce high purity hydrogen for fuel grade hydrogen. PSA's have multiple vessels with zeolite-based adsorbent beds that individually operate in batch mode. The adsorbent only allows hydrogen molecules to pass through while the remaining species are trapped in the zeolite. As a bed becomes saturated, it is taken off-line and depressured to release the trapped gases and regenerate the adsorbent. The released gases are referred to as tail gas, which is used as low heating value fuel for the SMR furnace. PSA units can achieve 99.99+ vol% purity hydrogen with 85-90% hydrogen recovery. The hydrogen product from the PSA is routed to any necessary compression and storage before being fed to a pipeline or a downstream unit.

SMRs are widely used and well-established technology with operating references more than 150 MMSCFD and can be considered TRL 9. SMR capacities are constrained mechanically by the practical size of the SMR furnace.

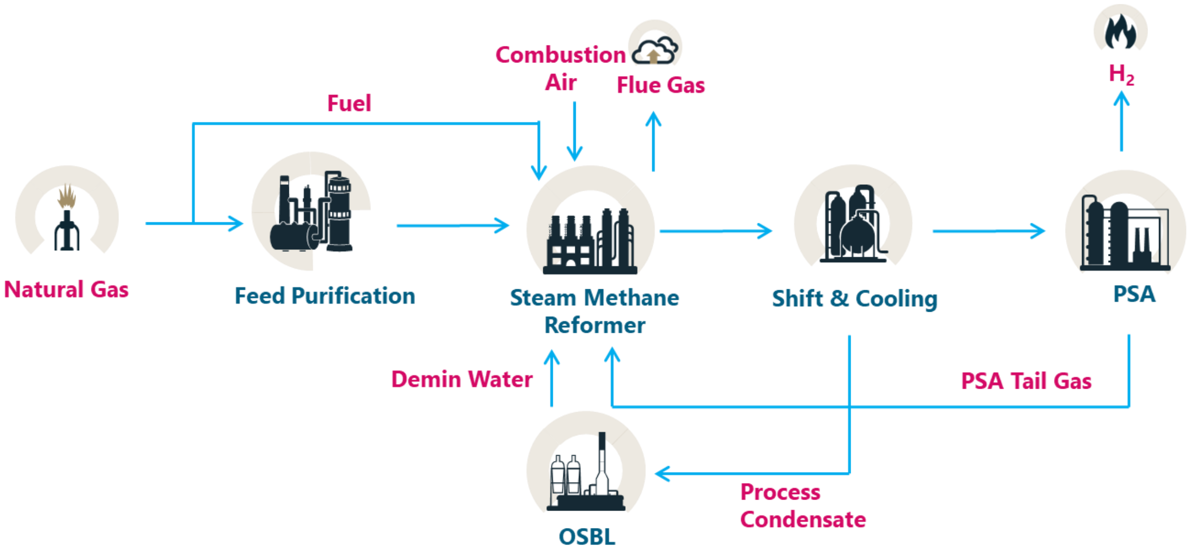

Figure 3-5 Steam Methane Reforming Process Flow Diagram (PFD)

3.2.1.2 Material Balance

The following section evaluates the mass balance for a reference 360 tpd hydrogen production SMR unit.

Table 3-4 SMR Process-Side Mass Balance

Inputs	Mass Flow (TPD)
Natural Gas	1,000
Steam	3,100
Total	**4,100**
Outputs	**Mass Flow (TPD)**
Hydrogen	360
PSA Tail Gas	2,580
Process Condensate	1,160
Total	**4,100**

3.2.1.3 Utility Balance

The following section evaluates the utility balance for the reference hydrogen plant. As noted in the process description, the PSA tail gas is source of low heating value for the furnace and is thus, combined with make-up natural gas to provide the required energy.

Table 3-5 SMR Utility Mass Balance

Inputs	Mass Flow (TPD)
Natural Gas	240
PSA Tail Gas	2,580
Air	9,180
Total	**12,000**
Outputs	**Mass Flow (TPD)**
Flue Gas[8]	12,000
Total	**12,000**

Table 3-6 SMR Electricity Import

Utility	MW
Electricity Imports	2.1

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[8] Composition - 28 mass% CO_2, 59 mass% N_2, 11 mass% H_2O, 1 mass% O_2 and 1 mass% Ar

3.2.1.4 Emissions Balance

Table 3-7 Emissions Balance SMR

	Carbon Intensity	Value	Emissions ($kgCO_{2e}/kgH_2$)
Feed Transportation (to gate)			
Natural Gas	15 gCO_2/MJ	1,000 TPD	2.3
Boiler Feed Water	0.0002 gCO_2/gH_2O	3,100 TPD	0.0
Process (H_2 Production)			
CO_2 emissions	1 gCO_2/ gH_2	3,326 TPD	9.3
Fuel (H_2 Production)			
Natural Gas	70 gCO_2/MJ	20,736 GJ/d	2.1
Electricity[9]	184 gCO_2/kwh	2 MW	0.0
Other GHG and Pollutant Emissions from Nat Gas Combustion			
N_2O	273 tCO_{2e}/tN_2O	4 kg/d	0.003
CH_4	27 tCO_{2e}/tN_2O	20 kg/d	0.001
Particulates[10]		43 kg/d	-
SO_x		3 kg/d	-
Total			**13.6**

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[9] 2030 Grid Carbon Intensity

[10] $PM_{2.5}$ – 2.5 µm

3.2.2 Autothermal Reforming (ATR)

Autothermal reforming (ATR) of natural gas is a process used for hydrogen production that combines the benefits of steam reforming, partial oxidation, and the water gas shift reactions. ATRs are more competitive at the largest scales than SMRs, which are constrained mechanically by the practical size of the SMR furnace. ATRs are limited by the capacity of the amine absorber but this is not as constraining as the SMR limit.

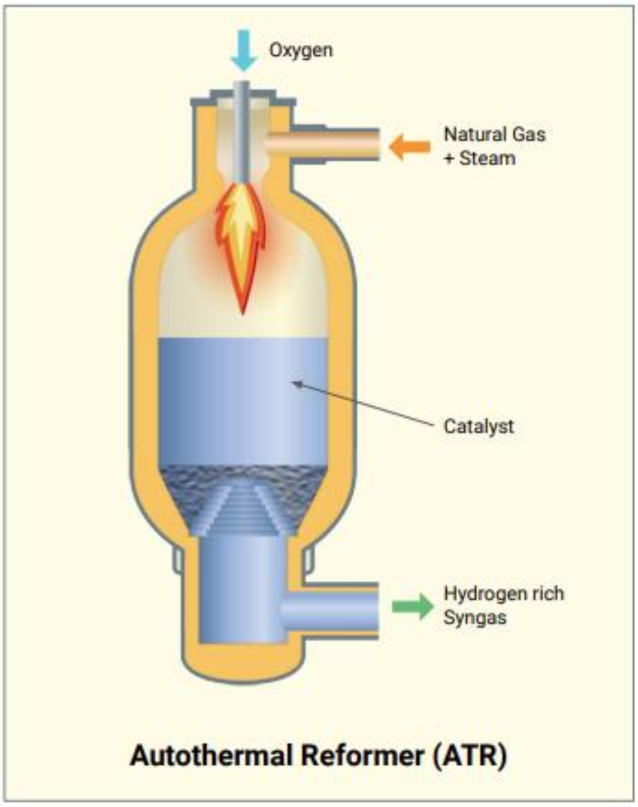

Figure 3-6 Auto Thermal Reforming Schematic

(Source: Air Liquide)

Air Liquide’s schematic for an ATR is illustrated in Figure 3-6. In January 2023, the company announced that it will deploy its ATR to a pilot project for the production of low-carbon hydrogen and ammonia for Inpex Corporation. Inpex said that the commissioning of the surface plant facilities will begin in March 2025, with the aim of completing construction in August 2025.[11],[12]

Topsoe, Johnson Matthey (JM), and Air Liquide are the main ATR and process technology providers, with patented technologies that are appealing for future grey and blue hydrogen facilities. These technologies are interesting to project developers due to their unique designs. Topsoe's SynCOR reformer uses a multi-layered bed of Topsoe's unique Ni-based catalysts, while JM's LCH process layout pre-reforms natural gas with a gas-heated reformer to boost energy efficiency. Industrial gases, petrochemicals, and carbon capture and storage (CCS) businesses

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[11] https://www.airliquide.com/sites/airliquide.com/files/2023-01/air-liquide-brief-atr-produce-low-carbon-hydrogen-scale_63bd17312b8a5.pdf

[12] https://www.offshore-energy.biz/inpex-moves-forward-with-its-clean-hydrogen-ammonia-project-in-japan/

show considerable interest in such technologies. As a result, these firms often work with one another to build large-scale blue hydrogen plants to serve refineries, ammonia plants, and industrial zones.[13]

In the autothermal reformer (ATR) process, most of the process CO_2 is available for capture in the shifted syngas, resulting in potential for overall capture rates between 93-98%. The gas partial oxidation (POx) process developed by Shell is reported to yield overall plant capture rates up to 99%. To date, no operational plant has achieved these levels of capture, but two ATR projects targeting 90-95% capture are currently under construction in North America.[14]

3.2.2.1 Process Description

An ATR combines the effects of both the endothermic steam reforming and the exothermic partial oxidation reactions by feeding the fuel together with the oxidant (air or oxygen) and steam over a catalyst in a fixed bed reactor. Thus, in a reforming process of natural gas, many reactions are likely to occur. When CO_2 is present in the feed, the H_2:CO ratio is of the order of 1:1. However, when the process utilizes steam, the H_2:CO ratio produced is 2.5:1 as shown by the equations below:

$$2CH_4 + O_2 + CO_2 \rightarrow 3H_2 + 3CO + H_2O$$

Equation 3 Partial oxidation and simultaneous steam methane reforming 1

$$4CH_4 + O_2 + 2H_2O \rightarrow 10H_2 + 4CO$$

Equation 4 Partial oxidation and simultaneous steam methane reforming 2

The process begins with a hydrocarbon feedstock, typically natural gas, which may undergo pre-treatment such as pre-reforming and purification. The feedstock may then be heated externally using a fired heater which uses process off gases from the downstream purification steps as a fuel before being introduced into an ATR reactor. Oxygen from a separate air separation unit (ASU) and water are also introduced into the ATR reactor. In the ATR, the feedstock undergoes partial oxidation and steam reforming simultaneously, with the endothermic heat requirement for the steam reforming being provided by the exothermic partial oxidation reaction. This reaction takes place in the range of 40-50 bar, with the process gas increasing in temperature from an inlet of 400-500°C to an outlet of 1000-1100°C. The result is a synthesis gas (syngas) consisting of hydrogen, carbon monoxide, carbon dioxide, and other trace components.

In most cases an ATR is fed by oxygen as detailed in the rest of this section. However, it is possible to use an air, or an enriched air, fed ATR. This version of the flowsheet removes the need for an ASU although results in a bigger ATR and associated syngas cooling stream. Additionally, the resulting syngas has high levels of nitrogen which increases treatment costs.

The syngas from the ATR is then directed to a water gas shift (WGS) reactor along with additional steam. In the WGS, the carbon monoxide in the syngas reactors with the steam to produce additional hydrogen and carbon dioxide, increasing the hydrogen content while reducing the

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[13] https://www.prnewswire.com/news-releases/autothermal-reforming-a-promising-technology-for-blue-hydrogen-production-says-idtechex-301795446.html

[14] IEA Global Hydrogen Review 2023

carbon monoxide concentration. As the WGS reaction is exothermic, waste heat recovery (WHR) may be added on the WGS products to improve the energy efficiency of the system.

After the WGS reaction, the syngas undergoes a hydrogen purification step to remove impurities from the gas mixture. A variety of purification technologies can be used, but pressure swing adsorption (PSA) technologies, as described in the SMR process description, are predominant. At this stage, the hydrogen is at its final product purity and can be compressed and stored before being sent to the battery limit.

The process is visualised by the process flow diagram in Figure 3-7.

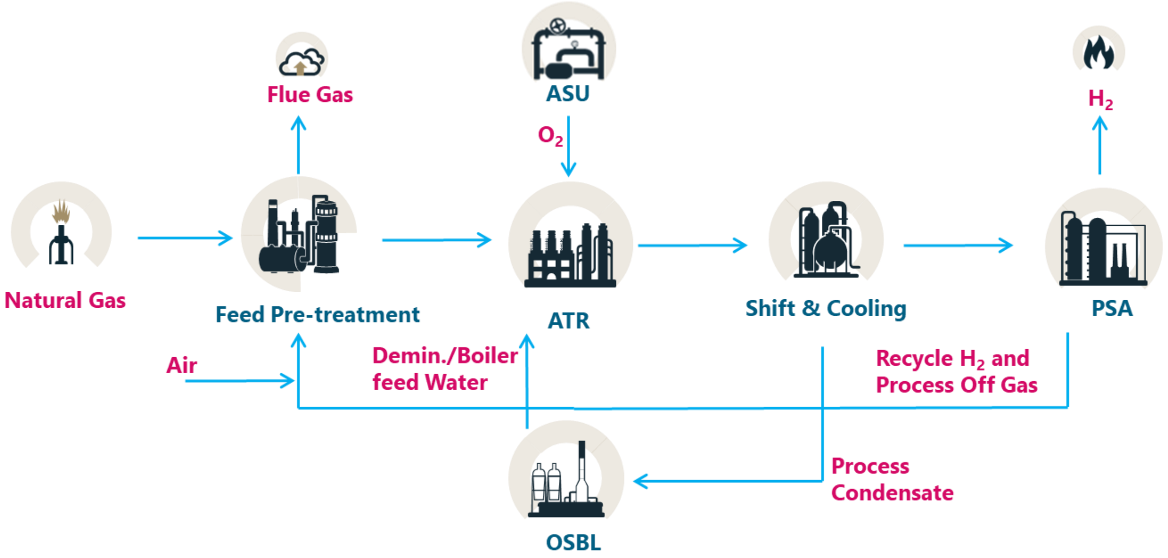

Figure 3-7 Autothermal Reforming Process Flow Diagram

The large quantity of CO_2 produced in the process leaves the hydrogen purification as part of the low pressure tailgas.

3.2.2.2 Material Balance

The following section evaluates the mass balance for a reference 360 tpd hydrogen production ATR unit.

Table 3-8 ATR Process-Side Mass Balance

Inputs	**Mass Flow (TPD)**
Natural Gas	1,200
Demin Water	3,500
Oxygen	1,400
Total	6,100

Outputs	Mass Flow (TPD)
Hydrogen	360
PSA Tail Gas	3,440
Condensate	2,300
Total	6,100

3.2.2.3 Utility Balance

It is important to note that ATRs are highly energy integrated, and thus, require minimal energy input. Approximately 90% of the electricity imports shown in Table 3-9 is used for the Air Separation Unit (ASU).

Table 3-9 ATR Electricity Import

Utility	MW
Electricity Imports	35

3.2.2.4 Emissions Balance

Table 3-10 Emissions Balance ATR

	Carbon Intensity	Value	Emissions ($kgCO_{2e}/kgH2$)
Feed Transportation (to gate)			
Natural Gas	15 gCO_2/MJ	1,200 TPD	1.8
Water	0.0002 gCO_2/gH_2O	3,500 TPD	0.0
Process (H_2 Production)			
CO_2 emissions	1 gCO_2/ gH_2	3,313 TPD	9.3
Fuel (H_2 Production)			
Electricity[15]	184 gCO_2/kWh	35 MW	0.4
Total			**11.5**

3.3 Group 2 Technologies: Lower TRL and CRI

3.3.1 Methane Pyrolysis

Pyrolysis of natural gas (methane) is a well-known technical process applied for production of carbon black. The process holds potential for contributing to carbon dioxide-free hydrogen production if the carbon by-product of the process can be used suitably. Production of hydrogen from natural gas pyrolysis has thus gained interest in research and energy technology. Hydrogen produced through this process is colloquially known as turquoise hydrogen.

Methane pyrolysis (also called methane cracking) is a family of process technologies that involves a reaction in which a methane feedstock is decomposed into hydrogen and solid carbon at high temperature.

As it is an endothermic process, external energy is required for the reaction to take place. This can be achieved through thermal (fired furnace) or electrical (plasma/microwave) means. Plasma pyrolysis uses electricity to generate temperatures in the 1000-2000 ºC range while thermal processes operate in the 1000-1500 °C range. The addition of a catalyst will result in operation at slightly lower temperatures (<800 °C). The use of electricity to supply the process energy results in a reduction in greenhouse gas emissions (close to zero if renewable electricity is used) and is therefore a route towards the lowest carbon hydrogen of the methane pyrolysis technology set.

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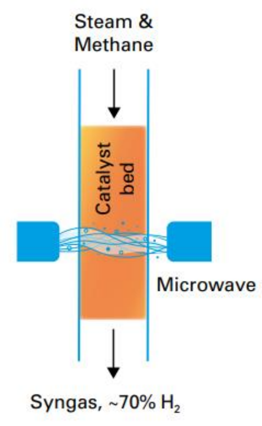
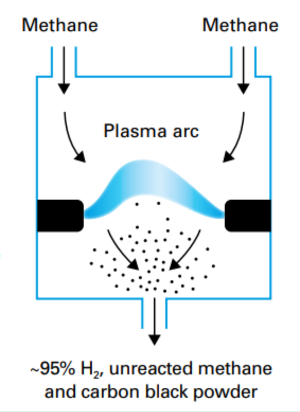
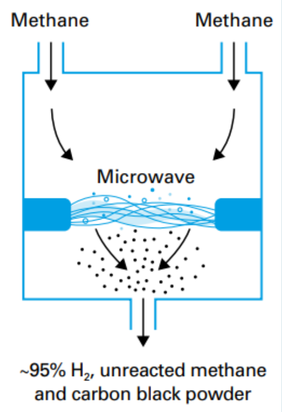
[15] 2030 Grid Carbon Intensity

An overview of the different electrically powered methane pyrolysis production processes is shown in Table 3-11.

Table 3-11 Electrically heated pyrolysis production processes

Process	**Dielectric Microwave Catalytic Steam Methane Reforming**	**Plasma Pyrolysis of Methane**	**Microwave Plasma Pyrolysis of Methane**
			
Carbon feedstock	Methane from natural gas or biomethane	Methane from natural gas	Methane from natural gas or biomethane
Target chemical reactions	$CH_4 + H_2O \rightarrow CO + 3H_2$	$CH_4 \rightarrow C + 2H_2$	$CH_4 \rightarrow C + 2H_2$
Additional side reactions	$CO + H_2O \rightarrow CO_2 + H_2$	$2CH_4 \rightarrow C_2H_2 + 3H_2$	$2CH_4 \rightarrow C_2H_2 + 3H_2$
Carbon produced as	CO and CO_2	Carbon black powder	Carbon black powder
Hydrogen content in product gas	~70%	~95%	~95%
Product gas pressure	10 to 40 bar	Close to atmospheric pressure	Close to atmospheric pressure
Product gas temperature	500 °C to 850 °C	1500 to 2000 °C	1200 to 1500 °C

Several companies are at various stages of technology development aligned with the use of electricity to drive the pyrolysis reaction.[16]

Table 3-12 Electrical methane pyrolysis companies

Company	Technology	Status
Graforce	Plasma arc pyrolysis	Founded in 2012 and launch of first prototype (2 kW) for hydrogen generation from potable water; plans underway to scale the technology in starting in Australia, China, and other parts of Asia (20MW).
Monolith materials	Plasma arc pyrolysis	Founded in 2012; first carbon black pilot plant (2013-2015); first carbon black commercial scale plant (2020) with a production capacity of 14,000 tpa of C black, and 2,500 tpa of H_2. A second, larger plant is being planned with a production capacity of 194,000 tpa of C black, and about 40,000 tpa of H_2
Aurora Hydrogen	Microwave pyrolysis	Bench scale of 1kg H_2/day in operation. Pilot Plant of 40 kg H_2/day (2022). Demonstration plant of 0.2 t H_2/day (2023). Industrial Scale of 2.3 t H_2/day (2025)

A key consideration for methane pyrolysis in the context of low carbon hydrogen production is the end use of the solid carbon. It can be refined to a high value carbon black saleable product or be sold as a fuel. Disposing of the carbon into the fuels market negates the objective of producing low carbon hydrogen and therefore is not considered.

The carbon black market is relatively small at present (global market size of was approximately 14.5 million ton in 2022)[17]; however, it is expected to grow in the U.S., linked particularly to its use in tyres as a strengthening agent. As in Figure 3-8 below, carbon black is also used in the manufacture of industrial rubber and for speciality uses.

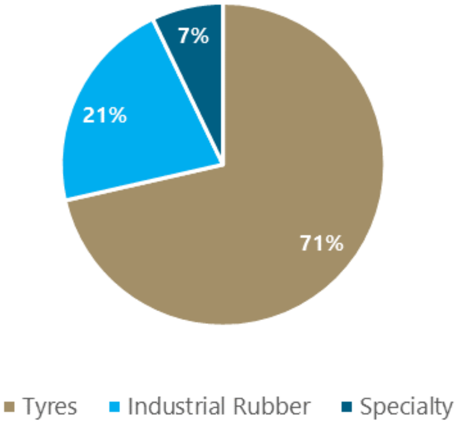


Figure 3-8 Carbon Black Market Breakdown[18]

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[16] https://hydrogen.monolith-corp.com/; https://aurorahydrogen.com/; https://www.graforce.com/en/

[17] https://www.chemanalyst.com/industry-report/carbon-black-market-440

[18] https://hydrogen.monolith-corp.com/

The expected growth may still not however be at the relative scale required to absorb additional production from methane pyrolysis. The last alternative would be sequestration as a solid in a landfill. This is a viable alternative due carbon black being non-toxic and additionally it will not leach or release any constituents to the groundwater from a landfill. Carbon black is not biodegradable and has a high surface area with a strong adsorptive capacity meaning that organic materials that come in contact with it can be adsorbed and are not easily liberated thereafter.

3.3.1.1 Process Description

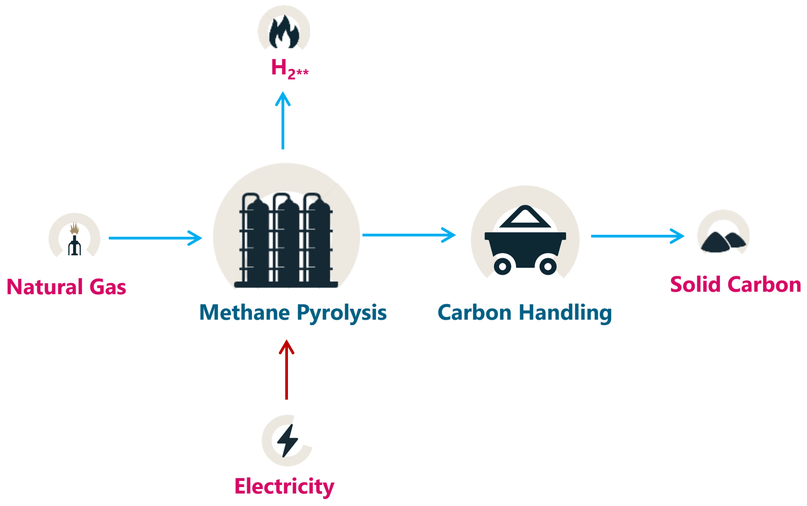
The main reaction of methane pyrolysis is endothermic and produces solid carbon and gaseous hydrogen according to the following reaction equation:

$$CH_4 \rightarrow C + 2H_2$$

Equation 5 Methane pyrolysis main reaction

Equation 5 describes only the main reaction path of methane pyrolysis. In addition to the actual target products, hydrogen and carbon, side reactions produce further saturated and unsaturated hydrocarbons and (poly)cyclic aromatic compounds such as ethane, ethene, acetylene and benzene.

Figure 3-9 provides a high-level overview of the process.



*** 95% purity – can be increased with additional treating*

Figure 3-9 General Methane Pyrolysis Block Flow Diagram

Natural gas is fed to a purification step that can include removal of hydrogen sulphide and carbon dioxide, the separation of water, natural gas liquid (NGL) extraction, and fractionation thereafter the purified natural gas is fed to the pyrolysis step where heat is added to drive decomposition of methane to hydrogen and solid carbon at high temperature. As discussed in prior section, the heat can be in the form of thermal or electrical with the latter being more suitable to produce low carbon hydrogen.

Further treatment of the product gas can occur to increase hydrogen purity however existing electrical processes results are only able to achieve a content of approximately 95% with hydrogen compression and storage following.

The produced solid carbon goes through a physical handling step involving separation and compression to prepare it for storage or transport. This carbon can be refined to a high value carbon black saleable product or be sold as a fuel.

3.3.1.2 Material Balance

As discussed earlier, several companies are at various stages of technology development and therefore methane pyrolysis is currently at small scale production. The largest plasma pyrolysis production is by Monolith Materials at approximately 50MMSCFD H_2 (40,000 tons/y)[19] which has been used as the basis reference capacity in the study for methane pyrolysis.

Table 3-13 Mass Balance Methane Pyrolysis (Plasma)

Inputs	Mass Flow (TPD)
Natural Gas	703
Total	**703**
Outputs	**Mass Flow (TPD)**
Hydrogen[20]	110
Solid Carbon	583
Total	**692**

3.3.1.3 Utility Balance

Electricity is the only utility used as the energy source for driving the reaction towards the desirable production. Typical electricity use for Plasma arc pyrolysis is 10 – 20 MWh/tH_2[21].

Table 3-14 Utilities Balance Methane Pyrolysis (Plasma)

Utility	MW
Net Electricity	68

3.3.1.4 Emissions Balance

Table 3-15 Emissions Balance Methane Pyrolysis (Plasma)

	Carbon Intensity	Value	Emissions (kgCO_{2e}/kgH2)
Feed Transportation (to gate)			
Natural Gas	0.56 tCO_2/ton (Nat. gas)	703 TPD	4.9
Process (H_2 Production)			

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[19] https://hydrogen.monolith-corp.com/

[20] 95 vol% H_2 purity

CO_2 emissions	1 gCO_2/ gH_2	-	-
Fuel (H_2 Production)			
Electricity[22]	184 gCO_2/kwh	68 MW	3.8
Total			**8.7**

There are no direct CO_2 emissions from methane pyrolysis.

3.4 Group 3 Technologies: Smaller scale

3.4.1 Gasification

Gasification is a thermochemical process that converts carbonaceous materials into gases in the presence of a gasification agent. Coal, petcoke, biomass, and agricultural/forest residues are potential feedstocks to the process. Pre-treatment of the feedstocks is the primary differentiator in terms of the gasification process flow with all downstream units essentially focused on gas cleaning and hydrogen separation. A further differentiator is the gasification agent used and related to this the heat supply.

The conversion of coal with steam and oxygen (coal gasification) to a synthesis gas (which generally consists of CO, H_2, CO_2, CH_4, higher hydrocarbons, and impurities) is the most developed. Biomass gasification essentially makes use of biogenic or fossil waste as a feedstock to the process. Regional variation on the type or quality of feedstock is significant and this therefore limits the availability of feedstock and has a strong influence on the pre-treatment that would be required.[23]

Processing biogenic waste has potential for low-carbon hydrogen, but fossil waste will require carbon capture to make this viable as an option.

The gasification of residue is a potential option that is commercially viable. Residue is primarily a blend-stock for fuel oil and shifts in types of fuel used in the maritime industry with respect to sulphur and carbon, would mean traditional oil refineries will seek other outlets for this bottom of the crude oil barrel product.

Table 3-16 Gasification feedstock summary

Feedstock	Coal/Petcoke	Biomass	Residue
Feedstock Availability	High	Medium/Low – strongly location dependent	High
Pre-treatment	Chemical	Physical, chemical, or biological to separate lignin, hemicellulose, cellulose, and inorganic compounds	Chemical

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[22] 2030 Grid Carbon Intensity

[23] IEA Global Hydrogen Review 2023 https://www.iea.org/reports/global-hydrogen-review-2023

Additionally, there are variations in gasification reactor design technology. Figure 3-10 below provides a visual overview of existing technologies.

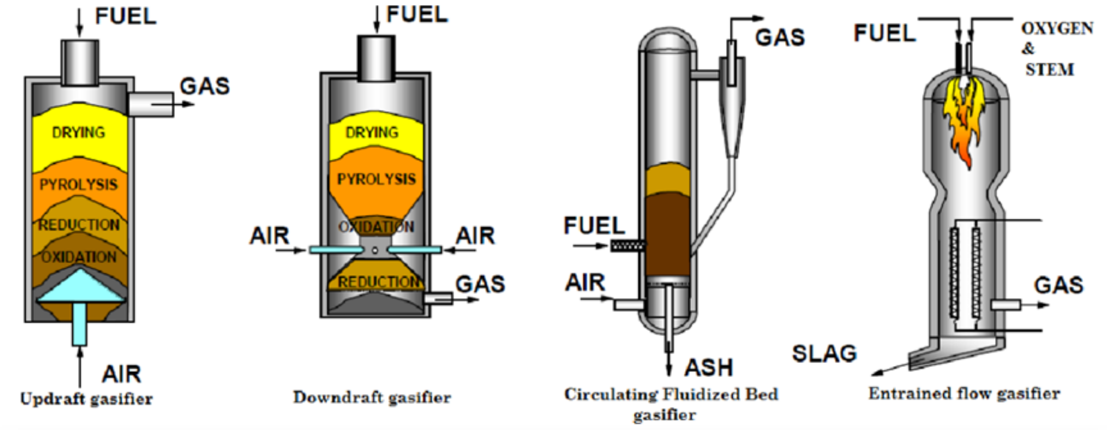

Figure 3-10 Gasification reactor design[24]

There are many competing gasification technologies available, such as entrained flow, fixed bed, fluidised bed and plasma. Fixed and fluidized bed gasifier have simpler feed systems but have greater challenges with tar in the syngas and effectively characterizing and removing them. Plasma gasifiers use plasma torches using electricity to gasify at very high temperatures and are effective and destroying difficult waste feedstocks, but the technology is still at an early stage.

Entrained flow gasifiers can operate at higher pressures and temperatures relative to other technologies which helps maximize conversion to syngas and ensures any tar formed is destroyed prior to exiting the reactor. This improves yields and simplifies the downstream syngas clean-up which would otherwise require additional equipment to destroy the tar formed.

3.4.1.1 Process Description

Four main reactions occur during the production of hydrogen via gasification. The (sub-stochiometric) combustion reaction (Equation 6) and gasification (Equation 7) and (Equation 8) reactions occur in the gasification reactors. The water-gas shift reactor (Equation 9) occurs in the high and low temperature shift reactors, downstream of the first stage of gas treatment.

$$C + O_2 \rightarrow CO_2$$

Equation 6 Combustion reaction (Gasification)

$$C + H_2O \rightarrow H_2 + CO$$

Equation 7 Gasification reaction 1

$$C + CO_2 \rightarrow 2CO$$

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[24] Three zone modelling of downdraft biomass gasification : equilibrium and finite kinetic approach, Environmental Science, 2013 https://www.semanticscholar.org/paper/Three-zone-modeling-of-downdraft-biomass-%3A-and-Budhathoki/8df1f9a54bb0198593ce53d9fecb3482cda38001

Equation 8 Gasification reaction 2

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

Equation 9 Water-Gas Shift reaction (Gasification)

In addition to the above reactions, there are other reactions (e.g., pyrolysis) that also take place that can a role in the gasification process. Based on these equations, O_2, H_2O, CO_2, and H_2 are typical gasification agents that can be used. Figure 3-11 illustrates how these can be manipulated with various feeds to drive towards the desired products.

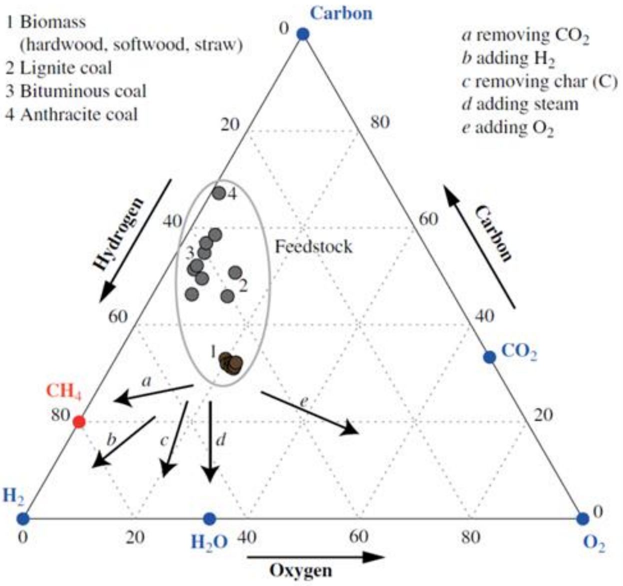

Figure 18: C-H-O-diagram for coal and biomass. (Schildhauer and Biollaz, 2016)

Figure 3-11 C-H-O diagram for coal and biomass[25]

The first step in the gasification process is the preparation of the feed. This can take many different forms depending on the specific feed type and is summarised in Table 3-16. This step is intended to ensure the feed is of a suitable level required by the downstream processes and can involve physical (e.g., milling, sorting), reactive (e.g., mild pyrolysis) or biological mechanisms (e.g., fungi or enzymes). As an example, a process flow that has an entrained gasifier will require grinding to small particle sizes to enable entrainment.

In the gasification reactor, carbonaceous feedstock is contacted with sub-stoichiometric oxygen to produce syngas, a combination of CO and H_2. The prepared feedstock is fed into the gasification reactor along with high purity oxygen from an air separation unit (ASU) and steam to optimize the CO:H_2 ratio at the outlet. Ash/slag is collected at the bottom of the reactor as well as in downstream cyclones. The syngas generated may contain particulates, and other contaminants depending on the feedstock.

Syngas processing in gasification alters slightly from that in SMRs and ATRs; there are two gas treatment stages, pre and post water gas shift. The syngas is first cooled and scrubbed in a gas

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[25] Synthetic Natural Gas from Coal, Dry Biomass, and Power-to-gas Applications, Schilhauer and Biollaz, 2016

treatment purification step where acid gas comprising 90 vol% H_2S and 10 vol% HCN (hydrogen sulphide and hydrogen cyanide respectively) is removed in addition to heat recovery. In the next step, the scrubbed syngas is fed to a water gas shift step to produce the desired H_2 and CO_2 by-product. A further gas treatment step is required to separate the H_2 and CO_2 at a high purity.

Gasifiers have typically been designed with physical sorbent or chemical solvent technologies for the first gas treating step and therefore expansion of these systems to the second gas treating step is logical. As there are no biomass gasification for hydrogen production units operational, the upcoming facilities are expected to future proof design and incorporate technologies for effective carbon capture.

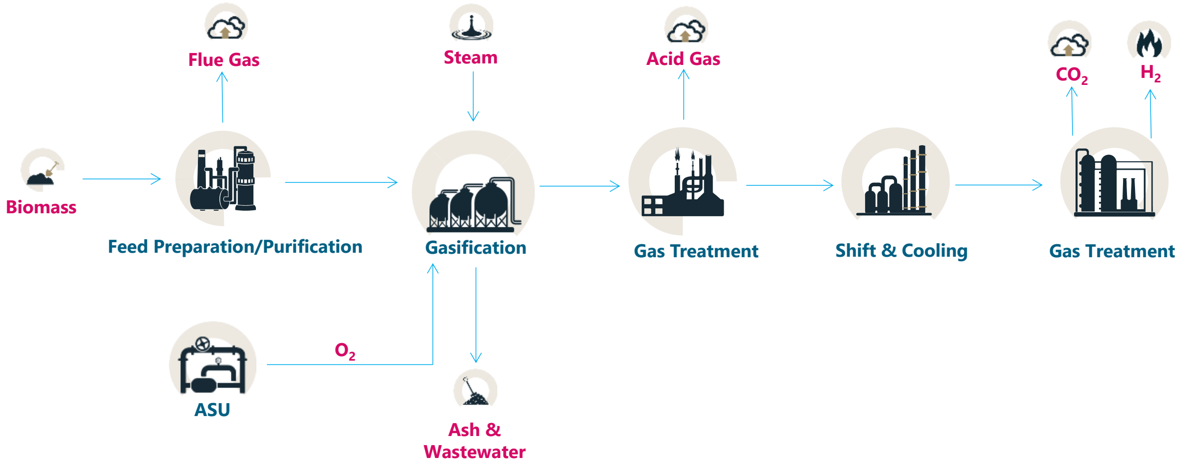

Figure 3-12 General Gasification Block Flow Diagram

3.4.1.2 Material Balance

A capacity of 2,000 MTD of wood chips feed (i.e., biomass feed) was considered as it was assumed that this is reasonably supplied through availability in North America (supported by IEA Bioenergy's assessment of Sustainable Biomass Program[26]). This feed is considered non-biogenic (for the purposes of GHG calculations) and has an ash content of 1-2.5%. A further assumption for the purposes of this study is that the biomass was sourced from a practical transportation radius of about 100 km. It is also assumed that steam required in the process is OSBL.

Table 3-17 Mass Balance Gasification (Biomass)

Inputs	Mass Flow (TPD)
Biomass	2,000
Air	3,535
Steam	2,448
Total	**7,983**

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[26] IEA Bioenergy Review, 2023, https://www.ieabioenergyreview.org/

Outputs	Mass Flow (TPD)
Hydrogen	164
Carbon dioxide off-gas	1,923
Wastewater	1,171
Flue gas[27]	621
Vent gas[28]	4,034
Ash	70
Total	**7,983**

3.4.1.3 Utility Balance

Table 3-18 Utilities Balance Gasification (Biomass)

Utility	MW
Net Electricity	27

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[27] Average composition of Flue gas from feed preparation - 13 vol% CO_2, 76 vol% N_2, 11 vol% H_2O

[28] Average composition of vented gas - 87 vol% N_2, 13 vol% H_2O, trace H_2S and HCN

3.4.1.4 Emissions Balance

Table 3-19 Emissions Balance Gasification (Biomass)

	Carbon Intensity	Value	Emissions ($kgCO_{2e}/kgH_2$)
Feed Transportation (to gate)			
Biomass[29]	0.00006 gCO_2/g(biomass)	2,000 TPD	0.0
Water	0.0002 gCO_2/gH_2O	2,448 TPD	0.0
Process (H_2 Production)[30]			
Feed Preparation CO_2 emissions	1 gCO_2/gH_2	128 TPD	0.8
Gasification CO_2 emissions	1 gCO_2/gH_2	1,923 TPD	11.7
Fuel (H_2 Production)			
Electricity[31]	184 gCO_2/kwh	12 MW	0.3
Total			**12.8**

Flue gas formed from torrefaction (mild pyrolysis of the feed) results in emissions. This is required to prepare the feed for downstream gasification. The gasification process also results in particulate emissions that are mainly in the size range 0.25-1.0 µm and 1.0-2.5 µm.[32] There are potential negative process impacts, e.g., catalysts used for cleaning product gases, and health impacts from particulates. The technology for physical removal of particulate matter e.g., ceramic candle filters at high temperatures[33] exists to ensure regulatory emission requirements are met. In the U.S., the National Ambient Air Quality Standards (NAAQS) for particular matter (PM[34]) gives guidance on requirements but there may also be stricter local legislation in different states or cities.

3.5 Group 4 Technologies: Comparison

3.5.1 Electrolysis

Water electrolysis is an electrochemical process that involves the application of an electric current to water, causing the dissociation of the water into hydrogen and oxygen. By combining this with renewable power, the production of green hydrogen is enabled. There has been significant rapid

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[29] https://www.ecta.com/wp-content/uploads/2021/03/ECTA-CEFIC-GUIDELINE-FOR-MEASURING-AND-MANAGING-CO2-ISSUE-1.pdf

[30] As the feed is non-biogenic, the CO_2 released is considered an emission.

[31] 2030 Grid Carbon Intensity

[32] Yao, Z., You, S., Dai, Y., Wang, C.-H., Particulate emission from the gasification and pyrolysis of biomass: Concentration, size distributions, respiratory deposition-based control measure evaluation, Environmental pollution (2018), doi: 10.1016/j.envpol.2018.07.126

[33] Wenbin Zhang, Hao Liu, Irfan Ul Hai, York Neubauer, Philipp Schröder, Holger Oldenburg, Alexander Seilkopf, Axel Kölling, Gas cleaning strategies for biomass gasification product gas, International Journal of Low-Carbon Technologies, Volume 7, Issue 2, June 2012, Pages 69–74, https://doi.org/10.1093/ijlct/ctr046

[34] National Ambient Air Quality Standards (NAAQS) for PM, 2023, https://www.epa.gov/pm-pollution/national-ambient-air-quality-standards-naaqs-pm

growth in installed electrolyzer capacity, and this is anticipated to continue with several planned projects being announced.

Electrolysis processes are roughly divided into three main commercial technologies: alkaline water electrolysis (AWE), proton exchange membrane (PEM), and solid oxide electrolyzer cell (SOEC). Of these, AWE-based electrolyzers make up most of the currently existing capacity (approximately 60%) and are currently the technology used by the largest operating facilities.

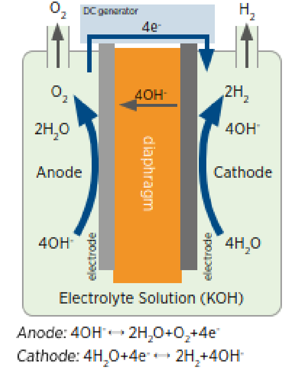
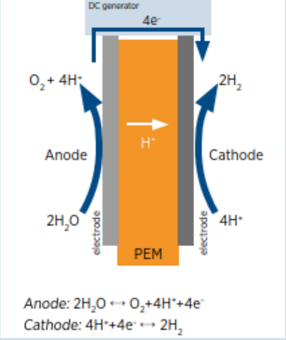
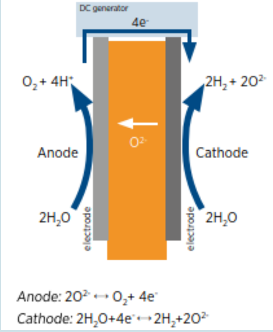
AWE and PEM electrolyzers are currently commercially available, with ongoing innovation aimed at decreasing the costs. Solid oxide electrolyzers (SOEC) represent the most efficient type of this technology and is approaching commercialization, with the first MW-scale projects coming online this year.

Other recent innovations with regards electrolyzer technology are:

- Anion exchange membrane (AEM) electrolyzers (early development)
- Direct electrolysis of seawater (demonstrated at an offshore platform in China)

Table 3-20 shows a comparison between AWE, PEM and SOEC technologies.

Table 3-20 Electrolyzer production technologies

Description	AWE	PEM	SOEC
Diagram[35]			
Operating Temperature [°C]	60-90	50-80	600-800
Operating Pressure [bara]	1-30	1-40	1-3
Stack Efficiency [kWh/kg H_2]	49-52	50-55	36-40
Annual degradation [%/y]	1-1.2	1-2.3	2-3.5
Stack Lifetime [hours]	80,000	80,000	30,000
Electrolyte	KOH (30% wt.)	Polymer Electrolyte	Solid Oxide Electrolyte
Catalysts	Nickel based	Platinum and Iridium	Strontium and Nickel
Largest Plants in Operation (MW)	150MW, China	20MW, Canada & Spain	4MW, California

Electrolyzers employ a highly modular design and therefore capacity limitations for electrolysis plants are driven by accessibility to renewable power rather than by any limitations in design or manufacturability.

3.5.1.1 Process Description

A typical AWE plant begins with raw water demineralization to remove any impurities which could cause excess degradation of the electrolyzer electrodes. The demineralized water may be pumped to a higher pressure to improve the efficiency of the electrolysis.

The main reaction of electrolysis is endothermic and produces gaseous hydrogen and oxygen according to the following reaction equation:

$$2H_2O\ (l) \rightarrow 2H_2(g) + O_2(g)$$

Equation 10 Electrolysis main reaction

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[35] IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal, International Renewable Energy Agency, Abu Dhabi

The electrolysis of water requires electrical energy input to dissociate each mole of water in addition to energy required to overcome the change in entropy of the reaction.

AWE electrolyzers make use of an alkaline electrolyte solution, typically potassium hydroxide (KOH) or sodium hydroxide (NaOH) in water. They consist of an anode and cathode separated by the electrolyte, allowing the flow of hydroxide ions (OH-) during the electrolysis process. When an electric current is applied, oxidation occurs at the anode, generating oxygen gas (O_2), while reduction occurs at the cathode, producing hydrogen gas (H_2). A diaphragm separates the anode and cathode to help separate the produced oxygen and hydrogen.

Following electrolysis, the separate streams of oxygen and hydrogen gas first undergo one or more stages of gas/liquid separation and water cooling to remove most of the alkaline water which could be carried over from the electrolyzer. The carry-over water is recycled into the facility and the oxygen is typically vented to the atmosphere or sold. The hydrogen is then compressed before going to a final hydrogen purification stage for deoxygenation (deoxo) and dehydration, producing a hydrogen product with the required purity. At this stage, the hydrogen product may be further compressed for storage, transport, usage, or conversion into another product.

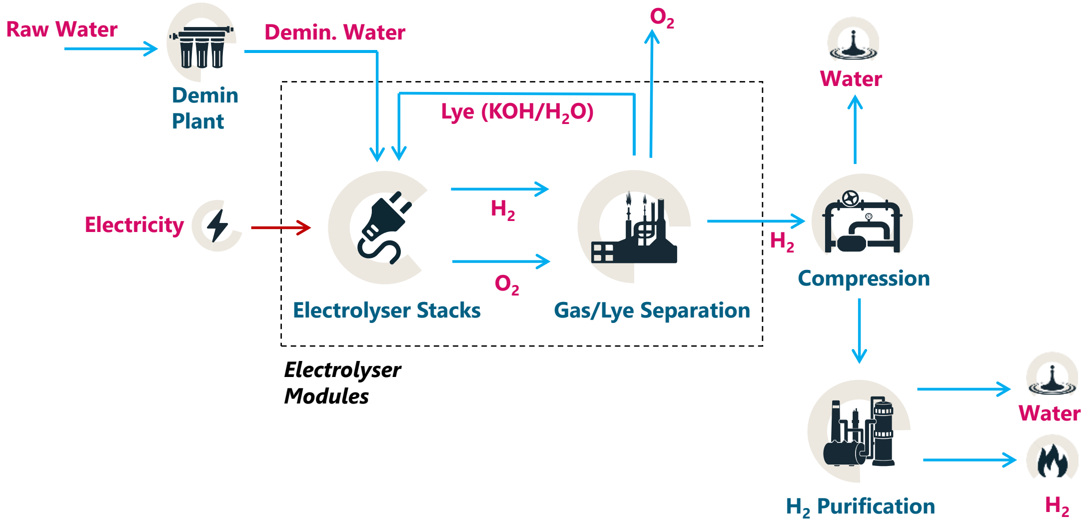

Figure 3-13 Alkaline Electrolysis Process Flow Diagram (PFD)

3.5.1.2 Mass Balance

There are several currently operating commercial examples of AWE electrolyzers at scales up to ~100 MW and only one or two at scale up to ~100 MW of nameplate power consumption. The trend is for larger projects with higher capacity scale. The current average size of electrolyser plants is about 12 MW, but this could grow to hundreds of MW in few years and to 1 GW by 2030 if announced projects are executed.

A reference capacity of 100 MW of electrolysis was considered. This capacity coincides with the largest plants in operation today and is in line with the maximum sizing of medium voltage switchgear which limits the economies of scale on an equipment basis. This 100 MW block can be repeated to increase the total capacity of the facility as required.

Table 3-21 Mass Balance Electrolysis

Inputs	Mass Flow (TPD)
Demineralised water	399
Total	**399**
Outputs	**Mass Flow (TPD)**
Hydrogen	43
Oxygen	342
Water Losses[36]	14
Total	**399**

3.5.1.3 Utility Balance

To counteract the degradation that occurs within electrolyser stacks and maintain a constant hydrogen supply across the life of the stacks, typically the electrical power supplied to the stacks is ramped up.

Table 3-22 shows the net AC electrical requirement of a 100 MW facility at the end of life (EoL) of the stacks.[37]

Table 3-22 Utilities Balance Electrolysis

Utility	MW
Net Electricity (EoL)	107

3.5.1.4 Emissions Balance

Table 3-23 Emissions Balance Electrolysis

	Carbon Intensity	Value	Emissions ($kgCO_{2e}/kgH2$)
Feed Transportation (to gate)			
Water	0.0002 tCO_2/tH_2O	399 TPD	0.0
Process (H_2 Production)			
CO_2 emissions	1 gCO_2/ gH_2	-	-
Fuel (H_2 Production)			
Electricity[38]	184 gCO_2/kwh	107 MW	11.0
Total			**11.0**

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[36] Assumes condensate recycled within the system.

[37] Due to stack degradation, electrolyser vendors design equipment to EoL specifications, to be able to cope with increased electricity supply for constant hydrogen production..

[38] 2030 Grid Carbon Intensity

There are no direct CO_2 emissions from electrolysis. The emissions are primarily because of the use of grid electricity which is still carbon intensive.

4. GHG Emissions Reduction Pathways

4.1 GHG Emissions Reduction Pathways Overview

Greenhouse gas emissions from hydrogen production can be reduced by further process optimisation, carbon capture, feedstock switching, and low-carbon utilities consumption. A combination of these options can be applied to the selected technologies in order to meet the IRA thresholds for low-carbon hydrogen production and become eligible for the financial incentives.

4.1.1 Process Optimisation

Process optimisation and improved energy efficiency are generally the first step towards decarbonisation of a plant. These include utility system optimisation, waste heat upgrading, pinch analysis, advanced process control (APC) and improved energy monitoring amongst other studies. Although every facility has different scopes of process optimisation, most can benefit from a combination of the aforementioned options.

Specific projects regularly implemented on sites include furnace efficiency improvements, process pre-heating, and diligent energy monitoring for maximised steam generation. Whilst some of these projects have medium to no CAPEX investment, they can result in 3% - 5% reduction in energy consumption, further resulting in reduced emissions and operating costs. When looking at hydrogen production specifically, SMR is a mature technology which has been optimized over time. Still, some improvements have been found by improving steam generation via low grade heat recovery into demineralization water/boiler feed water preheating.

ATR, on the other hand, have just been commercially developed to produce grey or blue hydrogen at large scales. The process can be optimised for maximum process heat recovery into high pressure steam generation and into reboiling of the amine regeneration column (for amine -based absorption units).

4.1.2 Carbon Capture

Carbon capture, utilisation, and storage (CCUS) has an important role to play in industry. Increasing social and regulatory pressure has meant that ever-increasing numbers of industrial users of fossil combustion units are seeking to adopt CCUS technologies into their assets to bring meaningful emissions reduction to their operations.

The majority of current dedicated hydrogen production uses steam methane reforming of natural gas. When SMR is paired with CCUS technologies, namely post-combustion carbon capture, low carbon hydrogen, known as blue hydrogen, is produced. In the evolving hydrogen production industry, autothermal reformers (ATR) and gasifiers integrated with pre-combustion carbon capture or oxy-combustion carbon capture are gaining traction. Oxy-combustion is when oxygen is used for combustion instead of air, resulting in a flue gas that consists mainly of CO_2, which is potentially suitable for storage; this technology is most suited for gasification.

Post-combustion carbon capture typically uses a solvent to extract CO_2 from flue gas with comparatively low partial pressures (i.e., low concentration of CO_2, ~20% in the flue gas at close to atmospheric pressure), at rates of around 95%. Chemical solvents, namely amines, are most commonly used for this process, although they require relatively large amounts of energy (i.e., steam) for regeneration due to their high affinity to CO_2. Amine based carbon capture technology is well understood, widely available from numerous vendors and is a fully commercialised technology for post combustion applications.

Figure 4-1 illustrates a typical post-combustion carbon capture process on a SMR.

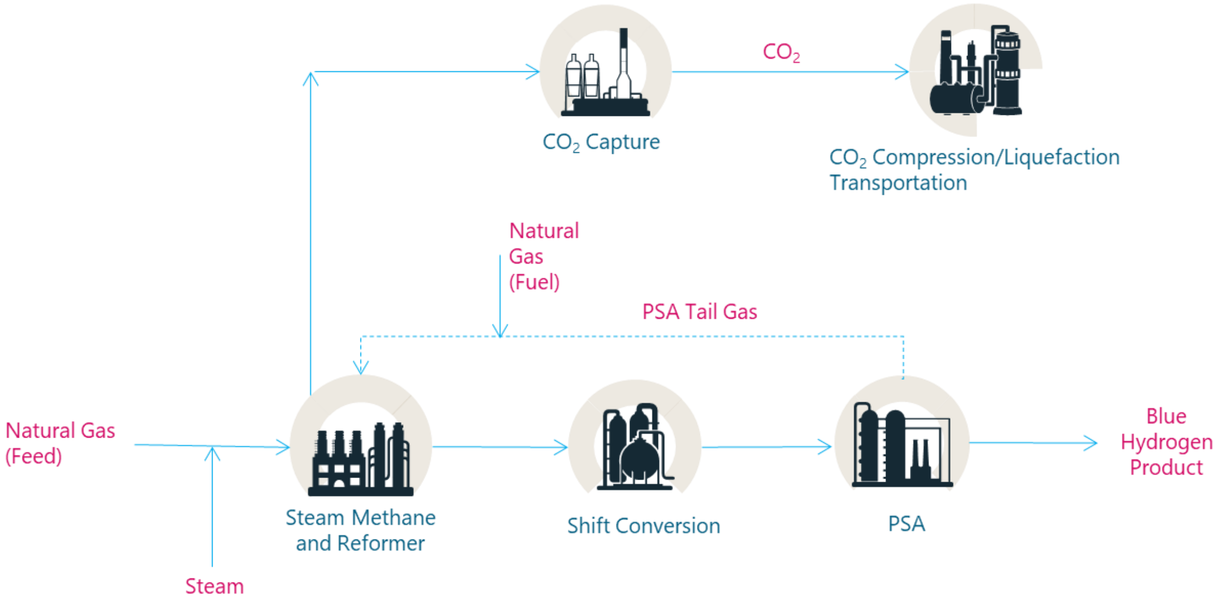

Figure 4-1 Post-Combustion Carbon Capture on SMR

In a conventional SMR unit, there are two streams of CO_2. Around 60-65% of the CO_2 is generated in concentrated form at medium pressures during hydrogen production. The remaining one-third of the CO_2 is generated in dilute form at atmospheric pressure upon burning natural gas for heating purposes. The process CO_2 emissions can be captured at relatively low cost but only cover a portion of CO_2 emissions; however, flue gas emissions can be captured at an overall higher rate, but it is more CAPEX and OPEX intensive.

Pre-combustion carbon capture extracts CO_2 from shifted gas, which has a relatively high partial pressure (i.e., high concentration of CO_2 in the syngas at a high pressure) at rates of around 97%. These systems typically use either chemical or physical solvents. The latter involves the physical absorption, at below ambient temperatures, of CO_2 into a refrigerated liquid carrier which is regenerated by reducing its pressure and thus, reducing the solubility. The main energy requirement is electricity to drive the refrigerant compressor. A minor amount of heat may be required for full regeneration of the solvent. Figure 4-2 illustrates pre-combustion carbon capture on an ATR unit.

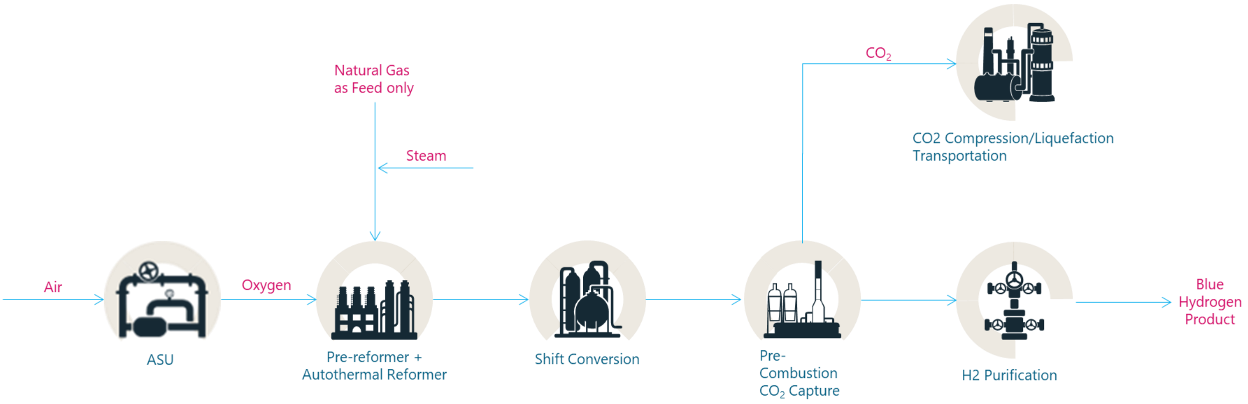

Figure 4-2 Pre-Combustion Carbon Capture on ATR

Globally, the number of CCS facilities under development have increased significantly in 2023, with 11 new facilities commencing operations and 15 new projects in construction. As of July 2023, there are 392 global carbon capture projects in the pipeline, representing a 102% year-on-year increase.[39]

In the U.S. and Canada, the ethanol industry hosts the most carbon capture facilities; over 60 facilities. CCS is gaining momentum in the blue ammonia, hydrogen, and fertiliser production, as well as power generation and heat, including natural gas processing.[40]

4.1.3 Low Carbon Feedstock

Switching to low-carbon feedstock is becoming prevalent across multiple industries; examples include: refineries diversifying to process bio-feedstock; industries, such as plastic and metals, shifting towards a more circular economy by processing recycled feedstocks; and processes using renewable or synthetic natural gas (RNG) as feed and fuel. The latter is applicable to hydrogen production as it is currently dominated by the conversion of natural gas, or more specifically methane.

The switch to renewable natural gas for on-purpose hydrogen production, however, is not commercially competitive due limited RNG availability and as alternate decarbonisation technologies, such as carbon capture, are technically feasible. For this reason, low-carbon feedstock switching is not considered for SMR, ATR, or methane pyrolysis in this study.

Apart from natural gas, biomass is also used as a feedstock for hydrogen production, as evaluated in Section 3.4.1 Gasification. An effective decarbonisation strategy for this technology is switching to carbon-neutral biomass feedstock such as agricultural waste, forestry residue, or organic waste. The gasification or combustion of these feedstocks is considered carbon neutral as the carbon returned to the atmosphere as carbon dioxide is the same as would otherwise have resulted from biomass decomposition.

Note that woody biomass, such as wood chips, are not included in the low-carbon feedstock list. It is usually assumed that woody biomass emissions are part of a natural cycle in which, over time, forest growth balances the carbon emitted by burning wood for energy. In fact, since in general woody biomass is less energy dense than fossil fuels, and contains higher quantities of moisture and less hydrogen, at the point of combustion burning wood for energy usually emits more greenhouse gases per unit of energy produced than fossil fuels.[41]

4.1.4 Low Carbon Electricity Supply

In assessing the potential low carbon electricity supply for various hydrogen production processes, the evolving landscape of the energy grid in the U.S. must be considered. One overarching trend is the increasing share of renewable energy sources within the grid supply, along with a simultaneous shift away from coal as a primary energy source. This shift will see a natural reduction in carbon intensity across the various production methods, with the greatest effect on water electrolysis, the most electricity demanding process. Additionally, hydrogen production facilities could co-locate with renewable resources or directly procure renewable or other zero carbon electricity to serve operations.

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[39] Global CCS Institute

[40] Global CCS Institute Report, 2023

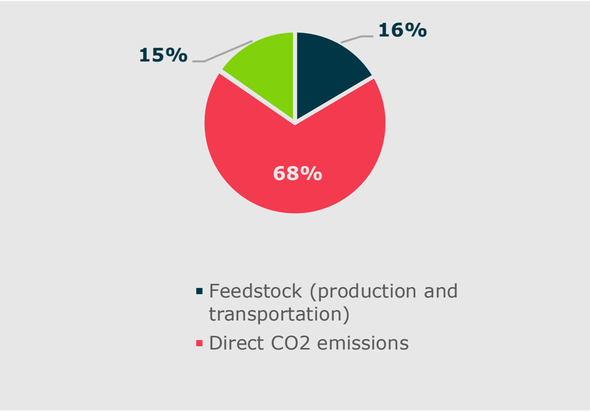
[41] Chatham House Woody Biomass Power and Heat

Whilst the general trends described above are helpful when looking at the big picture, it is also crucial to recognise that the U.S. grid is not a monolith. Large disparities exist between states in terms of their energy sources, policies, and commitments to decarbonisation. Some states have been quick in adopting renewable energy and reducing carbon-intensive sources, while others still heavily rely on fossil fuels. This variation from state to state underlines the importance of local context when evaluating the low carbon potential for hydrogen production processes in the US. Averages can be misleading when not considered carefully, and a one-size-fits-all approach may therefore not be suitable. As an example, in cases where the grid remains heavily reliant on fossil fuels, the carbon emissions associated with hydrogen production via water electrolysis may be much higher than those from other production methods, whereas with a fully renewable grid electrolysis would be the lowest carbon intensive option.

4.2 Technology Application

4.2.1 Steam Methane Reforming

From Section 3.2.1.4, the contributing emissions in Steam Methane Reforming are from four broad categories as shown in Figure 4-3. The accompanying table provides an indication of applicability of the specific abatement options.



Abatement Option	Applicability
Process optimization	●
Low carbon feedstock	-
Low carbon electricity supply	●
Carbon capture	●

Figure 4-3 Emissions by contributor and abatement applicability – SMR

The abatement options for this technology are limited in addressing emissions related to the feedstock as these are driven by upstream processes over which it is assumed this facility will not have influence. However, in this study, varying degrees of abatement for these upstream processes have been explored through sensitivity analyses.

The abatement options for this technology should focus on addressing the direct CO_2 emissions and process emissions which have a much larger contribution than the electricity supply.

Further discussion on and the effects of implementing these options follows.

Table 4-1 Abatement Options – SMR

Abatement Option	Description
Process optimization	Focus on improving energy efficiency of the existing operation. This may also include investment to improve equipment or configuration.
Low carbon electricity supply – Renewable Electricity	Replacing the current grid sourced electricity with a renewable or zero carbon alternative will result in reduced emissions. Zero carbon electricity will come at a higher cost which will be discussed later in the report.
Carbon capture – post combustion	Carbon capture on flue gas from the SMR furnace at 95% efficiency. The energy requirement for CCS is assumed to be met by waste heat from the SMR, and that additional steam required is met by an electric boiler that is using zero-emissions electricity.

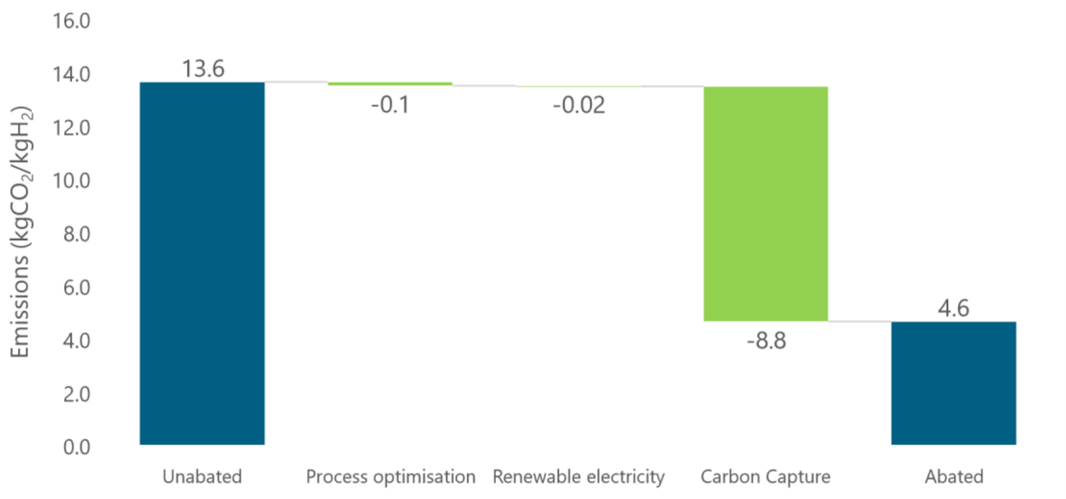


Figure 4-4 Emissions reduction – SMR

The introduction of carbon capture results in significantly lower emissions in the low GHG case. There is potential for energy efficiency improvements as existing SMR plants are mature with retrofits or upgrades driving this. Investment will be required while the carbon emissions impact will be minimal.

The emissions for this technology will be lower if the production and transport emissions associated with the feed reduced, as observed in Figure 4-5. The carbon intensity at 100% feedstock emissions reduction is still not zero as there are remaining emissions associated with carbon capture only at 95% efficiency, renewable electricity, and combustion of fuel.

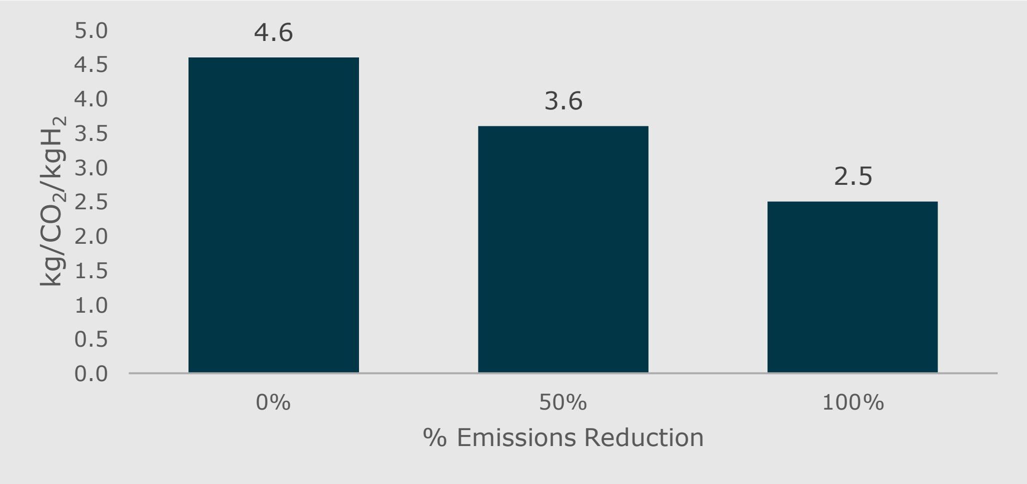
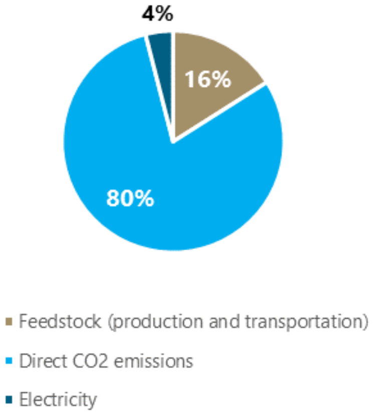


Figure 4-5 Natural Gas (Upstream) Emissions Reduction – SMR

4.2.2 Autothermal Reforming

From Section 3.2.2.4, the contributing emissions in Autothermal Reforming are from three broad categories as shown in Figure 4-6. The accompanying table provides an indication of applicability of the specific abatement options.



Abatement Option	Applicability
Process optimization	-
Low carbon feedstock	-
Low carbon electricity supply	●
Carbon capture	●

Figure 4-6 Emissions by contributor and abatement applicability – ATR

The abatement options for this technology are limited in addressing emissions related to the feedstock as these are driven by upstream processes over which it is assumed this facility will not have influence . However, in this study, varying degrees of abatement for these upstream processes have been explored through sensitivity analyses.

The abatement options for this technology should focus on addressing the direct CO_2 emissions and the electricity supply.

Further discussion on and the effects of implementing these options follows.

Table 4-2 Abatement Options – ATR

Abatement Option	Description

Low carbon electricity supply – renewable electricity	Replacing the current grid sourced electricity with a renewable alternative will result in reduced emissions. Renewable electricity will come at a higher cost which will be discussed later in the report.
Carbon capture – syngas	Carbon capture of shifted gas at 97% efficiency

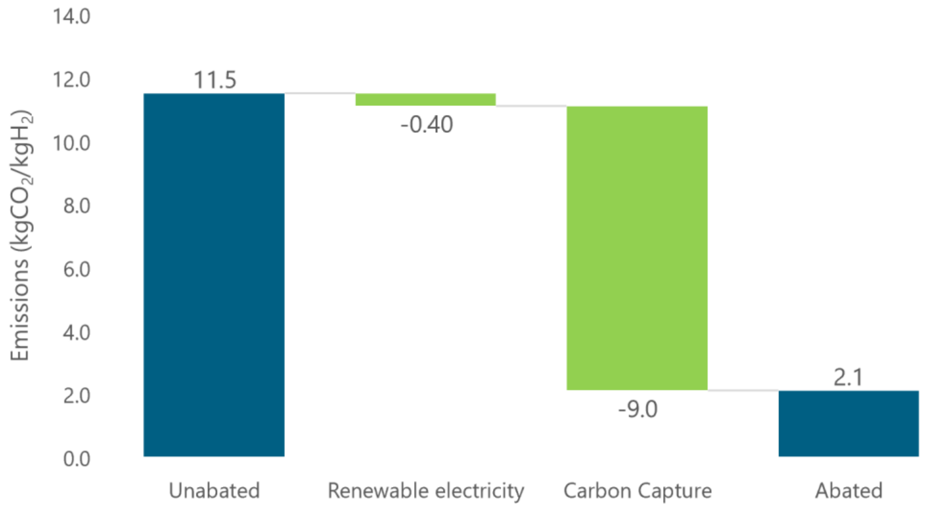


Figure 4-7 Emissions reduction – ATR

Replacement with renewable or other zero carbon electricity and the introduction of carbon capture results in significantly lower emissions in the low GHG case. The emissions for this technology will be lower if the production and transport emissions associated with the feed reduce as observed in Figure 4-8. The carbon intensity at 100% feedstock emissions reduction is still not zero as there are emissions remaining associated with carbon capture only at 97% efficiency and renewable electricity.

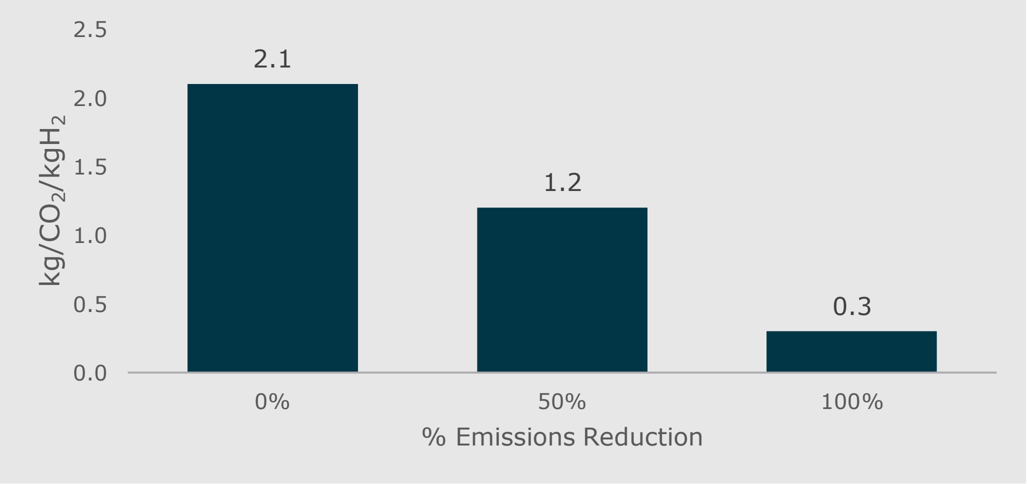
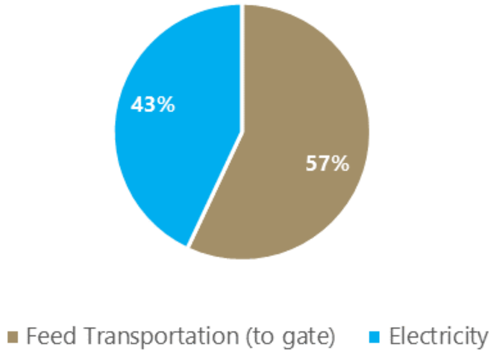


Figure 4-8 Natural Gas (Upstream) Emissions Reduction - ATR

4.2.3 Methane Pyrolysis

The contributing emissions in methane pyrolysis are from two broad categories as shown in

Figure 4-9. The accompanying table provides an indication of applicability of the specific abatement options.



Abatement Option	Applicability
Process Optimization	●
Low Carbon Feedstock	-
Low carbon electricity Supply	●
Carbon Capture	-

Figure 4-9 Emissions by contributor and abatement applicability – Methane Pyrolysis

The abatement options for this technology are limited in addressing emissions related to the feedstock as these are driven by upstream processes over which it is assumed this facility will may not have influence. However, in this study, varying degrees of abatement for these upstream processes have been explored through sensitivity analyses.

The abatement options for this technology should focus on addressing these two contributors. Further discussion on and the effects of implementing these options follows.

Table 4-3 Abatement Options – Methane Pyrolysis

Abatement Option	Description
Process optimization – waste heat recovery	Industrial grade heat is a by-product from the plasma pyrolysis process which if recovered can be used for producing steam in power generation. Power generation from the waste heat presents an opportunity to reduce the imported electricity which will result in emissions and cost reduction.
Low carbon electricity Supply – renewable electricity	The use of electricity has the largest contribution to the emissions. Replacing the current grid sourced electricity with a renewable alternative will result in reduced emissions. Renewable electricity will come at a higher cost which will be discussed later in the report.

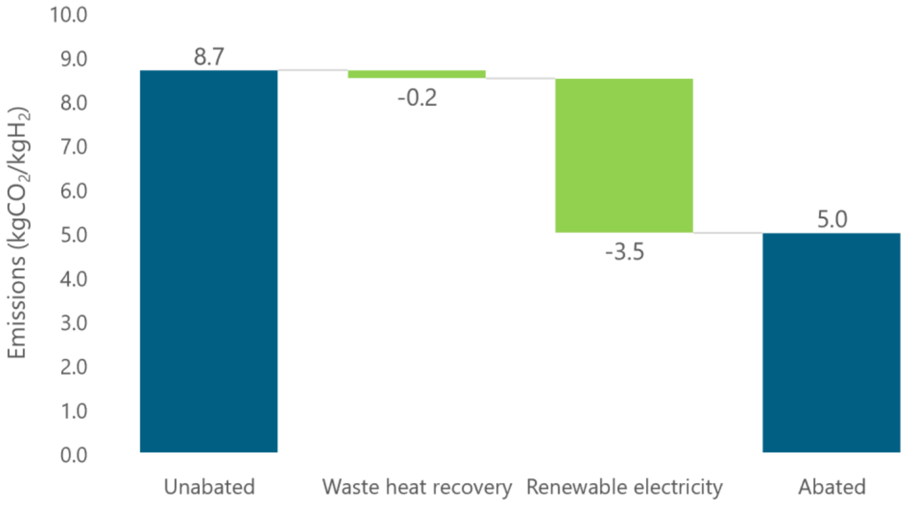


Figure 4-10 Emissions reduction – Methane Pyrolysis

Even when abated, the carbon intensity for this technology remains relatively high. This is due to the hydrogen yield being approximately 15 wt.-%, in comparison to the ATR and SMR which is at approximately 30 wt.-% which also use natural gas as a primary feedstock. This difference in yield is driven by the different chemistry and reactions of the respective processes.

The emissions for this technology will be lower if the production and transport emissions associated with the feed reduce as observed in Figure 4-11.

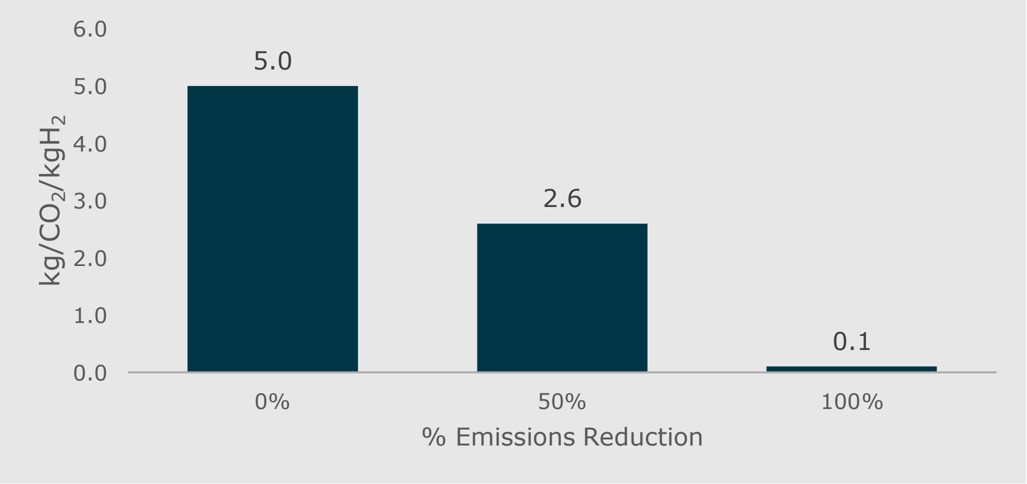
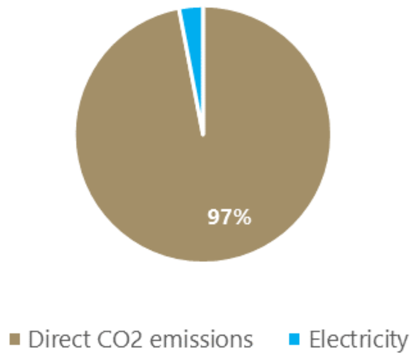


Figure 4-11 Feed emission reduction sensitivity – Methane Pyrolysis

4.2.4 Gasification

The contributing emissions in Biomass Gasification are from two broad categories as shown in Figure 4-12. The accompanying table provides an indication of applicability of the specific abatement options.



Abatement Option	Applicability
Process Optimization	-
Low Carbon Feedstock	●
Low carbon electricity Supply	●
Carbon Capture	●

Figure 4-12 Emissions by contributor and abatement applicability – Biomass Gasification

The abatement options for this technology should focus on addressing these two contributors. The use of a biogenic feedstock as a low carbon feedstock would significantly reduce the carbon intensity as any CO_2 emitted directly may not be accounted for as a contributor to CO_2e emissions.

Further discussion on and the effects of implementing these options follows.

Table 4-4 Abatement Options – Gasification

Abatement Option	Description
Low carbon feedstock – 100% biogenic	The base case makes use of wood chips which is considered non-biogenic. The use of a biogenic feedstock as a low carbon feedstock would significantly reduce the carbon intensity as any CO_2 emitted directly would not be accounted for as a contributor to CO_2e emissions.
Low carbon electricity supply – renewable electricity	Replacing the current grid sourced electricity with a renewable alternative will result in reduced emissions. Renewable electricity will come at a higher cost which will be discussed later in the report.
Carbon capture – Compress captured CO_2 from syngas	The base technology includes CO_2 removal from the syngas which is released to atmosphere directly. Capturing and compressing this CO_2 will result in lower emissions (this will be negative if the feed is biogenic).

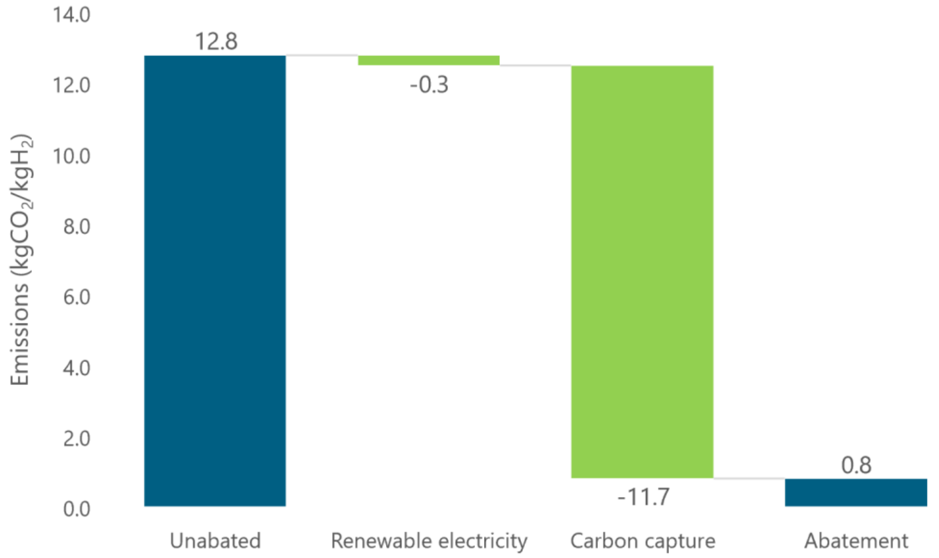


Figure 4-13 Emissions reduction – Gasification (Non-biogenic feed)

As observed, capturing the CO_2 is the primary driver to achieving a relatively lower carbon intensity for this technology.

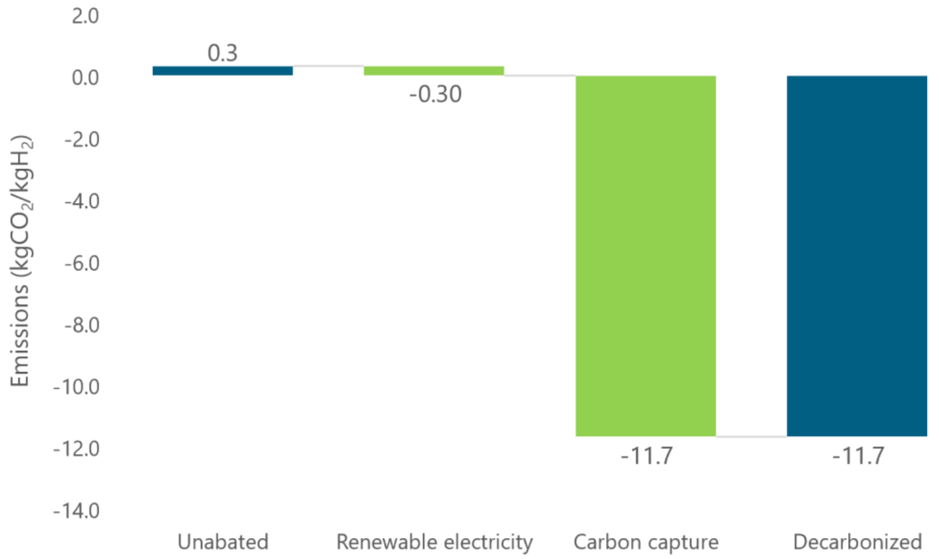
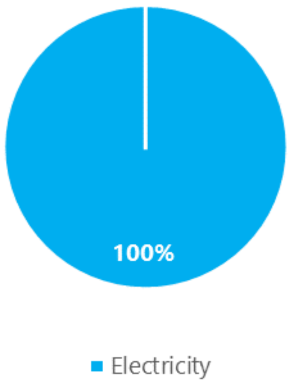


Figure 4-14 Emissions reduction – Gasification (Biogenic feed)

Replacement with biogenic feed, results in significantly lower unabated emissions at the outset, meaning that once the abatement options are applied, the emissions go negative.

4.2.5 Electrolysis

Electricity is the only significant contributor to emissions associated with electrolysis as shown in Figure 4-15. The accompanying table provides an indication of applicability of the specific abatement options.



Abatement Option	Applicability
Process optimization	-
Low carbon feedstock	-
Low carbon electricity supply	●
Carbon capture	-

Figure 4-15 Emissions by contributor and abatement applicability – electrolysis

The abatement options for this technology are limited to addressing the carbon intensity of the electricity supply. As indicated in the emissions assumptions, the emissions factor associated with grid supplied electricity is 184 gCO_2/kWh in 2030 while renewable power is 5 gCO_2/kWh.

Further discussion on and the effect of implementing this option follows.

Table 4-5 Abatement Options – Electrolysis

Abatement Option	Description
Low carbon electricity Supply – Renewable Electricity	Replacing the current grid sourced electricity with a renewable or zero carbon alternative will result in reduced emissions. Renewable electricity will come at a higher cost which will be discussed later in the report.

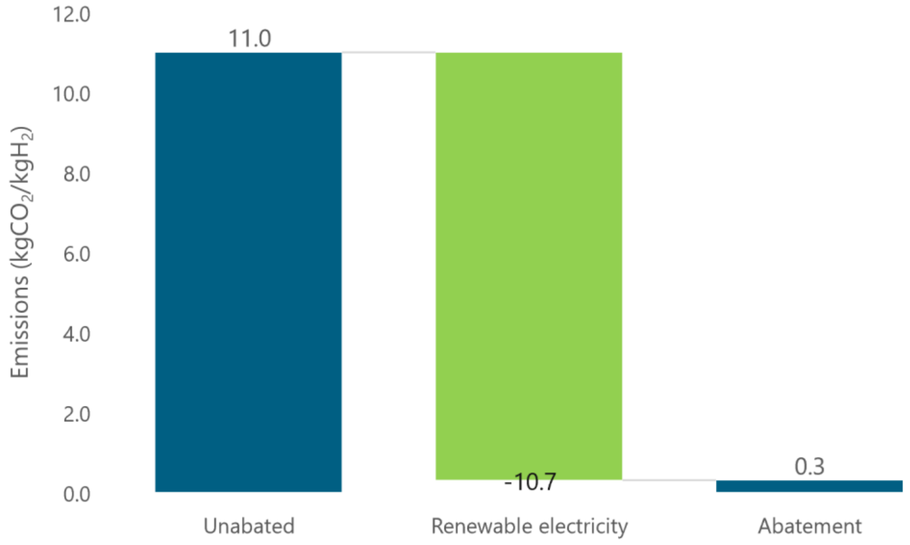


Figure 4-16 Emissions reduction – Electrolysis

Replacement with renewable electricity results in significantly lower emissions in the low GHG case as electricity input to the process is significant.

5. Economic Analysis

5.1 Base Cost Estimates

Below cost basis was used for all of the Levelized Cost of Hydrogen (LCOH) assessments.

Price Assumptions			
Parameter	**Units**	**Value**	**Source**
Natural Gas (LHV)	$/MMBtu	AEO Price Forecast	EIA (2023)
Electricity (Grid 2030)	$/MWh	79	EIA (2023)
Renewable Electricity (PPA 2023)	$/MWh	25	EMB / IEA (2023)
Biomass (2023 basis - Woodchips)	$/t	35	Statista (2023)
Oxygen (2023 basis)	$/t	580	IEA (2023)
Water (2023 basis)	$/t	1.9	Worley Consulting Internal
Carbon Black (2023 basis)	$/t	1880	Worley Consulting Internal
Plant Life	Years	25	Worley Consulting Internal
Plant Construction Start Year	Year	2027	Worley Consulting Internal
Plant Construction Completion Year	Year	2030	Worley Consulting Internal
Discount Rate	%	8%	Worley Consulting Internal
Price Inflation [42]	% pa	2%	Worley Consulting Internal
Natural Gas Inflation	% pa	0.5%	Worley Consulting Internal
Power/Electricity Inflation	% pa	1.6%	EIA (2022-2050)
Carbon Transport & Storage (2023 basis)	$/t	10	NETL (2023)

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[42] Excludes natural gas and electricity.

5.2 CAPEX Basis and Inclusions

The CAPEX required for SMR/ATR production units is heavily dependent on the level of integration with existing facilities. As integration increases so too does the complexity, significantly increasing the CAPEX required. The CAPEX estimate within this study considered a minimum amount of integration i.e., all greenfield projects.

All technology pathway CAPEX estimates include direct costs (e.g., equipment, construction, OSBL) and indirect costs (e.g. owners' costs, license fees, engineering, contingency, working capital).

In addition to the general assumptions noted above, the economic analysis for methane pyrolysis and biomass gasification includes the following assumptions

5.2.1 Methane Pyrolysis

- Price basis is an approximation based on engineering judgement due to limited existing applications of the technology. Capital costs are weighted using existing sites in operation.
- Current plants in operation are primarily focused on the carbon black product production as opposed to hydrogen (higher value for carbon black).
- It is assumed that waste heat recovery projects require negligible CAPEX investment.

5.2.2 Biomass gasification

- Price basis is an order of magnitude estimate based on engineering judgement due to limited existing applications of the technology for pure hydrogen production.
- It is assumed that for the low GHG emissions scenario, carbon-neutral biomass (e.g. agricultural waste) is available at the same price as woodchips.

5.3 Levelized Cost of Hydrogen

The levelized cost of unabated hydrogen is broken down in the below table for the five different technology pathways. The levelized cost is impacted by the assumptions around utility costs and the value of additional by-products. In the following sections sensitivity cases are shown where the prices of natural gas, carbon black, biomass, and electricity are adjusted. The below Table 5-1 shows OPEX/Revenue and CAPEX values in 2023 before inflation is applied.

Table 5-1 Base Case 2023 Operating Expenses, Revenue streams and CAPEX

Parameter	SMR	ATR	Methane Pyrolysis	Biomass Gasification	Electrolysis
Hydrogen Production (tpd)	**358**	**358**	**79**	**164**	**43**
OPEX (2023 USD Millions)	**$107**	**$134**	**$114**	**$83**	**$68**
Electricity (grid)	$1	$20	$38	$15	$61
Natural Gas (Process and/or Fuel)	$96	$92	$55		
Water	$2	$3		$1	<$1
Biomass				$23	
O&M	$8	$19	$20	$43	$7
Other Revenue (2023 USD Millions)					
Carbon Black			$365		
Oxygen					$66
CAPEX (2023 USD Millions) (1)	**$286**	**$651**	**$506**	**$740**	**$242**
CAPEX/Production (2023 USD Millions/tpd H_2)	**$0.8**	**$1.8**	**$6.4**	**$4.5**	**$5.6**
Levelized Cost of Hydrogen (USD/kg H_2) (2)	**$1.3**	**$2.0**	**-$11.3**	**$3.7**	**$7.6**

Note 1 – Class V CAPEX Estimates.

Note 2 – LCOH is calculated from 2027 construction start date, 25 years operation, from 2030 (Inflation applied).

In the unabated scenario, SMR is clearly the dominant technology economically (apart from methane pyrolysis, which is heavily driven by the assumption of sale of Carbon Black). With access to abundant natural gas supply at a reasonable price, it is the cheapest way to produce grey hydrogen. The only places where you see alternatives being used are:

- Limited access to natural gas and easy access to cheap coal (e.g., China for methanol production)
- Availability of a low value by-product or waste products (e.g., petcoke gasification, gasification of oil refinery residues)
- World-class scale (particularly for ammonia and methanol). The economics of ATR become more favourable at relatively larger scale because CAPEX of the ASU doesn't scale down to smaller sizes.

5.3.1 Natural Gas Sensitivity

The technology paths that use natural gas as a feedstock/fuel are the SMR, ATR and methane pyrolysis. The levelized cost of hydrogen is shown for three different AEO forecasted prices of natural gas:

- Reference Case forecast
- High oil and gas resource (HOGR)
- Low oil and gas resource (LOGR)

For hydrogen production (where CO_2 is unabated), the SMR technology path is lower cost than an ATR at the reference 360tpd plant scale. ATR levelized costs significantly drop at higher capacities – benefiting from economy of scale.

The below estimated levelized cost of SMR production ranges between \$1.2-\$1.8/kg H_2. From literature review the International Energy Agency placed SMR hydrogen production at \$1.0/kg in 2018 [43]. Applying a CEPCI (The Chemical Engineering Plant Cost Index) factor to the IEA figure brings the 2023 cost to \$1.3/kg H_2, which is aligned with the range of calculated values.

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[43] https://www.iea.org/data-and-statistics/charts/hydrogen-production-costs-using-natural-gas-in-selected-regions-2018-2

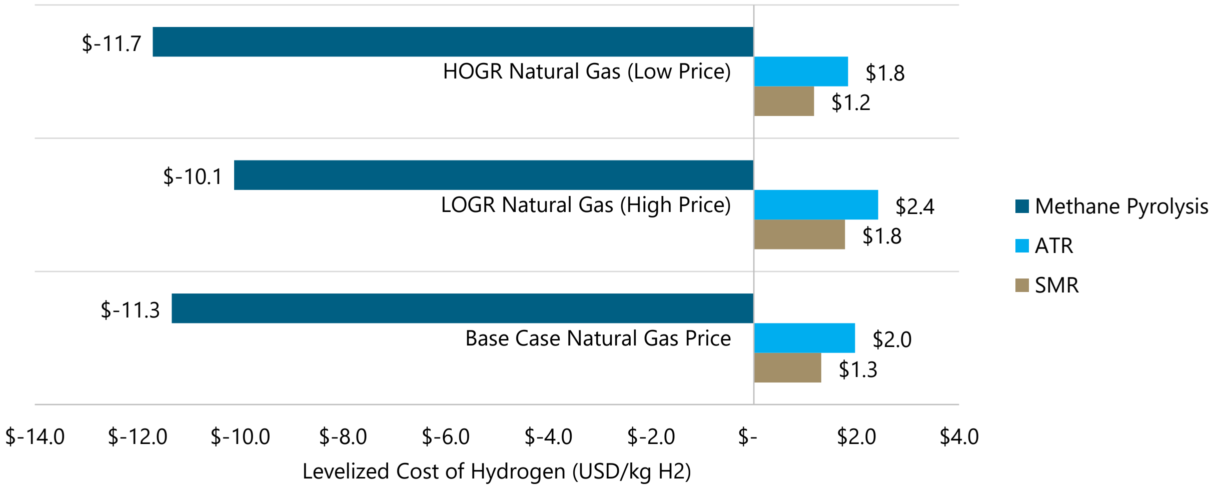

Figure 5-1 LCOH Natural Gas Price Sensitivity Cases (AEO forecasted values)

5.3.2 Methane Pyrolysis – Carbon Black Sensitivity

As shown in Table 5-1 above, the levelized cost of hydrogen is negative when produced via the methane pyrolysis route. The reason for this is due to the high sale value of carbon black that the plant is producing, which typically is the main product (hydrogen being the by-product).

To give a more comparable figure the below graph shows the levelized cost of hydrogen when the carbon black product is at the base case price of US$1880, then lowered by 50% and then 100% to simulate a "no demand" case. The demand for carbon black is not expected to increase significantly in the U.S., so the introduction of new sources/operational plants may drive the price down.

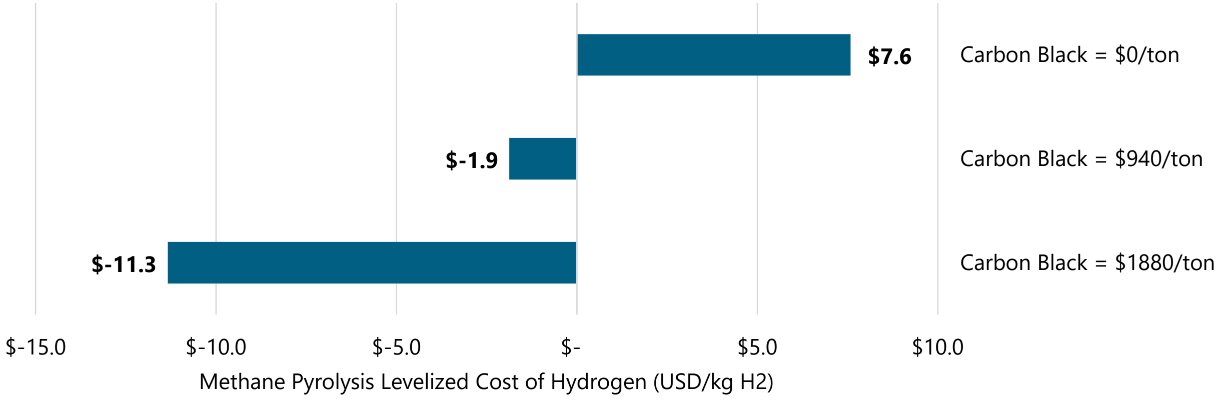

Figure 5-2 LCOH Carbon Black Price Sensitivity Cases.

5.3.3 Biomass Cost Sensitivity

One of the main constraints on the gasification pathway to hydrogen is the availability of suitable biomass. There is the potential that prices may trend higher, as additional demand comes online for biofuels and SAF.

The levelized cost of hydrogen in Table 5-1 for gasification is approximately 3 times more than the SMR pathway with a biomass feedstock cost of $35/ton. The below graph shows that if the cost of feedstock increases by 115% (to $75/ton) the levelized cost only increases by $0.6/kg H_2. The main contributors to the cost of gasification are the high capital costs for the technology and the high operating/maintenance costs involved in solids processing.

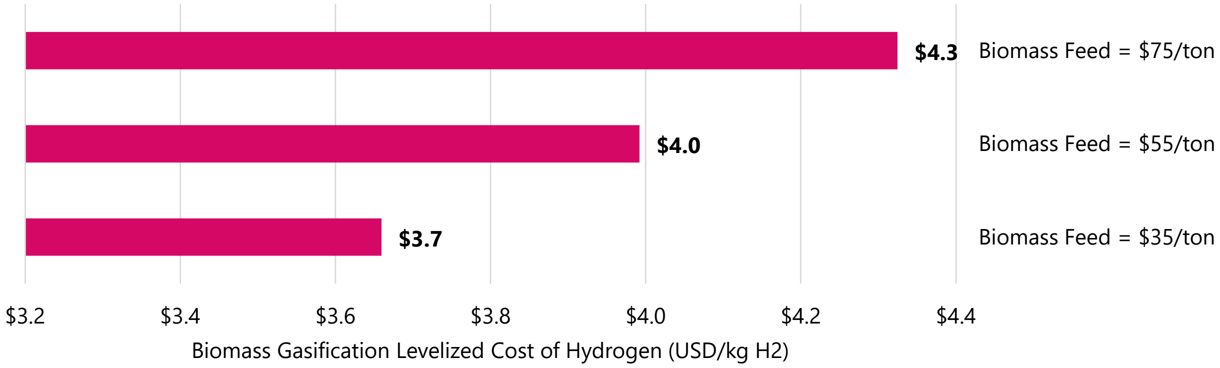

Figure 5-3 LCOH Carbon Biomass Feedstock Price Sensitivity Cases

5.3.4 Electrolyzer Electricity and Oxygen Sensitivity

The main contributor to the levelized cost of hydrogen from water electrolysis is the cost of electricity. Of the five technology pathways, electrolysis has the highest unabated levelized cost at $7.6/kgH$_2$. This LCOH is calculated on the basis that the 2030 U.S. grid electricity price aligns with EIA forecasted levels of $79/MWh.

The figure below shows three additional scenarios where the 2030 starting price of electricity decreases to $60/MWh $35/MWh, and $17/MWh. The $17/MWh scenario is considered optimistically low and would only be achievable with direct wire generation of renewable energy (current U.S. grid charges would make this price unachievable).

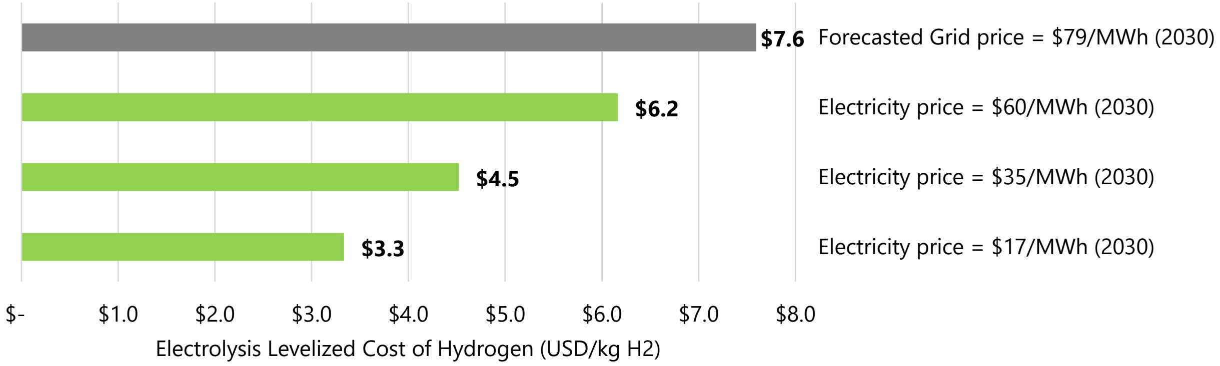

Figure 5-4 LCOH Electrolyzer Electricity Price Sensitivity Cases

The above cases for LCOH all assume that the hydrogen electrolysis plant can sell the oxygen by-product to a nearby facility at $580/ton. If the plant is unable to find a purchaser for the oxygen stream, then this revenue needs to be removed from the LCOH. The figure below shows the base electrolyzer scenario **with** oxygen sales and **without**:

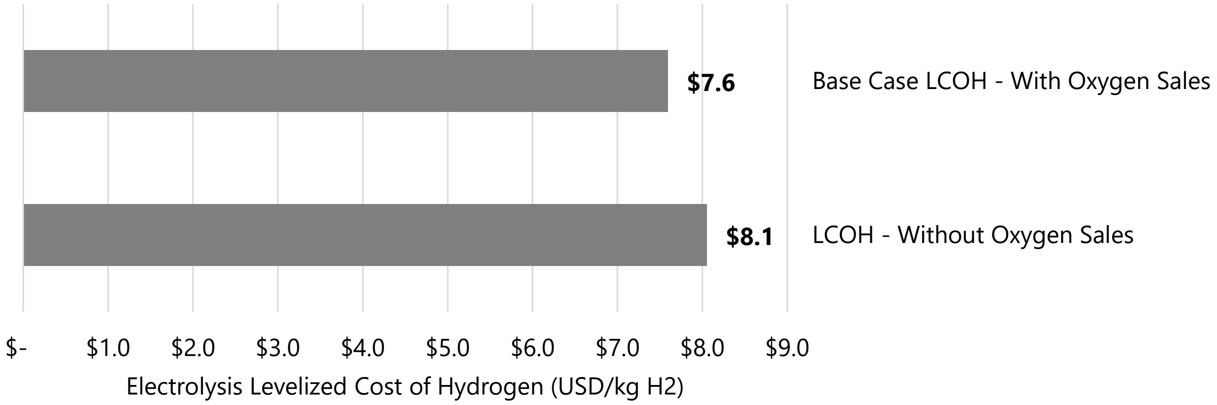

Figure 5-5 LCOH Electrolyzer Oxygen Revenue Sensitivity Cases

5.4 Levelized Cost of Low GHG Hydrogen (decarbonised)

The levelized cost of hydrogen is broken down in the below table for the 5 different technology pathways **after main abatement/ decarbonisation** has been applied (more details in following sections) and before any subsidies. The below Table 5-2 shows OPEX/Revenue and CAPEX values in 2023 before inflation is applied. Below table does not include 45V and 45Q credits, that analysis is performed in Section 6.1.5.

Table 5-2 Low GHG Technology Scenario - Operating Expenses, Revenue, CAPEX and LCOH

Parameter	SMR	ATR	Methane Pyrolysis	Biomass Gasification	Electrolysis
Hydrogen Production (tpd)	358	358	79	164	43
OPEX (2023 USD Millions)	**$130**	**$127**	**$90**	**$73**	**$29**
Electricity (Renewable)	$11	$10	$14	$7	$22
Natural Gas (Process and/or Fuel)	$96	$92	$55		
Water	$2	$3		$2	>$1
Biomass				$23	
O&M	$21	$21	$20	$41	$7
Other Revenue (2023 USD Millions)					
Carbon Black			$365		
Oxygen					$66
CAPEX (2023 USD Millions) (1)	**$741**	**$738**	**$506**	**$783**	**$242**
CAPEX/Production (2023 USD Millions/tpd H_2)	**$2.1**	**$2.1**	**$6.4**	**$4.8**	**$5.6**
Levelized Cost of Hydrogen (USD/kg H_2) (2)	**$2.1**	**$2.1**	**-$12.5**	**$3.7**	**$4.1**

Note 1 – Class V CAPEX Estimates.
Note 2 – LCOH is calculated from 2027 construction start date, 25 years operation, from 2030 (Inflation applied).

5.4.1 Carbon Capture Application

To create low carbon hydrogen, the SMR, ATR and biomass gasification pathways will need carbon capture and storage technology applied on flue gas and/or syngas streams to reduce the product carbon intensity. The below basis has been applied for each hydrogen technology pathway.

SMR Carbon Capture	ATR Carbon Capture	Biomass Gasification Carbon Capture
• For the SMR technology, **post-combustion** carbon capture is placed on the flue gas stream. This captures the combined process and fuel emissions.	• For the ATR technology, **pre-combustion** carbon capture occurs after the low-temperature shift reactor and process condensate removal. Capture efficiencies are higher than post-combustion carbon capture.	• For the gasification technology, a **pre-combustion** carbon capture Rectisol unit is typically already included at the end of the process (gas treatment stage), which separates CO_2
• Excess LP steam is generated by the SMR which can be used for CC, however an additional 37MW of electric boiler LPS generation is also required for our archetype SMR.	• Solvent regeneration heat requirements are supplied by process heat recovery. No additional steam generation units are required.	• Solvent regeneration heat requirements are supplied by the process. No additional steam generation units are required.
• Compression of **post-combustion** CC CO_2 stream from atmospheric conditions to 80barg.	• Compression of **pre-combustion** CC CO_2 stream from atmospheric conditions to 80barg.	• Compression of **pre-combustion** CC CO_2 streams from atmospheric conditions to 80barg.
• Renewable PPA electricity at $25/MWh (2030)	• Renewable PPA electricity at $25/MWh (2030)	• Renewable PPA electricity at $25/MWh (2030)

For the biomass gasification carbon capture, an additional design alternative would be to change the gas treatment section to a pressure swing adsorption (PSA) treatment unit (in place of the Rectisol unit). The PSA would separate the CO_2 and CO from the hydrogen and could then be redirected back to the torrefaction stage. Any CO present would then be combusted to CO_2 in the torrefaction flue gas. Post-combustion carbon capture could then be installed on the combined flue gas stream – however post-combustion capture has lower capture efficiency than pre-combustion capture. The additional amount of CO_2 captured from the torrefaction section would be marginal as the mass flow is only 7% of the gas treatment section CO_2.

Table 5-3 below shows the levelized cost of hydrogen with carbon capture (with base case prices sets for electricity, natural gas, water etc.)

Table 5-3 Carbon Capture details for SMR, ATR and Biomass gasification pathways

	Units	SMR	ATR	Biomass Gasification
Carbon Capture Efficiency	%	95%	97%	95%
CO_2 Capture Annual	ktpa	1166	1180	702
Additional Power Import	MW	53	16	7
Additional Carbon Capture/ Compression Capex	USD (Millions)	$455	$87	$43
Annual cost of Carbon disposal (2023)	USD (Millions)	$12	$12	$7
Levelized cost of Hydrogen				
Without Carbon Capture	(USD/kg H_2)	$1.3	$2.0	$3.7
With Carbon Capture	(USD/kg H_2)	$2.1	$2.1	$3.7
Percentage Increase	%	62%	7%	0%

The addition of post combustion carbon capture on the SMR pathway closes the cost gap between the ATR and SMR technology, with the cost being at $2.1/kg H_2. The cost of carbon dioxide transport and storage is based off National Energy Technology Laboratory (NETL) figures; however this price is not yet established and may vary depending on storage site or use. The below Table 5-4 shows the levelized cost of hydrogen at varying CO_2 storage/transport costs.

Table 5-4 Carbon Dioxide Transport and Storage Cost Sensitivity

	Units	SMR	ATR	Biomass Gasification
CO_2 Transport and Storage of $10/ton	(USD/kg H_2)	$2.1	$2.1	$3.7
CO_2 Transport and Storage of $20/ton	(USD/kg H_2)	$2.3	$2.2	$3.8
CO_2 Transport and Storage of $30/ton	(USD/kg H_2)	$2.4	$2.4	$4.0
CO_2 Transport and Storage of $40/ton	(USD/kg H_2)	$2.5	$2.5	$4.1

5.4.2 Renewable Electricity Application

Another way to lower the CI of each technology pathway is to replace the grid electricity supply source with 100% renewable or zero carbon either through a PPA or construction of a direct wire renewable energy.

The below graph shows a sensitivity scenario where the 2030 renewable PPA electricity price ($25/MWh) is increased to $35/MWh (high demand case) and decreased to $17/MWh (simulating potential direct wire renewable supply). The future pricing of renewable electricity is uncertain as there are currently several factors that impact the price in the U.S.:

- Increasing renewable power capacity coming online (supply increase)
- Increasing in renewable demand from industry and states with renewable procurement targets (demand increase)
- Price of fossil fuel used for electricity generation (coal and natural gas).

Note the below LCOH figures <u>do include</u> the carbon capture applications on SMR, ATR or Biomass Gasification Pathways. Figure does not include federal subsidies for hydrogen production, for 45V and 45Q analysis see Section 6.1.5.

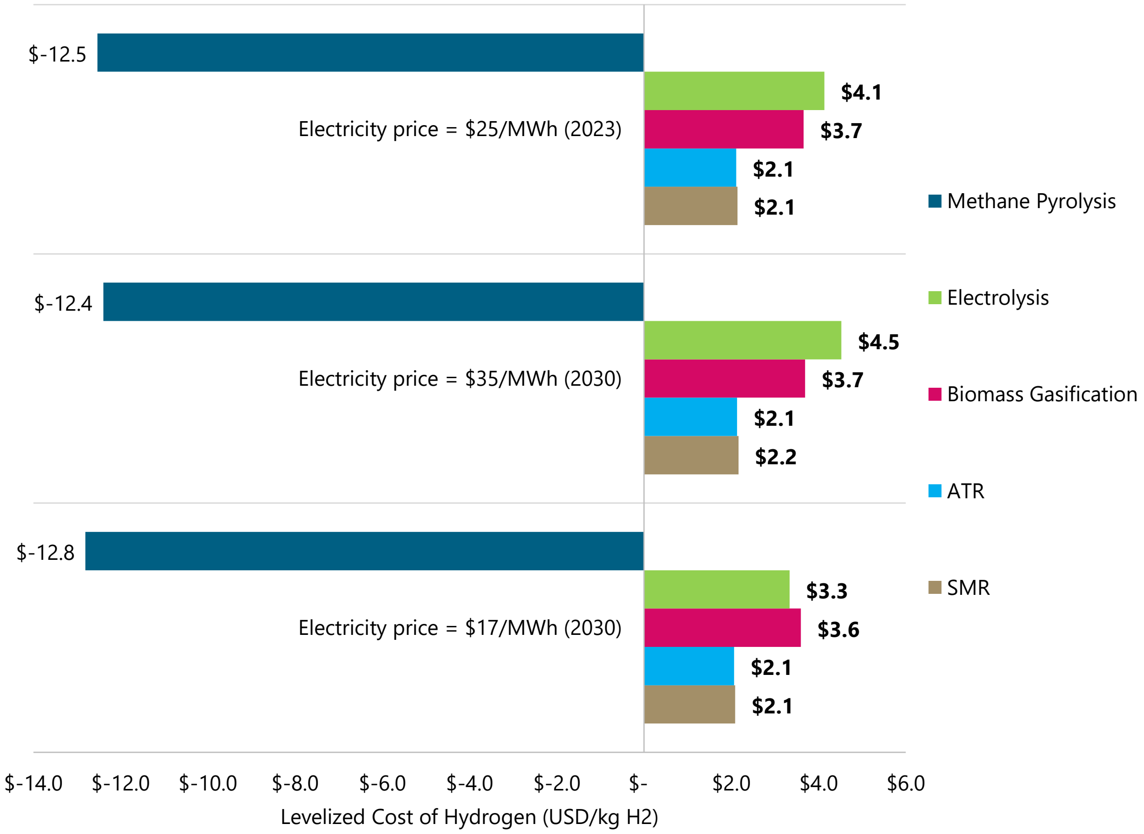

Figure 5-6 Low GHG LCOH Electricity Sensitivity Cases (Including Carbon Capture)

Note the below LCOH figures <u>do not</u> include the carbon capture applications on SMR, ATR or Biomass Gasification Pathways. Figure does not include federal subsidies for hydrogen production, for 45V and 45Q analysis see Section 6.1.5.

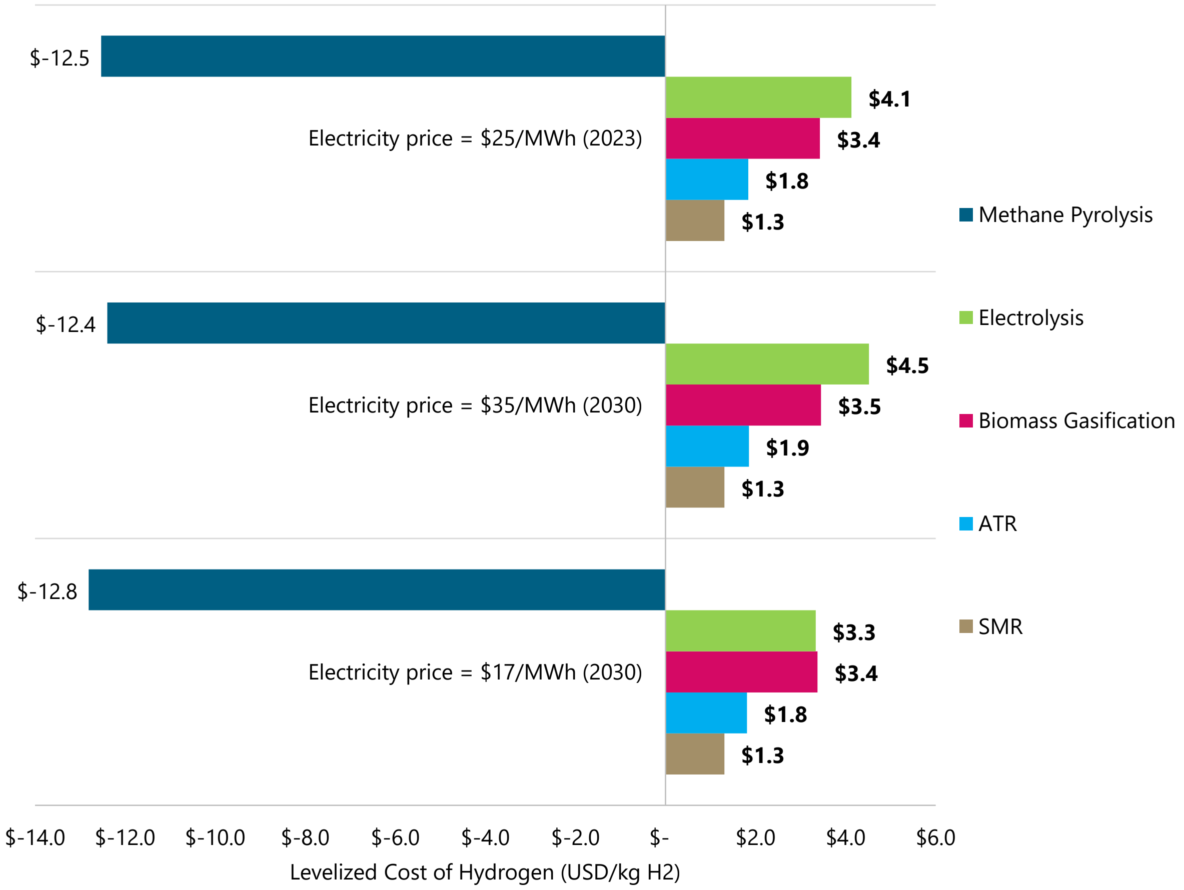

Figure 5-7 Low GHG LCOH Electricity Sensitivity Cases (Excluding Carbon Capture)

6. Environmental Impact and Conclusions

6.1 Hydrogen Production Pathways Comparison

6.1.1 Environmental Impact

The environmental impact of hydrogen production pathways varies depending on various factors, such as feedstock, raw material inputs, production process, co-products, energy source used, process configurations, geography, and others. As the hydrogen economy grows, projects may be required to increasingly consider mitigating direct and indirect environmental impacts throughout their value chains.

In some instances, limited data was available regarding specific environmental impacts (e.g., NO_x, SO_x, PM, etc.) due to the current lack of commercial scale projects utilising the technologies in this study. As such, this section aims to provide a high-level summary of overall environmental considerations of the hydrogen production technologies based on available information and Advisian subject matter expertise. Every hydrogen production technology and pathway will have a specific set of direct and indirect impacts, either intended or unintended, affecting environmental objectives and performance. Individual projects should assess these impacts to determine whether hydrogen production contributes to or harms environmental objectives.

Examples of direct or indirect environmental impacts associated with hydrogen production can include the following:

- CO_2 emissions (discussed under Section 4) and non-CO_2 Emissions to air (NO_x, SO_x, VOC, $PM_{2.5}$, PM_{10}, etc.).
- Upstream life cycle considerations and broader sustainability implications associated with feedstocks (e.g., biomass), upstream manufacturing (e.g., PV production) or raw materials (e.g., mining and processing of energy transition metals).
- Impacts on land use associated with deployment of renewable power.
- Noise, vibration, visual, light, and odour emissions (e.g., combustion air fans, compressors, steam vents, flares, etc.).
- Hydrogen leakage during transportation and storage, or through electrolyser casings (although hydrogen leakage is generally considered to be negligible compared to other environmental impacts).
- Impacts associated with downstream hydrogen use or displacement of other fuels (e.g., natural gas, diesel, coal, etc.).

In addition to the examples above, water sustainability issues have generally been raised as a concern in hydrogen production, and not necessarily solely from the perspective of limited availability. Generally, water demand for hydrogen production ranges based on the technology and process. While it is uncertain how much water methane pyrolysis will require, generally water demand for other technologies is between approximately 7 to 15 kg of water per kg of hydrogen produced.

There are design choices concerning new low-carbon hydrogen production facilities that can significantly impact the environment and the project’s overall water sustainability. Once-through cooling can be attractive in some geographies but actively discouraged in others due to the large volumes of water required. Discharging water above ambient temperature can have environmental impacts, especially in rivers and seawater outfalls near the coast. Whilst desalination can be attractive in water scarce regions, it has its challenges in protecting marine life from intakes and outfalls, brine management, and the GHG emissions related to power supply. Hydrogen producers must understand the trade-offs between using desalination as a water supply solution and energy costs, GHG emissions, and environmental impacts.

As demand for green hydrogen production via electrolysis grows, further emphasis on social perceptions concerning water may need to be considered. This may include perceptions on usage and how communities or others view a new project with water demands. Consideration should be given to local stakeholders' concerns and addressing social perceptions that there could be restrictions on water use or access to water, which a community relies on.

It is also important to consider the scale and context at which the environmental impacts described below should be regarded as relative to fossil-based processes and industries such as oil & gas, refining, coal, or others, as the overall environmental footprint of fossil-based pathways can exceed that of hydrogen. For example, crude oil recovery and diesel refining can use more water than green hydrogen production per unit of energy. In addition, legislation is increasingly being introduced to mitigate the environmental impacts further and encourage producers to consider the broader environmental burdens across their supply chains. Section 2 provides an overview of relevant legislation.

6.1.1.1 Steam Methane Reforming & Autothermal Reforming

Both reforming technologies have similar emissions profiles and potentially similar environmental impacts. External combustion associated with the reformer can be a source of air emissions. N_2O, SO_x, and particulate emissions data are summarised in the GHG emissions balances in Section 3.

If the process is air fired, it will likely generate NO_x from the combustion process. Where SMR or ATR are combined with carbon capture using amine solvents, there may be a higher likelihood of impacts associated with NO_x emissions or fugitive emissions. A possible mitigation for NO_x may include post-combustion NO_x treatment (e.g., simple catalytic or SCR). More recent projects are looking towards oxy-firing, and while experience in this is currently limited, the NO_x formation will be reduced, and carbon capture rates increased.

A study was conducted by the European Environmental Agency on direct and indirect emissions associated with different CCS technologies, which considered emissions such as CO_2, SO_2, NO_X, PM, and NH_3.[44] The study suggested that there are a number of potential environmental impacts and air pollutants generated as part of the CCS life cycle, such as solvent manufacturing, treatment of solvent wastes, drilling CO_2 storage wells, and other fugitive emissions.[44]

A recent study evaluated the environmental impacts of hydrogen production via SMR based on emissions, including impacts on human health and ecosystems.[45] The study assessed emissions of major pollutants from 33 US SMR hydrogen production facilities using data from the GHG reporting program (GHGRP), the US national emissions inventory (NEI), and

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[44] European Environment Agency (2011). Air pollution impacts from carbon capture and storage (CCS). No 14/2011.

[45] Cho, H. H., Strezov, V., & Evans, T. J. (2022). Environmental impact assessment of hydrogen production via steam methane reforming based on emissions data. Energy Reports, 8, 13585-13595.

the toxic release inventory (TRI). A summary of the pollutant data and the US NEI is summarised in Table 6-1. For SMR, the emissions profile is generally dominated by CO_2 and CO, with minimal volumes of other pollutants. It is expected that ATR would generally have a similar emissions profile.

Table 6-1 Emissions of major pollutants from 33 SMR hydrogen production facilities from Cho et at. (2022)

Pollutant (kg/kgH_2)	Average	Minimum	Maximum
CO_2	9.35	4.69	17.31
CH_4	2.36E-04	3.83E-06	3.30E-03
NH_3	2.36E-04	1.54E-07	1.97E-03
CO	0.27	2.10E-06	8.81
NO_x	1.68E-03	1.46E-04	1.43E-02
SO_2	1.00E-04	1.33E-06	3.19E-03
$PM_{2.5}$	4.44E-04	1.35E-06	8.94E-03
PM_{10}	5.35E-04	1.39E-05	8.98E-03
VOC	9.01E-04	3.18E-05	2.36E-02
Lead	5.07E-08	4.86E-10	1.27E-06
Methanol	2.14E-05	8.06E-09	1.15E-04

Metal catalysts are used in SMR and ATR, which can introduce potential upstream or downstream environmental impacts associated with the extraction, processing, and production of these materials, as well as disposal or final disposition. However, there may be opportunities to mitigate these impacts via recycling or reusing catalyst material or sustainable procurement practices.

6.1.2 Methane Pyrolysis

Hydrogen production via methane pyrolysis is considered to be at an early stage of development. Therefore, it isn't easy to fully characterise the environmental impacts associated with this technology based on currently available information.

Methane pyrolysis would likely not utilise a pure methane feedstock, but natural gas composed of various gases. The process must effectively break down these other constituents to prevent the emission of hazardous gases in the hydrogen production process.

Solid carbon is a by-product of the process, introducing potential environmental impacts associated with waste management, disposal, and end uses. Possible mitigations include identifying alternate end uses or markets for the carbon black product, such as used in automobile tires, pigments, additives, etc. Additionally, there may be a growing market for carbon black use in agriculture as a soil enhancer. The carbon black market in the US is expected to grow; however, growth may not be at the scale required to absorb additional production. Sequestration as a solid in a landfill has been considered an alternative because carbon black is non-toxic and not expected to leach or release constituents into the groundwater. Carbon black is not biodegradable, and organic materials that come in contact with it can be adsorbed and are not easily liberated.

6.1.2.1 Gasification

The main outputs associated with hydrogen production via gasification include CO_2 off gas, wastewater, flue gas, vent gas, and ash. Gasification is expected to produce Nox, Sox, and particulate pollutants. The process results in particulate emissions mainly in the size range 0.25-1.0 μm and 1.0-2.5 μm. Technologies for physically removing particulate matter (e.g., ceramic candle filters at high temperatures) can ensure regulatory emission requirements are met. The NAAQS for particulate matter (PM) provides guidance on the requirements in the U.S., but there may also be stricter local legislation in different states or cities. Depending on the feedstock, the syngas generated in the gasification reactor may contain particulates and other contaminants. The volume and content of ash generated as part of the process depends on the type of gasifier.

Similar to other SMRs and ATRs, there is the potential for adverse environmental impacts associated with catalysts used in the water gas shift gas part of gasification facilities

Gasification's wider environmental and sustainability impacts largely depend on feedstock sourcing and associated life cycle impacts. In the case of using woody biomass feedstock, direct and indirect impacts across the entire life cycle should be considered to mitigate potential environmental, commercial, reputational, and societal risks. During their growth or thermochemical conversions, biomass feedstocks can emit GHGs such as CO_2, CH_4, Nox, and Sox. Additionally, impacts to water use, land use, and ecosystems due to growth or harvesting of material, as well as wider resource or socioeconomic implications (e.g., impacts to farmers, reallocation of water resources, impacts to local markets, etc.) should also be considered.

6.1.2.2 Electrolysis

Increasing hydrogen production is expected to increase demand for electrolysers, which require various raw materials such as nickel, platinum, iridium, strontium, and others. The production and utilization of these metals can carry potential direct and indirect environmental impacts, for example:

- Energy consumption
- Land use or loss of agricultural land
- Degradation of biodiversity and ecosystems
- Impacts on Local communities
- Soil and air quality
- Water resources
- Generation of waste during extraction and processing

The extent of raw metal extraction required for a growing green hydrogen economy may be considerable. Environmental impacts associated with mining are more likely to occur locally, while economic benefits may be generated elsewhere. Electrolyser manufacturers and other value chain stakeholders may face pressure to adapt their supply strategy to ensure sustainable development of hydrogen projects requiring electrolysis.

Advances have been made in recent years to increase the integration and partial use of renewable energy in hydrogen production. Environmental impacts of renewable power include the raw materials and the large land area required; however, reduced GHG emissions can partially offset these. For example, hydrogen production using solar photovoltaic electrolysis can introduce environmental impacts associated with photovoltaic panel production and associated processing (e.g., raw materials and wastewater management).[46] There are also questions surrounding additionality.

6.1.3 Other Hydrogen Production Technologies

There are multiple upcoming technologies for hydrogen production, two of which are highlighted below.

Gas Heated Reforming (GHR) is where the reforming takes place in a tubular heat exchanger where the heat for reaction comes from another gas stream typically the reformed gas of an ATR.

There are two variants – parallel offered by KBR and Haldor Topsøe, and series, offered by Johnson Matthey. The parallel variant is less expensive than the series version, but the series version has the advantage of decreased methane slip and therefore can achieve higher carbon capture. GHR has been demonstrated on a semi- commercial scale for over 20 years at the Coogee methanol plant in Australia, which has since been dismantled, thus, there are no current operational GHR units for stand-alone hydrogen production.

Partial Oxidation (POX) is an oxygen-based system with direct firing in a refractory-lined reactor. It is a noncatalytic process that does not consume steam and has no direct CO_2 emissions. Compared with SMR, POX technology saves money by maximising carbon-capture efficiency and simplifying the process line-up, both of which offset the cost of oxygen production. A key advantage of POX over ATR is that the partial oxidation reaction does not require steam as a reactant. Instead, high-pressure steam is generated by using waste heat from the reaction, which can satisfy the steam consumption within the balance-of-plant as well as for export.

With no need for feed gas pre-treatment, POX technology has a far simpler process line-up than ATR and, as a noncatalytic, direct-fired system, it is robust against feed contaminants such as sulphur and can thereby accommodate a large range of natural gas quality.

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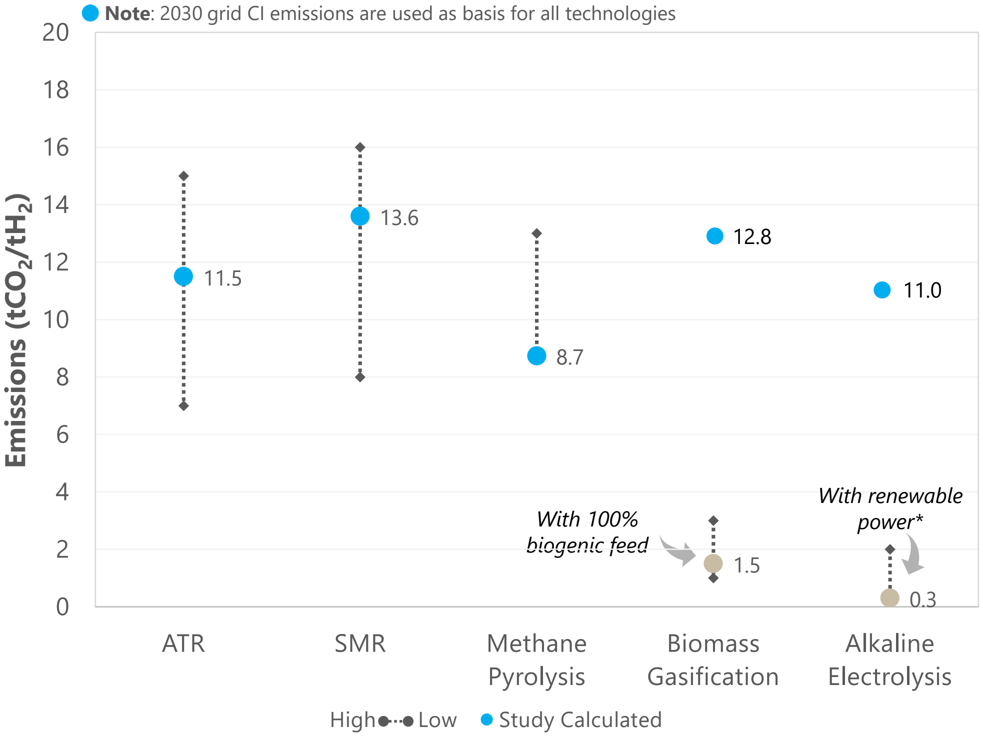
[46] Weidner, T., Tulus, V., & Guillén-Gosálbez, G. (2023). Environmental sustainability assessment of large-scale hydrogen production using prospective life cycle analysis. international journal of hydrogen energy, 48(22), 8310-8327.

6.1.4 Carbon Intensity Review

The carbon intensity of the different hydrogen production technologies considered in this study are shown in Section 4.2. When comparing against literature, it is observed that these are within the high and low ranges of sources.[47,48,49]

The relative carbon intensity of each technology is expected and largely consistent with literature sources[50] in terms of highest and lowest intensities i.e., Methane Pyrolysis comes out as lowest while Gasification is the highest.

The context of underlying assumptions and boundary limits should be kept in consideration when comparing these numbers with other information sources.


● **Note**: 2030 grid CI emissions are used as basis for all technologies

*Renewable Grid CI 0.005 tCO_2/MWh aligned with Evolved Energy ADP 2022

Figure 6-1 Calculated unabated emissions comparison to literature

Note the carbon intensity for the base case is calculated using power from the grid for electrolysis and woodchips (non-biogenic) as a feedstock for gasification. The literature values however quote a decarbonized scenario, thus, low GHG emissions for the two technologies are also highlighted in Figure 6-1 using renewable power for electrolysis and biogenic feedstock for gasification.

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[47] https://www.carbonsolutionsllc.com/hydrogen-lca/

[48] https://www.energy.gov/sites/default/files/2021-09/h2-shot-summit-panel2-methane-pyrolysis.pdf

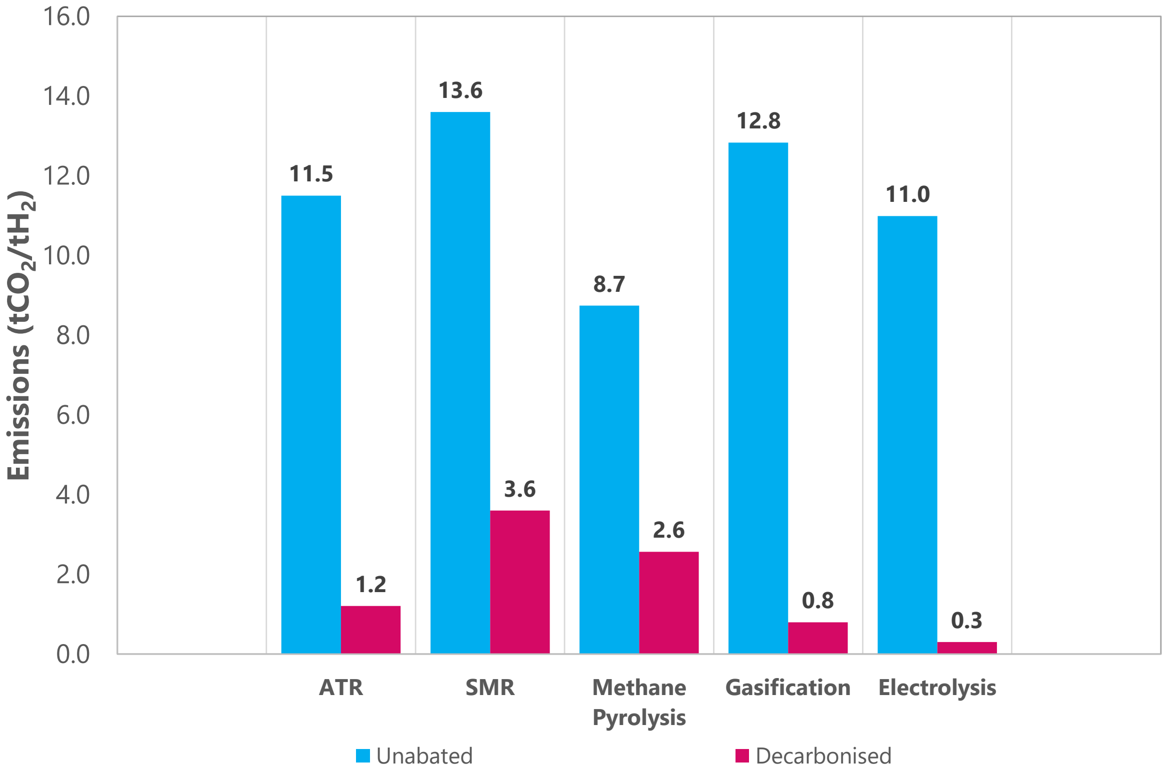
[49] https://www.iea.org/data-and-statistics/charts/comparison-of-the-emissions-intensity-of-different-hydrogen-production-routes-2021

[50] https://www2.gov.bc.ca/assets/gov/business/natural-resource-industries/reports/carbon_intensity_of_hydrogen_production_methods.pdf

SMR comes out at a higher carbon intensity than ATR in the unabated case largely because the trade-off between imported electricity (in the ATR) and natural gas combustion (in the SMR) indicates a lower carbon intensity contribution of the electricity despite the 2030 electrical grid still having a material carbon intensity.

The carbon intensity associated with methane pyrolysis and electrolysis is directly related to the use of electricity from the grid as there are no direct CO_2 emissions from these technologies. As anticipated, using renewable electricity and biogenic feed has a significant impact on the carbon intensities of Electrolysis and Gasification respectively.

As discussed in Section 4.2, the application of decarbonization options significantly reduces the carbon intensity of each technology. Figure 6-2 summarizes the unabated and low GHG carbon intensities for each technology.

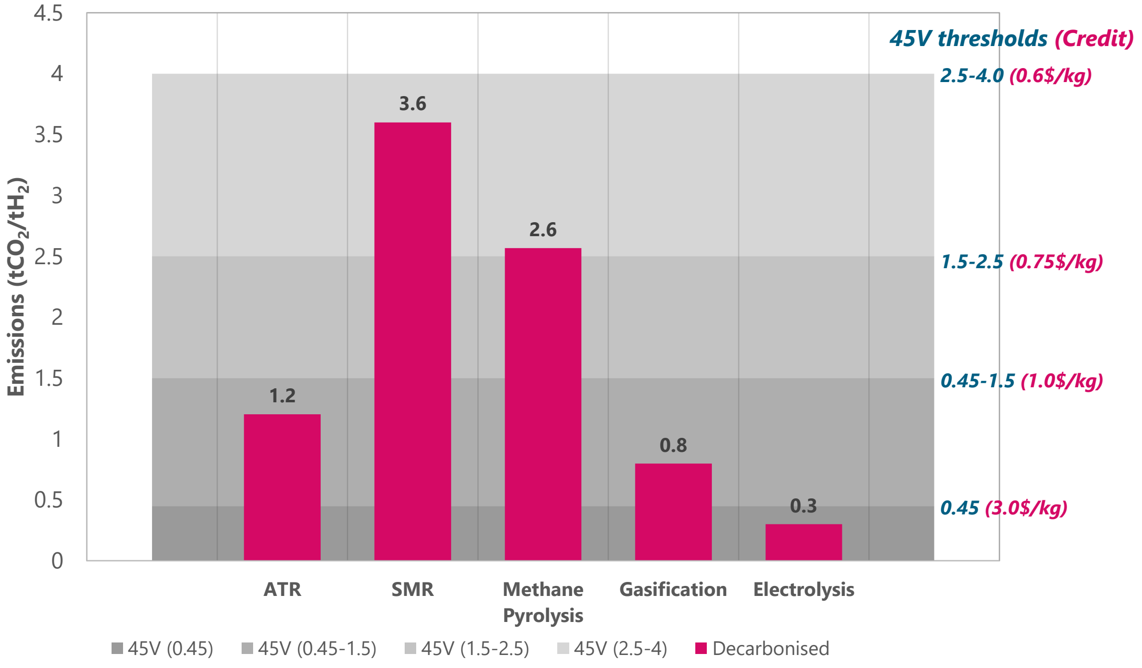


Note: Renewable Grid CI 0.005 tCO_2/MWh aligned with Evolved Energy ADP 2022; 50% feed emissions decarbonisation (ex. Gate)

Figure 6-2 Technology comparison of unabated and decarbonized emissions

Electrolysis comes out as the lowest post abatement as it has the highest electricity usage and is therefore most influenced by switching to a renewable source. Note that all technologies benefit from this to some degree. Methane pyrolysis is also strongly dependent on electricity; however, it does not benefit as much from switching to a renewable source. This is because methane pyrolysis uses natural gas as a feed, and it has a higher associated feed carbon intensity (linked to preparation and transport) than water which is the feed for electrolysis.

Carbon capture plays a significant role in the abatement of ATR, SMR and gasification as these technologies have direct CO_2 emissions. Using 100% biogenic feed (in the case of gasification) plays a major impact on the carbon intensity.



**Renewable Grid CI 0.005 tCO_2/MWh aligned with Evolved Energy ADP 2022; 50% feed emissions decarbonisation (ex. Gate)*

Figure 6-3 Technology comparison of decarbonized emissions with 45V

All the low GHG hydrogen production technologies qualify for varying degrees of tax credits under the 45V IRA thresholds as summarized in Figure 6-3. However, only electrolysis qualifies for the maximum credit of $3/kg. The total savings for the different technologies will also depend on hydrogen yield, therefore, maximum credits shown here do not translate to highest possible savings from all subsidy options as further explored in Section 6.1.4.

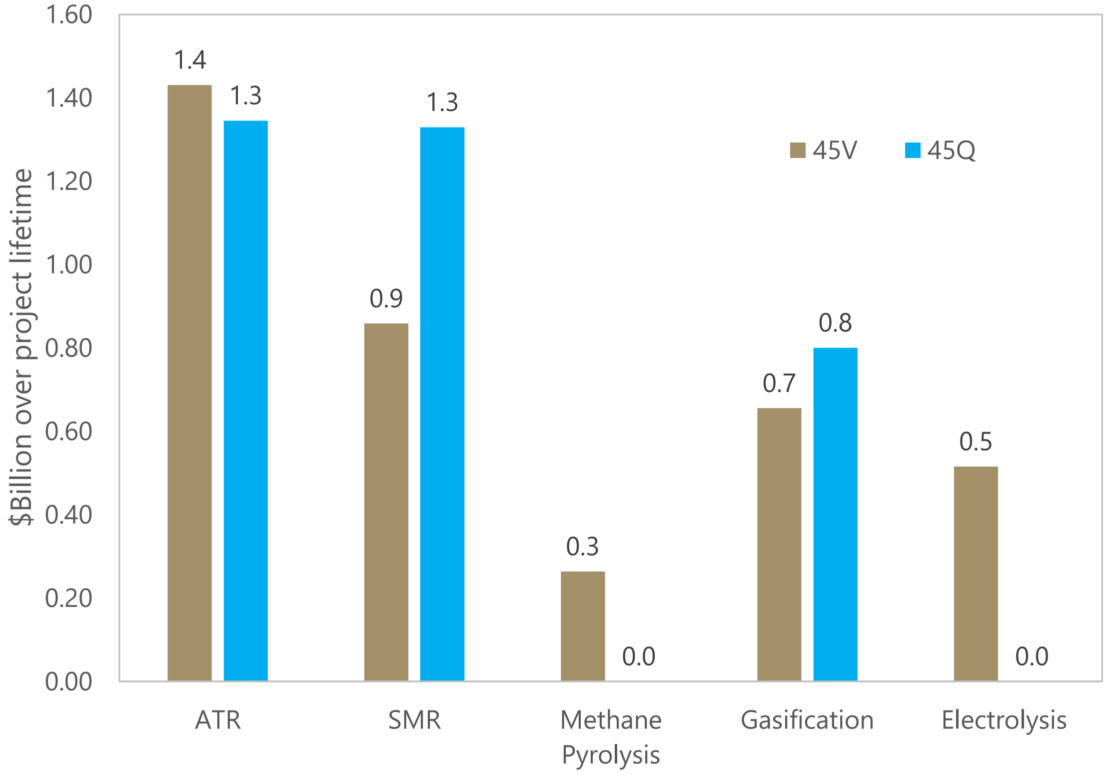
6.1.5 Tax Credits Evaluation

All three technologies that use carbon capture to abate emissions are eligible for 45Q credits at a base credit of $17/$tCO_2$ and bonus credit up to $85/$tCO_2$. However, as discussed in Section 2, the IRC specifically disallows the combination of the new 45V hydrogen production tax credit with the carbon oxide sequestration tax credit provided under section 45Q for the taxable year or any prior taxable year.

The practical application of 45V and Q can be described as follows:

- The period for which the incentives can be claimed is for 10 years under 45V and 12 years under 45Q
- For tax liable companies, either incentive can be claimed as a direct payment for first 5 years, and thereafter to off-set tax for the next 5-7 years.

On application of these two principles, the total tax savings for the 25-year life of the projects for each technology is shown in Figure 6-4.



Note that in the above figure, comparing the savings of each technology against each other is not meaningful as the scale of hydrogen production for each is different e.g., electrolysis H2 production is 43tpd while ATR is 358tpd.

Figure 6-4 Total tax credit savings over project lifetime

The key observation from this analysis is that for those technologies that are eligible for both credits, 45Q represents better savings over 45V for the SMR and gasification, while for ATR, the reverse is true driven by SMR qualifying for a lower 45V tax credit than ATR ($0.6/kg vs $1.0/kg respectively) and a higher hydrogen to CO_2 ratio for reforming technologies in comparison to gasification technology.

The analysis indicates that the of reforming technologies (SMR and ATR) remain competitive against electrolysis even though they qualify for a lower tier value credit.

It is important to note that this analysis is based on a 2030 renewable electricity price of $27.90/MWh against which the LCOH of Electrolysis is particularly sensitive as shown in Section 5.4.2.

Gasification remains the technology with the highest LCOH while methane pyrolysis is the lowest driven by the assumed carbon black price.

The tax impacts (from year 6 onwards) need to be understood to further evaluate the impact of total credit savings on the LCOH. Since the levelised cost does not consider the cash flow of a project, tax credit breaks cannot be directly deducted from the LCOH.

Appendix A.
Technology on a Page

Submitted as a separate file.

Appendix B.
Conversion Tables

Table B-1 Hydrogen Energy Flow

	Yearly		Daily		Hourly	
Energy Flow (LHV)	GWh	4262	MWh	11676	MWh	486
Energy Flow (HHV)	GWh	5037	MWh	11676	MWh	575
Energy Flow (LHV)					MMBTUh	1660
Energy Flow (HHV)					MMBTUh	1962

Table B-2 Hydrogen Unit Conversion

MW	lb/hr	kg/hr	tpd (Metric)	SCFM[51]	Nm3/hr[52]
1	39.7	18	0.4	127	200
10	397	180	4.3	1,270	2,000
50	1,985	900	21.5	6,350	10,000
100	3,970	1,800	4.3	12,700	20,000

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[51] Standard Cubic Foot (SCF) measured at 1 atm, 70 F

[52] Normal Cubic Meter measured at 1 atm, 0 C